PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2013

VIA ELECTRONIC FILING
AND COURIER DELIVERY

Public Utility Commission Oregon
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

Attn: Filing Center

RE: Advice No. 13-006
Docket UE 263 – PacifiCorp's Request for General Rate Revision

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing an original and 30 copies of the following proposed tariff pages associated with the Company's Tariff P.U.C. OR No. 36, applicable to electric service in the State of Oregon, together with the Executive Summary and supporting direct testimony and exhibits. The tariffs reflect an effective date of March 31, 2013. Provided on the enclosed CDs (three) are electronic versions of the testimony, exhibits and workpapers, in their original format when available.

Second Revision of Sheet No.4	Schedule 4	Residential Service Delivery Service
Second Revision of Sheet No.5	Schedule 5	Separately Metered Electric Vehicle Service for Residential Consumers Delivery Service
Third Revision of Sheet No.15-1	Schedule 15	Outdoor Area Lighting Service – No New Service Delivery Service
Second Revision of Sheet No.23-1	Schedule 23	General Service – Small Nonresidential Delivery Service
Second Revision of Sheet No.28-1	Schedule 28	General Service Large Nonresidential 31KW to 200 KW Delivery Service
Second Revision of Sheet No.30-1	Schedule 30	General Service Large Nonresidential 201 KW to 999 KW Delivery Service
Second Revision of Sheet No.41-1	Schedule 41	Agricultural Pumping Service Delivery Service.
Second Revision of Sheet No.47-1	Schedule 47	Large General Service Partial Requirements 1,000 KW and Over Delivery Service
Second Revision of Sheet No.48-1	Schedule 48	Large General Service 1,000 KW and Over Delivery Service
Second Revision of Sheet No.50-1	Schedule 50	Mercury Vapor Street Lighting Service No New Service Delivery Service
Second Revision of Sheet No.51-1	Schedule 51	Street Lighting Service Company – Owned System Delivery Service
Third Revision of Sheet No.52-1	Schedule 52	Street Lighting Service Company –

		Owned System No New Service Delivery Service
Second Revision of Sheet No.53-1	Schedule 53	Street Lighting Service Consumer – Owned System Delivery Service
Third Revision of Sheet No.54-1	Schedule 54	Recreational Field Lighting – Restricted Delivery Service
Third Revision of Sheet No.55-1	Schedule 55	Led Pilot Street Lighting Service Company – Owned System Delivery Service
Second Revision of Sheet No.76R-1	Schedule 76R	Large General Service – Partial Requirements Service Economic Replacement Power Rider Delivery Service
Third Revision of Sheet No.200-1	Schedule 200	Base Supply Service
Second Revision of Sheet No.200-2	Schedule 200	Base Supply Service
Second Revision of Sheet No.200-3	Schedule 200	Base Supply Service
Third Revision of Sheet No.299	Schedule 299	Rate Mitigation Adjustment
Second Revision of Sheet No.723-1	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
Second Revision of Sheet No.728-1	Schedule 728	General Service Large Nonresidential 31 KW to 200 KW Direct Access Delivery Service
Second Revision of Sheet No.730-1	Schedule 730	General Service Large Nonresidential 201 KW to 999 KW Direct Access Delivery Service
Second Revision of Sheet No.741-1	Schedule 741	Agricultural Pumping Service Direct Access Delivery Service
Second Revision of Sheet No.747-1	Schedule 747	Large General Service Partial Requirements 1,000 KW and Over Direct Access Delivery Service
Second Revision of Sheet No.748-1	Schedule 748	Large General Service 1,000 KW and Over Direct Access Delivery Service
Second Revision of Sheet No.751-1	Schedule 751	Street Lighting Service Company-Owned System Direct Access Delivery Service
Second Revision of Sheet No.752	Schedule 752	Street lighting Service Company-Owned System – No New Service Direct Access Delivery Service
Second Revision of Sheet No.753-1	Schedule 753	Street Lighting Service Consumer-Owned System Direct Access Delivery Service
Second Revision of Sheet No.754	Schedule 754	Recreational Field Lighting– Restricted Direct Access Delivery Service

Second Revision of Sheet No.776R-1	Schedule 776R	Large General Service-Partial Requirements Service-Economic Replacement Service Rider Direct Access Delivery Service

Copies of the Company's responses to the Standard Data Requests are provided under separate cover.

Please address all communications related to this filing to:

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Additionally, PacifiCorp respectfully requests that all data requests in this docket be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to Bryce Dalley, Director, Regulatory Affairs, at (503) 813-6389.

A copy of this filing has been served on all parties to PacifiCorp's last general rate case, docket UE 246, as indicated on the attached certificate of service. Confidential material in support of the filing has been provided to parties under the protective order issued February 27, 2013 (Order No. 13-061).

Sincerely,

William R. Griffith /RBD

William R. Griffith
Vice President, Regulation

Enclosures

cc: UE 246 Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 263

In the Matter of PACIFICORP d/b/a PACIFIC POWER Request for a General Rate Revision.	**PACIFICORP'S EXECUTIVE SUMMARY**

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (the Company) is filing this request for a general rate revision under ORS 757.205 and ORS 757.220 to revise its schedules of rates and charges for electric service in Oregon, effective January 1, 2014. The revised rates reflect an Oregon-allocated revenue requirement increase of $56.0 million, or 4.6 percent. If the tariff rider for the Mona-to-Oquirrh transmission project approved by the Commission in the Company's 2012 general rate case (2012 Rate Case), becomes effective while this proceeding is pending, the overall price increase in this case would be reduced by approximately $11.4 million, to $44.6 million or 3.7 percent.[1] The revised rates produce revenues necessary to sustain a stable, reliable, and low-cost power supply, while preserving the Company's ability to attract capital for future investments.

The Company has also included in this filing the analysis and evidence demonstrating that the Lake Side 2 natural gas fired generating plant (Lake Side 2) is a prudent investment that will be used and useful during calendar year 2014, which is the test period for this proceeding. Because Lake Side 2 is not projected to go into service until the second quarter

[1] As discussed in the testimony of Ms. Joelle R. Steward, the increase to net rates is $56.2 million, or 4.7 percent ($44.8 million or 3.7 percent if the Mona-to-Oquirrh separate tariff rider becomes effective while this proceeding is pending), as a result of resetting the Rate Mitigation Adjustment to reflect forecast customer loads by rate schedule.

of 2014, the Company is proposing to delay implementation of the revenue requirement increase associated with the investment ($22.7 million on an Oregon-allocated basis, or 1.8 percent) until it is serving customers. The Company files this executive summary and the attached Exhibit A in compliance with OAR 860-022-0019.

PacifiCorp is an electric company and public utility in Oregon within the meaning of ORS 757.005. The Public Utility Commission of Oregon (Commission) has jurisdiction over the prices and terms of PacifiCorp's electric service to its Oregon retail customers. The Company provides electric service to approximately 580,000 retail customers in Oregon and approximately 1.7 million total retail customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is Portland, Oregon.

The Company requests that communications regarding this filing be addressed to:

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Additionally, PacifiCorp respectfully requests that all data requests in this docket be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to Bryce Dalley at (503) 813-6389.

II. CASE SUMMARY

This case is based upon a historical base period of 12 months ended June 2012, with normalizing and pro forma adjustments to calculate a calendar year 2014 future test period. The new rates will become effective no later than January 1, 2014, assuming application of the full nine-month statutory suspension period to the 30-day effective date now contained in the tariffs. Thus, the rate effective period closely aligns with the test period in this case.

A. Return on Equity

PacifiCorp is currently forecast to earn a return on equity (ROE) in Oregon of 7.9 percent on a normalized basis for the test period. Because the Company is filing this case less than three months after the order was issued in the 2012 Rate Case, the Company is not requesting to change its authorized return on rate base, ROE, or capital structure in this case.[2] The currently approved 9.8 percent ROE is necessary to maintain the financial integrity of the Company, while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impacts.

The Company's approach in this case is consistent with the Commission's actions in the Company's 2010 general rate case, docket UE 217 (2010 Rate Case). On January 26, 2010, the Commission determined the Company's ROE, ROR, and capital structure in docket UE 210 (the Company's 2009 general rate case). On March 1, 2010, the Company filed its 2010 Rate Case, including a request to increase ROE. In a prehearing conference report issued by the Commission in the 2010 Rate Case on March 18, 2010, the Commission stated:

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[2] The parties to the partial stipulation in the 2012 Rate Case agreed to an overall rate of return (ROR) of 7.655 percent and a 9.8 percent ROE for Oregon regulatory purposes. The stipulation was approved by the Commission in Order No. 12-493 on December 20, 2012.

> [B]ecause Pacific Power's last rate of return (which included an ROE component) was approved only a few months before the rate filing in this docket, the Commission will be looking for evidence of a material change in the markets, a change in circumstances, or some other good cause before it will be inclined to change the company's existing 10.125 percent ROE.

If other parties to this proceeding contest the Company's capital structure or cost of capital, the Company will respond with comprehensive analysis in its reply filing.

B. Cost Drivers

1. Revised Depreciation Rates

The Company's need for this rate increase is driven primarily by the impact associated with the revised depreciation rates proposed by the Company in docket UM 1647. The Company filed its application for authority to implement revised depreciation rates on January 31, 2013. As part of that filing, the Company requested authority to implement the revised depreciation rates in its accounting system on January 1, 2014, which coincides with the beginning of the rate effective period in this proceeding.

2. New System Investments

The Company continues to make new investments in the system required to provide safe, adequate, and reliable service to customers and to comply with regulatory mandates. This case includes investments in all facets of the system—including transmission, generation, and distribution—to bolster reliability and improve power delivery. For example, this filing includes the addition of a fish collector system at the Company's Lewis River hydroelectric project that is required to comply with the license requirements of the Federal Energy Regulatory Commission. This filing also includes transmission infrastructure investments made to comply with mandatory system reliability and performance requirements, as well as investment in two-way radio equipment required to comply with

Federal Communications Commission narrowband rules.

In addition, this filing includes a turbine upgrade project at Unit 2 of the Jim Bridger generating plant. The upgraded turbine is expected to produce 12 megawatts of additional generation with no increase in fuel input or emissions at full load. Finally, this filing includes a proposal for a separate tariff rider for the Lake Side 2 generating plant, discussed in more detail below.

3. Prepaid Pension Asset

Consistent with the Company's position in the Commission's investigation into prepaid pensions in docket UM 1633, the Company is proposing to include PacifiCorp's net prepaid pension and accrued other post-retirement liability balances in rate base. The outcome of the Commission investigation may require modifications to the Company's proposal in this proceeding.

C. Lake Side 2 Generating Plant

To mitigate the rate impacts on customers, the Company included plant in service through December 31, 2013, rather than through the end of the test period (December 31, 2014). The one exception is the Lake Side 2 generating plant. Lake Side 2 is currently expected to go into service in the second quarter of 2014, which is during the test period. Lake Side 2 is located on a 63.6 acre site in Vineyard, Utah, at the site of the Company's existing Lake Side generating facility. Lake Side 2 consists of a natural gas-fired combined-cycle plant with a capacity of 638 MW. The electrical energy generated by Lake Side 2 will be delivered to a new 345 kV point of interconnection substation (Steel Mill) where it will tie into the PacifiCorp transmission system. To begin recovery of the investment concurrent with the provision of service to customers, the Company is requesting approval to make an advice filing for a separate tariff rider to recover the investment when it goes into service in the second quarter of the test period. The Oregon-allocated revenue requirement associated with this project is approximately $22.7 million.

D. Mitigating Factors

In light of the current economic climate, PacifiCorp is keenly aware of the financial pressures faced by its customers. The Company has therefore taken several steps to mitigate the rate increase request.

First, the Company continues to aggressively and proactively control operations and maintenance (O&M) expense, the Company's filing includes a normalizing adjustment to reduce Oregon O&M expense by approximately $4.0 million. Second, the Company has prudently controlled increases in labor costs, particularly benefit costs. Although health care costs have continued to rise at a steep rate, the Company has made adjustments to cost sharing and plan design to control costs and align market practices. Finally, as discussed above, the Company is not proposing changes to the capital structure or cost of capital approved by the Commission in the 2012 Rate Case.

III. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of 12 witnesses:

Richard Patrick "Pat" Reiten, President, Pacific Power, provides the Company's policy testimony.

Stefan A. Bird, Senior Vice President, Commercial and Trading, discusses the Lake Side 2 natural gas-fired generating plant.

Mark R. Tallman, Vice President of Renewable Resources, discusses an addition at the Lewis River hydroelectric project required to comply with the license issued by FERC.

Dana M. Ralston, Vice President of Thermal Generation, provides information supporting the prudence of a turbine upgrade project at Jim Bridger Unit 2.

Richard A. Vail, Vice President of Transmission, describes mandatory transmission system reliability and performance requirements and provides information on capital investments in the Company's transmission system.

Robert A. Ward, Manager, Narrowband Compliance, describes the Company's narrowband compliance program.

Kelcey A. Brown, Regulatory Manager, Commercial and Trading, presents the load forecasting methodologies used in this case.

Erich D. Wilson, Director, Human Resources, presents an overview of compensation and incentive plans and supports the costs related to these areas included in the test period.

Douglas K. Stuver, Senior Vice President and Chief Financial Officer, addresses the Company's treatment of costs related to pensions and other post-retirement benefits.

Gary W. Tawwater, Manager, Revenue Requirement, presents the Company's overall revenue requirement using the 2010 Protocol inter-jurisdictional allocation methodology.

C. Craig Paice, Regulatory Specialist, Cost of Service and Pricing, presents the Company's cost of service study.

Joelle R. Steward, Director, Pricing, Cost of Service and Regulatory Operations, presents the Company's proposed allocation of the proposed price increase across rate schedules and the proposed changes in rate design for the affected rate schedules.

IV. CONCLUSION

The Company requests that the Commission issue an order approving the proposed rate changes and tariffs described above.

Respectfully submitted March 1, 2013.

Sarah K. Wallace
Senior Counsel

Etta Lockey
Associate Counsel

PacifiCorp d/b/a Pacific Power

Exhibit A
Summary of Requested Electric General Rate Increase
Oregon Allocated
Filed March 1, 2013

(A)	Total revenues collected under proposed rates:		$901,056,204
(B)	Revenue change requested:		
	Total:		$55,986,989
	Net of credits from federal agencies:		$55,986,989
(C)	Percentage change in revenues requested:		
	Total %:		4.6%
	Net of credits from federal agencies:		4.6%
(D)	Test period:		Calendar year 2014
(E)	Requested return on capital:		7.655%
	Requested return on equity:		9.8%
(F)	Rate base proposed in filing:		$3,384,540,086
(G)	Results of operation:		
	Utility operating income, before proposed change:		$225,375,688
	Utility operating income, after proposed change:		$259,098,491
(H)	Effect of rate change on each customer class:	Base Change	Net Change[1]
	• Residential:	3.9%	2.9%
	• Small General Service (Schedule 23):	5.1%	4.1%
	• General Service 31-200 kW (Schedule 28):	2.9%	1.7%
	• General Service 201-999 kW (Schedule 30):	6.4%	5.2%
	• Large General Service >= 1,000 kW (Schedule 48):	7.4%	6.5%
	• Agriculture Pumping Service (Schedule 41):	0.8%	3.7%
	• Street lighting:	9.2%	6.5%
(I)	Information Required by Utility Staff General Rate Case Data Request Form A:		Provided under separate cover

[1] Net Change reflects the net impact to customers on January 1, 2014, of the proposed price change including resetting Schedule 299, the Rate Mitigation Adjustment. It also includes the net impact to customers following the effect of a separate tariff rider authorized in docket UE 246 which is expected to go into effect in 2013. Including these adjustments, a net increase of $44.8 million, or 3.7 percent overall, is proposed to take effect on January 1, 2014.

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UE 246, on the date indicated below by email, addressed to said parties at his or her last-known address(es) indicated below.

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DATED: March 1, 2013

Carrie Meyer
Supervisor, Regulatory Operations

Docket No. UE 263
Exhibit PAC/100
Witness: Richard P. Reiten

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Richard P. Reiten

March 2013

DIRECT TESTIMONY OF RICHARD P. REITEN

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Richard Patrick "Pat" Reiten. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is President and Chief Executive Officer (CEO) of Pacific Power.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Bachelor's degree in political science with an emphasis in economics from the University of Washington and completed executive training at the Wharton School of Business, University of Pennsylvania. Before joining PacifiCorp in September 2006, I was president and CEO of PNGC Power, an energy cooperative located in Portland, Oregon, that provides power management services to electric distribution utilities serving parts of seven western states. I was appointed to that position in May 2002. I joined PNGC Power in 1993, advancing through positions of increasing responsibility. Before PNGC Power, I served as an aide to U.S. Senator Mark O. Hatfield, handling issues associated with the U.S. Senate Energy and Natural Resources Committee. I also was an official in several different capacities at the U.S. Department of Interior, including serving as acting deputy director of the U.S. Bureau of Land Management.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony provides an overview of the Company's request for an increase in its base electric prices, describes the major factors driving the need for the price increase, and discusses the steps taken by the Company to mitigate the increase. My testimony also introduces the other witnesses providing testimony on behalf of the Company.

Q. Please provide a brief introduction to PacifiCorp.

A. PacifiCorp is a regulated electric utility company comprised of three business units: Pacific Power, Rocky Mountain Power, and PacifiCorp Energy. Pacific Power, headquartered in Portland, Oregon, serves customers in Oregon, Washington, and California. Rocky Mountain Power, headquartered in Salt Lake City, Utah, serves customers in Utah, Wyoming, and Idaho. PacifiCorp Energy, containing the electric generation, commercial, energy trading, and coal mining operations of the Company, is also headquartered in Salt Lake City.

In 2006, PacifiCorp was acquired by MidAmerican Energy Holdings Company. Today, PacifiCorp serves more than 1.7 million customers across 136,000 square miles of service territory in six states. In Oregon, the Company proudly serves approximately 587,000 retail customers. Maps of the Company's service territories are provided in Exhibit PAC/101.

SUMMARY OF PACIFICORP'S PRICE INCREASE REQUEST

Q. Please summarize the Company's price increase request.

A. The Company is requesting an increase to its base electric prices in Oregon. Based on the evidence provided in the direct testimony of Mr. Gary W. Tawwater, the Company will earn a return on equity (ROE) in Oregon of 7.9 percent on a normalized basis for the test period. An overall price increase of $56.0 million or 4.6 percent is required to produce the 9.8 percent ROE approved by the Public

Utility Commission of Oregon (Commission) in docket UE 246 (2012 Rate Case).[1] As discussed by Ms. Joelle R. Steward, if the Transmission Investment Adjustment for the Mona-to-Oquirrh transmission project approved by the Commission in the 2012 Rate Case becomes effective while this proceeding is pending, the overall price increase in this case would be reduced by approximately $11.4 million, to $44.6 million or 3.7 percent.[2]

The Company is also including in this filing the analysis and evidence that demonstrates that the Lake Side 2 natural gas-fired generating plant (Lake Side 2) is a prudent investment that will be used and useful during calendar year 2014, which is the test period for this proceeding. The testimony of Mr. Stefan A. Bird describes the Lake Side 2 investment in further detail.

Because Lake Side 2 is not projected to be in service until the second quarter of 2014, the Company is proposing to delay implementation of the revenue requirement increase related to Lake Side 2 ($22.7 million or 1.8 percent on an Oregon-allocated basis) until it is serving customers. The testimony of Ms. Steward describes and provides an illustrative tariff that would be used to implement the tariff rider to recover the investment. The proposed separate tariff rider for Lake Side 2 is consistent with the separate tariff rider for the Mona-to-Oquirrh transmission project proposed by the Company and approved by the Commission in the 2012 Rate Case.

[1] The parties to the partial stipulation in the 2012 Rate Case agreed to an overall rate of return (ROR) of 7.655 percent and a 9.8 percent ROE for Oregon regulatory purposes. The stipulation was approved by the Commission in Order No. 12-493 on December 20, 2012.

[2] As discussed in the testimony of Ms. Steward, the increase to net rates is $56.2 million, or 4.7 percent ($44.8 million or 3.7 percent if the Mona-to-Oquirrh separate tariff rider becomes effective while this proceeding is pending), as a result of resetting the Rate Mitigation Adjustment to reflect forecast customer loads by rate schedule.

Q. What is the test period in this case?

A. As described in the testimony of Mr. Tawwater, the test year for this filing is the 12 months ending December 31, 2014.

Q. What is the primary factor driving the need for a price increase?

A. The primary factor driving the price increase in this case is the impact associated with the revised depreciation rates proposed by the Company in docket UM 1647. The Company filed its application for authority to implement revised depreciation rates on January 31, 2013. As part of that filing, the Company requested authority to implement the revised depreciation rates in its accounting system on January 1, 2014, which coincides with the beginning of the rate effective period in this proceeding. The revenue requirement impact associated with the implementation of the revised depreciation rates is reflected in the direct testimony and exhibits of Mr. Tawwater.

Q. What are the other drivers of the revenue requirement in this filing?

A. As described in the testimony of Mr. Tawwater, the Company is continuing to make significant investments to serve its customers. This case includes investments in all facets of the system, including transmission, generation, and distribution investment, which will help bolster reliability, improve power delivery, and comply with regulatory mandates.

In addition to Lake Side 2, this filing includes a turbine upgrade project at Unit 2 of the Jim Bridger generating plant. The upgraded turbine is expected to produce 12 megawatts of additional generation with no increase in fuel input or emissions at full load. This project is described in the direct testimony of Mr. Dana M. Ralston.

This filing also includes an addition to the Company's hydro generation plant at the Lewis River hydroelectric project that is required to comply with the license issued by the Federal Energy Regulatory Commission (FERC). This project is described in the direct testimony of Mr. Mark R. Tallman.

The direct testimony of Mr. Richard A. Vail describes transmission infrastructure investments made to comply with mandatory system reliability and performance requirements. Mr. Robert A. Ward's direct testimony discusses two-way radio investments necessary to comply with Federal Communications Commission narrowband rules that took effect on January 1, 2013.

Q. Is the Company making any other proposals in this docket?

A. Yes. As discussed in the testimony of Mr. Douglas K. Stuver, the Company is proposing to include PacifiCorp's net prepaid pension and accrued other post-retirement liability balances in rate base. Currently, the Commission has an open investigation into the treatment of pension costs in utility rates (docket UM 1633). The outcome of that investigation may require modifications to the Company's proposal in this proceeding.

Q. Are increases associated with net power costs part of the increase requested in this case?

A. No. Concurrent with this case, the Company is filing a separate Transition Adjustment Mechanism (TAM) to address changes in the Company's net power costs. The TAM rate changes related to 2014 net power costs will also have a January 1, 2014 effective date.

Q. What steps has the Company taken to mitigate cost increases in the current business environment?

A. The Company has taken several steps to mitigate the price increase. First, the Company reduced operations and maintenance (O&M) expenses in this case through its continuing efforts to operate more efficiently. As discussed in the testimony of Mr. Tawwater, these efforts reduce Oregon O&M expenses by approximately $4.0 million.

Second, Mr. Erich D. Wilson discusses how the Company has prudently contained increases to labor expenses and, in particular, has kept increases in benefit costs at a reasonable level that reflect the economic conditions and market. Health care costs have also continued to rise at a steep rate, and the Company has made adjustments to cost sharing and plan design to control costs and align with market practices.

In addition, in this filing the Company is not proposing changes to the capital structure or cost of capital approved by the Commission in the 2012 Rate Case. Because this filing is being made less than three months from the December 20, 2012 Commission order in that case, the Company's Oregon revenue requirement calculations use the current authorized ROR of 7.655 percent and an ROE of 9.8 percent. Accordingly, the Company is not filing direct testimony or exhibits on these issues. If other parties to this proceeding contest the Company's capital structure or ROE, the Company will respond with a comprehensive cost of capital analysis in its reply filing.

INTRODUCTION OF WITNESSES

Q. Please list the Company witnesses in this case and provide a brief description of their testimonies.

A. **Stefan A. Bird**, Senior Vice President, Commercial and Trading, discusses the Lake Side 2 natural gas-fired generating plant.

Mark R. Tallman, Vice President of Renewable Resources, discusses an addition at the Lewis River hydroelectric project required to comply with the license issued by FERC.

Dana M. Ralston, Vice President of Thermal Generation, provides information supporting the prudence of a turbine upgrade project at Jim Bridger Unit 2.

Richard A. Vail, Vice President of Transmission, describes mandatory transmission system reliability and performance requirements and provides information on capital investments in the Company's transmission system.

Robert A. Ward, Manager, Narrowband Compliance, describes the Company's narrowband compliance program.

Kelcey A. Brown, Regulatory Manager, Commercial and Trading, presents the load forecasting methodologies used in this case.

Erich D. Wilson, Director, Human Resources, presents an overview of compensation and incentive plans and supports the costs related to these areas included in the test period.

Douglas K. Stuver, Senior Vice President and Chief Financial Officer, addresses the Company's treatment of costs related to pensions and other post-retirement benefits.

Gary W. Tawwater, Manager, Revenue Requirement, presents the Company's overall revenue requirement using the 2010 Protocol inter-jurisdictional allocation methodology.

C. Craig Paice, Regulatory Specialist, Cost of Service and Pricing, presents the Company's cost of service study.

Joelle R. Steward, Director, Pricing, Cost of Service and Regulatory Operations, presents the Company's proposed allocation of the proposed price increase across rate schedules and the proposed changes in rate design for the affected rate schedules.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/101
Witness: Richard P. Reiten

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

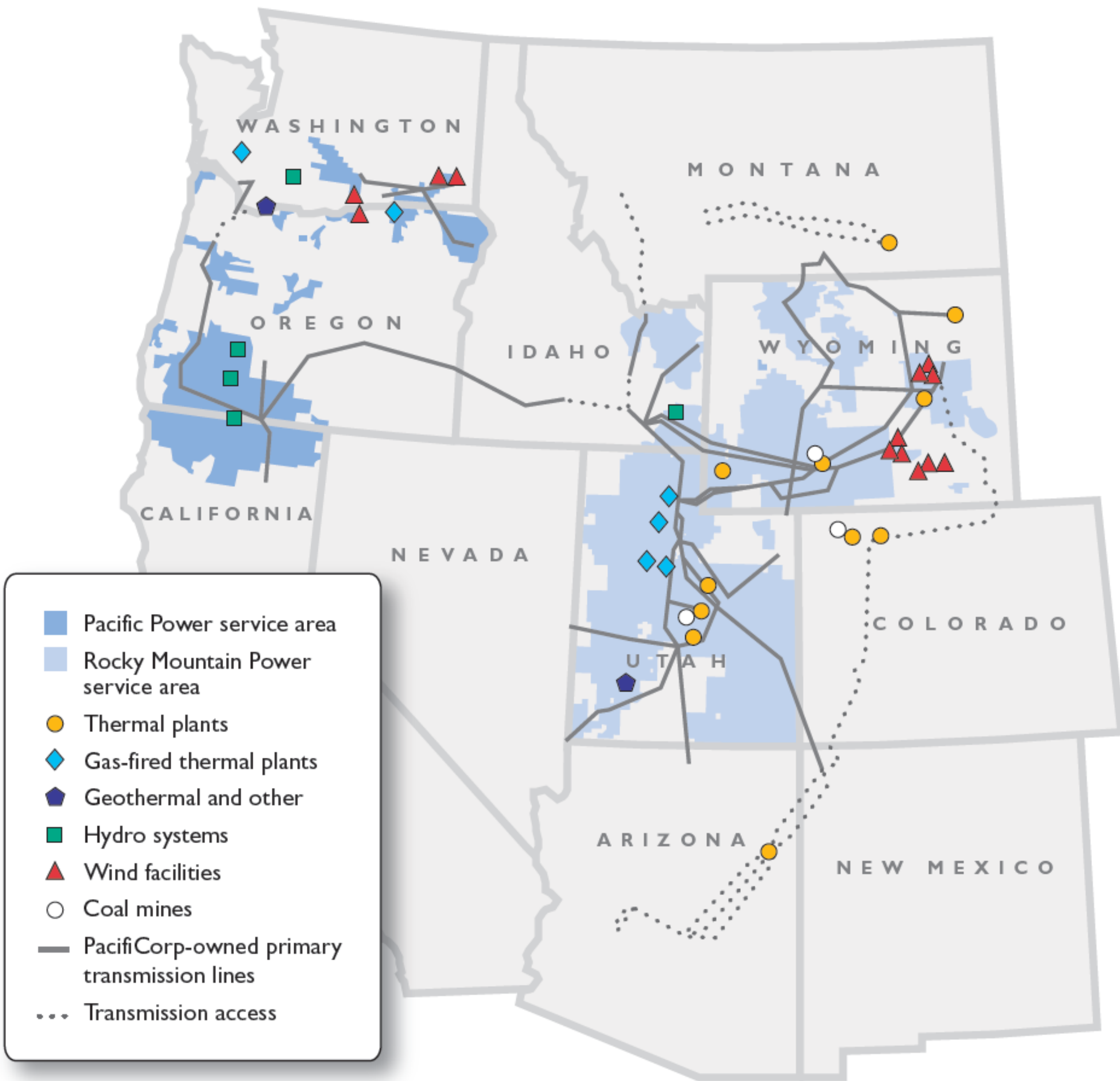
Exhibit Accompanying Direct Testimony of Richard P. Reiten

Service Territory Map

March 2013

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

PacifiCorp Service Territories



PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

PacifiCorp's Oregon Service Territory

REDACTED
Docket No. UE 263
Exhibit PAC/200
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Stefan A. Bird

March 2013

REDACTED DIRECT TESTIMONY OF STEFAN A. BIRD

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Stefan A. Bird. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am Senior Vice President, Commercial and Trading, for PacifiCorp Energy, a division of PacifiCorp.

QUALIFICATIONS

Q. Briefly describe your education and professional background.

A. I hold a Bachelor of Science in mechanical engineering from Kansas State University. I joined PacifiCorp Energy and assumed my current position in January 2007. From 2003 to 2006, I served as president of CalEnergy Generation U.S., an owner and operator of Qualifying Facility and merchant generation assets, including geothermal and natural gas-fired cogeneration projects across the United States. From 1999 to 2003, I was vice president of acquisitions and development for MidAmerican Energy Holdings Company (MEHC). From 1989 to 1997, I held various positions at Koch Industries, Inc., including energy marketing, financial services, corporate acquisitions, project engineering and maintenance planning in the Americas and Europe.

In my current position, I oversee the Company's Commercial and Trading organization, which is responsible for dispatch of the Company's owned and contracted generation resources and procurement of natural gas and electricity wholesale purchases and sales to balance the Company's load and resources. I am also responsible for PacifiCorp's load and revenue forecast, integrated resource plan (IRP), and net power costs modeling. Most relevant to this docket, I am responsible for acquisition of power resources for the Company's east and west balancing authority areas (the System) through negotiated power purchase agreements and the acquisition of generation resources, including implementation of requests for proposals (RFPs) consistent with applicable law and guidelines.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony demonstrates the prudence of the Company's Lake Side 2 natural gas-fired generating plant (Lake Side 2), a 645 megawatt (MW)[1] resource located adjacent to Lake Side 1 in Vineyard, Utah County, Utah. As explained in the testimony of Ms. Joelle R. Steward, the Company proposes to include Lake Side 2 in rates through a separate tariff rider when the plant goes into service in the second quarter of 2014.

Q. Please provide a summary of your testimony.

A. The Lake Side 2 acquisition is the result of a comprehensive regulatory review process spanning nearly five years at the Public Utility Commission of Oregon (Commission). That process included two distinct phases and several key milestones, including acknowledgment of three consecutive IRPs that reflected the need for Lake Side 2 and its planned acquisition; approval of the RFP through which PacifiCorp acquired Lake Side 2; acknowledgment of the shortlist including Lake Side 2; and a favorable report from the Oregon Independent

[1] The Company's practice is to report the ratings of its combustion-turbine-based resources at the average ambient temperature in a "new and clean" condition. The net output rating of Lake Side 2 is 645 MW, based on the engineering, procurement, and construction (EPC) contract current performance estimates at 52 degrees Fahrenheit. The evaluation in the RFP used a consistent approach for all resources, which was an estimated output at each of the 12 months average ambient temperature (*i.e.*, the average of the 12 estimated outputs at each month's average temperature) which was 637 MW.

Evaluator (IE) regarding the fairness and transparency of the Company's RFP process. *See* Confidential Exhibit PAC/201.

My testimony provides the complete history of the Lake Side 2 acquisition process. This process took several years in part because it was temporarily interrupted when the Company took advantage of the time-limited opportunity in 2008 to acquire the Chehalis natural gas-fired plant at an advantageous price with a Commission-approved RFP waiver. The Chehalis acquisition saved customers [redacted] million dollars and enabled the Company to make mid-course changes in the RFP process that also took into account the global economic downturn and anticipated change in market conditions.

Several months after the Chehalis acquisition, the Company suspended its acquisition process and terminated a similar but more expensive resource (Original Lake Side 2), which was the winning bid in the Company's initial RFP (the 2012 RFP). With Commission approval, the Company then revised and re-issued its more recent RFP (the 2008 RFP) in late 2009. The Company acquired Lake Side 2 in late 2010 as the winning bid in the revised 2008 RFP. Because of technology improvements and favorable market conditions, Lake Side 2 is more than [redacted] dollars [redacted] costly than Original Lake Side 2 from the 2012 RFP, provides more output, has a lower heat rate, and has materially favorable construction contract terms and conditions.

This history demonstrates that the Company's decision to acquire Lake Side 2 was fully evaluated and prudent. It also shows that the timing of the acquisition resulted in dramatic savings to customers. At the end of this acquisition process, customers have the benefit of two natural gas-fired plants, Lake Side 2 and Chehalis, acquired at prices that are attractive in current market conditions and highly favorable as compared to market conditions that existed when PacifiCorp began the acquisition process.

My testimony also provides additional details on the Lake Side 2 acquisition. I explain certain key terms and conditions of the engineering, procurement, and construction agreement (Agreement) with CH2M Hill Engineers, Inc. (CH2M Hill) for the construction of Lake Side 2. I also provide an explanation of the managed long-term gas turbine parts and services contract (LTP) with Siemens Energy, Inc. The LTP is attached as Confidential Exhibit PAC/202. Finally, I explain how Lake Side 2 is integrated into the Company's System, and I provide the Lake Side 2 Large Generation Interconnection Agreement (LGIA) as Confidential Exhibit PAC/203.

HISTORY OF LAKE SIDE 2 ACQUISITION—OVERVIEW

Q. Please provide an overview of the history of the Lake Side 2 acquisition process.

A. The history of the Company's decision to acquire Lake Side 2 spans several years and is intertwined with three IRPs and three RFPs. To clearly show the important milestones in the acquisition process, including Commission filings and approvals, I have prepared a Lake Side 2 timeline as an exhibit to my testimony. *See* Exhibit PAC/204.

Q. Was the need for Lake Side 2 established in the Company's acknowledged IRPs?

A. Yes. The need for a resource such as Lake Side 2 was recognized as a part of the Commission's acknowledgement of the Company's 2007 and 2008 IRPs.[2] These are the two IRPs that immediately preceded the Company's execution of the Lake Side 2 acquisition agreement in December 2010.

Q. Was Lake Side 2 specifically included in the Company's most recent acknowledged IRP?

A. Yes. The Commission acknowledged the Company's 2011 IRP in March 2012.[3] Item 2 in the 2011 IRP Revised Action Plan indicates that the Company will: Acquire a combined cycle combustion turbine resource at the Lake Side site in Utah by the summer of 2014; the plant is proposed to be constructed by CH2M Hill E&C, Inc. ("CH2M Hill") under the terms of an engineering, procurement and construction (EPC) contract. This resource corresponds to the 2014 CCCT proxy resource included in the 2011 preferred portfolio.[4]

HISTORY OF LAKE SIDE 2 ACQUISITION—PHASE I

Q. Please provide background on how the Company initially sought to acquire this resource in the Company's 2012 RFP.

A. In July 2006, the Company filed a draft of its 2012 RFP with the Commission in docket UM 1208. One month later, the Commission issued competitive bidding

[2] *In re PacifiCorp, dba Pacific Power, 2008 Integrated Resource Plan*, Docket No. LC 47, Order No. 10-066 (Feb. 24, 2010); *In re PacifiCorp, dba Pacific Power, 2007 Integrated Resource Plan*, Docket No. LC 42, Order No. 08-232 (Apr. 24, 2008).
[3] *In re PacifiCorp 2011 Integrated Resource Plan*, Docket No. LC 52, Order No. 12-082 (March 9, 2012).
[4] *Id.* at App. A, page 3.

guidelines for new supply side resources in docket UM 1182.[5] To comply with these guidelines, the Company revised the 2012 RFP, and the Commission ordered retention of an Oregon IE.[6]

In January 2007, the Commission denied approval of the 2012 RFP, but indicated that the Company could seek acknowledgement of the final shortlist of bidders from the 2012 RFP.[7] The Company filed for acknowledgement of the 2012 RFP final shortlist in December 2008. The shortlist included the Original Lake Side 2, a 607 MW[8] gas-fired facility with a total project cost of [redacted] million and a June 2012 in-service date.

In the request for acknowledgment, the Company relied in part on the report of the IE, which concurred with the final shortlist of bidders. *See* Confidential Exhibit PAC/201. The Company also relied upon the fact that Original Lake Side 2 was consistent with the Company's acknowledged 2007 IRP.

In February 2009, the Company exercised the contractual option it had negotiated to terminate Original Lake Side 2 and withdrew its request for acknowledgment of the 2012 RFP shortlist.

Q. Did the Company issue the 2008 RFP while the 2012 RFP remained pending?

A. Yes. In December 2007, the Company filed for approval of the 2008 RFP in docket UM 1360. The 2012 RFP was designed to meet up to 2,000 MW of the

[5] *In re Investigation Regarding Competitive Bidding*, Docket No. UM 1182, Order No. 06-446 (Aug. 10, 2006).
[6] *In re PacifiCorp, dba Pacific Power, 2012 Draft Request for Proposals,* Docket No. UM 1208, Order No. 06-050 (Sept. 26, 2006), *clarified*, Order No. 06-676 (Dec. 20, 2006).
[7] *In re PacifiCorp, dba Pacific Power, 2012 Draft Request for Proposals*, Docket No. UM 1208, Order No. 07-018 (Jan. 16, 2007).
[8] More specifically, 524 MW base load with 83 MW of duct firing for a total capacity of 607 MW at 52 degrees Fahrenheit (new and clean).

Company's capacity and energy resource needs for calendar years 2012-2016. In June 2008, the Commission approved the 2008 RFP.[9] On October 2, 2008, the Company issued the RFP and received bidders' proposals on December 16, 2008. The pricing of bids received in this first issuance of the 2008 RFP did not yet reflect the impact of the global economic downturn. In February 2009, the Company filed to suspend the 2008 RFP.

Q. Please provide background on the acquisition of the Chehalis gas-fired resource during the pendency of the 2008 and 2012 RFPs.

A. After both the 2012 and 2008 RFPs were well underway, the Company became aware of an opportunity to acquire the Chehalis plant, an existing natural gas-fired combined cycle plant with a nominal output of about 500 MW located in Washington, at a cost of [redacted] million, or [redacted] per kilowatt. The purchase price for the Chehalis plant was very beneficial for customers. For example, as compared to the cost of Original Lake Side 2, ([redacted] million for 607 MW or [redacted] per kilowatt), the Chehalis plant has a cost advantage of [redacted] per kilowatt. Due to the unique value and time-limited nature of the Chehalis opportunity, the Company sought and obtained a waiver from the Commission's RFP process for the acquisition of Chehalis in July 2008 in docket UM 1374.[10] The Company acquired the Chehalis plant in September 2008. The Commission determined that the Chehalis plant was prudent and allowed it into rates in January 2010.[11]

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[9] *In re PacifiCorp, dba Pacific Power, Request for Approval of 2008 Draft Request for Proposals*, Docket No. UM 1360, Order No. 08-310 (June 5, 2008).

[10] *In re PacifiCorp, dba Pacific Power, Petition for Waiver of the Commission's Competitive Guidelines*, Docket No. UM 1374, Order No. 08-376 (July 17, 2008).

[11] *In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 210, Order No. 10-022 (Jan. 26, 2010).

Q. Did the Chehalis acquisition play a role in the Company's decision to terminate the Original Lake Side 2 agreement and suspend the 2008 RFP in February 2009?

A. Yes. The addition of low cost capacity from Chehalis allowed the Company to defer the acquisition of the natural gas-fired combined cycle resource need identified in the 2008 IRP for 2014. This enabled the Company an opportunity to reevaluate its acquisition strategy in light of the global economic downturn and anticipated change in market conditions. The Company determined that it was not in the best interests of its customers to immediately proceed with the Original Lake Side 2 resource or the 2008 RFP at the time, given the reasonable possibility that it would receive more favorable bids in the future as economic and market conditions changed.

HISTORY OF THE LAKE SIDE 2 ACQUISITION—PHASE II

Q. Please explain why the Company reissued the 2008 RFP.

A. In October 2009, the Company filed a notice proposing to resume the 2008 RFP. In this notice, the Company indicated that: (1) the economic downturn in late 2008 resulted in a reduction of customer loads, a reduction in commodity prices, an anticipated reduction in construction costs, and other changes in economic and market conditions; (2) the Company's 2008 IRP indicated that the Company could serve its load from current resources supplemented by low cost market purchases until June 2014; and (3) it appeared that the recession had slowed down and economic conditions might start to improve. Based on these factors, the Company concluded that there was a reasonable possibility that it would receive more favorable bids than those it received in December 2008. The Commission approved the reissued 2008 RFP in December 2009.[12]

Q. How did the Company revise the 2008 RFP?

A. The size of the 2008 RFP decreased from 2,000 MW to 1,500 MW, reflecting the 500 MW addition of the Chehalis plant. In addition, after receiving input from the intervening parties and with concurrence of the Oregon IE, the Company made other modifications including (1) a change in the time period for which the resource need was sought from 2012–2016 to 2014–2016, and (2) a reduction of the number of Company benchmarks from three to one benchmark located at the Lake Side site.

Q. Please describe the benchmark in the revised 2008 RFP.

A. PacifiCorp's benchmark proposal consisted of a natural gas-fired combined-cycle plant at the Lake Side site with a capacity of 631 MW and an online date of May 1, 2014, or May 1, 2015 (Benchmark). PacifiCorp submitted the Benchmark to its IRP Team and the Oregon IE on February 15, 2010. The IRP Team completed the price score analysis for the Benchmark and submitted the models and the analysis to the Oregon IE before the receipt of the bids from the market on March 1, 2010.

The Oregon IE locked down the Benchmark prior to the opening of market bids on March 2, 2010. The Oregon IE provided a memorandum of its initial evaluation of the Benchmark to the Commission on February 26, 2010, which is attached as Confidential Exhibit PAC/201. The Oregon IE compared the

[12] *In re PacifiCorp, dba Pacific Power, Requests Approval to Resume 2008 Request for Proposal*, Docket No. UM 1360, Order No. 09-491 (Dec. 14, 2009).

Benchmark costs and assumptions to actual bids from Phase I of 2008 RFP and to Original Lake Side 2. In so doing, the Oregon IE concluded that the Benchmark's capital costs, operating and maintenance costs (fixed and variable), and heat rates were all reasonable.

Q. Did the Company receive a robust response to the reissued 2008 RFP?

A. Yes. The Company received a total of [redacted] bids. In the base load category, PacifiCorp received [redacted] bid variants from [redacted] bidders, totaling [redacted] MW, excluding the Benchmark. These bids included [redacted] tolling service agreements (TSA), [redacted] asset purchase and sale agreements (APSA), and [redacted] TSA/APSA bid variants. In the intermediate category, the Company received [redacted] bid variants from [redacted] bidders, totaling [redacted] MW (depending upon the technology at a given site). These bids included [redacted] TSA bid variants, [redacted] APSA bid variants, and [redacted] TSA/APSA bid variants. There were [redacted] proposals submitted in the summer peaking category.

Q. Which projects did the Company include in the initial shortlist?

A. The Company included [redacted] projects in its initial shortlist for the base load category: [redacted].

In the intermediate category, the initial shortlist was comprised of the following [redacted].

Q. Did the Oregon IE concur with the Company's selection of the initial shortlists?

A. Yes. As stated in the Oregon IE's November 10 Final Report, the Oregon IE concurred with the Company's selection of the initial shortlists. *See* Confidential Exhibit PAC/201.

Q. How was the final shortlist developed?

A. The Company asked the bidders on the initial shortlists and the Benchmark to submit best and final offers. The Company submitted firm pricing for the Benchmark options on July 1, 2010. The bidders on the initial shortlists submitted their best and final offers by July 15, 2010, which were reviewed after the Oregon IE locked down the best and final offer on the Benchmark option. The Oregon IE provided a second memorandum on July 16, 2010, of its final evaluation of the Company Benchmark to the Commission, which is included in Confidential Exhibit PAC/201. The Oregon IE concluded that the final

Benchmark was reasonable and was lower cost and better performing than the initial Benchmark.

Q. How did the Company determine the final shortlist?

A. To determine the final shortlist, the Company used its IRP models and a three-step solicitation process analysis consistent with the Commission-approved 2008 RFP. PacifiCorp selected [redacted] proposals for the final shortlist: [redacted]

Q. Please provide a description of the [redacted] proposals comprising the final shortlist.

A. [redacted].

Q. Did the Oregon IE recommend acknowledgement of the final shortlist?

A. Yes, the Oregon IE recommended acknowledgment of the final shortlist.

Q. Did the Oregon Commission acknowledge the final shortlist?

A. Yes. In December 2010, the Commission acknowledged the final shortlist.[13]

[13] *In re PacifiCorp, dba Pacific Power, Request for Acknowledgment of Final Shortlist of Bidders in the 2008 Request for Proposals*, Docket No. UM 1360, Order No. 10-494 (Dec. 27, 2010).

Q. What was the result of evaluation of the [redacted] final shortlist proposals?

A. In the course of the negotiations in the 2008 RFP final shortlist, [redacted]

After the final shortlist negotiations, the Company selected Lake Side 2 as the winning proposal. [redacted] *See* Confidential Exhibit PAC/201.

Q. What are the benefits to customers from the Company's Lake Side 2 acquisition?

A. As a result of the process that led to the Company's acquisition of Lake Side 2, customers will experience cost savings of [redacted] of millions of dollars and significantly reduced risks. Specifically:

- Lake Side 2 has a projected cost in the 2008 RFP of [redacted] million, [redacted] million less than Original Lake Side 2, prior to recent updates that I will discuss in the next section. Furthermore, the pricing for Lake Side 2 has significantly less risk than the proposal for Original Lake Side 2.
- Lake Side 2 has a better heat rate, more output and materially more favorable contract terms and conditions compared to Original Lake Side 2.
- Concurrently with the Lake Side 2 acquisition process, the Company acquired the Chehalis plant for [redacted] million. This resource provides approximately [redacted] percent of the output at one-third the price—or

[redacted] million lower cost—as compared to the winning bid from the 2012 RFP, Original Lake Side 2.

DESCRIPTION OF LAKE SIDE 2

Q. Please describe Lake Side 2 and its integration into PacifiCorp's System.

A. Lake Side 2 is located on a 63.6 acre site in Vineyard, Utah. It is a 645 MW[14] natural gas-fired electric generation facility, consisting of a 2x1 configuration, using two Siemens SGT6-5000F combustion turbine generators and a single SST6-5000 steam turbine generator. Each combustion turbine exhausts into its own heat recovery steam generator and, together, they supply a single steam turbine generator. The electrical energy generated by Lake Side 2 will be delivered to a new 345 kV point of interconnection substation (Steel Mill) where it will tie into the PacifiCorp transmission system. Lake Side 2 will reach substantial completion to generate and provide energy and capacity to customers by the end of the second quarter in 2014.

Q. Please describe the characteristics of Lake Side 2.

A. Lake Side 2 is located in the Company's east balancing authority. The Company can dispatch power and energy from Lake Side 2 on a forward, day-ahead basis, with real-time optimization of the plant's usage. This dispatch flexibility will give the Company an additional system resource with the ability to provide operating reserves, load-following reserves, and automatic generation control. The added System flexibility will provide increasing benefit to PacifiCorp as

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[14] More specifically, Lake Side 2 is nominally rated at 548 MW base load and 94 MW of duct firing for a total net capacity of 645 MW at the average ambient temperate of 52 degrees Fahrenheit.

(1) load grows, (2) PacifiCorp's existing flexible contracts expire, and (3) new wind and solar resources are added to the system.

TOTAL PROJECTED COST OF LAKE SIDE 2

Q. What is the total projected cost of Lake Side 2 as evaluated in the 2008 RFP?

A. The total projected cost of Lake Side 2 as evaluated in the 2008 RFP is [redacted] million.

Q. Please describe the components of the total projected cost associated with the development and engineering, procurement, and construction of Lake Side 2 as evaluated in the 2008 RFP.

A. The total estimated capital investment of [redacted] million includes the following estimated costs:

- A transfer to in-service cost of [redacted] million for the generation asset, including:
  - [redacted] million for the Agreement
  - [redacted] million for sales tax
  - [redacted] million for owner's cost
  - [redacted] million for allowance for funds used during construction (AFUDC)
  - [redacted] million for property taxes during construction

- [redacted] million for transmission upgrade costs required to integrate the plant into the Company's east balancing authority.[15]

Q. Have there been any changes in Lake Side 2's generation asset cost forecast to be placed in service in 2014?

A. Yes, the Company has reduced its forecast of owner's costs to be placed in service in 2014 by approximately [redacted] million. This reduction is due to a restructuring of the water purchases from the Central Utah Water Conservancy District (CUWCD). Instead of purchasing all of the water needed to meet the long-term requirements of Lake Side 2 during the construction period, the water purchases from the CUWCD have been phased in to align with expected generation and cooling water needs from Lake Side 2. This phasing in of water purchases is currently estimated to reduce revenue requirement on a present value basis by approximately [redacted] million due to deferred capital payments and avoided fixed "take or pay" O&M costs for water under the CUWCD water supply agreement. This approach reduces the Lake Side 2 owner's costs to be placed in service in 2014 from [redacted] million to [redacted] million. However, future water purchases, amounting to approximately [redacted] million, will be phased in over the 2015 to 2019 time period.

In addition to changes in owner's costs, the Company's current Lake Side 2 generation asset cost forecast reflects reductions of approximately [redacted] million associated with changes in AFUDC, property taxes, and internal costs. The

[15] PacifiCorp Transmission estimated the integration costs for each delivery point in Attachment 13 of the RFP. An initial estimate of $66 million was updated on July 29, 2010, to $45 million in 2010 dollars escalated at 1.89% annually through 2014 for a nominal cost of $48 million. These two estimates are available at http://www.oasis.pacificorp.com/oasis/ppw/main.htmlx. The $48 million estimate was used in the Final Shortlist evaluation process.

combination of these updates results in reducing the total capital investment forecast for the generating asset to be placed in service in 2014 from [redacted] million to [redacted] million.

Q. Have there been any changes to the estimated transmission upgrade costs to integrate the plant into the Company's east balancing authority from the [redacted] million used in the final shortlist evaluation process?

A. Yes. The Company's forecast for the transmission upgrade costs is currently approximately [redacted] million.

Q. What is the updated total estimated capital investment for Lake Side 2?

A. The combination of the updated forecast of generation asset to be placed in service in 2014 and the updated transmission upgrade costs described above results in reducing the total estimated capital investment for Lake Side 2 from [redacted] million to [redacted] million.

PRICING AND PAYMENT STRUCTURES

Q. Please describe the pricing and payment structure under the Agreement.

A. If CH2M Hill does not achieve substantial completion of Lake Side 2 by June 1, 2014, the Agreement provides for delay liquidated damages. Any delay in achieving substantial completion that is greater than [redacted] following June 1, 2014, will entitle the Company to terminate the Agreement and to seek additional appropriate remedies. CH2M Hill's performance is secured by a parent guarantee and retainage or a retainage letter of credit equal to five percent of all payments made (other than the final payment).

The warranty under the Agreement is effective for [redacted] beginning June 1, 2014; provided that any repairs (other than the Siemens equipment) made during the warranty period will be warranted for a period that is the greater of one year or the balance of the warranty period. CH2M Hill has agreed to obtain insurance and assume risk of loss at the customary levels requested by the Company. CH2M Hill will not be liable for consequential damages; but, with a few exceptions, it will be liable for losses under the Agreement up to the aggregate amount of 100 percent of the contract price. In addition, the Company has secured an additional warranty on the Siemens power generation equipment (the combustion turbines, steam turbine and associated generators) for the earlier of the three-year anniversary of the substantial completion date, 24,000 equivalent operating hours, or 54 months following delivery of the equipment.

Q. Are the pricing and payment structure of the Agreement more favorable than the agreement for Original Lake Side 2?

A. Yes. The Agreement has more favorable terms that decrease the overall cost and risk to customers.

Q. Please explain.

A. First, the contract structure was changed from Original Lake Side 2. That agreement had an APSA structure (Developer and EPC Contractor). The current Lake Side 2 Agreement is an EPC contract, which minimizes the overall management of risks between the developer and the EPC contractor. Second, the agreement for Original Lake Side 2 was structured with 80 percent as a fixed price and 20 percent variable price, subject to a true up. The Lake Side 2

Agreement provides a single fixed price. Third, the Lake Side 2 Agreement improved the terms associated with liquidated damages and performance damages, increased the total limits of liability of the EPC contract, increased the warranty coverage, and improved performance guarantees.

DESCRIPTION OF THE LONG-TERM PROGRAM

Q. Please briefly explain the LTP between Siemens and the Company for CH2M Hill.

A. The LTP provides for the parts and services associated with the scheduled maintenance on the two combustion turbines, steam turbine, and three generators that are the core of Lake Side 2. The LTP Agreement is attached as Confidential Exhibit PAC/202.

Q. Are LTP contracts common in the industry for these types of transactions?

A. Yes. LTP contracts are used regularly in these types of transactions. With regard to pricing, the LTP with Siemens is comparable to other similar LTP contracts.

Q. Are the LTP costs consistent with the LTP costs used in the analysis of the economics of Lake Side 2 during the reissued 2008 RFP process?

A. Yes. The costs in the LTP are consistent with those costs used in the cost proposal submitted in the reissued 2008 RFP.

Q. Did the Company consider alternative options to the LTP?

A. Yes, although these options are limited. The Company's options are either to enter into a LTP with Siemens or to purchase parts and services on a transactional basis from Siemens. The Lake Side 2 LTP is based on Siemens SGT6-5000F (F4) combustion turbine which at the time of contract execution was the latest "F" class design. These turbine designs are proprietary and exclusive to Siemens—Siemens is the only supplier who can provide the full range of parts, repair services, expertise, and the other services that will be provided under the negotiated terms and conditions. As these particular combustion turbines become more prevalent, alternative full-service suppliers may emerge; however, this market does not currently exist.

Q. Does this conclude your direct testimony?

A. Yes.

CONFIDENTIAL
Docket No. UE 263
Exhibit PAC/201
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Stefan A. Bird

Independent Evaluator Final Report, RFP Shortlist

March 2013

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

CONFIDENTIAL
Docket No. UE 263
Exhibit PAC/202
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Stefan A. Bird

Siemens LTP Contract

March 2013

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CONFIDENTIAL
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Stefan A. Bird

Lake Side 2 Large Generation Interconnection Agreement

March 2013

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 263
Exhibit PAC/204
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Stefan A. Bird

Lake Side 2 Timeline

March 2013

Lake Side 2 Oregon Regulatory Timeline

- **July 2006**. The Company files an application requesting Commission approval of the 2012 Request for Proposals (RFP). The 2012 RFP sought up to four baseload resources totaling 1,775 MW. The application was docketed as UM 1208.
- **August 2006**. Commission issues competitive bidding guidelines in Docket UM 1182.[1]
- **September 2006**. The Commission issues Order No. 06-550 in docket UM 1208, establishing a process for selection of an Oregon Independent Evaluator (IE).[2]
- **January 2007**. The Commission issues Order No. 07-018 in docket UM 1208, denying the Company's request for approval of the 2012 RFP, but providing that the Company may still seek acknowledgment of the final shortlist in the 2012 RFP.[3]
- **May 2007**. The Company files its 2007 Integrated Resource Plan (2007 IRP), which identifies the need for thermal capacity in 2012. The application is docketed as LC 42.
- **December 2007**. The Company files an application requesting Commission approval of the 2008 RFP. The 2008 RFP sought up to 2,000 MW of cost-effective capacity and energy resources, excluding coal or intermittent resources. The application was docketed as UM 1360.
- **April 2008.**
    - The Company files a petition to waive the competitive bidding guidelines for the acquisition of the 520 MW Chehalis generating plant. The petition is docketed as UM 1374.
    - The Commission issues Order No. 08-232 in docket LC 42, acknowledging with modifications the Company's 2007 IRP.[4]
- **June 2008.** The Commission issues Order No. 08-310 in docket UM 1360, approving the 2008 RFP, with conditions.[5]

[1] *In re Investigation Regarding Competitive Bidding*, Docket No. UM 1182, Order No. 06-446 (Aug. 10, 2006).
[2] *In re PacifiCorp, dba Pacific Power, 2012 Draft Request for Proposals,* Docket No. UM 1208, Order No. 06-050 (Sept. 26, 2006), *clarified,* Order No. 06-676 (Dec. 20, 2006).
[3] *In re PacifiCorp, dba Pacific Power, 2012 Draft Request for Proposals*, Docket No. UM 1208, Order No. 07-018 (Jan. 16, 2007).
[4] *In re PacifiCorp, dba Pacific Power, 2007 Integrated Resource Plan,* Docket No. LC 42, Order No. 08-232 (Apr. 24, 2008).
[5] *In re PacifiCorp, dba Pacific Power, Request for Approval of 2008 Draft Request for Proposals*, Docket No. UM 1360, Order No. 08-310 (June 5, 2008).

- **July 2008**. The Commission issues Order No. 08-376 in docket UM 1374, waiving the competitive guidelines for the Company's acquisition of the Chehalis plant.[6]

- **September 2008.** The Company executes an agreement for the acquisition of the Chehalis plant.

- **October 2008**.
  - The Company executes an agreement for the acquisition of Original Lake Side 2, the winning bid from the 2012 RFP, a 607 MW gas-fired facility with a June 2012 in-service date.
  - The Company issues the 2008 RFP.

- **December 2008**.
  - The Company files an application in docket UM 1208 requesting Commission acknowledgment of the final shortlist of bidders in the 2012 RFP.
  - Company receives bids from the 2008 RFP.

- **February 2009.**
  - The Company files notice in docket UM 1208 of its withdrawal of its request for Commission acknowledgment of the final shortlist of bidders in the 2012 RFP. The Company simultaneously requests the Commission close docket UM 1208.
  - The Company files for suspension of the 2008 RFP in docket UM 1360.
  - The Company exercises the contractual option it had negotiated to terminate the Original Lake Side 2 agreement.

- **May 2009.** The Company files its 2008 Integrated Resource Plan (2008 IRP), which identifies the need for a natural gas-fired combined cycle resource in 2014. The application is docketed as LC 47.

- **June 2009**. The Commission issues Order No. 09-244 closing docket UM 1208.[7]

- **November 2009**. The Company files in docket UM 1360 for approval to resume and reissue the 2008 RFP.

- **December 2009**. The Commission issues Order No. 09-491 in docket UM 1360, approving the reissued 2008 RFP, with conditions.[8] The Company reissues the 2008 RFP

[6] *In re PacifiCorp, dba Pacific Power, Petition for Waiver of the Commission's Competitive Guidelines*, Docket No. UM 1374, Order No. 08-376 (July 17, 2008).
[7] *In re PacifiCorp, dba Pacific Power, Draft 2012 Request for Proposals*, Docket No. UM 1208, Order No. 09-244 (June 17, 2009).
[8] *In re PacifiCorp, dba Pacific Power, Requests Approval to Resume 2008 Request for Proposal*,

to market, seeking up to 1,500 MW from base load, intermediate load, and summer peak resources to meet the Company's system position during the 2014–2016 time period.[9]

- **January 2010**. The Commission issues Order No. 10-022 in docket UE 210, approving a stipulation resolving, among other things, the prudence of the Company's acquisition of the Chehalis plant.[10]

- **February 2010**. The Commission issues Order No. 10-066 in docket LC 47, acknowledging with modifications the 2008 IRP.[11]

- **October 2010.** The Company files an application in docket UM 1360 requesting Commission acknowledgment of the final shortlist of bidders in the reissued 2008 RFP.

- **December 2010.**
    - The Commission issues Order No. 10-494 in docket UM 1360 acknowledging the final shortlist of bidders in the reissued 2008 RFP.[12]
    - The Company executes an agreement for the acquisition of Lake Side 2.

- **March 2011.** The Company files its 2011 Integrated Resource Plan (2011 IRP), which includes acquisition of a proxy gas-fired resource in 2014 in the 2011 preferred portfolio. The application is docketed as LC 52.

- **March 2012.** The Commission acknowledges with exceptions the Company's 2011 IRP in March 2012.[13] Item 2 in the 2011 IRP Revised Action Plan indicates that the Company will: [Acquire a combined cycle combustion turbine resource at the Lake Side site in Utah by the summer of 2014; the plant is proposed to be constructed by CH2M Hill E&C, Inc. ("CH2M Hill") under the terms of an engineering, procurement and construction (EPC) contract. This resource corresponds to the 2014 CCCT proxy resource included in the 2011 preferred portfolio.[14]]

Docket No. UM 1360, Order No. 09-491 (Dec. 14, 2009).
[9] *In re PacifiCorp, dba Pacific Power, Request for Acknowledgment of Final Shortlist of Bidders in the 2008 Request for Proposals,* Docket No. UM 1360, Order No. 10-494, Appendix A (December 27, 2010).
[10] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 210, Order No. 10-022 (Jan. 26, 2010).
[11] *In re PacifiCorp, dba Pacific Power, 2008 Integrated Resource Plan,* Docket No. LC 47, Order No. 10-066 (Feb. 24, 2010).
[12] *In re PacifiCorp, dba Pacific Power, Request for Acknowledgment of Final Shortlist of Bidders in the 2008 Request for Proposals*, Docket No. UM 1360, Order No. 10-494 (Dec. 27, 2010).
[13] *In re PacifiCorp 2011 Integrated Resource Plan,* Docket No. LC 52, Order No. 12-082 (March 9, 2012).
[14] *Id,* Appendix A at 3.

Docket No. UE 263
Exhibit PAC/300
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Mark R. Tallman

March 2013

DIRECT TESTIMONY OF MARK R. TALLMAN

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Mark R. Tallman. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Vice President of Renewable Resources. I am responsible for hydro-powered and wind-powered generation resources owned by the Company.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science degree in Electrical Engineering from Oregon State University and a Master of Business Administration from City University of Seattle. I am also a Registered Professional Engineer in Oregon and Washington. I have been the Vice President of Renewable Resources since January 2011. Before that, I was Vice President of Renewable Resource Acquisition from December 2007 to January 2011 and Managing Director of Renewable Resource Acquisition from April 2006 to December 2007. I have worked at the Company for more than 26 years in a variety of positions of increasing responsibility including the commercial and trading organization, the engineering organization, and the retail organization (as a District Manager in Washington state).

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe an addition to the Company's hydro generation plant and non-labor operations and maintenance (O&M) adjustments associated with the Company's hydro-powered and wind-powered generation resources. I will demonstrate why the hydro plant addition and O&M adjustments are reasonable, prudent, and should be included the Company's revenue requirement in this case.

Q. Please summarize your testimony.

A. My testimony describes: a $41.7 million (total company) construction project required by one of the Federal Energy Regulatory Commission (FERC) licenses issued to the Company for the Lewis River hydroelectric project (the Merwin Fish Collector); $3.1 million (total company) of incremental non-labor O&M costs associated with the Company's hydro-powered generation resources; and $2.2 million (total company) of decreased O&M costs associated with the Company's wind-powered generation resources.

Q. Please provide a brief description of the Company's hydro facilities.

A. The Company operates approximately 1,074 megawatts (MW) of hydroelectric projects in the Pacific Northwest and the Rocky Mountains that provide carbon-free electricity for the benefit of customers. The Lewis River project in Washington and the North Umpqua River project in Oregon are the Company's two largest hydro projects with a generating capacity of approximately 510 MW and 188.5 MW respectively.

Q. Please provide a brief description of the Company's wind facilities.

A. The Company operates more than 900 MW of wind projects in the Pacific Northwest and Wyoming that provide carbon-free electricity and tax benefits for the benefit of customers. The Leaning Juniper I project near Arlington, Oregon, and the Marengo project near Dayton, Washington, are the Company's two largest wind projects with a nominal generating capability of 100.5 MW and 140.4 MW respectively.

MERWIN FISH COLLECTOR

Q. Please describe the need for and purpose of the Merwin Fish Collector.

A. The Merwin Fish Collector is needed to implement a fish passage system designed to collect, trap, and haul juvenile and adult anadromous fish around the three Lewis River dams. The purpose of the Merwin Fish Collector is to implement and comply with the Merwin hydroelectric project license issued by FERC.[1]

Q. Please describe the Merwin Fish Collector facility.

A. The facility is designed to attract and collect fish so that they can be hauled upstream past the dams on the Lewis River and released back into the river to continue their upstream migration. The fish collection facility is installed directly downstream of Merwin dam. Water is pumped through a tube to attract fish toward a land-mounted collection facility and a land-mounted sorting facility. After the fish are captured and sorted, they are transferred into a truck for transport and release upstream of Swift dam.

Q. Was the design of the Merwin Fish Collector subject to review and approval by resource agencies?

A. Yes. Per the FERC license that incorporates the Lewis River settlement agreement, the Company engaged in design reviews with parties to the Lewis River settlement agreement, which included the National Marine Fisheries

[1] *See* Order Issuing New License, 123 FERC ¶ 62, 258 (June 26, 2008) (attached as Exhibit PAC/301). *See also* Order on Rehearing, 125 FERC 61,046 (October 16, 2008) (attached as Exhibit PAC/302).

Services (a division of the National Oceanic and Atmospheric Administration), the U.S. Fish and Wildlife Service, and the Washington Department of Fish and Wildlife. The final design was ultimately approved by the National Oceanic and Atmospheric Administration and the U.S. Fish and Wildlife Service. Although the Company provides input, these agencies have final authority over the design of the facility. Based on the design required by these agencies, the plant addition included in this filing for the Merwin Fish Collector is approximately $41.7 million on a total-company basis.

Q. When will the Merwin Fish Collector be placed into service?

A. The Merwin Fish Collector will be placed into service in phases. The first phase consists of a fish sorting facility. It is estimated that the sorting facility will be placed into service on or about May 2013, with a cost of $14.6 million on a total-company basis. The second phase consists of the water attraction system that will be placed in service on or about July 2013, with a cost of $27.2 million on a total-company basis. It is anticipated that the third and final phase consisting of a fish trap, lift, and conveyance process will be placed in service and operable on or about December 31, 2013 with any remaining components completed by February 2014. The cost of phase three is $15.0 million on a total-company basis.[2]

[2] As explained in the testimony of Mr. Gary W. Tawwater, Exhibit PAC/1000, the Company is including capital additions to plant in service through December 31, 2013. Accordingly, the Company has not included the costs associated with the third phase of the Merwin Fish Collector in rate base.

O&M ADJUSTMENTS

Q. Please describe the non-labor O&M adjustments the Company has included in its filing.

A. The Company has included $3.1 million (total company) of incremental non-labor O&M costs associated with the Company's hydro-powered generation resources, including O&M costs associated with the Merwin Fish Collector and $2.2 million (total company) of decreased O&M costs associated with the Company's wind-powered generation resources.

Q. Please describe the incremental non-labor O&M costs associated with the Merwin Fish Collector.

A. The incremental non-labor O&M costs associated with the Merwin Fish Collector are $282,000 per year on a total-company basis. These costs are for: contract maintenance; periodic assistance from the Washington Department of Fish and Wildlife; fish monitoring supplies; and general supplies.

Q. Please describe the other incremental non-labor O&M costs associated with the Company's hydro-powered generation resources.

A. Also included in the incremental non-labor hydro O&M costs of $3.1 million per year on a total-company basis are increased FERC and other regulatory fees, increased costs associated with FERC hydro license implementation, and increased costs associated with the Company's FERC dam safety program.

Q. Please describe the decreased non-labor O&M costs associated with the Company's wind-powered generation resources.

A. Included in the decreased non-labor wind O&M costs of $2.2 million per year on a total-company basis are decreased third party O&M contracts partially offset by increased material expenses and increased expenses associated with normal wind turbine generator oil changes.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/301
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark R. Tallman

FERC Order Issuing New License

March 2013

123 FERC ¶ 62,258

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp   Project No. 935-053

ORDER ISSUING NEW LICENSE

(June 26, 2008)

1. On April 28, 2004, PacifiCorp filed an application for a new license, pursuant to sections 4(e) and 15 of the Federal Power Act (FPA),[1] for the continued operation and maintenance of the 136-megawatt (MW) Merwin Project No. 935, located on the North Fork Lewis River in Cowlitz and Clark Counties, Washington. The project occupies federal lands administered by the U.S. Bureau of Land Management (BLM).[2]

2. PacifiCorp's application for Project No. 935 is one of three applications it filed to relicense its projects on the North Fork Lewis River (referred to as the Lewis River in this order). In addition to the Merwin Project, PacifiCorp filed license applications for two other projects just upstream of the Merwin Project – the Swift No. 1 Project No. 2111 on April 28, 2004 and the Yale Project No. 2071 on May 5, 1999. Also, on April 28, 2004, the Public Utility District of Cowlitz County (Cowlitz PUD) filed a license application for another Lewis River project, the upstream Swift No. 2 Project No. 2213. The existing licenses for these four projects expired between 2001 and 2006.[3] In this order, we refer to the four projects collectively as the Lewis River Projects. While the granting

[1] 16 U.S.C. §§ 797(e) and 808 (2000), respectively.

[2] The project is required to be licensed under section 23(b)(1) of the FPA, 16 U.S.C. § 817 (2000), because it occupies federal lands.

[3] The expiration date of the Merwin Project license was accelerated from December 11, 2009 to April 30, 2006 to coincide with the expiration dates for the Swift No. 1 and Swift No. 2 licenses. In addition, the Yale Project license expired in 2001, but at the request of PacifiCorp, the processing of that application was held in abeyance so that all four projects could be considered together in a single environmental document.

of a new license for the Merwin Project is the subject of this order, I am concurrently issuing three other orders granting new licenses for the other three Lewis River Projects.[4]

BACKGROUND

3. The Commission issued a new license for the Merwin Project No. 935 on October 10, 1983.[5] The license expired on April 30, 2006, and since that time PacifiCorp has operated the project under an annual license pending the disposition of its new license application.

4. On December 3, 2004, PacifiCorp and Cowlitz PUD filed a comprehensive Settlement Agreement (Agreement) entered into with 22 stakeholders.[6] The applicants' proposed action is to relicense the Lewis River Projects in accordance with the terms of the Agreement. The Agreement provides for: (1) a phased approach to produce self-sustaining, naturally-reproducing, harvestable anadromous salmonid populations above Merwin dam; (2) reconnecting all life stages of bull trout populations in the Lewis River basin; (3) funding measures to enhance and improve wetlands, riparian, and riverine habitats; (4) restoring marine-derived nutrients to the upper watershed; (5) developing a hatchery and supplementation (release of artificially propagated fish) program that supports the reintroduction of anadromous fish to the upper watershed upstream of Merwin dam, and the continued harvest of resident and native anadromous fish species; (6) implementing instream flows, including ramping rates, that benefit fish and wildlife in the basin; (7) acquiring interests in land and managing lands to benefit a broad range of fish, wildlife, and native plant species; (8) diversifying and managing a comprehensive

[4] *See PacifiCorp*, 123 FERC ¶¶ 62,257 and 62,260 (2008); and *Public Utility District No. 1 of Cowlitz County*, 123 FERC ¶ 62,259 (2008).

[5] 25 FPC 61,052 (1983).

[6] PacifiCorp; Cowlitz PUD; National Marine Fisheries Service (NMFS); National Park Service; BLM; U.S. Fish and Wildlife Service (FWS); U.S. Forest Service (Forest Service); Confederated Tribes and Bands of the Yakama Nation (Yakama Nation); Washington Department of Fish and Wildlife (Washington Fish and Wildlife); Washington Interagency Committee for Outdoor Recreation; Cowlitz County; Cowlitz-Skamania Fire District No. 7; North Country Emergency Medical Service; City of Woodland; Woodland Chamber of Commerce; Lewis River Community Council; Lewis River Citizens-at-Large; American Rivers; Fish First; Rocky Mountain Elk Foundation, Inc; Trout Unlimited; and the Native Fish Society. On February 10, 2005, PacifiCorp filed additional signature pages to add the following four parties to the Agreement: the Lower Columbia River Fish Recovery Board, Clark County, Skamania County, and Cowlitz Indian Tribe (Cowlitz Tribe).

suite of recreational opportunities; (9) improving flood management during the likely high-flow event periods; (10) protecting known and yet-to-be discovered cultural resources; and (11) addressing project-related transportation, communications, public safety, and law enforcement needs. These measures are described in detail in the Order on Offer of Settlement and Issuing New License for the Swift No. 1 Project (Master Order), one of the four orders issued concurrently for the Lewis River Projects. The Agreement is attached as Appendix A of the Master Order for informational purposes.

5. On December 9, 2004, the Commission issued a notice of the Agreement, and that the four applications and applicant-prepared environmental assessments were accepted for filing. The notice solicited motions to intervene, protests, comments, and final recommendations, terms and conditions, and prescriptions. Timely motions to intervene were filed by the Washington Fish and Wildlife; jointly by American Rivers, Trout Unlimited, and Native Fish Society; U.S. Department of the Interior (Interior); Forest Service; Washington Department of Ecology (Washington Ecology); Cowlitz PUD; Cowlitz Tribe; NMFS; and Yakama Nation. Fish First filed a late motion to intervene, which was granted.[7] None of the intervenors oppose the project.

6. On September 23, 2005, the Commission staff issued a draft environmental impact statement (EIS) for the relicensing of all four Lewis River Projects. American Rivers, Cowlitz Tribe, Cowlitz PUD, NMFS, PacifiCorp, Swiftview Owners Group, Three Rivers Recreational Area, Interior, Forest Service, U.S. Environmental Protection Agency (EPA), Washington Fish and Wildlife, Washington Ecology, and Yakama Nation filed comments on the draft EIS. The final EIS was issued on March 24, 2006. The potential environmental impacts of the measures proposed in the Agreement, along with additional staff-recommended measures, were considered in the EIS. References in this order to the EIS are to the final EIS, unless otherwise noted.

7. On January 5, 2006, PacifiCorp filed draft license articles implementing the terms of the Agreement for each of its projects. Many of these requirements duplicate the mandatory conditions of the section 18 prescriptions and the water quality certifications and the provisions of the National Marine Fisheries Service (NMFS) Biological Opinion. While the proposed draft articles are not included in the license, this order includes requirements consistent with the Agreement and proposed articles, except as noted below.

8. The motions to intervene, comments, and recommendations have been fully considered in determining whether, and under what conditions, to issue this license.

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[7] *See* unpublished notice dated May 30, 2007.

PROJECT AREA

9. The Lewis River is a tributary of the Columbia River in southwest Washington, with a drainage area of 1,050 square miles. The river originates in the Cascade Range of the Gifford Pinchot National Forest and flows westward about 93 miles, joining the Columbia River near Woodland, Washington.

10. From upstream to downstream, the Lewis River hydropower projects include Swift No. 1 [river mile (RM) 47.9], Swift No. 2 (RM 44), Yale (RM 34.2), and Merwin (RM 19.5), and affect almost 40 miles of river.

11. The Lewis River Basin downstream of Merwin dam supports wild fall Chinook salmon and hatchery stocks of spring Chinook, early and late coho salmon, and winter and summer steelhead. The project area is described in more detail in the Master Order.

PROJECT DESCRIPTION

12. The Merwin Project, the oldest and most downstream of the Lewis River Projects, includes a 313-foot-high concrete arch dam extending 1,252 feet across the Lewis River. Deepwater inlets lead to three short penstocks with a total capacity of 11,470 cubic feet per second (cfs), which enter the powerhouse immediately downstream of the dam. The plant has a nameplate capacity of 136 MW. Power from the project is carried by three 115-kilovolt (kV) primary transmission lines 1,000 feet to the Merwin substation. Flows in excess of powerhouse capacity are controlled by five Taintor gates situated above the 206-foot-long spillway. The project impounds the 14.5-mile-long Lake Merwin, with a surface area of about 4,000 acres at full pool. Merwin's 263,700 acre-feet of useable storage is managed for the purposes of power generation, flood management, recreation, and downstream fish habitat enhancement.

13. The Merwin Project boundary includes all shoreline recreational sites (Merwin Park, Speelyai Bay Park, Cresap Bay Campground); a narrow shoreline buffer around the reservoir; the Lower Speelyai Creek diversion and Speelyai Fish Hatchery; all project development facilities (dam, powerhouse, switchyard); the Merwin Fish Hatchery; the Hydro North Control Center; and lands downstream of the dam along the Lewis River that include the Merwin fishing access on the north shore of the river and the PacifiCorp fishing easement on the south shore.

14. As the downstream facility, Merwin operates as a re-regulation facility for the other three Lewis River Projects, providing minimum instream flows and ramping rates for the lower river. Minimum flow releases under the current license range from 1,000 to 5,400 cfs, depending on season, while downramping rates are limited to 2 inches per hour. The reservoir is maintained at a fairly constant level throughout the year, fluctuating between elevations 235 feet above mean sea level (msl) (normal minimum

summer pool) and 239.6 feet msl (full pool). Due to its large size, Lake Merwin experiences only minimal hourly fluctuations in response to peaking operations at the upstream Yale Project. The pattern of releases from the Merwin Project varies seasonally, with median monthly values ranging from 1,300 cfs in August to 8,000 cfs in December. During periods of high runoff, the Merwin facility spills water in volumes ranging from a few thousand cfs in moderate high runoff events to as much as 80,000 cfs or more during severe floods. The Merwin Project, together with the Swift No. 1 Project and the Yale Project, is also operated to meet Commission and Federal Emergency Management Agency requirements for flood management.

WATER QUALITY CERTIFICATION

15. Under section 401(a)(1) of the Clean Water Act (CWA),[8] the Commission may not issue a license for a hydroelectric project unless the state water quality certifying agency has issued water quality certification for the project or has waived certification by failing to act within a reasonable period of time, not to exceed 1 year. Section 401(d) of the CWA provides that state certification shall become a condition of any federal license that authorizes construction or operation of the project.[9]

16. On February 3, 2005, PacifiCorp applied to Washington Ecology for water quality certification. PacifiCorp subsequently withdrew and refiled its application on December 2, 2005. Pursuant to Section 4.1(9) of the water quality certification,[10] Washington Ecology issued amendments on December 21, 2007 and January 17, 2008.[11]

17. The conditions of the certification include general requirements: (1) compliance with all state water quality standards approved by the EPA; (2) compliance with sediment

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[8] 33 U.S.C. § 1341(a)(1) (2000).

[9] 33 U.S.C. § 1341(d) (2000).

[10] Ecology reserves the right to amend this certification if it determines that the provisions are no longer adequate to provide reasonable assurance of compliance with applicable water quality standards or other appropriate requirements of state law.

[11] Washington Ecology replaced three of the conditions of the certification dealing with oil spill prevention and control (conditions 4.6.3.e, 4.6.4.e, and 4.6.5.a). The revisions require that the oil-water separator be sized to accommodate inflows up to the total volume of the largest transformer plus 15 percent and that the transformer containment area will contain spills from the volume of the largest transformer plus 15 percent. With regard to the sumps, the revision requires that the oil sensors be calibrated and maintained to detect oil at 15 parts per million or less.

quality standards; (3) prohibition of discharge of any solid or liquid waste to the waters of Washington; and (4) reservation of Washington Ecology's authority.

18. The certification also includes specific conditions: (1) release specified instream flows and provide habitat; (2) maintain specified total dissolved gas levels; (3) maintain specified temperature and dissolved oxygen levels; (4) implement measures to protect water quality during construction projects, miscellaneous discharges, and habitat modifications; (5) implement oil spill prevention and control measures; (6) implement measures to protect water quality during pesticide applications; and (7) implement monitoring and reporting measures.

19. The water quality certification conditions are attached as Appendix A to this order. Ordering Paragraph (D) incorporates the certification conditions of Appendix A as conditions of the license.

SECTION 18 FISHWAY PRESCRIPTION

20. Section 18 of the FPA[12] provides that the Commission shall require the construction, maintenance, and operation by a licensee of such fishways as may be prescribed by the Secretary of the Interior or the Secretary of Commerce, as appropriate.

21. Both Commerce and Interior filed modified fishway prescriptions (Commerce filed on February 17, 2006, and Interior filed on February 22, 2006). Both prescriptions involve passage of anadromous salmon and steelhead species, while FWS's prescriptions also involve bull trout. Both agencies state that these prescriptions are consistent with the Agreement.

22. The fishway prescriptions include structures for upstream and downstream passage past the project, project operations, performance standards, outcome goals, and other measures to ensure effective passage. Within 6 months after the fourth anniversary of the new Merwin license, PacifiCorp will construct and begin operating an upgraded upstream fish passage facility at Merwin dam that would collect, sort, and transport upstream-migrating adult Chinook, coho, steelhead, sea-run cutthroat trout, and bull trout. Initially, adult Chinook, coho, and steelhead collected at Merwin dam will be transported and released above Swift dam. Any bull trout collected below Merwin dam will be transported to Yale Lake unless otherwise directed by FWS. On or before the 17th anniversary of the new licenses (unless otherwise directed by FWS and NMFS), PacifiCorp will construct and begin operating a downstream passage facility at Merwin dam. The FWS' prescriptions also include measures for the collection and hauling of bull trout.

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[12] 16 U.S.C. § 811 (2000).

23. The Commerce section 18 prescription is attached as Appendix B to this order and the Interior prescription is attached as Appendix C. Ordering Paragraphs (E) and (F) incorporate the Commerce and Interior prescriptions, respectively, as conditions of the license.

24. Both agencies also reserve their rights under Section 18 of the FPA to modify the fishway prescriptions based upon significant new information and conclusions developed in connection with the fulfillment of other statutory consultation and review requirements. Consistent with Commission policy, Article 410 of this license reserves the Commission's authority to require fishways that may be prescribed by Interior or Commerce for the Merwin Project.

THREATENED AND ENDANGERED SPECIES

25. Section 7(a)(2) of the Endangered Species Act (ESA) of 1973,[13] requires federal agencies to ensure that their actions are not likely to jeopardize the continued existence of federally listed threatened and endangered species, or result in the destruction or adverse modification of their designated critical habitat. The draft EIS evaluated effects of the project on listed species and served as our biological assessment (BA). Staff's conclusions with regards to threatened and endangered species and the measures included in the biological opinions (BOs) issued by NMFS and FWS are outlined in the Master Order.

26. On September 30, 2005, Staff requested formal consultation with NMFS on the listed salmon and steelhead species. NMFS issued a BO on August 27, 2007, which contains four incidental take terms and conditions that require the licensee to: (1) comply with the provisions of the Agreement that relate to anadromous fish (specifically, sections 3, 4, 5, 7, 8, and 9 of the Agreement); (2) for all construction activities, implement measures to control sediment and minimize other potential effects on salmonids; (3) implement monitoring and evaluation measures contained in the Agreement; and (4) report any dead or injured steelhead that are discovered. These terms and conditions are contained in Appendix D of this order, and incorporated into this license by Ordering Paragraph (G), with the exception of section 6.1.5.a of the Agreement (flows through the upper release point during spill flows) prohibited by the mandatory water quality certification.[14] The absence of this measure will not minimize the protection of listed species.

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[13] 16 U.S.C. § 1536(a) (2000).

[14] The BO issued for the four Lewis River Projects requires compliance with section 6 of the Agreement that, among other things, allows the licensees for the Swift No. 1 and Swift No. 2 Projects, at their discretion, to stop releases through the Upper

27. Staff requested consultation with FWS on September 30, 2005. FWS issued a BO for bull trout, bald eagle, and northern spotted owl on September 15, 2006. The BO contains five incidental take terms and conditions related to bull trout that require the licensee to: (1) minimize coho redd superimposition on bull trout; (2) conduct annual bull trout surveys; (3) implement procedures for transporting fish to minimize predation; (4) follow instream construction timing; and (5) implement measures for monitoring and handling bull trout. These terms and conditions are provided in Appendix E of this order and incorporated by Ordering Paragraph (H).

ESSENTIAL FISH HABITAT

28. Section 305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act[15] requires federal agencies to consult with the Secretary of Commerce regarding any action or proposed action authorized, funded, or undertaken by the agency that may adversely affect Essential Fish Habitat (EFH) identified under the Act. Under section 305(b)(4)(A)[16] of the Magnuson-Stevens Act, NMFS is required to provide EFH Conservation Recommendations for actions that would adversely affect EFH. Under section 305(b)(4)(B) of the Act,[17] an agency must, within 30 days after receiving recommended conservation measures from NMFS or a Regional Fishery Management Council, describe the measures proposed by the agency for avoiding, mitigating, or offsetting the effects of the agency's activity on the EFH.[18]

29. The Pacific Fisheries Management Council has designated EFH for the following federally managed Pacific salmon: Chinook, coho, and Puget Sound pink salmon. Freshwater EFH for these Pacific salmon includes all streams, lakes, ponds, wetlands,

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Release Point in the vicinity of the Swift No. 1 powerhouse during the time that spills displace scheduled releases from the Upper Release Point into the Lewis River bypassed reach (section 6.1.5.a of the Agreement). Section 4.2(5) of the water quality certifications issued for the Swift No. 1 and Swift No. 2 Projects do not allow such modification.

[15] 16 U.S.C. § 1855(b)(2) (2000).

[16] 16 U.S.C. § 1855(b)(4)(A) (2000).

[17] 16 U.S.C. § 1855(b)(4)(B) (2000).

[18] The measures recommended by the Secretary of Commerce are advisory, not prescriptive. However, if the federal agency does not agree with the recommendations of the Secretary of Commerce, the agency must explain its reasons for not following the recommendations.

and other water bodies currently or historically accessible to salmon in Washington, Oregon, Idaho, and California, except areas upstream of certain impassable artificial (man-made) barriers, and longstanding naturally impassable barriers. The Lewis River Basin comprises EFH for Chinook and coho salmon.

30. Staff concluded in the EIS that relicensing the projects as proposed by the applicants would continue to have an adverse effect on Chinook and coho EFH, but that elements of the proposed action, such as improvements to upstream and downstream passage, would reduce these effects over current conditions.

31. NMFS included an analysis of effects on EFH in its BO for the four projects provided in response to the Commission's September 30, 2005 request to initiate formal consultation under the ESA. In the BO, dated August 27, 2007, NMFS concluded that the proposed action would adversely affect designated EFH for Pacific coast salmon. NMFS adopted the terms and conditions of the BO's incidental take statement (discussed above) as conservation measures to minimize the effects on EFH. NMFS' conservation measures are included in this license in accordance with the terms and conditions of the NMFS BO (Appendix D of this order).

PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT

32. In 1980, Congress enacted the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).[19] This act created the Northwest Power Planning Council (now known as the Northwest Power and Conservation Council) and directed it to develop a Columbia River Basin Fish and Wildlife Program (Program). The Program is to protect, mitigate, and enhance fish and wildlife resources affected by the development and operation of hydroelectric projects on the Columbia River and its tributaries, while assuring the Pacific Northwest an adequate, efficient, economical and reliable power supply.[20] Section 4(h)(11)(A) of the Northwest Power Act[21] provides that federal agencies operating or regulating hydroelectric projects within the Columbia River Basin shall exercise their responsibilities to provide equitable treatment for fish and wildlife resources with other purposes for which the river system is utilized and shall take the Council's Program into account "at each relevant stage of decision-making processes to the fullest extent practicable."

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[19] 16 U.S.C. §§ 839(b) (2000) *et seq.*

[20] 16 U.S.C. § 839b(h)(5) (2000).

[21] 16 U.S.C. § 839(h)(11)(A) (2000).

33. To mitigate harm to fish and wildlife resources, the Council has adopted specific provisions to be considered in the licensing or relicensing of non-federal hydropower projects (Appendix B of the Program). The provisions of the Agreement required by this license, including anadromous fish reintroduction and passage measures (sections 3 and 4), flow releases (section 6), aquatic habitat enhancement (section 7), hatchery and supplementation program (section 8), and wildlife land acquisition and management (section 10) are consistent with applicable provisions of the Program, as discussed in more detail in the EIS.[22] As part of the Program, the Council has designated over 40,000 miles of river in the Pacific Northwest region as not being suitable for hydroelectric development ("protected area"). The Merwin Project is not located within a protected area designated under Appendix B of the Program. Further, Article 411 reserves to the Commission the authority to require future alterations in project structures and operations to take into account, to the fullest extent practicable, the applicable provisions of the program.

NATIONAL HISTORIC PRESERVATION ACT

34. Under section 106 of the National Historic Preservation Act (NHPA),[23] and its implementing regulations,[24] federal agencies must take into account the effect of any proposed undertaking on properties listed or eligible for listing in the National Register of Historic Places (defined as historic properties) and afford the Advisory Council on Historic Preservation a reasonable opportunity to comment on the undertaking. This generally requires the Commission to consult with the State Historic Preservation Officer (SHPO) to determine whether and how a proposed action may affect historic properties, and to seek ways to avoid or minimize any adverse effects.

35. To satisfy these responsibilities, the Commission executed a Programmatic Agreement (PA) with the Washington State Historic Preservation Officer and invited PacifiCorp, Forest Service, Cowlitz Tribe, and Yakama Nation to concur with the stipulations of the PA.[25] The PA requires PacifiCorp to implement the final Historic Properties Management Plan (HPMP), dated March 2004. Execution of the PA demonstrates the Commission's compliance with section 106 of the NHPA.

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[22] *See* EIS at 5-23 to 5-31.

[23] 16 U.S.C. § 470 (2000) *et seq*.

[24] 36 C.F.R. Part 800 (2007).

[25] No historic properties associated with the Swift No. 2 Project were identified. As a result, this PA did not include the Swift No 2 Project.

36. PacifiCorp will implement the HPMP, as described in Section 13.1.1 of the Agreement. The HPMP guides the licensee's treatment of known and yet to be discovered cultural and historic resources through the license term and identifies the consultation procedures the licensee shall undertake with the Cowlitz Tribe, Yakama Nation, and oversight agencies. Additionally, the licensee will implement the following specific measures for protection of cultural resources relevant to the Merwin Project:

(1) curate archeological artifacts recovered from the project area and associated documentation at the visitor information facility described in section 13.2.4 of the Agreement or at another project facility created by the licensee in one of its existing buildings that meets the applicable federal curation guidelines;

(2) provide access by the Cowlitz Tribe and Yakama Nation to project lands for traditional cultural practices except where unsafe conditions exist;

(3) undertake a program to monitor and protect cultural resources in the draw-down zones;

(4) designate a cultural resource coordinator for the licensee's Lewis River Projects; and

(5) undertake a program for annual training and education of the licensee's employees whose work may affect cultural resources in the project areas.

37. The existing HPMP approved by the PA includes the requirements stated above. Article 412 requires PacifiCorp to implement the PA and associated HPMP consistent with section 13.1.1 of the Agreement.

RECOMMENDATIONS OF FEDERAL AND STATE FISH AND WILDLIFE AGENCIES

A. Recommendations Pursuant to Section 10(j) of the FPA

38. Section 10(j)(1) of the FPA,[26] requires the Commission, when issuing a license, to include conditions based on recommendations by federal and state fish and wildlife agencies submitted pursuant to the Fish and Wildlife Coordination Act,[27] to "adequately and equitably protect, mitigate damages to, and enhance fish and wildlife (including related spawning grounds and habitat)" affected by the project.

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[26] 16 U.S.C. § 803(j)(1) (2000).

[27] 16 U.S.C. §§ 661 (2000) *et seq.*

39. In response to the Commission's notice that the projects were ready for environmental analysis (dated December 9, 2004), NMFS, Interior, and Washington Fish and Wildlife filed letters of comment that included section 10(j) recommendations.[28] These agencies are also parties to the Agreement.[29] In their letters containing their 10(j) recommendations, these agencies recommended that the Commission approve the Agreement and all the provisions thereof. Four recommendations were determined to be outside the scope of section 10(j) and are discussed in the next section. The remaining 10(j) recommendations that were provisions of the Agreement are consistent with the section 4(e) conditions, fishway prescriptions, water quality certification conditions, and BO terms and conditions and are therefore incorporated into the license. As a result, this license includes conditions consistent with the recommendations that are within the scope of section 10(j).

B. Recommendations Pursuant to Section 10(a)(1) of the FPA

40. The agencies made recommendations that are not specific measures to protect, mitigate damages to, or enhance fish and wildlife. Consequently, I do not consider these recommendations under section 10(j) of the FPA. Instead, I consider these recommendations under the broad public-interest standard of FPA section 10(a)(1).[30]

41. Staff did not recommend in the draft EIS four measures relevant to the Merwin Project that are outside the scope of section 10(j). These include: (1) adoption of a contingency monetary fund (In-lieu Fund) to implement mitigation measures for anadromous salmonids if it is determined that reintroduction of salmonids is not required; (2) certain measures to be funded by the Aquatics Fund; (3) funding for three additional marine and land based law enforcement officers; and (4) improvements to five river access sites outside of the Merwin Project boundary along the lower Lewis River.

42. The In-lieu Fund is not within the scope of section 10(j), in that it is not a specific measure for fishery resources but rather a contingency fund. Under Section 7.6 of the

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[28] These letters were dated February 3, 4, and 7, 2005, respectively.

[29] The Agreement was filed with the Commission on December 3, 2004.

[30] 16 U.S.C. § 803(a)(1) (2000). Section10(a)(1) requires that any project for which the Commission issues a license shall be best adapted to a comprehensive plan for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce; for the improvement and utilization of waterpower development; for the adequate protection, mitigation, and enhancement of fish and wildlife; and for other beneficial public uses, including irrigation, flood control, water supply, recreation, and other purposes.

Agreement, PacifiCorp would fund mitigation measures for anadromous salmonids in the event that an upstream fish passage is not implemented ($30 million for the Yale, Merwin, and Swift No. 1 Projects). For the Merwin Project, PacifiCorp would provide $10 million in lieu of the Merwin downstream facility. The process for making the decision to implement the fund is outlined in section 4.1.9 of the Agreement. As indicated in the Master Order, because this is a fund for events that may or may not occur, staff was unable to determine what measures would be supported by this fund, or whether they would be directly linked to effects of the projects or their operations.[31] Furthermore, it was unclear to staff what circumstances would be the basis for the fund's implementation. Instead, staff recommended that the licensees prepare a report that presents the rationale for how the decision to forego fish passage was made and a plan that describes the procedures for determining which specific measures in lieu of fish passage would be implemented.

43. The intent of the In-lieu Fund--implementation of measures necessary to protect and enhance Lewis River salmonid population in lieu of fish passage—is consistent with the intent of the staff recommendation. Although I do not endorse establishing a $10 million fund for the Merwin Project because of the unknown nature of any needed measures, it is a condition required by NMFS's BO, and therefore I include it in the Merwin Project license [Ordering Paragraph (G) and Appendix D of this order]. In addition, I require that PacifiCorp file, for Commission approval, all plans and measures in lieu of fish passage that are proposed, before they are implemented, and that all proposed measures demonstrate a clear nexus to the objectives set forth in section 7.6.3 of the Agreement (Article 401).

44. The Aquatics Fund is not within the scope of section 10(j), in that the fishery measures lack specificity. The fund is proposed to benefit fish recovery throughout the North Fork Lewis River, with priority to federal ESA-listed species; to support the reintroduction of anadromous fish throughout the basin; and to enhance fish habitat in the Lewis River Basin, with priority given to the North Fork Lewis River. While benefits of the fund will most likely extend to the enhancement, protection, and restoration of aquatic habitat and other resources affected by the project, it is not certain that funds would be used solely for measures that provide a demonstrated benefit to resources affected by project structures and operations.[32] To ensure that the fund achieves the objectives listed under section 7.5 of the Agreement and has a project nexus, however, I will require that the strategic plan that will guide resource project development and the annual report describing proposed resource projects be filed with the Commission for approval (Article 401) after the plan is approved by the Aquatic Coordination Committee

[31] *See* EIS, section 3.3.3.2.

[32] *Id.*, section 5.1.5.

(ACC).[33] I include the Aquatics Fund because it would provide substantial benefits to resources affected by the project [Ordering Paragraph (G) and Appendix D].

45. Funding law enforcement is not within the scope of section 10(j) in that it is not a recommendation related to fish and wildlife resources. I do not include funding law enforcement because law enforcement is the responsibility of the county and state agencies and would not necessarily be directed at project-related recreational use.

46. Improvements to five river access sites outside of the Merwin Project boundary are not within the scope of section 10(j), in that they are not specific measures for fish and wildlife resources. As outlined in section 11.2.4.1 through 11.2.4.3 of the Agreement, PacifiCorp proposes to continue to maintain and improve five lower river access sites downstream of Merwin dam. The improvements would include replacing or providing vault toilets at all of the sites and providing two to three picnic tables at each of the lower sites. Although the proposed measures would improve public access to the Lewis River downstream of the Merwin Project, there is no physical nexus between most of these sites and the project.[34] The proposed measures would be located at sites approximately 5 miles downstream of the project, and as a result, would not be associated with displaced recreation use. Therefore, I do not include these recreational facilities as part of the Merwin Project. Nevertheless, PacifiCorp is free to continue to operate these facilities outside of the Merwin Project license.

OTHER ISSUES

A. Fisheries and Aquatic Resources

47. Many of the fisheries and aquatic resources plans required by the mandatory NMFS and FWS fishway prescriptions or conditions of the NMFS BO do not require Commission approval. Article 401(a) requires that PacifiCorp file the following plans or designs for Commission approval before implementation: upstream transport plan, downstream transport plan, downstream passage design at Merwin dam, design of stress release ponds, bull trout collection and transport program, habitat preparation plan, Aquatics Fund strategic plan, In-lieu Fund strategic plan, hatchery and supplementation plan and operating plan, and monitoring and evaluation plan.

48. Several fishway prescriptions and BO conditions contemplate changes to project operations or facilities over the course of the new license as a result of studies or changed

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[33] The ACC and Terrestrial Coordination Council (TCC) are made up of representatives from the Agreement signatories, as outlined above.

[34] *See* EIS at 3-157.

circumstances. Because the comprehensive development standard of FPA section 10(a)(1) continues to govern regulation of a project throughout the term of its license,[35] it is the Commission's responsibility to give prior approval, through appropriate license amendments, for all material changes to the project and its maintenance and operation.[36] Article 401(b) identifies these conditions and requires Commission approval of these changes before they may be implemented.

49. Section 5.5 of the Agreement provides that PacifiCorp perform a limiting factors analysis for bull trout occurring in Lake Merwin tributary streams to determine potential for long-term, sustainable habitat. Such an analysis would be valuable by identifying those habitat elements critical to bull trout survival that require restorative efforts.[37] This analysis is required by article 402.

50. Section 6.2 of the Agreement requires PacifiCorp to provide minimum flows downstream of Merwin dam and ramping rates that would result in improved aquatic habitat and reduce the potential for stranding below Merwin dam for the listed bull trout, anadromous salmonids, and other aquatic organisms.[38] The Agreement allows the licensee to modify flow releases during low-flow periods. Any changes to the flow regime would require Commission approval.

51. PacifiCorp also proposes to continue the following aquatic resources measures: (1) maintain downramping rates of 2 inches/hour (with exceptions provided by the Agreement) and maintain minimum flow releases below Merwin dam; (2) follow NMFS and FWS facility and handling guidelines for anadromous fish and bull trout; (3) operate the upstream adult salmon and steelhead collection trap at Merwin dam; (4) in conjunction with the other Lewis River Projects, maintain current salmon and steelhead smolt production levels (3,125,000) to achieve a goal of 86,000 ocean recruits, or as determined by the ACC; (5) in conjunction with the other Lewis River Projects, maintain current production levels for kokanee and rainbow trout; (6) support the Washington Fish and Wildlife's annual evaluation of fall Chinook in the lower Lewis River; and (7) in

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[35] *See, e.g., S.D. Warren Co.*, 68 FERC ¶ 61,213 at p. 62,022 (1994).

[36] The Commission's regulations, as well as the terms of the license and basic due process principles, govern what types of alterations require what sorts of submittals or public notice. A license article can not provide for automatic amendment of the license based on future occurrences. Rather, the licensee is free to file with the Commission for an amendment of its license, if future conditions warrant.

[37] *See* EIS, section 3.3.3.2.

[38] *Id.*, section 3.3.3.2.

conjunction with the other Lewis River Projects, annually evaluate bull trout and kokanee populations. These measures would ensure the maintenance and restoration of anadromous fish species and the federally listed bull trout and are required by Article 402, the water quality certification (minimum flows and ramping rates), or conditions of the NMFS BO (production goals and Merwin trap).

B. Wildlife Resources

52. PacifiCorp currently manages the 5,600-acre Merwin Wildlife Habitat Management Area under a Wildlife Habitat Management Plan (Habitat Plan). PacifiCorp proposes to develop, fund, and implement Habitat Plans on existing PacifiCorp-owned lands, as provided for in section 10.8 of the Agreement. This would replace the current Habitat Plan for the Merwin Wildlife Habitat Management Area. The lands covered by the new Habitat Plans for the Merwin Project shall include: (1) 5,600 acres currently managed as part of the Merwin Wildlife Habitat Management Area; and (2) all other PacifiCorp-owned lands adjacent to the project, except as provided in Exhibit A of the Agreement. The general wildlife objectives are outlined in schedule 10.8, *Wildlife Objectives* of the Agreement.

53. Implementation of the new Habitat Plan would continue to offset habitat impacts and associated wildlife losses resulting from continued operation of the project by enhancing the quality of wildlife habitat within and adjacent to the project boundary, benefiting many wildlife species. Article 403 requires PacifiCorp to file a Habitat Plan for Commission approval within 6 months from the date of issuance of this license and any future modifications to the Habitat Plan. The licensee shall continue to implement the current Merwin Project Wildlife Habitat Management Plan in the Merwin Wildlife Habitat Management Area until approval of the new Habitat Plan required by this license. Article 403 also requires the licensee to file annual plans outlining the proposed wildlife measures and costs and showing the benefits to resources affected by project structures or operations. The annual plans shall explain the consistency with wildlife objectives outlined in the Agreement. Article 203 requires that all PacifiCorp-owned lands adjacent to the project boundary managed under the Habitat Plan be included in the project boundary.

54. With respect to wildlife resources, PacifiCorp proposes to continue the following measures: (1) buffer sensitive aquatic and terrestrial habitat from ground-disturbing activities (timber harvest, construction, etc.); (2) maintain road closures through sensitive habitat areas by installing and maintaining gates, and identify additional areas for access control on PacifiCorp lands; (3) manage PacifiCorp lands to benefit wildlife habitat; and (4) continue to manage project roads to maintain existing aquatic connectivity and control runoff and erosion. Article 404 of the license requires these measures.

C. Recreation Resources

55. The Recreation Resource Management Plan (Recreation Plan) filed with the Agreement on November 30, 2004, includes all recreation measures proposed in the Agreement, along with additional recreational measures and timelines. The recreation measures outlined in section 11.2.3.1 of the Agreement provide for PacifiCorp to make a number of improvements, including promoting existing and new non-motorized, multi-use trails; upgrading river access at Speelyai Bay Park and providing an improved river access site at the Yale Bridge; upgrading and developing recreation facilities at Merwin Park and Speelyai Bay Park; and maintaining all existing and new recreation facilities, including shoreline camping and day use sites in a manner consistent with the Recreation Dispersed Shoreline Use Program (Shoreline Program) pursuant to maintenance standards and frequencies set forth in the Recreation Plan on all lands within the Merwin Project boundary. All existing campsites and day-use sites would be assessed to determine suitability for continued day-use recreation within the first year of license issuance and those sites that would not allow camping would be identified by the fourth year of issuance. In addition, PacifiCorp will collaborate with the licensee for the Swift No. 2 Project to produce a single Interpretation and Education Program, which will include a public information program to protect bull trout, as outlined in section 5.7 of the Agreement, for all four Lewis River Projects. These measures would provide substantial improvements to existing conditions and would improve access to recreational opportunities in the project area.[39] Therefore, Article 405 requires PacifiCorp to implement the Recreation Plan with the exception of the measures proposed for the recreation facilities downstream of the project as discussed below. In addition, article 405 requires the licensee to file a report documenting the implementation of the public information program to protect bull trout as outlined in section 5.7 of the Agreement.

56. PacifiCorp also proposes to evaluate the feasibility of a trail easement to connect a proposed Clark County regional park to the south side of Lake Merwin as outlined in section 11.2.3.4 of the Agreement. PacifiCorp would provide the easement and Clark County would develop and operate the trail. PacifiCorp estimated that the demand for trail-related activities will increase significantly over the next 30 years. By providing a trail easement between the County's regional park and Lake Merwin, this would allow pedestrian access to the shoreline and provide a new trail-related recreational opportunity within the project. PacifiCorp is free to work with Clark County to construct, operate, and maintain the trail, as outlined in the Agreement. Nevertheless, PacifiCorp would be ultimately responsible for the trail. Therefore PacifiCorp shall file a trail access plan under Article 406 and shall include the access trail within the Merwin Project boundary.

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[39] *Id.* at 3-160.

57. As outlined in 11.2.3.5 of the Agreement, PacifiCorp, as part of the Recreation Plan, would evaluate accessibility for the disabled at existing Lake Merwin recreation facilities and subsequently would make accessibility improvements to those facilities based on this evaluation. The Agreement, however, includes no mechanism for Commission review and approval of the actual upgrades or modification of project recreation facilities. Therefore, Article 407 of this order requires PacifiCorp, once the evaluation is complete, to file a report with the Commission that summarizes the results of the evaluation, and describes its plan for modifying existing project recreation facilities, including a timeline for construction. Improving access for the disabled at the project would be consistent with the Commission's policy on recreation facilities at licensed projects[40] under which licensees are expected to consider the needs of the disabled in the design and construction of such facilities**.** It would also help address growing recreational demand at this project.[41]

58. As outlined in section 11.2.3.10 and 11.2.3.11 of the Agreement, PacifiCorp proposes to make several improvements to Speelyai Bay Park, including upgrading the existing restroom building to meet Americans with Disabilities Act standards, improving parking in the quarry area by providing gravel and marked parking spaces. This license requires these measures through Article 405. In addition, PacifiCorp proposes to evaluate the feasibility of providing additional parking with trail access to the boat launch area. This measure is required under Article 408.

59. As outlined in section 11.2.4.1 through 11.2.4.3 of the Agreement, PacifiCorp proposes to continue to construct a new river access site downstream of Merwin dam and within the project boundary (Merwin Hatchery River Access Site) to meet recreation demands at the project. Although we exclude five recreational access sites located downstream of Merwin dam because of lack of nexus with the project (see above), this access site is within the project boundary and has a direct connection to the project. The new improvements would include providing a vault toilet and two picnic tables at the lower site. Article 409 requires PacifiCorp to implement these improvements at the Merwin Hatchery River Access Site.

D. Flood Management

60. The Lewis River Projects have provided important flood management for the local communities below Merwin dam. PacifiCorp is subject to an agreement with the Federal Emergency Management Agency (FEMA) dated August 18, 1983 under which PacifiCorp is obligated to follow its existing Standard Operating Procedure manual in

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[40] *See* 18 CFR section 2.7 (2007).

[41] *See* EIS at 3-157.

operating its projects. Article 302 requires that the licensee shall provide not less than 70,000 acre-feet of storage space in the Merwin, Yale, and Swift No. 1 hydroelectric developments for flood control on the Lewis River, beginning withdrawal by September 20 and reaching not less than 70,000 acre-feet by November 1 of each year, and retaining such space through April 1 and permitting gradual filling by April 30 of the following year, according to an approved schedule.[42] In the Agreement, the parties agreed that PacifiCorp would request FEMA to shorten the Flood Management Season to begin refilling the project reservoir by March 15 instead of April 1 if forecasts predict below average spring runoffs. As required in Article 302, PacifiCorp would file a revised Standard Operating Procedure Manual with the Commission for review and comment if the Flood Management Season is modified. The Standard Operating Manual would provide details on how the project is to be operated to achieve the desired target elevations, during normal and flood conditions.

61. Article 302 also requires the licensee to notify the Commission by November 1 of each year how they will achieve the 70,000 acre-feet of flood storage.

62. Article 303 requires the licensee to reimburse the U.S. Geological Survey (USGS) for the monthly operating cost of maintaining the telephone line that provides gaging information necessary for operation of the project, as described in the Agreement.

63. Under sections 12.6 and 12.7 of the Agreement, PacifiCorp proposes to provide funding to Clark County and Cowlitz County for the acquisition, installation, and maintenance of a new emergency telephone notification system for those portions of those counties that are subject to inundation. PacifiCorp also proposes to reimburse NOAA for the installation and maintenance of a weather radio transmitter at Davis Peak that provides reservoir storage data, flow data, and flood warnings.

64. Funding of the county's emergency phone system and the NOAA weather transmitter would help improve communications coverage in this rural area. Article 304 requires that PacifiCorp be responsible for these measures. However, implementation of these measures may be accomplished through the funding of a third party.

ADMINISTRATIVE PROVISIONS

A. Annual Charges

65. The Commission collects annual charges from licensees for administration of the FPA and for the use, occupancy and enjoyment of federal lands. Article 201 provides for

[42] The flood control requirements are the same as in the existing Swift No. 1 license. 48 FERC ¶ 62,106 (1989).

the collection of funds for administration of the FPA and for recompensing the United States for the use of its lands.

B. Exhibit F and G Drawings

66. The Commission requires licensees to file sets of approved project drawings on microfilm and in electronic file format. Article 202 requires the filing of project works drawings (Exhibit F).

67. PacifiCorp filed Exhibit G (project boundary) maps as part of its license application, and recently revised them based on the use of Light Detection and Ranging (LIDAR), a remote sensing system used to collect topographic data.[43] These maps differ from the currently approved project boundary maps under the existing license. PacifiCorp, however, provides no explanation for the differences in acreage of total lands and federal lands between the approved and proposed maps. This order does not approve the changes, and will instead require PacifiCorp to file revised maps resolving those differences. If this resolution results in removal of certain areas from the project, PacifiCorp may include an amendment of license application with its filing, containing support for its request.

68. I am including Article 203 in the license to require PacifiCorp to file revised Exhibit G drawings that enclose within the project boundary all project facilities and lands, including recreation and wildlife lands and federal lands occupied by the project. The revised drawings must also explain discrepancies in acreages of total lands within the project boundary, including federal land acreages, between currently approved and proposed drawings.

C. Headwater Benefits

69. Some projects directly benefit from headwater improvements that were constructed by other licensees, by the United States, or by permittees. Article 204 requires the licensee to reimburse such entities for these benefits if they were not previously assessed and reimbursed.

D. Amortization Reserve

70. The Commission requires that for new major licenses, licensees must set up and maintain an amortization reserve account upon license issuance. Article 205 requires the establishment of the account.

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[43] *See* June 7, 2007 filing of PacifiCorp.

E. Modified Project Facilities

71. Article 301 requires the licensee to file revised Exhibit A, F, and G drawings, as applicable, upon the completion of all construction/removal activities authorized by this license, to describe and show those project facilities as built.

F. Use and Occupancy of Project Lands and Waters

72. Requiring a licensee to obtain prior Commission approval for every use or occupancy of the project would be unduly burdensome. Therefore, Article 413, the standard land use article, allows the licensee to grant permission, without prior Commission approval, for the use and occupancy of project lands for such minor activities as landscape planting. Such uses must be consistent with the purposes of protecting and enhancing the scenic, recreational, and environmental values of the project.

STATE AND FEDERAL COMPREHENSIVE PLANS

73. Section 10(a)(2) of the FPA[44] requires the Commission to consider the extent to which a project is consistent with federal or state comprehensive plans for improving, developing, or conserving a waterway or waterways affected by the project.[45] Under section 10(a)(2)(A), federal and state agencies filed 73 comprehensive plans that address various resources in Washington. Of these, the staff identified and reviewed 11 comprehensive plans[46] that are relevant to this project. No conflicts were found.

APPLICANT'S PLANS AND CAPABILITIES FOR THE MERWIN PROJECT

74. In accordance with sections 10(a)(2)(c) and 15(a) of the FPA,[47] Commission staff evaluated PacifiCorp's record as a licensee with respect to the following: (A) conservation efforts; (B) compliance history and ability to comply with the new license; (C) safe management, operation, and maintenance of the project; (D) ability to provide efficient and reliable electric service; (E) need for power; (F) transmission service; (G) cost effectiveness of plans; and (H) actions affecting the public. I agree with staff's findings in each of the following areas.

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[44] 16 U.S.C. § 803(a)(2)(A) (2000).

[45] Comprehensive plans for this purpose are defined at 18 C.F.R. § 2.19 (2007).

[46] The list of applicable plans can be found in Section 5.4 of the EIS at 5-40 to 5-41.

[47] 16 U.S.C. §§ 803(a)(2)(C) and 808(a) (2000).

A. Conservation Efforts

75. PacifiCorp has devised a demand-side management (DSM) program consisting of over 10 components. The DSM program goal is to increase energy efficiency. The principal components of the program are: (1) the Energy FinAnswer, a program that provides engineering and incentive package for improved energy efficiency in new construction and retrofit projects for commercial, industrial and irrigation customers; (2) lighting retrofit incentive for energy efficient lighting retrofits in commercial and industrial facilities; (3) the low income weatherization program; (4) a do-it-yourself home audit; and (5) an energy efficiency education program. Staff concludes that PacifiCorp is making a good faith effort to conserve electricity and promote energy conservation by its customers.

B. Compliance History and Ability to Comply with the New License

76. Commission staff reviewed PacifiCorp's compliance with the terms and conditions of the existing license. Staff finds that PacifiCorp's overall record of making timely filings and compliance with its license is satisfactory. Thus, PacifiCorp has or can acquire the resources and expertise necessary to carry out its plans and comply with all articles and terms and conditions of a new license.

C. Safe Management, Operation, and Maintenance of the Project

77. Commission staff reviewed PacifiCorp's management, operation, and maintenance of the Merwin Project pursuant to the requirements of 18 C.F.R. Part 12 (2007) and the Commission's Engineering Guidelines and periodic Independent Consultant's Safety Inspection Reports. Based on our review of the most recent operation inspection reports, independent consultant's safety inspection reports, and project files, we conclude that the Merwin Project works are in good condition and well maintained. No significant deficiencies were noted during the inspections and no maintenance items require immediate remedial action. There is no reason to deny issuance of the license based on the licensee's record of managing, operating, and maintaining these structures.

78. Staff determined that the dam and other project works are safe, and that there is no reason to believe that PacifiCorp cannot continue to safely manage, operate, and maintain these facilities under a new license.

D. Ability to Provide Efficient and Reliable Electric Service

79. Staff reviewed PacifiCorp's plans and its ability to operate and maintain the project in a manner most likely to provide efficient and reliable electric service. Based on review of the information, Staff believes that PacifiCorp will operate the project in an

efficient manner within the constraints of the license and that the project will continue to provide efficient and reliable electric service in the future.

E. Need for Power

80. The Merwin Project is owned and operated by PacifiCorp, a utility supplying electricity to residential, wholesale, commercial and industrial users. PacifiCorp is an integrated electric utility serving more than 1.6 million customers in a six-state service area.

81. Under the terms of this license, the Merwin Project will generate an average of 506,642 megawatt hours (MWh) of electric energy per year which is available to serve the power needs of six western states. The project has a nameplate capacity of 136 MW, and a dependable capacity of 31.9 MW.

82. Residential customers account for 85 percent of PacifiCorp's customers, 11 percent are commercial business, and 4 percent industrial users. PacifiCorp anticipates that 3,171 MW of additional capacity will be needed by 2016 for PacifiCorp to meet its customer loads.[48] Future energy needs will need to be met using a variety of renewable and non-renewable fuel sources, including natural gas, geothermal, and wind facilities.

83. The project is located in the Northwest Power Pool Area (NWPP) of the Western Electricity Coordinating Council (WECC) region of the North American Electric Reliability Council. The peak demand requirements for the NWPP area are projected to grow at an average annual compound rate of 1.5 percent.[49]

84. Based on the above projections, the power from the Merwin Project would continue to be useful in meeting local as well as part of the regional need for power. The project would continue to displace some of the fossil-fueled electric power generation the regional utilities now use, and thereby conserve nonrenewable resources and reduce the emission of noxious byproducts caused by the combustion of fossil fuels.

F. Transmission Services

85. The project's transmission facilities that are required to be licensed include the three 1,000-foot-long, 115-kV lines conveying power from the generator step-up

[48] PacifiCorp's 2007 Integrated Resource Plan.

[49] 2007 Long-Term Reliability Assessment 2007-2016 to ensure the reliability of the bulk power system. North American Electric Reliability Corporation. Princeton, NJ. October 2007.

transformers to the Merwin substation. PacifiCorp proposes no changes that would affect transmission facilities.

G. Cost Effectiveness of Plans

86. PacifiCorp has no plans for changing project facilities or operations for power development purposes, but is proposing a number of measures for the enhancement of natural resources and recreational opportunities. Staff concludes, based on the license application, that PacifiCorp's plans for implementing these measures, as well as its continued operation of the project, will be achieved in a cost-effective manner.

H. Actions Affecting the Public

87. In its license application, PacifiCorp cited numerous examples of actions it has taken that affect the public, including: providing flood control benefits by using the Lewis River Projects[50] to provide flood control storage, offering energy education to schools, and developing demand-side management programs to assist the public in controlling electrical consumption. During the previous license period, PacifiCorp provided facilities to enhance the public use of project lands, and operated the project with consideration for the protection of downstream uses of the Lewis River. PacifiCorp uses the project to help meet local power needs and also pays taxes annually to local and state governments, and the project provides employment opportunities.

PROJECT ECONOMICS

88. In determining whether to issue a new license for an existing hydroelectric project, the Commission considers a number of public interest factors, including the economic benefits of project power. Under the Commission's approach to evaluating the economics of hydropower projects, as articulated in *Mead Corp.*,[51] the Commission uses current costs to compare the costs of the project and likely alternative power with no forecasts concerning potential future inflation, escalation, or deflation beyond the license issuance date. The basic purpose of the Commission's economic analysis is to provide a general estimate of the potential power benefits and the costs of a project, and of reasonable alternatives to project power. The estimate helps to support an informed decision concerning what is in the public interest with respect to a proposed license.

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[50] On annual basis PacifiCorp provides 70,000 acre-feet of flood control storage for the Lewis River with storage divided between the Merwin, Yale, and Swift No. 1 Projects.

[51] 72 FERC ¶ 61,027 (1995).

89. I considered two options: PacifiCorp's proposed action (the project as proposed by PacifiCorp in accordance with the Agreement) and PacifiCorp's proposed action with staff modifications and mandatory measures (the project as licensed herein). Under the proposed action, the levelized annual cost of operating the project is about $15,370,000 or $30.34/MWh. The Merwin Project would generate about 506,642 MWh of energy annually. When we multiply our estimate of average annual generation by the alternative power cost of $48.25/MWh,[52] we get a total value of the project's power of $24,444,000. To determine whether the project is currently economically beneficial, we subtract the project costs from the value of the project's power. Therefore, the project would cost $9,073,000 or $17.91/MWh less than the likely alternative cost of power.

90. As proposed by PacifiCorp and licensed herein with the staff measures with mandatory measures, the levelized annual cost of operating the project would be about $15,274,000 million, or about $30.15/MWh. Based on an estimated average generation of 506,642 MWh, the project would produce power valued at $24,444,000 when multiplied by the $48.25/MWh value of the project's power. Therefore, in the first year of operation the project power would cost $9,170,000 or $18.1/MWh less than the likely cost of alternative power.

91. In analyzing public interest factors, the Commission takes into account that hydroelectric projects offer unique operational benefits to the electric utility system (ancillary benefits). For projects with useable water storage, these benefits include their value as almost instantaneous load-following response to dampen voltage and frequency instability on the transmission system, system-power-factor-correction through condensing operations, and a source of power available to help in quickly putting fossil-fuel based generating stations back on line following a major utility system or regional blackout. The Merwin Project will continue to provide a broad range of ancillary service benefits to the region.

COMPREHENSIVE DEVELOPMENT

92. Sections 4(e) and 10(a)(1) of the FPA[53] require the Commission to give equal consideration to the power development purposes and to the purposes of energy conservation, the protection, mitigation of damage to, and enhancement of fish and wildlife, the protection of recreational opportunities, and the preservation of other aspects of environmental quality. Any license issued shall be such as in the Commission's judgment will be best adapted to a comprehensive plan for improving or developing a

[52] Power value estimates are based on PacifiCorp's December 1, 2006 filing for the Klamath Hydroelectric Project No. 2082.

[53] 16 U.S.C. §§ 797(e) and 803(a)(1) (2000).

waterway or waterways for all beneficial public uses. The decision to license this project, and the terms and conditions included herein, reflect such consideration.

93. The EIS for the Merwin Project contains the background information, analysis of effects, and support for related license requirements.

94. Based on our independent review and evaluation of the project, recommendations from the resource agencies and other stakeholders, and the no-action alternative, as documented in the EIS, I have selected the proposed Merwin Project, and find that it is best adapted to a comprehensive plan for improving and developing the Lewis River.

95. I selected this alternative because: (1) issuance of a new license will serve to maintain a beneficial, dependable, and an inexpensive source of electric energy; (2) the required environmental measures will protect and enhance fish and wildlife resources, water quality, recreation resources, and historic properties; and (3) the 136 MW of electric energy generated from a renewable resource will continue to offset the use of fossil-fueled, steam-generating electric generating plants, thereby conserving nonrenewable energy resources and reducing atmospheric pollution.

LICENSE TERM

96. Section 15(e) of the FPA[54] provides that any new license shall be for a term that the Commission determines to be in the public interest, but not be less than 30 years nor more than 50 years. The Commission's general policy is to establish 30-year terms for projects with little or no redevelopment, new construction, new capacity, or environmental mitigation and enhancement measures; 40-year terms for projects with a moderate amount of such activities; and 50-year terms for projects with extensive measures.

97. The license for the Merwin Project requires extensive long-term environmental measures including construction of a modular surface collector and transport facilities for salmon and steelhead smolts at the Merwin Project, installation of upstream and downstream passage facilities for bull trout, habitat enhancement measures, upgrades to Lewis River hatcheries, a comprehensive aquatic monitoring program, and new recreational facilities and improvements to existing facilities. The annualized capital costs for environmental measures for the Merwin Project are in excess of $10 million. Therefore, a term of 50 years is appropriate.[55]

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[54] 16 U.S.C. § 808(e) (2000).

[55] The parties agreed to support or not oppose the licensees' request that the Commission issue new licenses for 50 years. *See* section 1.6 of the Agreement.

The Director orders:

(A) This license is issued to PacifiCorp (licensee) for a period of 50 years, effective the first day of the month in which this order is issued. The license is subject to the terms and conditions of the Federal Power Act (FPA), which is incorporated by reference as part of this license, and subject to the regulations the Commission issues under the provisions of the FPA.

(B) The project consists of:

(1) All lands, to the extent of the licensee's interests in these lands, described in the project description and the project boundary discussion of this order.

(2) Project works consisting of: (a) a reservoir (Lake Merwin) with a surface area of 4,000 acres at the normal maximum operating level (239.6 feet mean sea level); (b) a 728-foot-long, 313-foot-high concrete variable radius arch dam (Merwin dam) with a crest elevation of 240 feet mean sea level; (c) a 75-foot-long, concrete gravity thrust block; (d) a 206-foot-long concrete gated overflow spillway with a crest elevation of 205.0 feet mean sea level, and flow controlled by five Taintor gates that return flow to the Lewis River; (e) a 209-foot-long, concrete non-overflow section; (f) a 34 foot-long, concrete wall; (g) a 1,462-foot-long, horseshoe-shaped diversion tunnel; (h) four intakes with one intake/penstock bulkheaded on the downstream end for future development; (i) three
150-foot-long, 15.6-foot-diameter penstocks; (j) a 304-foot-long by 104-foot-wide reinforced concrete semi-outdoor powerhouse, containing three 45-megawatt (MW) units and one
1-MW house generating unit, having a total installed capacity of 136 MW; (k) three 1,000-foot-long ,115-kilovolt transmission lines from each step-up transformer to the Merwin substation; and (l) appurtenant facilities.

The project works generally described above are more specifically shown and described by those portions of exhibits A and F shown below:

Exhibit A: The following parts of exhibit A filed on April 28, 2004:

Table A 3.0-1 entitled "Merwin Project Data" on pages 3 and 4, and section A3.2 entitled "Major Mechanical Systems."

Exhibit F: The following exhibit F drawings filed on April 28, 2004:

Exhibit F Drawing	FERC Drawing No. 935-	Title

Exhibit F Drawing	FERC Drawing No. 935-	Title
Sheet F-1	1001	General Plan and Sections
Sheet F-2	1002	Powerhouse Plan and Sections
Sheet F-3	1003	Spillway Plan and Sections
Sheet F-4	1004	Non-overflow section and thrust block elevations and sections

(3) All of the structures, fixtures, equipment, or facilities used to operate or maintain the project, all portable property that may be employed in connection with the project, and all riparian or other rights that are necessary or appropriate in the operation or maintenance of the project.

(C) The Exhibits A, and F described above are approved and made part of this license. The revised Exhibit G drawings filed on June 6, 2007 are inconsistent with regard to lands occupied by the project, including amount of federal lands, under the previous license and are not approved.

(D) This license is subject to the conditions submitted by the Washington Department of Ecology under section 401(a)(1) of the Clean Water Act, as those conditions are set forth in Appendix A to this order.

(E) This license is subject to the conditions submitted by the Secretary of the U.S. Department of Commerce under section 18 of the FPA, as those conditions are set forth in Appendix B to this order.

(F) This license is subject to the conditions submitted by the Secretary of the U.S. Department of the Interior under section 18 of the FPA, as those conditions are set forth in Appendix C to this order.

(G) This license is subject to the incidental take terms and conditions of the Biological Opinion submitted by the National Marine Fisheries Service under section 7 of the Endangered Species Act, with the exception of section 6.1.5.a of the Agreement (flows through the upper release point during spill flows), as those conditions are set forth in Appendix D of this order.

(H) This license is subject to the incidental take terms and conditions of the Biological Opinion submitted by the U.S. Fish and Wildlife Service under section 7 of the Endangered Species Act, as those conditions are set forth in Appendix E of this order.

(I) This license is also subject to the articles set forth in Form L-1 (Oct. 1975), entitled "Terms and Conditions of License for Constructed Major Project Affecting Lands of the United States" (*see* 54 FPC 1799 *et seq*.), and the following additional articles:

Article 201. *Annual Charges.* The licensee shall pay the United States annual charges, effective the first day of the month in which the license is issued, and as determined in accordance with provisions of the Commission's regulations in effect from time to time, for the purposes of:

(a) reimbursing the United States for the cost of administration of Part I of the Federal Power Act. The authorized installed capacity for that purpose is 136,000 kilowatts.

(b) recompensing the United States for the use, occupancy and enjoyment of lands the amount to be determined pursuant to article 203.

Article 202. *Exhibit Drawings*. Within 45 days of the date of issuance of this license, the licensee shall file the approved exhibit drawings in aperture card and electronic file formats.

(a) Three sets of the approved exhibit drawings shall be reproduced on silver or gelatin 35mm microfilm. All microfilm shall be mounted on type D (3-1/4" X 7-3/8") aperture cards. Prior to microfilming, the FERC Drawing Number (e.g., P-935-1001 through P-935-1004) shall be shown in the margin below the title block of the approved drawing. After mounting, the FERC Drawing Number shall be typed on the upper right corner of each aperture card. Additionally, the Project Number, FERC Exhibit (e.g., F-1, etc.), Drawing Title, and date of this license shall be typed on the upper left corner of each aperture card.

Two of the sets of aperture cards shall be filed with the Secretary of the Commission, ATTN: OEP/DHAC. The third set shall be filed with the Commission's Division of Dam Safety and Inspections Portland Regional Office.

(b) The licensee shall file two separate sets of exhibit drawings in electronic raster format with the Secretary of the Commission, ATTN: OEP/DHAC. A third set shall be filed with the Commission's Division of Dam Safety and Inspections Portland Regional Office. The drawings must be identified as (CEII) material under 18 CFR § 388.113(c). Each drawing must be a separate electronic file, and the file name shall include: FERC Project Drawing Number, FERC Exhibit, Drawing Title, date of this license, and file extension [e.g., P-935-1001, F-1, Description, MM-DD-YYYY.TIF]. Electronic drawings shall meet the following format specification:

IMAGERY - black & white raster file
FILE TYPE – Tagged Image File Format, (TIFF) CCITT Group 4
RESOLUTION – 300 dpi desired, (200 dpi min)
DRAWING SIZE FORMAT – 24” X 36” (min), 28” X 40” (max)
FILE SIZE – less than 1 MB desired

Article 203. *Exhibit G Drawings*. Within 90 days of the issuance date of the license, the licensee shall file, for Commission approval, revised Exhibit G drawings enclosing within the project boundary all principal project works necessary for operation and maintenance of the project, including the project’s transmission facilities and substations, and the following PacifiCorp-owned wildlife lands: (1) 5,600-acre Merwin Wildlife Habitat Management Area; and (2) all PacifiCorp-owned lands adjacent to the project boundary, except as provided in Exhibit A of the Settlement Agreement filed on December 3, 2004. Differences between the currently approved and the revised Exhibit G drawings, including the federal land acreages, shall be indicated and explained. The Exhibit G drawings must comply with sections 4.39 and 4.41 of the Commission’s regulations, 18 C.F.R. §§ 4.39 and 4.41 (2007).

Article 204. *Headwater Benefits*. If the licensee's project was directly benefited by the construction work of another licensee, a permittee, or the United States on a storage reservoir or other headwater improvement during the term of the original license (including extensions of that term by annual licenses), and if those headwater benefits were not previously assessed and reimbursed to the owner of the headwater improvement, the licensee shall reimburse the owner of the headwater improvement for those benefits, at such time as they are assessed, in the same manner as for benefits received during the term of this new license. The benefits will be assessed in accordance with Part 11, Subpart B, of the Commission's regulations.

Article 205. *Amortization Reserve*. Pursuant to section 10(d) of the Federal Power Act, a specified reasonable rate of return upon the net investment in the project shall be used for determining surplus earnings of the project for the establishment and maintenance of amortization reserves. The licensee shall set aside in a project amortization reserve account at the end of each fiscal year one half of the project surplus earnings, if any, in excess of the specified rate of return per annum on the net investment. To the extent that there is a deficiency of project earnings below the specified rate of return per annum for any fiscal year, the licensee shall deduct the amount of that deficiency from the amount of any surplus earnings subsequently accumulated, until absorbed. The licensee shall set aside one-half of the remaining surplus earnings, if any, cumulatively computed, in the project amortization reserve account. The licensee shall maintain the amounts established in the project amortization reserve account until further order of the Commission.

The specified reasonable rate of return used in computing amortization reserves shall be calculated annually based on current capital ratios developed from an average of 13 monthly balances of amounts properly included in the licensee's long-term debt and proprietary capital accounts as listed in the Commission's Uniform System of Accounts. The cost rate for such ratios shall be the weighted average cost of long-term debt and preferred stock for the year, and the cost of common equity shall be the interest rate on 10-year government bonds (reported as the Treasury Department's 10-year constant maturity series) computed on the monthly average for the year in question plus four percentage points (400 basis points).

Article 301. *As-built Drawings*. Within 90 days of completion of all construction/removal activities authorized by this license, the licensee shall file for Commission approval, revised exhibits A, F, and G, as applicable, to describe and show those project facilities as built. A courtesy copy shall be filed with the Commission’s Division of Dam Safety and Inspections (D2SI)--Portland Regional Engineer, the Director, D2SI, and the Director, Division of Hydropower Administration and Compliance.

Article 302. *Flood Management*. The licensee shall cooperate with the licensees for Yale Hydroelectric Project No. 2071, and Swift No. 1 Project No. 2111 to provide not less than 70,000 acre-feet of storage space for flood control on the Lewis River, beginning withdrawal by September 20 and reaching not less than 70,000 acre-feet by November 1 of each year, and retaining such space through April 1 and permitting gradual filling by April 30 of the following year, according to the following schedule:

Date	Minimum Storage Space (Acre-feet)
September 20	0
October 10	35,000
November 1-April 1	70,000
April 15	35,000
April 30	0

By November 1 of each year, the licensee shall provide a letter to the Division of Dam Safety and Inspections (D2SI) – Portland Regional Engineer, and two copies to the Commission (one of these shall be a courtesy copy to the Director, D2SI) detailing how the 70,000 acre-feet of flood storage will be achieved.

The licensee shall also periodically review the Standard Operating Procedure

Manual for the Lewis River Projects with the other dam owners on the Lewis River and Corps of Engineers, and revise the procedures when necessary. The licensee shall submit one copy of the manual for review and comment to the Commission's Division of Dam Safety and Inspections (D2SI) – Portland Regional Engineer, and two copies to the Commission (one of these shall be a courtesy copy to the Director, D2SI) within 60 days from the issuance date of the license, as well as whenever the procedures are revised.

Article 303. *Telephone Maintenance*. The licensee shall cooperate with the licensees for the Swift No. 1 Project No. 2111 and Yale Project No. 2071 to reimburse the United States Geological Survey for the monthly operation cost of maintaining the telephone line that provides gaging information necessary for the operation of the Lewis River Projects, consistent with section 12.7 of the Settlement Agreement filed on December 3, 2004.

Article 304. *Emergency Communications.* Within 1 year of the effective date of this license, the licensee shall cooperate with the licensees for the Swift No. 1 Project No. 2111 and Yale Project No. 2071 to implement the following emergency communication provisions consistent with section 12.4.1 and 12.6 of the Settlement Agreement filed on December 3, 2004:

(a) acquire, install, and maintain a new emergency telephone notification service for those portions of Clark County and Cowlitz County that are subject to inundation from the Lewis River Projects; and

(b) provide for a weather radio transmitter at Davis Peak.

Article 401. *Scheduling and Reporting Requirements and Amendment Applications.*

(a) Requirement to File Plans for Commission Approval and Requirement to Consult

Various conditions of this license required by Appendices B (Department of Commerce section 18 fishway prescription) and C [Department of the Interior fishway prescription) of this order, and Appendix D of this order [National Marine Fisheries Service (NMFS) biological opinion (BO)], require the licensee to prepare plans for approval by some or all of the signatories of the Lewis River Settlement Agreement. Each such plan shall also be submitted to the Commission for approval and shall include an implementation schedule. These plans are listed below.

	Commerce/ Interior section	NMFS BO condition	Plan	Due Date

	18 condition			
1	7.1	1 (4.1.8.e)	Upstream transport plan	Within 18 months of license issuance
2	8.1	1 (4.1.8.e)	Downstream transport plan	Within 18 months of license issuance
3	9	1 (4.6)	Downstream passage design at Merwin dam	Within 13.5 years of license issuance
4	10	1 (4.4.3)	Design of stress release ponds	Within 1 year of license issuance
5	12	1 (4.9)	Bull trout collection and transport program	Within 6 months of license issuance.
6		1 (7.4)	Habitat preparation plan	Within 6 months of license issuance.
7		1 (7.5)	Aquatics fund strategic plan and annual report	Within 1 year of license issuance; report annually after license issuance
8		1 (7.6)	In-lieu fund strategic plan and annual report	Within 1 year of establishment of in-lieu fund; report annually after establishment of in-lieu fund
9		1 (8.2)	Hatchery and supplementation plan	Within 1 year of license issuance, updates every 5 years thereafter
10		1 (8.2.3)	Hatchery and supplementation operating plan	Annually, after approval of the hatchery and supplementation plan
11		1 (9.1)	Monitoring and evaluation plan.	Within 2 years of license issuance

The licensee shall submit to the Commission documentation of its consultation, copies of comments and recommendations made in connection with the plan, and a description of how the plan accommodates the comments and recommendations. The licensee shall allow a minimum of 30 days for the consulted entities to comment and to make recommendations before filing the plan with the Commission. If the licensee does not adopt a recommendation, the filing shall include the licensee's reasons, based on project-specific information. The Commission reserves the right to make changes to any plan submitted. The plan shall not be implemented until the licensee is notified by the Commission that the plan is approved. Upon Commission approval the plan becomes a requirement of the license, and the licensee shall implement the plan or changes in project operations or facilities, including any changes required by the Commission.

(b) Requirement to File Amendment Applications

Certain conditions in the appendices contemplate unspecified long-term changes to project operations, requirements, or facilities for the purpose of protecting and enhancing environmental resources. These changes may not be implemented without prior Commission authorization granted after the filing of an application to amend the license (18 CFR 4.200). The conditions are listed below.

	Condition No.	Modification
1	Section 18 no. 4.5 and BO no. 1	Adjustments or modifications to passage facilities to achieve performance standards
2	Section 18 no. 7 and BO no. 1	Implementation of alternative fish transport technologies, should they be deemed necessary
3	Section 18 no. 8 and BO no. 1	Implementation of an alternate method of downstream fish passage
4	Section 18 no. 9.2 and BO no. 1	Merwin trap upgrades
5	Section 18 no. 10 and BO no. 1	Construction of stress release ponds
6	Section 18 no. 11 and BO no. 1	Construction of upstream fish passage facility

Article 402. *Aquatic Resources Management Measures*. The licensee shall continue to implement the following aquatic resources management measures:

(a) follow the National Marine Fisheries Service and U.S. Fish and Wildlife Service's facility and handling guidelines for anadromous fish and bull trout;

(b) support the Washington Department of Fish and Wildlife's annual evaluation of fall Chinook in the lower Lewis River; and

(c) in conjunction with the Swift No. 1 Project No. 2111 and the Yale Project No. 2071 annually evaluate bull trout and kokanee populations.

The licensee shall include evidence of compliance with these measures in the annual reports filed with the Commission under section 14.2.6 of the Settlement Agreement (Agreement) filed on December 3, 2004.

In addition, the licensee shall file with the Commission within 2 years of license issuance, a bull trout limiting factor analysis, as described in section 5.5 of the Agreement filed on December 3, 2004.

Article 403. *Wildlife Habitat Management Plan.* Within 6 months from the issuance of this license, the licensee shall file with the Commission for approval, a Wildlife Habitat Management Plan (Habitat Plan) as described in section 10.8 of the Settlement Agreement (Agreement) filed on December 3, 2004. The Habitat Plan shall be developed for lands that are associated with the Merwin Project (as shown in Exhibit A to the Agreement and designated in section 10.8.1 of the Agreement). The purpose of the Habitat Plan shall be to accomplish the wildlife objectives referenced in Schedule 10.8 of the Agreement. The licensee shall continue to implement the current Merwin Project Wildlife Habitat Management Plan in the Merwin Wildlife Habitat Management Area until approval of the new Habitat Plan required by this article.

The Habitat Plan shall be developed after consultation with Terrestrial Coordination Committee (as defined in section 14 of the Agreement). The licensee shall include with the Habitat Plan an implementation schedule, documentation of consultation, copies of recommendations on the schedule, documentation of consultation, copies of recommendations on the completed plan after it has been prepared and provided to the entities above, and specific descriptions of how the entities' comments are accommodated by the plan. The licensee shall allow a minimum of 30 days for the entities to comment and to make recommendations before filing the plan with the Commission. If the licensee does not adopt a recommendation, the filing shall include the licensee's reasons, based on project-specific reasons.

The Commission reserves the right to require changes to the plan. Implementation of the Habitat Plan shall not begin until the licensee is notified by the Commission that the plan is approved. Upon Commission approval the licensee shall implement the plan, including any changes required by the Commission.

The licensee shall file annual plans provided by section 10.8.3 of the Agreement, for Commission approval, outlining the proposed wildlife measures and costs and showing the benefit to resources affected by project structures or operations. The annual plans shall explain the consistency with wildlife objectives outlined in the Agreement.

The licensee shall review the effectiveness of the Habitat Plan consistent with section 10.8.4 of the Agreement. The licensee shall file for Commission approval, within 18 years of issuance of the license, the results of the analysis, and any proposed changes to the Habitat Plan.

Article 404. *Wildlife and Terrestrial Resources Management Measures*. The licensee shall continue to implement the following measures to protect wildlife and terrestrial resources:

(a) buffer sensitive aquatic and terrestrial habitat from ground-disturbing activities (timber harvest, construction, etc.);

(b) maintain road closures through sensitive habitat areas by installing and maintaining gates, and identify additional areas for access control on PacifiCorp lands;

(c) manage PacifiCorp lands to benefit wildlife habitat; and

(d) continue to manage project roads to maintain existing aquatic connectivity and control runoff and erosion.

The licensee shall include evidence of compliance with these measures in the annual reports filed with the Commission under section 14.2.6 of the Settlement Agreement filed on December 3, 2004.

Article 405. *Recreation Resources Management Plan*. The licensee shall implement the Recreation Resources Management Plan (Recreation Plan) dated April 2004 as it relates to the relicensing of the Merwin Project, consistent with section 11.2.3 of the Settlement Agreement (Agreement) filed on December 3, 2004, with the exception of measures required by sections 11.2.3.4 (South Shore Merwin Trail Access), 11.2.3.11 (Day Use Parking), and 11.2.4.3 (Lower Lewis River Sites) of the Agreement. The following existing facilities shall be operated and maintained for the term of the license: Merwin Park, Cresap Bay Campground and Day Use Area, Marble Creek Trail, Speelyai Bay Park, and all existing trails within the Merwin Project boundary. In addition, within 1 year of license issuance, the licensee shall file a report documenting the implementation of the public information program to protect bull trout as outlined in section 5.7 of the Agreement.

Article 406. *South Shore Merwin Trail Access Plan.* Within 2 years of license issuance, the licensee shall file with the Commission for approval, a plan to provide a trail easement to connect a proposed Clark County regional park to the south side of Lake Merwin, as outlined in section 11.2.3.4 of the Settlement Agreement filed on December 3, 2004. The plan shall include a map showing the location of the trail easement and a schedule for implementation. Upon Commission approval, the licensee will be required to file revised Exhibit G drawings incorporating the trail within the Merwin Project boundary.

The access plan shall be developed after consultation with Clark County. The licensee shall include with the plan an implementation schedule, documentation of consultation, copies of recommendations on the completed plan after it has been prepared and provided to the entities above, and specific descriptions of how the entities' comments are accommodated by the plan. The licensee shall allow a minimum of 30 days for the entities to comment and to make recommendations before filing the plan with the Commission. If the licensee does not adopt a recommendation, the filing shall include the licensee's reasons, based on project- specific reasons.

The Commission reserves the right to require changes to the plan. Improvements shall not begin until the licensee is notified by the Commission that the plan is approved. Upon Commission approval the licensee shall implement the plan, including any changes required by the Commission.

Article 407. *Recreation Renovation Plan.* Within 6 months of the completion of the accessibility evaluation proposed under section 11.2.3.5 of the Settlement Agreement (Agreement) filed on December 3, 2004, the licensee shall file with the Commission, for approval, a report that summarizes the findings of the evaluation and includes the licensee's plan for modifying existing facilities based on the results of the evaluation. The plan shall include a narrative description of the proposed facility modifications, conceptual design drawings, and an implementation schedule.

The plan for modifying existing recreation facilities shall be developed after consultation with Lewis River Advisory Committee (Committee) (as defined in section 11.2.16 of the Agreement). The licensee shall include with the plan documentation of consultation, copies of comments and recommendations on the completed plan after it has been prepared and provided to the Committee, and specific descriptions of how the Committee's comments are accommodated by the plan. The licensee shall allow a minimum of 30 days for the Committee to comment and to make recommendations before filing the plan with the Commission. If the licensee does not adopt a recommendation, the filing shall include the licensee's reasons, based on project-specific reasons.

The Commission reserves the right to require changes to the plan. Improvements shall not begin until the licensee is notified by the Commission that the plan is approved. Upon Commission approval the licensee shall implement the plan, including any changes required by the Commission.

Article 408. *Day Use Parking Plan.* Within 12 years of license issuance, the licensee shall file with the Commission for approval, a plan to assess the feasibility of additional parking with trail access to the boat launch area at Speelyai Bay Park, as outlined in section 11.2.3.11 of the Settlement Agreement (Agreement) filed on December 3, 2004. The plan shall include the results of a feasibility study to identify the most feasible location to construct the parking and trail access, and, if the study results find these facilities to be feasible, a plan providing detailed design drawings, and a schedule for construction.

The access plan shall be developed after consultation with Lewis River Advisory

Committee (Committee) (as defined in section 11.2.16 of the Agreement). The licensee shall include with the plan an implementation schedule, documentation of consultation, copies of recommendations on the completed plan after it has been prepared and provided to the Committee, and specific descriptions of how the Committee's comments are accommodated by the plan. The licensee shall allow a minimum of 30 days for the Committee to comment and to make recommendations before filing the plan with the Commission. If the licensee does not adopt a recommendation, the filing shall include the licensee's reasons, based on project-specific reasons.

The Commission reserves the right to require changes to the plan. Improvements shall not begin until the licensee is notified by the Commission that the plan is approved. Upon Commission approval the licensee shall implement the plan, including any changes required by the Commission.

<u>Article 409.</u> *Merwin Hatchery Access Site.* Within 1 year of license issuance, the licensee shall file a report documenting the completion of construction at this site and the installation of one single-vault toilet and two picnic tables at the Merwin Hatchery River Access site, as outlined in 11.2.4.1 and 11.2.4.2 of the Settlement Agreement filed on December 3, 2004.

<u>Article 410.</u> *Reservation of Authority to Prescribe Fishways*. Authority is reserved to the Commission to require the licensee to construct, operate, and maintain, or provide for the construction, operation, and maintenance of such fishways as may be prescribed by the Secretary of the Interior pursuant to section 18 of the Federal Power Act.

<u>Article 411.</u> *Columbia River Basin Fish and Wildlife Program.* The Commission reserves the authority to order, upon its own motion or upon the recommendation of federal and state fish and wildlife agencies, affected Indian Tribes, or the Northwest Power and Conservation Council, alterations of project structures and operations to take into account to the fullest extent practicable the regional fish and wildlife program developed and amended pursuant to the Pacific Northwest Electric Power Planning and Conservation Act.

<u>Article 412.</u> *Programmatic Agreement and Historic Properties Management Plan.* The licensee shall implement the Programmatic Agreement Among the Federal Energy Regulatory Commission and the Washington State Historic Preservation Officer for Managing Historic Properties that may be Affected by a License Issuing to PacifiCorp for the Continued Operation of the Swift No. 1, Yale, and Merwin Hydroelectric Projects in Clark, Cowlitz, and Skamania Counties, Washington (FERC Nos. 2111, 2071, and 935), executed on November 24, 2005, including but not limited to the Historic Properties Management Plan (HPMP) for the projects. In the event that the

Programmatic Agreement is terminated, the licensee shall continue to implement the provisions of its approved HPMP. The Commission reserves the authority to require changes to the HPMP at any time during the term of the license. If the Programmatic Agreement is terminated, the licensee shall obtain approvals from or make notifications to the Commission and the Washington State Historic Preservation Office where the HPMP calls upon the licensee to do so.

Article 413. *Use and Occupancy*. (a) In accordance with the provisions of this article, the licensee shall have the authority to grant permission for certain types of use and occupancy of project lands and waters and to convey certain interests in project lands and waters for certain types of use and occupancy, without prior Commission approval. The licensee may exercise the authority only if the proposed use and occupancy is consistent with the purposes of protecting and enhancing the scenic, recreational, and other environmental values of the project. For those purposes, the licensee shall also have continuing responsibility to supervise and control the use and occupancies, for which it grants permission, and to monitor the use of, and ensure compliance with the covenants of the instrument of conveyance for, any interests that it has conveyed, under this article. If a permitted use and occupancy violates any condition of this article or any other condition imposed by the licensee for protection and enhancement of the project's scenic, recreational, or other environmental values, or if a covenant of a conveyance made under the authority of this article is violated, the licensee shall take any lawful action necessary to correct the violation. For a permitted use or occupancy, that action includes, if necessary, canceling the permission to use and occupy the project lands and waters and requiring the removal of any non-complying structures and facilities.

(b) The type of use and occupancy of project lands and waters for which the licensee may grant permission without prior Commission approval are: (1) landscape plantings; (2) non-commercial piers, landings, boat docks, or similar structures and facilities that can accommodate no more than 10 water craft at a time and where said facility is intended to serve single-family type dwellings; (3) embankments, bulkheads, retaining walls, or similar structures for erosion control to protect the existing shoreline; and (4) food plots and other wildlife enhancement. To the extent feasible and desirable to protect and enhance the project's scenic, recreational, and other environmental values, the licensee shall require multiple use and occupancy of facilities for access to project lands or waters. The licensee shall also ensure, to the satisfaction of the Commission's authorized representative, that the use and occupancies for which it grants permission are maintained in good repair and comply with applicable state and local health and safety requirements. Before granting permission for construction of bulkheads or retaining walls, the licensee shall: (1) inspect the site of the proposed construction; (2) consider whether the planting of vegetation or the use of riprap would be adequate to control erosion at the site; and (3) determine that the proposed construction is needed and would not change the basic contour of the reservoir shoreline. To implement this paragraph (b), the licensee may, among other things, establish a program for issuing permits for the specified types of use and occupancy of project lands and waters, which may be subject to the payment of a reasonable fee to cover the licensee's costs of administering the permit program. The Commission reserves the right to require the licensee to file a description of its standards, guidelines, and procedures for implementing this paragraph (b) and to require modification of those standards, guidelines, or procedures.

(c) The licensee may convey easements or rights-of-way across, or leases of project lands for: (1) replacement, expansion, realignment, or maintenance of bridges or roads where all necessary state and federal approvals have been obtained; (2) storm drains and water mains; (3) sewers that do not discharge into project waters; (4) minor access roads; (5) telephone, gas, and electric utility distribution lines; (6) non-project overhead electric transmission lines that do not require erection of support structures within the project boundary; (7) submarine, overhead, or underground major telephone distribution cables or major electric distribution lines (69-kV or less); and (8) water intake or pumping facilities that do not extract more than one million gallons per day from a project reservoir. No later than January 31 of each year, the licensee shall file three copies of a report briefly describing for each conveyance made under this paragraph (c) during the prior calendar year, the type of interest conveyed, the location of the lands subject to the conveyance, and the nature of the use for which the interest was conveyed.

(d) The licensee may convey fee title to, easements or rights-of-way across, or leases of project lands for: (1) construction of new bridges or roads for which all necessary state and federal approvals have been obtained; (2) sewer or effluent lines that discharge into project waters, for which all necessary federal and state water quality certification or permits have been obtained; (3) other pipelines that cross project lands or waters but do not discharge into project waters; (4) non-project overhead electric transmission lines that require erection of support structures within the project boundary, for which all necessary federal and state approvals have been obtained; (5) private or public marinas that can accommodate no more than 10 water craft at a time and are located at least one-half mile (measured over project waters) from any other private or public marina; (6) recreational development consistent with an approved Exhibit R or approved report on recreational resources of an Exhibit E; and (7) other uses, if: (i) the amount of land conveyed for a particular use is five acres or less; (ii) all of the land conveyed is located at least 75 feet, measured horizontally, from project waters at normal surface elevation; and (iii) no more than 50 total acres of project lands for each project development are conveyed under this clause (d)(7) in any calendar year. At least 60 days before conveying any interest in project lands under this paragraph (d), the licensee must submit a letter to the Director, Office of Energy Projects, stating its intent to convey the interest and briefly describing the type of interest and location of the lands to be conveyed (a marked Exhibit G map may be used), the nature of the proposed use, the identity of any federal or state agency official consulted, and any federal or state approvals required for the proposed use. Unless the Director, within 45 days from the filing date, requires the licensee to file an application for prior approval, the licensee may convey the intended interest at the end of that period.

(e) The following additional conditions apply to any intended conveyance under paragraph (c) or (d) of this article:

(1) Before conveying the interest, the licensee shall consult with federal and state fish and wildlife or recreation agencies, as appropriate, and the State Historic Preservation Officer.

(2) Before conveying the interest, the licensee shall determine that the proposed use of the lands to be conveyed is not inconsistent with any approved Exhibit R or approved report on recreational resources of an Exhibit E; or, if the project does not have an approved Exhibit R or approved report on recreational resources, that the lands to be conveyed do not have recreational value.

(3) The instrument of conveyance must include the following covenants running with the land: (i) the use of the lands conveyed shall not endanger health, create a nuisance, or otherwise be incompatible with overall project recreational use; (ii) the grantee shall take all reasonable precautions to ensure that the construction, operation, and maintenance of structures or facilities on the conveyed lands will occur in a manner that will protect the scenic, recreational, and environmental values of the project; and (iii) the grantee shall not unduly restrict public access to project waters.

(4) The Commission reserves the right to require the licensee to take reasonable remedial action to correct any violation of the terms and conditions of this article, for the protection and enhancement of the project's scenic, recreational, and other environmental values.

(f) The conveyance of an interest in project lands under this article does not in itself change the project boundaries. The project boundaries may be changed to exclude land conveyed under this article only upon approval of revised Exhibit G drawings (project boundary maps) reflecting exclusion of that land. Lands conveyed under this article will be excluded from the project only upon a determination that the lands are not necessary for project purposes, such as operation and maintenance, flowage, recreation, public access, protection of environmental resources, and shoreline control, including shoreline aesthetic values. Absent extraordinary circumstances, proposals to exclude lands conveyed under this article from the project shall be consolidated for consideration when revised Exhibit G drawings would be filed for approval for other purposes.

(g) The authority granted to the licensee under this article shall not apply to any part of the public lands and reservations of the United States included within the project boundary.

(J) The licensee shall serve copies of any Commission filing required by this order on any entity specified in this order to be consulted on matters related to that filing. Proof of service on these entities must accompany the filing with the Commission.

(K) This order is final unless a request for rehearing is filed within 30 days of the date of its issuance, as provided in section 313(a) of the FPA. The filing of a request for rehearing does not operate as a stay of the effective date of this license or of any other date specified in this order, except as specifically ordered by the Commission. The licensee's failure to file a request for rehearing shall constitute acceptance of this order.

J. Mark Robinson
Director
Office of Energy Projects

Form L-1
(October, 1975)
FEDERAL ENERGY REGULATORY COMMISSION
TERMS AND CONDITIONS OF LICENSE
FOR CONSTRUCTED MAJOR PROJECT AFFECTING
LANDS OF THE UNITED STATES

Article 1. The entire project, as described in this order of the Commission, shall be subject to all of the provisions, terms, and conditions of the license.

Article 2. No substantial change shall be made in the maps, plans, specifications, and statements described and designated as exhibits and approved by the Commission in its order as a part of the license until such change shall have been approved by the Commission: Provided, however, That if the Licensee or the Commission deems it necessary or desirable that said approved exhibits, or any of them, be changed, there shall be submitted to the Commission for approval a revised, or additional exhibit or exhibits covering the proposed changes which, upon approval by the Commission, shall become a part of the license and shall supersede, in whole or in part, such exhibit or exhibits theretofore made a part of the license as may be specified by the Commission.

Article 3. The project area and project works shall be in substantial conformity with the approved exhibits referred to in Article 2 herein or as changed in accordance with the provisions of said article. Except when emergency shall require for the protection of navigation, life, health, or property, there shall not be made without prior approval of the Commission any substantial alteration or addition not in conformity with the approved plans to any dam or other project works under the license or any substantial use of project lands and waters not authorized herein; and any emergency alteration, addition, or use so made shall thereafter be subject to such modification and change as the Commission may direct. Minor changes in project works, or in uses of project lands and waters, or divergence from such approved exhibits may be made if such changes will not result in a decrease in efficiency, in a material increase in cost, in an adverse environmental impact, or in impairment of the general scheme of development; but any of such minor changes made without the prior approval of the Commission, which in its judgment have produced or will produce any of such results, shall be subject to such alteration as the Commission may direct.

Article 4. The project, including its operation and maintenance and any work incidental to additions or alterations authorized by the Commission, whether or not conducted upon lands of the United States, shall be subject to the inspection and supervision of the Regional Engineer, Federal Energy Regulatory Commission, in the region wherein the project is located, or of such other officer or agent as the Commission may designate, who shall be the authorized representative of the Commission for such purposes. The Licensee shall cooperate fully with said representative and shall furnish him such information as he may require concerning the operation and maintenance of the project, and any such alterations thereto, and shall notify him of the date upon which work with respect to any alteration will begin, as far in advance thereof as said representative may reasonably specify, and shall notify him promptly in writing of any suspension of work for a period of more than one week, and of its resumption and completion. The Licensee shall submit to said representative a detailed program of inspection by the Licensee that will provide for an adequate and qualified inspection force for construction of any such alterations to the project. Construction of said alterations or any feature thereof shall not be initiated until the program of inspection for the alterations or any feature thereof has been approved by said representative. The Licensee shall allow said representative and other officers or employees of the United States, showing proper credentials, free and unrestricted access to, through, and across the project lands and project works in the performance of their official duties. The Licensee shall comply with such rules and regulations of general or special applicability as the Commission may prescribe from time to time for the protection of life, health, or property.

Article 5. The Licensee, within five years from the date of issuance of the license, shall acquire title in fee or the right to use in perpetuity all lands, other than lands of the United States, necessary or appropriate for the construction maintenance, and operation of the project. The Licensee or its successors and assigns shall, during the period of the license, retain the possession of all project property covered by the license as issued or as later amended, including the project area, the project works, and all franchises, easements, water rights, and rights or occupancy and use; and none of such properties shall be voluntarily sold, leased, transferred, abandoned, or otherwise disposed of without the prior written approval of the Commission, except that the Licensee may lease or otherwise dispose of interests in project lands or property without specific written approval of the Commission pursuant to the then current regulations of the Commission. The provisions of this article are not intended to prevent the abandonment or the retirement from service of structures, equipment, or other project works in connection with replacements thereof when they become obsolete, inadequate, or inefficient for further service due to wear and tear; and mortgage or trust deeds or judicial sales made thereunder, or tax sales, shall not be deemed voluntary transfers within the meaning of this article.

Article 6. In the event the project is taken over by the United States upon the termination of the license as provided in Section 14 of the Federal Power Act, or is transferred to a new licensee or to a nonpower licensee under the provisions of Section 15 of said Act, the Licensee, its successors and assigns shall be responsible for, and shall make good any defect of title to, or of right of occupancy and use in, any of such project property that is necessary or appropriate or valuable and serviceable in the maintenance and operation of the project, and shall pay and discharge, or shall assume responsibility for payment and discharge of, all liens or encumbrances upon the project or project property created by the Licensee or created or incurred after the issuance of the license: Provided, That the provisions of this article are not intended to require the Licensee, for the purpose of transferring the project to the United States or to a new licensee, to acquire any different title to, or right of occupancy and use in, any of such project property than was necessary to acquire for its own purposes as the Licensee.

Article 7. The actual legitimate original cost of the project, and of any addition thereto or betterment thereof, shall be determined by the Commission in accordance with the Federal Power Act and the Commission's Rules and Regulations thereunder.

Article 8. The Licensee shall install and thereafter maintain gages and stream-gaging stations for the purpose of determining the stage and flow of the stream or streams on which the project is located, the amount of water held in and withdrawn from storage, and the effective head on the turbines; shall provide for the required reading of such gages and for the adequate rating of such stations; and shall install and maintain standard meters adequate for the determination of the amount of electric energy generated by the project works. The number, character, and location of gages, meters, or other measuring devices, and the method of operation thereof, shall at all times be satisfactory to the Commission or its authorized representative. The Commission reserves the right, after notice and opportunity for hearing, to require such alterations in the number, character, and location of gages, meters, or other measuring devices, and the method of operation thereof, as are necessary to secure adequate determinations. The installation of gages, the rating of said stream or streams, and the determination of the flow thereof, shall be under the supervision of, or in cooperation with, the District Engineer of the United States Geological Survey having charge of stream-gaging operations in the region of the project, and the Licensee shall advance to the United States Geological Survey the amount of funds estimated to be necessary for such supervision, or cooperation for such periods as may mutually agreed upon. The Licensee shall keep accurate and sufficient records of the foregoing determinations to the satisfaction of the Commission, and shall make return of such records annually at such time and in such form as the Commission may prescribe.

Article 9. The Licensee shall, after notice and opportunity for hearing, install additional capacity or make other changes in the project as directed by the Commission, to the extent that it is economically sound and in the public interest to do so.

Article 10. The Licensee shall, after notice and opportunity for hearing, coordinate the operation of the project, electrically and hydraulically, with such other projects or power systems and in such manner as the Commission any direct in the interest of power and other beneficial public uses of water resources, and on such conditions concerning the equitable sharing of benefits by the Licensee as the Commission may order.

Article 11. Whenever the Licensee is directly benefited by the construction work of another licensee, a permittee, or the United States on a storage reservoir or other headwater improvement, the Licensee shall reimburse the owner of the headwater improvement for such part of the annual charges for interest, maintenance, and depreciation thereof as the Commission shall determine to be equitable, and shall pay to the United States the cost of making such determination as fixed by the Commission. For benefits provided by a storage reservoir or other headwater improvement of the United States, the Licensee shall pay to the Commission the amounts for which it is billed from time to time for such headwater benefits and for the cost of making the determinations pursuant to the then current regulations of the Commission under the Federal Power Act.

Article 12. The operations of the Licensee, so far as they affect the use, storage and discharge from storage of waters affected by the license, shall at all times be controlled by such reasonable rules and regulations as the Commission may prescribe for the protection of life, health, and property, and in the interest of the fullest practicable conservation and utilization of such waters for power purposes and for other beneficial public uses, including recreational purposes, and the Licensee shall release water from the project reservoir at such rate in cubic feet per second, or such volume in acre-feet per specified period of time, as the Commission may prescribe for the purposes hereinbefore mentioned.

Article 13. On the application of any person, association, corporation, Federal agency, State or municipality, the Licensee shall permit such reasonable use of its reservoir or other project properties, including works, lands and water rights, or parts thereof, as may be ordered by the Commission, after notice and opportunity for hearing, in the interests of comprehensive development of the waterway or waterways involved and the conservation and utilization of the water resources of the region for water supply or for the purposes of steam-electric, irrigation, industrial, municipal or similar uses. The Licensee shall receive reasonable compensation for use of its reservoir or other project properties or parts thereof for such purposes, to include at least full reimbursement for any damages or expenses which the joint use causes the Licensee to incur. Any such compensation shall be fixed by the Commission either by approval of an agreement between the Licensee and the party or parties benefiting or after notice and opportunity for hearing. Applications shall contain information in sufficient detail to afford a full understanding of the proposed use, including satisfactory evidence that the applicant possesses necessary water rights pursuant to applicable State law, or a showing of cause why such evidence cannot concurrently be submitted, and a statement as to the relationship of the proposed use to any State or municipal plans or orders which may have been adopted with respect to the use of such waters.

Article 14. In the construction or maintenance of the project works, the Licensee shall place and maintain suitable structures and devices to reduce to a reasonable degree the liability of contact between its transmission lines and telegraph, telephone and other signal wires or power transmission lines constructed prior to its transmission lines and not owned by the Licensee, and shall also place and maintain suitable structures and devices to reduce to a reasonable degree the liability of any structures or wires falling or obstructing traffic or endangering life. None of the provisions of this article are intended to relieve the Licensee from any responsibility or requirement which may be imposed by any other lawful authority for avoiding or eliminating inductive interference.

Article 15. The Licensee shall, for the conservation and development of fish and wildlife resources, construct, maintain, and operate, or arrange for the construction, maintenance, and operation of such reasonable facilities, and comply with such reasonable modifications of the project structures and operation, as may be ordered by the Commission upon its own motion or upon the recommendation of the Secretary of the Interior or the fish and wildlife agency or agencies of any State in which the project or a part thereof is located, after notice and opportunity for hearing.

Article 16. Whenever the United States shall desire, in connection with the project, to construct fish and wildlife facilities or to improve the existing fish and wildlife facilities at its own expense, the Licensee shall permit the United States or its designated agency to use, free of cost, such of the Licensee's lands and interests in lands, reservoirs, waterways and project works as may be reasonably required to complete such facilities or such improvements thereof. In addition, after notice and opportunity for hearing, the Licensee shall modify the project operation as may be reasonably prescribed by the Commission in order to permit the maintenance and operation of the fish and wildlife facilities constructed or improved by the United States under the provisions of this article. This article shall not be interpreted to place any obligation on the United States to construct or improve fish and wildlife facilities or to relieve the Licensee of any obligation under this license.

Article 17. The Licensee shall construct, maintain, and operate, or shall arrange for the construction, maintenance, and operation of such reasonable recreational facilities, including modifications thereto, such as access roads, wharves, launching ramps, beaches, picnic and camping areas, sanitary facilities, and utilities, giving consideration to the needs of the physically handicapped, and shall comply with such reasonable modifications of the project, as may be prescribed hereafter by the Commission during the term of this license upon its own motion or upon the recommendation of the Secretary of the Interior or other interested Federal or State agencies, after notice and opportunity for hearing.

Article 18. So far as is consistent with proper operation of the project, the Licensee shall allow the public free access, to a reasonable extent, to project waters and adjacent project lands owned by the Licensee for the purpose of full public utilization of such lands and waters for navigation and for outdoor recreational purposes, including fishing and hunting: Provided, That the Licensee may reserve from public access such portions of the project waters, adjacent lands, and project facilities as may be necessary for the protection of life, health, and property.

Article 19. In the construction, maintenance, or operation of the project, the Licensee shall be responsible for, and shall take reasonable measures to prevent, soil erosion on lands adjacent to streams or other waters, stream sedimentation, and any form of water or air pollution. The Commission, upon request or upon its own motion, may order the Licensee to take such measures as the Commission finds to be necessary for these purposes, after notice and opportunity for hearing.

Article 20. The Licensee shall clear and keep clear to an adequate width lands along open conduits and shall dispose of all temporary structures, unused timber, brush, refuse, or other material unnecessary for the purposes of the project which results from the clearing of lands or from the maintenance or alteration of the project works. In addition, all trees along the periphery of project reservoirs which may die during operations of the project shall be removed. All clearing of the lands and disposal of the unnecessary material shall be done with due diligence and to the satisfaction of the authorized representative of the Commission and in accordance with appropriate Federal, State, and local statutes and regulations.

Article 21. Timber on lands of the United State cut, used, or destroyed in the construction and maintenance of the project works, or in the clearing of said lands, shall be paid for, and the resulting slash and debris disposed of, in accordance with the requirements of the agency of the United States having jurisdiction over said lands. Payment for merchantable timber shall be at current stumpage rates, and payment for young growth timber below merchantable size shall be at current damage appraisal values. However, the agency of the United States having jurisdiction may sell or dispose of the merchantable timber to others than the Licensee: Provided, That timber so sold or disposed of shall be cut and removed from the area prior to, or without undue interference with, clearing operations of the Licensee and in coordination with the Licensee's project construction schedules. Such sale or disposal to others shall not relieve the Licensee of responsibility for the clearing and disposal of all slash and debris from project lands.

Article 22. The Licensee shall do everything reasonably within its power, and shall require its employees, contractors, and employees of contractors to do everything reasonably within their power, both independently and upon the request of officers of the agency concerned, to prevent, to make advance preparations for suppression of, and to suppress fires on the lands to be occupied or used under the license. The Licensee shall be liable for and shall pay the costs incurred by the United States in suppressing fires caused from the construction, operation, or maintenance of the project works or of the works appurtenant or accessory thereto under the license.

Article 23. The Licensee shall interpose no objection to, and shall in no way prevent, the use by the agency of the United States having jurisdiction over the lands of the United States affected, or by persons or corporations occupying lands of the United States under permit, of water for fire suppression from any stream, conduit, or body of water, natural or artificial, used by the Licensee in the operation of the project works covered by the license, or the use by said parties of water for sanitary and domestic purposes from any stream, conduit, or body of water, natural or artificial, used by the Licensee in the operation of the project works covered by the license.

Article 24. The Licensee shall be liable for injury to, or destruction of, any buildings, bridges, roads, trails, lands, or other property of the United States, occasioned by the construction, maintenance, or operation of the project works or of the works appurtenant or accessory thereto under the license. Arrangements to meet such liability, either by compensation for such injury or destruction, or by reconstruction or repair of damaged property, or otherwise, shall be made with the appropriate department or agency of the United States.

Article 25. The Licensee shall allow any agency of the United States, without charge, to construct or permit to be constructed on, through, and across those project lands which are lands of the United States such conduits, chutes, ditches, railroads, roads, trails, telephone and power lines, and other routes or means of transportation and communication as are not inconsistent with the enjoyment of said lands by the Licensee for the purposes of the license. This license shall not be construed as conferring upon the Licensee any right of use, occupancy, or enjoyment of the lands of the United States other than for the construction, operation, and maintenance of the project as stated in the license.

Article 26. In the construction and maintenance of the project, the location and standards of roads and trails on lands of the United States and other uses of lands of the United States, including the location and condition of quarries, borrow pits, and spoil disposal areas, shall be subject to the approval of the department or agency of the United States having supervision over the lands involved.

Article 27. The Licensee shall make provision, or shall bear the reasonable cost, as determined by the agency of the United States affected, of making provision for avoiding inductive interference between any project transmission line or other project facility constructed, operated, or maintained under the license, and any radio installation, telephone line, or other communication facility installed or constructed before or after construction of such project transmission line or other project facility and owned, operated, or used by such agency of the United States in administering the lands under its jurisdiction.

Article 28. The Licensee shall make use of the Commission's guidelines and other recognized guidelines for treatment of transmission line rights-of-way, and shall clear such portions of transmission line rights-of-way across lands of the United States as are designated by the officer of the United States in charge of the lands; shall keep the areas so designated clear of new growth, all refuse, and inflammable material to the satisfaction of such officer; shall trim all branches of trees in contact with or liable to contact the transmission lines; shall cut and remove all dead or leaning trees which might fall in contact with the transmission lines; and shall take such other precautions against fire as may be required by such officer. No fires for the burning of waste material shall be set except with the prior written consent of the officer of the United States in charge of the lands as to time and place.

Article 29. The Licensee shall cooperate with the United States in the disposal by the United States, under the Act of July 3l, 1947, 61 Stat. 681, as amended (30 U.S.C. sec. 601, et seq.), of mineral and vegetative materials from lands of the United States occupied by the project or any part thereof: Provided, That such disposal has been authorized by the Commission and that it does not unreasonably interfere with the occupancy of such lands by the Licensee for the purposes of the license: Provided further, That in the event of disagreement, any question of unreasonable interference shall be determined by the Commission after notice ad opportunity for hearing.

Article 30. If the Licensee shall cause or suffer essential project property to be removed or destroyed or to become unfit for use, without adequate replacement, or shall abandon or discontinue good faith operation of the project or refuse or neglect to comply with the terms of the license and the lawful orders of the Commission mailed to the record address of the Licensee or its agent, the Commission will deem it to be the intent of the Licensee to surrender the license. The Commission, after notice and opportunity for hearing, may require the Licensee to remove any or all structures, equipment and power lines within the project boundary and to take any such other action necessary to restore the project waters, lands, and facilities remaining within the project boundary to a condition satisfactory to the United States agency having jurisdiction over its lands or the Commission's authorized representative, as appropriate, or to provide for the continued operation and maintenance of nonpower facilities and fulfill such other obligations under the license as the Commission may prescribe. In addition, the Commission in its discretion, after notice and opportunity for hearing, may also agree to the surrender of the license when the Commission, for the reasons recited herein, deems it to be the intent of the Licensee to surrender the license.

Article 31. The right of the Licensee and of its successors and assigns to use or occupy waters over which the United States has jurisdiction, or lands of the United States under the license, for the purpose of maintaining the project works or otherwise, shall absolutely cease at the end of the license period, unless the Licensee has obtained a new license pursuant to the then existing laws and regulations, or an annual license under the terms and conditions of this license.

Article 32. The terms and conditions expressly set forth in the license shall not be construed as impairing any terms and conditions of the Federal Power Act which are not expressly set forth herein.

APPENDICES

The Settlement Agreement filed on December 2 and 3, 2004, for the four Lewis River Projects (for information only) is attached for ease of reference in Appendix A for the Swift No. 1 Project No. 2111, 123 FERC ¶ 62,260 (2008).

Appendix A – Washington Department of Ecology Section 401 Water Quality Certification

Appendix B – U.S. Department of Commerce Section 18 Fishway Prescription

Appendix C – U.S. Department of the Interior Section 18 Fishway Prescription

Appendix D -- National Marine Fisheries Service Biological Opinion Terms and Conditions

Appendix E – U.S. Fish and Wildlife Service Biological Opinion Terms and Conditions

APPENDIX A

State of Washington, Department of Ecology Water Quality Certification under Section 401 of the Clean Water Act for the Merwin Project No. 935

October 26, 2006
Amended December 21, 2007 and January 17, 2008

4.0 CONDITIONS

Through issuance of this Certification-Order, Ecology certifies that it has reasonable assurance that the operation of the Merwin Project and activities associated with its continued operation as conditioned will be conducted in a manner that will not violate applicable water quality standards and other appropriate requirements of state law. In view of the foregoing and in accordance with 33 USC § 1341, RCW 90.48.120 , RCW 90.48.260, and Chapter 173-201A WAC, this water quality certification is granted to PacifiCorp for the Merwin Hydroelectric Project (FERC No. 935) subject to the conditions within this Certification-Order.

Certification of this project does not authorize the Licensee to exceed applicable state water quality standards (Chapter 173-201A WAC). Furthermore, nothing in this Certification-Order shall absolve the Licensee from liability for contamination and any subsequent cleanup of surface waters, ground waters, or sediments occurring as a result of activities associated with Project operations and FERC license conditions.

4.1 GENERAL REQUIREMENTS

1) The project shall comply with all water quality standards approved by the Environmental Protection Agency (currently codified in ch. 173-201A WAC), ground water quality standards (currently codified in ch. 173-200 WAC), and sediment quality standards (currently codified in ch. 173-204 WAC) and other appropriate requirements of state law. The conditions below set forth adaptive management processes and measures to achieve full compliance with standards and constitute a water quality attainment plan under the 2003 WAC 173-201A-510(5) for TDG and temperature.

2) In the event of changes or amendments to the state water quality, ground water quality, or sediment standards, or changes in or amendments to the state Water Pollution Control Act (RCW 90.48), or changes in or amendments to the Clean Water Act, such provisions, standards, criteria, or requirements shall apply to this project and any attendant agreements, orders or permits. Ecology will notify the Licensee through an Administrative Order of any such changes or amendments applicable to its project.

3) Discharge of any solid or liquid waste to the waters of the state of Washington without approval from Ecology is prohibited.

4) The Licensee shall obtain Ecology review and approval before undertaking any change to the project or project operations that might significantly and adversely affect the water quality or compliance with any applicable water quality standard (including designated uses) or other appropriate requirement of state law.

5) This Certification-Order does not exempt compliance with other statutes and codes administered by federal, state, and local agencies.

6) A Hydraulic Project Approval (HPA) (under 77.55 RCW) shall be acquired from the Washington State Department of Fish and Wildlife (WDFW) prior to any work in waters of the State.

7) Ecology retains the right, by further Order, to modify schedules or deadlines provided under this Certification-Order or provisions it incorporates.

8) Ecology retains the right by Administrative Order to require additional monitoring, studies, or measures if it determines there is likelihood that violations of water quality standards or other appropriate requirements of state law have occurred or may occur, or insufficient information exists to make such determination.

9) Ecology reserves the right to amend this Certification-Order if it determines that the provisions hereof are no longer adequate to provide reasonable assurance of compliance with applicable water quality standards or other appropriate requirements of State law. Any such amended Certification-Order shall take effect immediately upon issuance, unless otherwise provided in the amended Certification-Order, and may be appealed to the Pollution Control Hearings Board (PCHB) under ch. 43.21B RCW.

10) Ecology reserves the right to issue administrative orders, assess or seek penalties, and to initiate legal actions in any court or forum of competent jurisdiction for the purposes of enforcing the requirements of this Certification-Order.

11) The conditions of this Certification-Order shall not be construed to prevent or prohibit the Licensee from either voluntarily or in response to legal requirements imposed by a court, the FERC, or any other body with competent jurisdiction, taking actions which will provide a greater level of protection, mitigation, or enhancement of water quality or of existing or designated uses.

12) If five (5) or more years elapse between the date this Certification-Order is issued and issuance of the new FERC license for the Project, this Certification-Order shall be deemed to be expired and denied without prejudice at such time and the Licensee shall send Ecology an updated application for a Clean Water Act Section 401 Certification that reflects then current conditions, regulations and technologies. This provision shall not be construed to otherwise limit the reserved

authority of Ecology to withdraw, amend, or correct the Certification-Order before or after the issuance of a FERC license.

13) This Certification-Order may be modified or withdrawn by Ecology prior to the issuance of the license based upon significant new information or changes to water quality standards or appropriate requirements of state law.

14) Copies of this Certification-Order and associated permits, licenses, approvals and other documents shall be kept on the Project site and made readily available for reference by the Licensee, its contractors and consultants, and by Ecology.

15) The Licensee shall allow Ecology access to inspect the project and project records required by this Certification-Order for the purpose of monitoring compliance with its conditions. Access shall occur after reasonable notice, except in emergency circumstances.

16) The Licensee shall, upon request by Ecology, fully respond to all reasonable requests for materials to assist Ecology in making determinations under this Certification-Order and any resulting rulemaking or other process.

17) Any work that is out of compliance with the provisions of this Certification-Order, or conditions that result in distressed, dying or dead fish, or any discharge of oil, fuel, or chemicals into state waters, or onto land with a potential for entry into state waters, or turbidity greater than 5 NTU over background in Lake Merwin; or greater than 5 NTU over background conditions or greater than 10% below Merwin Dam if background conditions are greater than 50 NTU is prohibited. If these conditions occur, the Licensee shall immediately take the following actions:

    a) Cease operations at the location of the violation to the extent such operations may reasonably be causing or contributing to the problem.

    b) Assess the cause of the water quality problem and take appropriate measures to correct the problem and/or prevent further environmental damage.

    c) Notify Ecology of the failure to comply. Oil or chemical spill events shall be reported immediately to Ecology's 24-Hour Spill Response Team at (800) 258-5990 within 24 hours. Other non-compliance events shall be reported to Ecology's Federal Permit Manager at 800 424-8802.

    d) Submit a detailed written report to Ecology within five (5) days that describes the nature of the event, corrective action taken and/or planned, steps to be taken to prevent a recurrence, results of any samples taken, and any other pertinent information.

    e) Observed violations at the project shall be highlighted in the annual monitoring report.

Compliance with these requirements does not relieve the Licensee from responsibility to maintain continuous compliance with the terms and conditions of this Certification-Order or the resulting liability from failure to comply.

18) The project shall meet the Class A standards below Merwin Dam and Lake Standards in Lake Merwin listed in WAC 173-201A-030.

19) A Water Quality Management Plan (WQMP) is required. All water quality related plans described below shall be included as separate sections of the WQMP.

4.2 INSTREAM FLOWS AND RAMPING RATES BELOW MERWIN DAM

1) The project shall comply with the instream flow measures identified in Section 9.8 of the Settlement Agreement signed November 30, 2005, submitted to FERC December 9, 2005, and provided herein as Exhibit A.

2) Spill from Merwin will be calculated and reported for every change in gate opening in accordance with condition 4.8.3 of this Certification-Order under Monitoring and Reporting.

4.3 TOTAL DISSOLVED GAS (TDG)

1) The Project shall not cause any exceedance of the TDG water quality criteria as specified in WAC 173-201A 030 (2)(c)(iii) below Merwin Dam, WAC 173-201A(5)(c)(iii) in Lake Merwin, and 173-201A-060 (4)(a) in any waters of the Project.

2) The Licensee shall operate Merwin Dam to maintain the TDG associated with air-injected to turbine flows to 110% or less TDG.
   a) The Licensee shall perform water quality monitoring in turbine water below Merwin Dam for turbine air injection generated TDG in accordance with condition 4.8.3 of this Certification-Order under Monitoring and Reporting.
   b) If, over the term of the license, turbines are replaced or modified, design such turbines to minimize TDG production.

3) The Licensee shall manage spill to limit TDG production to 110% or less saturation.
   a) The Licensee shall monitor spill water beginning during the first spill event after this Certification-Order is issued and as specified in the monitoring plan in Exhibit C and in conditions 4.2.2 under Flows and 4.8.3 of this Certification-Order under Monitoring and Reporting.
   b) Within six (6) months of the discovery of any exceedance of the 110% TDG criterion caused by spill, the Licensee shall submit a TDG Water Quality Attainment Plan (TDG WQAP) to Ecology for review and approval. The TDG WQAP plan shall include:

i. A description of standard Project operations with regard to minimizing TDG associated with spills;

ii. A description of how the Project will minimize all spills that produce TDG exceedances at the Project;

iii. An evaluation of all potential and preferred structural and operational improvements to minimize TDG production;

iv. A timeline showing when operational adjustments will occur;

v. A schedule for construction; and

vi. Monitoring plans to further evaluate TDG production and to test for effectiveness of gas abatement controls.

c) The Project shall operate according to the approved TDG WQAP with the objective of eliminating TDG exceedances.

d) Upon approval of the TDG WQAP, the Licensee shall immediately begin the necessary steps identified in the TDG WQAP to eliminate TDG criteria exceedances.

e) If monitoring to test the effectiveness of gas abatement controls implemented through the TDG WQAP shows the TDG abatement measures identified in the Plan and subsequently employed are not successful in meeting the water quality criterion, then, within the first ten (10) years of discovery of TDG criterion exceedances caused by spill, Ecology will require further activities to meet the water quality criterion. Significant structural or operational revisions that may impose potentially unreasonable costs or create potentially unreasonable societal effects may be evaluated as part of a formal Use Attainability Analysis consistent with the federal and state water quality regulations after the ten (10) year compliance period has ended.

4) Provided that all reasonable operational efforts are made to minimize TDG exceedances and Ecology is notified within 24 hours after the onset of the spill, compliance with the 110% TDG criteria does not apply, when:

a) Actual or predicted flows in the Lewis River exceed the rate equivalent to the 7Q10 flows as defined in WAC 173-201A-060(4)(a). At the writing of this Certification-Order, the 7Q10 flow for the Lewis River at Merwin Dam is 32,884 cfs. Either the Licensee or Ecology may request to reassess and modify the established 7Q10 flow. Modification and application of the 7Q10 flow requires Ecology's approval.

Because the Project exerts some control over the timing and amplitude of storm flows, a qualifying 7Q10 event for the purposes of the TDG criteria exemption includes flows accompanied by an actual or forecasted large storm event that provides an equivalent amount of water to the drainage basin, regardless of flows at Merwin Dam. Calculations of such qualifying events shall follow language contained in the Settlement Agreement pertaining to High Runoff Procedures (SA 12.8) which states:

> *"PacifiCorp shall obtain 3-day river flow forecasts from a reputable third party forecasting organization (which may include the National Weather Service's River Forecasting Center) for the Lewis River Watershed. This 3-day river flow forecast shall be used by PacifiCorp in its forecast-based high runoff procedure as described below. PacifiCorp shall periodically evaluate the forecasts being used against other commonly available forecasts, with the goal of improving forecasting accuracy for flood management through the use of evolving technology, to the extent practicable."*
>
> *"During the Flood Management Season, PacifiCorp shall calculate the "Forecasted Flow" for the Lewis River from the 3-day forecast by determining the forecasted flow that has an 85% probability of occurring. In the event that it appears that the Forecasted Flow will result in inflows significant enough to utilize a portion of the 17 feet of hole, as defined in the Manual, reserved for flood management purposes, PacifiCorp shall make a Pre-Release to provide additional capacity to store inflows into the reservoirs during the high-runoff event. Once the total hole is reduced to 17 feet, PacifiCorp shall continue to follow the flow release procedures contained in the Manual as of the Effective Date."*
>
> Any observed spike of TDG at the Merwin Dam forebay shall not be considered a TDG criteria exceedance if it was formed during a qualifying 7Q10 event at Swift No. 1.

b) Short term spills are necessary to protect public safety and respond to volcanic activity.

5) During high flows greater than the 7Q10, the Licensee shall manage spill levels and spill gate configuration to minimize TDG production.

4.4 TEMPERATURE AND DISSOLVED OXYGEN

1) Lewis River. The Project shall not cause any violation of the temperature and dissolved oxygen water quality criteria as specified for Class 'A' waters, WAC 173-201A-030(2)(c)(ii) and (iv) in and below Merwin Dam. The Licensee shall not cause these waters to exceed 18°C nor dissolved oxygen concentrations to go below 8 mg/L. If the presence or operation of the dam causes violation of these

criteria, the Licensee shall modify its operation to the extent necessary to ensure that the Project does not cause such exceedance.

2) Lake Merwin. The Project shall not cause any violation of the temperature or dissolved oxygen water quality criteria as specified for Lake Class waters in WAC 173-201A-030(5)(c)(ii) and (iv) in Lake Merwin. If the presence or operation of the Merwin Dam causes violation of these criteria, the Licensee shall modify its operation to the extent necessary following the compliance schedule outlined below to ensure that the Project does not cause such exceedance. The Lake Class temperature and dissolved oxygen criteria that applies to the reservoir mandates no measurable change from natural conditions. The Merwin Dam has created artificial lake conditions over which the project has some control. In such circumstances, Ecology requires the Licensee to use all reasonable and feasible measures to achieve conditions that best protect the designated or characteristic uses for fish and shellfish (WAC 173-201A(2)(b)(iii)) within the reservoir.

3) The Licensee shall develop a Temperature Water Quality Attainment Plan (TWQAP) for the Lake Merwin canyon (Canyon). The purpose of this TWQAP is to identify and maintain the highest attainable water quality conditions to provide a temperature regime that is reasonable and feasible to achieve and which will best protect the cold-water biota. The TWQAP must include a reasonable compliance schedule for carrying out an adaptive process within ten (10) years of license renewal to evaluate feasible technical and operational changes to improve temperature for cold water biota using the steps outlined below:
   a) Identify the Canyon's species of fish and macroinvertebrates (identified to the lowest practical level) and determine where they are found in the water column at different life stages and different times of day;
   b) evaluate the temperature requirements of those organisms that use the upper water column;
   c) evaluate the effects of the project-related temperature fluctuations on these organisms;
   d) identify all potential temperature improvements in the Canyon which will protect the organisms in the upper water column, lower water column and the benthos;
   e) pursue all reasonable and feasible methods to ensure that the water temperature fluctuations in the Canyon remain below levels which would harm the aquatic biota or limit the potential healthy cold water habitat; and.
   f) Identify follow-up studies and actions that can be taken to further improve the temperature regime for cold-water biota.

4) A draft of the TWQAP shall be submitted for Ecology review and approval. This draft shall be submitted within one (1) year of license issuance.

5) The Licensee shall monitor temperature and dissolved oxygen in the forebay and tailrace of Merwin Dam in accordance with condition 4.8.3 of this Certification-Order under Monitoring and Reporting. This monitoring is in addition to any temperature monitoring required in the approved TWQAP.

4.5 Construction Projects, Miscellaneous Discharges, and Habitat Modifications

The following applies to all over-water or near-water work related to the Project that can impact surface- or ground-water quality. This includes, but is not limited to, construction, operation, and maintenance of fish collection structures, generation turbines, penstocks, hatcheries, transportation facilities, portable toilets, boat ramps, transmission corridors, structures, and staging areas. This also includes emergencies for all activities related to Project operation.

1) If water quality exceedances are predicted as being unavoidable during construction or maintenance of a project, a short-term modification must be applied for in writing to Ecology at least three (3) months prior to project initiation. If any project has a long-term impact on a regulated water quality parameter, characterization monitoring must be performed for the impacted parameter(s), and a monitoring plan must be outlined in the Water Quality Protection Plan discussed below. This may require additional management practices to minimize impacts over the license period.

2) A Water Quality Protection Plan (WQPP) shall be prepared, and followed for all Project-related work that is in- or near-water that has the potential to impact surface- and/or groundwater quality. The WQPP shall include control measures to prevent contaminants from entering surface water and groundwaters, and shall include, but not be limited to, the following elements:

   a) <u>A Stormwater Pollution Prevention Plan (SWPPP)</u> shall specify the Best Management Practices (BMPs) and other control measures to prevent contaminants entering the Project’s surface water and groundwaters. The SWPPP shall address the pollution control measures for the Licensee’s activities that could lead to the discharge of stormwater or other contaminated water from upland areas. The SWPPP must also specify the management of chemicals, hazardous materials and petroleum (spill prevention and containment procedures), including refueling procedures, the measures to take in the event of a spill, and reporting and training requirements.

   b) <u>An In-Water-Work Protection Plan (IWWPP)</u> shall be consistent with the SWPPP and shall specifically address the BMPs and other control measures for the Licensee activities that require work within surface waters. Turbidity and dissolved oxygen shall be monitored upstream of the location where in-water construction is taking place and at the point of compliance (as defined in WAC

173 201A-110(3)(a-d)) during construction. Samples shall be taken at a minimum of once each day during construction in or adjacent to any water bodies within the Project area that may be affected by the construction. The IWWPP shall include all water quality protection measures consistent with a Hydraulics Project Approval (HPA) for the Project.

c) The WQPP shall include procedures for monitoring water quality, actions to implement should a water quality exceedance occur, and procedures for reporting any water quality violations to Ecology. The WQPP shall include all water quality protection measures consistent with a HPA for the Project. The WQPP shall be submitted to Ecology for review and approval at least three (3) months prior to Project initiation, and a copy of the WQPP shall be in the possession of the on-site construction manager, and available for review by Ecology staff, whenever construction work is under way.

d) When a construction project meets the coverage requirements of the National Pollution Elimination System (NPDES) permit and State Waste Discharge General Permit for Stormwater Discharges associated with construction activity, the Licensee shall either, at Ecology's discretion, apply for this permit and comply with the terms and conditions of the permit or apply for and comply with the terms of an individual NPDES permit.

3) Best Management Practices

a) Work in or near the reservoir, water within the dam, the river, or any wetlands shall include all reasonable measures to minimize the impacts of construction activity on waters of the state. Water quality constituents of particular concern are turbidity, suspended sediment, settleable solids, oil and grease, and pH. These measures include use of Best Management Practices (BMPs) to control erosion and sedimentation, proper use of chemicals, oil and chemical spill prevention and control, and clean-up of surplus construction supplies and other solid wastes.

b) During construction, all necessary measures shall be taken to minimize the disturbance of existing riparian, wetland, or upland vegetation.

c) All construction debris shall be properly disposed of on land so that the debris cannot enter a waterway or cause water quality degradation to state waters. Retention areas or swales shall be used to prevent discharging of water from construction placement areas.

d) The Licensee shall ensure that any fill materials that are placed for the proposed habitat improvements in any waters of the state do not contain toxic materials in toxic amounts.

4) Maintain Turbidity Standards

a) Certification of this Project does not authorize the Licensee to exceed the turbidity standard beyond the mixing zone described in (b), (c), (d), and (e) below. Turbidity in Class A waters in and below Merwin Dam shall not exceed 5 NTU over background turbidity when turbidity is 50 NTU or less, or have more than a 10 percent increase in turbidity when the background turbidity is more than 50 NTU. Turbidity in Lake Class waters of Lake Merwin shall not exceed 5 NTU over background turbidity.

b) For Class A waters, , a mixing zone is established, consistent with WAC 173-201A-100(7) and –110(3), within which the turbidity standard is waived. The mixing zone is established to allow only temporary exceedances of the turbidity criteria during and immediately after in-water work. The temporary turbidity mixing zone shall be as follows:

   i. For waters up to 10 cfs flow at the time of construction, the point of compliance shall be 100 feet downstream from activity causing the turbidity exceedance.

   ii. For waters above 10 cfs up to 100 cfs flow at the time of construction, the point of compliance shall be 200 feet downstream from activity causing the turbidity exceedance.

   iii. For waters above 100 cfs flow at the time of construction, the point of compliance shall be 300 feet downstream from activity causing the turbidity exceedance.

c) For Lake Class waters, certification of this Project does not authorize the Licensee to exceed the turbidity standard beyond the mixing zone described in (d) and (e) below.

d) Step 1. Mixing zones shall not be allowed unless it can be demonstrated to the satisfaction of Ecology that:

   i. Other siting, technological, and managerial options that would avoid the need for a lake mixing zone are not reasonably achievable;

   ii. Overriding considerations of the public interest will be served; and

   iii. All technological and managerial methods available for pollution reduction and removal that are economically achievable would be implemented prior to discharge

e) Step 2. Mixing zones, singularly or in combination with other mixing zones, shall comply with the most restrictive combination of the following:

   i. Not exceed ten percent of the waterbody volume;

   ii. Not exceed ten percent of the waterbody surface area (maximum radial extent of the plume regardless of whether it reaches the surface); and

iii. Not extend beyond fifteen percent of the width of the waterbody.

5) The above conditions do not relieve the Licensee from the need to obtain all the applicable permits. Activities that could discharge pollutants to waters of the state must use appropriate Best Management Practices to protect water quality.

4.6 OIL SPILL PREVENTION AND CONTROL

1) No oil, fuel, or chemicals shall be discharged into waters of the state, or onto land with a potential for entry into waters of the state as prohibited by Ch. 90.56 RCW and Ch. 90.48 RCW.

2) Contain and remove from the water, visible floating oils released from construction or Project operation.

   a) In the event of a discharge of oil, fuel or chemicals into state waters, or onto land with a potential for entry into state waters, immediately begin and complete containment and clean-up efforts, taking precedence over normal work. Clean-up shall include proper disposal of any spilled material and used clean-up materials.

   b) Do not use emulsifiers or dispersants in waters of the state without prior approval from Ecology, Southwest Regional Office.

   c) Within three (3) months of receiving the license from FERC, establish an Ecology-approved on-site spill cleanup material inventory. Maintain this on-site inventory and a complete inventory list.

   d) Project Operators shall be familiar with and trained on use of oil spill cleanup materials. In the event of an oil spill, properly dispose of used/contaminated materials and oil and as soon as possible restock new supplies. Include records of proper disposal in the oil consumption records and keep copies of disposal records of contaminated cleanup supplies on-site for inspection.

   e) Ensure that operational work boats and trained boat operators are available on short notice in the event of a spill. Install mechanisms as appropriate to safely launch or lower work boats into areas where work boats would be deployed in the event of an oil spill. These mechanisms must be pre-approved by Ecology.

   f) Keep SPCC Plans as required and historical spill records on-site. Provide these to Ecology immediately upon request.

   g) Identify and map floor drains. Post these maps at the Project in a conspicuous location for use by Operators and other personnel in the event of an oil spill. Seal floor drains that are no-longer needed.

h) Install, or have on site to deploy stair cases, ladders, etc. which will allow oil spill response staff to safely reach areas that could, in the event of an oil spill, need to be accessed to deploy sorbent pads and boom materials.

3) Oil-Water Separators (OWS)

a) Within three months of issuance of the FERC license, submit a maintenance plan for the OWS to Ecology for approval. This maintenance plan must include a process to periodically test the oil-stop valves and provide assurance that they will work as designed. (See condition 4.8.3 of this Certification-Order under Monitoring and Reporting)

b) OWS shall only admit rain and water run-off that originates in the containment area that is intended to drain into the OWS.

c) Perform periodic and appropriate maintenance and inspection on a schedule to include sediment removal. (See condition 4.8.3 of this Certification-Order under Monitoring and Reporting)

d) Clean and service the OWS after each event where oil is introduced into the OWS.

e) Evaluate each oil water separator (OWS) for inflows to account for the total volume of the largest transformer plus fifteen (15) percent. Verify and conduct corrective action that will insure that oil would not be washed through the OWS if a failure of the single largest transformer in the containment area occurs during a major rain event.

4) Transformers

a) Transformer deck containment areas must be impervious. Conduct periodic inspections and resurface areas, fill cracks, caulk metal plate footings or otherwise ensure that containment areas will contain spills from the volume of the largest transformer plus fifteen (15) percent.

b) Obtain prior approval from Ecology before breaching containment areas for reasons other than containment area maintenance.

c) Conform to industry standards for protecting water quality and preventing and containing oil spills when transporting transformers and transformer oil.

d) Snowy or icy conditions require daily inspections of transformer deck containment area including an inspection of the drains leading to the OWS for freeze-up conditions. Remove any observed rain water pooling in the containment areas. (See condition 4.8.3 of this Certification-Order under Monitoring and Reporting)

5) Sumps

a) Maintain oil sensors on the surface of the water in each sump. Inspect and test these sensors every three (3) months or sooner if needed to insure that they will work as designed. Visually inspect all of these areas each week or immediately if oil is suspected to be present such as in the event of an oil sensor alarm or the observance of an oil or grease spill in the turbine pit of sufficient volume to reach the sump. Oil detected in the sumps by visual inspection or by sensor requires immediate cleanup, and oil in an amount that triggers an oil sensor alarm must immediately be report to the Emergency Management Division (EMD). (See condition 4.8.3 of Certification-Order 3678 under Monitoring and Reporting.)

b) Immediately repair oil leaks in the turbine pit that are of sufficient volume to reach the sump and that can not be contained by placing a container underneath the leak. Immediately repair water leaks located in the turbine pit area that are leaking at a volume of greater than one gallon per hour.

c) Install or deploy hand rails and mechanisms so the sump covers can be removed for a visual inspection of the sump. Provide water-proof lighting in the sumps or spotlights adequate to view the surface water in the sumps. Provide a mechanism to satisfactorily deploy and recover sorbent boom in the sumps at each project.

6) Oil, fuel and chemical storage containers, containment areas, and conveyance systems

a) Provide proper containment around each storage container (including transformers) or around a combination of storage containers as appropriate and agreed upon by Ecology. Proper containment equals the volume of the container plus 10 per cent.

b) Recalculate required containment areas to insure proper containment still exists after major equipment changes. Example: when converting from water cooled transformer to an air cooled unit, re-calculate oil volume and compare to containment area. Calculate containment volumes from *maximum* storage volumes, not normal oil level volumes.

c) Provide external oil level gauges for governor oil tanks, transformers and other oil tanks that contain over 100-gallons of oil. Provide appropriate level markings for these gauges. Provide a sign or other means at each tank, near the tank level gauge, that describes these level markings and the relationship of each inch vs. how many gallons (in the case of a glass tube type of gauge). Dial gauges must also describe oil volume in gallons or have a sign or other indicator provided at each reservoir that adequately describes dial movement in relation to gallons. Provide a sign or other indication that shows ¼, ½, ¾, and full gauge readings or indications in gallons. If equipment must be placed in a special mode of operation, prior to level observance, this must also be posted.

Example: wicker gate ram position or other hydraulic ram positions, prior to oil level reading. (See condition 4.8 of this Certification-Order under Monitoring and Reporting)

d) Regularly check all fuel hoses, oil drums, oil or fuel transfer valves and fittings, etc, for drips and leaks. Maintain and properly store them to prevent spills into state waters. (See condition 4.8.3 of this Certification-Order under Monitoring and Reporting)

e) Do not refuel equipment within 50 feet of rivers, creeks, wetlands, or other waters of the state.

f) Provide full oil spill containment capacity plus 10 per cent when working on transformers and other equipment that might spill or drip oil.

g) Inspect containers once per week. Maintain container inspection sheets to include: maximum container volume and an exact reading recording of the oil level by the staff/operator conducting the inspection. Weekly inspection readings must be consistent; provide training to the staff/operator to ensure consistent and accurate readings. (See condition 4.8.3 of this Certification-Order under Monitoring and Reporting)

h) Keep oil consumption records maintained on-site; provide these records to Ecology immediately upon request and in the annual WQMP report.

i) In the event that the project modifies the oil transfer operation to include hard-plumbing to reservoirs such as the governor oil tank from the oil tank room, or other extensive modifications, the Licensee must notify and receive approval from Ecology.

j) Contain wash water containing oils, grease, or other hazardous materials resulting from wash-down of equipment or working areas for proper disposal, and do not discharge this water into state waters.

7) Other

a) Maintain site security at the project site to reduce chance of oil spills.

b) Initiate, plan for, document, and train staff for the deployment of General Response Plan and boom strategies for each project. Review and update as needed annually.

4.7 PESTICIDE APPLICATIONS (SEE DEFINITION OF PESTICIDE IN EXHIBIT B)

1) Prior to the application of pesticides to waters of the state, coverage under applicable Aquatic Pesticides Permit shall be obtained, and conformance with any other applicable state requirement such as SEPA, shall be attained.

2) Best Management Practices and other control measures for the application of pesticides to waters of the state must be addressed in an In-Water-Work Protection

Plan. An appropriate water quality monitoring plan shall be developed prior to the application and shall be implemented for all related work.

3) Prior to the use of pesticides adjacent to waters of the state, the Licensee shall follow Best Management Practices to avoid the entry of such materials into waters of the state. Applicable Best Management Practices include, but are not limited to, such actions as hand application and avoiding drift of materials into the water.

4.8 MONITORING AND REPORTING

1) The monitoring component of the Licensee's application to FERC is incorporated as a requirement of this Certification-Order and shall be followed except as further modified by this Certification-Order. Within 90 days of issuance of the new FERC license for the Project, the Licensee shall submit to Ecology for its review and approval a plan for any additional monitoring requirements set forth in this Certification-Order.

2) Monitoring pursuant to the requirements set forth in this Certification-Order shall begin as soon as practicable and in no event shall monitoring begin any later than one (1) year after issuance of the new FERC license for measures that do not specify a start date.

3) Representative water quality measurements shall be made for the parameters listed in Table 2 at the identified locations and frequencies. Further monitoring is required or may be required under compliance schedules or to respond to specific problems not identified at the time of this Certification-Order.

Table 2. Water Quality Monitoring Schedule

Parameter	Location	Depths (ft)	Frequency	Duration	Condition No.
Flow	Lewis River below Merwin Dam at USGS Ariel gauge	--	15 minutes	Ongoing for the term of the license	4.2.1 Flow
	Merwin Dam spill gates	Calculated using elevation of Lake Merwin times gate widths times gate heights	Every change in gate openings when spill occurs	Ongoing for the term of the license	4.2.2 Flow
Total Dissolved Gas (TDG)	Merwin Dam turbine outlets	15’	Hourly	1. One month before and after planned departure from normal operations reallocate the duration or the quantity of air injected into the turbines to the point that the 110% criterion is likely exceeded. 2. Ongoing if exceedances occur until three months after such exceedances are corrected.	4.3.2a
	Merwin spill downriver of aeration zone	~10’-15’	During spill events through the spillway, hourly, as close to 24 hrs before as possible to 48 after the event	Ongoing unless TDG during spill is found not to exceed 110% during river flows approaching 33,884 cfs	4.3.3a and Exhibit C
Temperature	Merwin Forebay	1, 5, 10, 20 40, 60, 100, 200	May 1–Oct 31: Hourly	Ongoing until temperature exceedances are found not to occur in the Merwin tailrace for a period of five consecutive years	4.4.5
	Merwin tailrace	1	Hourly all year	Ongoing	4.4.5

	Upper Merwin/ Yale tailrace	Profile	Hourly	Ongoing until temperature fluctuations in the upper Lake Merwin/Yale tailrace are sufficiently addressed per condition 4.4(3) of this Order	4.4.5
Dissolved Oxygen	Merwin tailrace	1	September and October hourly	Ongoing until dissolved oxygen sags are found not to exceed 8 m/L for a period of 5 consecutive years	4.4.5
Oil & Grease	Record amounts of oil, grease and hydraulic fluids used	n/a	Weekly	Ongoing for the term of the license	4.6.6h
	Sumps	Surface and bottom	At least weekly (visual) At least three months (test)	Ongoing for the term of the license	4.6.5a
	Trans-former deck	Drains	Daily during icy conditions	Ongoing for the term of the license	4.6.4d
	Oil tanks, transformers, other oil tanks >100 gallons	n/a	At least weekly	Ongoing for the term of the license	4.6.6c
	Fuel hoses, oil drums, oil & fuel transfer valves and fittings.	n/a	Weekly	Ongoing for the term of the license	4.6.6d
	Oil-water separators	n/a	Periodically test oil stop valves	Ongoing for the term of the license	4.6.3a
	Oil-water separators	n/a	Regularly prior to cleaning	Ongoing for the term of the license	4.6.3c

4) All water quality monitoring shall meet accepted standards for data quality. The monitoring plan shall include monitoring and data evaluation procedures and objectives that ensure data quality. Data quality procedures shall be consistent with United States Environmental Protection Agency and Ecology guidance on this subject.

5) The monitoring plan shall be updated annually by amendment to reflect any changes in monitoring parameters, schedule, or methodology. These amendments, or a notification of no change, shall be included in the Annual Report described below in condition 4.8.6 and in Section 14.2.6 of the Settlement Agreement. Ecology will provide its revisions and approval for the monitoring plan within three (3) months after receipt of an amendment or notification.

6) Data from all water quality monitoring shall be summarized and reported in a format approved by Ecology and submitted annually. The monitoring report shall include sample dates, times, locations, and results. Any violation of numeric state water quality standards and flow conditions shall be highlighted. The report shall be included in the Annual Report provided to FERC as described in Section 14.2.6 of the Settlement Agreement; provided that if Ecology determines that the format of that report does not meet Ecology's needs, the Licensee shall modify or supplement the report so that it is acceptable to Ecology. Data reports shall be submitted to Ecology's, Water Quality Program, Southwest Regional Office.

7) The Licensee may request to modify or eliminate parts of the monitoring program after a minimum of the ongoing monitoring requirements or a period of five (5) years of reliable data collection following issuance of the new license. Modifications to this monitoring schedule can be requested by submitting to Ecology reasons for the modifications along with a modified monitoring plan.

8) A more rigorous water quality sampling program for the parameters listed in Table 2 or additional parameters may be required by Ecology if necessary to protect water quality in the future based on monitoring results, regulatory changes, changes in project operations and/or requirements of TMDLs, or to otherwise provide reasonable assurance of compliance with state water quality standards.

Exhibit A

Section 6.2 of the Settlement Agreement Concerning Relicensing of the Lewis River Hydroelectric Projects signed November 30, 2005

6.2 Flow Fluctuations Below Merwin Dam.

Commencing upon Issuance of the New License for the Merwin Project, PacifiCorp shall implement the following operational regimes at Merwin Dam for the duration of the New License for the Merwin Project.

6.2.1 Ramping Rates Below Merwin Dam.

All flow rates and Ramping rates described in this Section 6.2.1 shall be measured at the Ariel gage. “Ramping” means those Project-induced increases (“up-Ramping”) and decreases (“down-Ramping”) in river discharge and associated changes in river surface elevation over time below Merwin Dam caused by Project operations or for Project maintenance. Ramping rate is the rate of change in stage resulting in regulated discharges. Ramping rates in this Agreement are stated in inches or feet of change in the surface elevation of the river per hour. Restrictions on Ramping shall not apply to

> (a) changes in flows due to natural increases or decreases in tributary input or surface runoff occurring entirely in the reach between Merwin Dam and the Ariel gage (such as changes caused by snowmelt or rain events), (b) PacifiCorp’s operations to comply with high runoff procedures, or (c) PacifiCorp’s response to emergency conditions related to an imminent threat to life or property. PacifiCorp shall limit the up-Ramping rate to 1.5 feet per hour below Merwin Dam for all periods when flows below Merwin Dam are at or less than hydraulic capacity of the Merwin Project turbines. PacifiCorp shall limit the down-Ramping rate to 2 inches per hour below Merwin Dam for all periods when flows below Merwin Dam are at or less than 8,000 cfs; except that during the period from February 16 through June 15, no down-Ramping shall occur (1) commencing one hour before sunrise until one hour after sunrise and (2) commencing one hour before sunset until one hour after sunset. PacifiCorp shall perform down-Ramping as gradually as practicable and shall avoid up-Ramping fluctuations during down-Ramping periods, to the extent practicable.

6.2.2 Plateau Operations at Merwin Dam.

PacifiCorp shall further restrict daily fluctuation in flows below Merwin during the period of February 16 through August 15 of each year by maintaining flow plateaus (periods of near-steady discharge) as provided in this Section 6.2.2. Once a flow plateau is established, PacifiCorp shall maintain the flow plateau for as long a duration as practicable, but flow plateaus may be altered to a new level as a result of changes in natural flow or operational demands on the Lewis River power system, subject to the limitations of this Section 6.2.2. If any Party questions the duration of flow plateaus, they may request a meeting with appropriate PacifiCorp staff to review the information PacifiCorp used in determining when Plateau Steps were required. PacifiCorp shall cooperate in providing necessary information about and explanation of the actions taken. PacifiCorp shall limit changes in flow plateaus during the period of February 16 through August 15 as provided in (a) and (b) below:

a. Plateau Steps. For the purposes of this Agreement, a “Plateau Step” shall be defined to be down-Ramping in flow below Merwin that would result in a change in river elevation of more than 0.2 (2/10) foot at the Ariel gage. A single Plateau Step event will begin when the elevation drops by more than 0.2 (2/10) foot and be deemed complete when (i) the elevation rises by more than 0.2 (2/10) foot or (ii) does not change by more than plus or minus 0.2 (2/10) foot for more than 6 hours. Down-Ramping that results in changes in river elevation of less than or equal to 0.2 (2/10) foot shall not be considered a Plateau Step and will not be included in the accumulated total of Plateau Steps, provided that down-Ramping that results in a change of more than 0.2 (2/10) foot in any six-hour period will be considered a Plateau Step. Plateau Steps shall be limited to no more than one change in any 24-hour period, no more than 4 in any seven-day period, and no more than six in any calendar month. If PacifiCorp is required to release flows from Merwin Dam pursuant to the high runoff procedure, then for each such release pursuant to the high runoff procedure, down-Ramping to return to a level maintained for more than 6 hours without decreasing river elevation by more than 0.2 (2/10) feet shall not be counted as a Plateau Step. During flood season, if there is less than 5 feet of storage capacity in addition to the required 17 feet of storage capacity under the high runoff procedure, then the first down-Ramping after each flow release to restore the storage capacity shall not count as a Plateau Step. If PacifiCorp uses more than a single release episode to reach or exceed 22 feet of storage capacity, only the down-Ramping after the first such release shall not count as a Plateau Step; the subsequent down-Rampings shall be counted as Plateau Steps. Finally, if PacifiCorp is asked to lower flows below Merwin Dam for public safety reasons or to facilitate aquatics studies, such changes in river level shall not be counted as Plateau Steps.

b. Plateau Changes. An accumulation of Plateau Steps will result in a “Plateau Change” as further defined in this Section. PacifiCorp shall limit Plateau Changes to no more than 20 during the period February 16 through August 15. When flows are greater than or equal to 3,500 cfs below Merwin Dam, a Plateau Change shall occur when any series of consecutive Plateau Steps totals 1 foot of down-Ramping between February 16 through August 15. Any periods of up-Ramping during such period shall be ignored in such calculations. When flows are less than 3,500 cfs below Merwin Dam, a Plateau Change shall mean a series of consecutive Plateau Steps, during the period February 16 through August 15, totaling 0.5 (5/10) foot. Any periods of up-Ramping during such period shall be ignored in such calculations. If a single Plateau Step in a series would cause the total to exceed one foot (when flows are greater than or equal to 3,500 cfs) or one-half foot (when flows are less than 3,500 cfs), the excess shall be counted toward the next Plateau Changes. If a Plateau Step begins when flows are greater than 3,500 cfs and ends when flows are less than 3,500 cfs, the Plateau Change will be determined by adding the fractions of a Plateau Change occurring before and after the river discharge below Merwin Dam passes 3,500 cfs. For example, if a Plateau Step begins when flows are at 5,000 cfs and has measured 6 inches when flows reach 3,500 cfs (one-half of a Plateau Change for flows above 3,500 cfs) and continues to decline an additional 3 inches ending at 3,000 cfs (one-half of a Plateau Change for flows below 3,500 cfs), it would count as one full Plateau Change.

6.2.3 Stranding Study and Habitat Evaluation.

By the third anniversary of the Issuance of the New License for the Merwin Project, PacifiCorp shall complete a stranding study and a habitat evaluation study below Merwin Dam to assess the potential effects of Project operations on steelhead, coho salmon, Chinook salmon, and chum salmon, and their habitats. The total cost to complete both the study and evaluation is estimated to be $300,000. PacifiCorp shall develop the stranding study objectives in Consultation with the ACC, with final approval by NOAA Fisheries and USFWS. The stranding study shall identify measurable factors affecting potential stranding, the relationship of such factors to each other, and the timeframe and season within which stranding may occur. The habitat evaluation study shall evaluate spawning and rearing habitat from Merwin Dam to the downstream end of Eagle Island across a range of minimum flow operational conditions. The design of the study and evaluations shall be limited to the objectives developed above, must be operationally implementable, and any operational changes implemented for the study and evaluation shall not be considered a breach of any other operational restrictions provided in this Agreement, e.g., shall not be considered a Plateau Change under Section 6.2.2. Based upon the results of the study and evaluation, the ACC may recommend to PacifiCorp, subject to the approval of NOAA Fisheries and USFWS, measures to minimize or mitigate stranding of salmonids below Merwin Dam. Such measures may include minor adjustments to instream flow levels, or minor adjustments to Merwin Project operations to address Project impacts below Merwin Dam. PacifiCorp shall consider any suggested adjustments to operations and flows of the Project, and shall make reasonable, good faith efforts to address such recommendations. In so doing, PacifiCorp should consider impacts on operational benefits of the Project, including, but not limited to, flood management, power generation, and recreational uses. If PacifiCorp determines not to implement the recommendations, because there would be significant impact on Project benefits, the ACC may elect to mitigate the impacts shown by the study and evaluation by development of habitat enhancement projects through the use of the Aquatics Fund.

6.2.4 Minimum Flows Below Merwin Dam.

PacifiCorp shall provide the following minimum flows below Merwin Dam during the following time periods, subject to the limitations and requirements provided in Section 6.2.5: (1) July 31 through October 15, 1,200 cfs; (2) October 16 through October 31, 2,500 cfs; (3) November 1 through December 15, 4,200 cfs; (4) December 16 through March 1, 2,000 cfs; (5) March 2 through March 15, 2,200 cfs; (6) March 16 through March 30, 2,500 cfs; (7) March 31 through June 30, 2,700 cfs; (8) July 1 through July 10, 2,300 cfs; (9) July 11 through July 20, 1,900 cfs; and (10) July 21 through July 30, 1,500 cfs. The above flows and timing were designed for the purpose of the maintaining and enhancing species downstream of Merwin Dam, including native fall Chinook. The preceding sentence shall not modify or be used to modify the obligations stated in this Section 6.2.4.

6.2.5 Low Flow Procedures.

During years when PacifiCorp projects that sufficient water will not be available to appropriately balance the respective needs of fishery resources, recreation, flood management, and power production, PacifiCorp shall convene a Flow Coordination Committee (the “FCC”) consisting of representatives from PacifiCorp, NOAA Fisheries, USFWS, WDFW, the CIT, and the Yakama Nation. PacifiCorp shall provide the FCC with relevant information, and the FCC shall independently evaluate available data regarding water availability during the projected low flow period and decrease or maintain the minimum flows levels provided in Section 6.2.4 as it deems appropriate. PacifiCorp shall maintain minimum flow levels provided in Section 6.2.4 unless such levels are temporarily decreased by Consensus of the FCC members; provided that if there is an impasse, determinations shall be made by a majority of the agency members of the FCC. Changes requested by the FCC shall not require PacifiCorp to violate its agreement with FEMA concerning high runoff management, as described in Section 12. The FCC shall consider the following interests in modifying minimum flow levels (the order of listing is not intended to indicate priority): (1) the needs of fish species, with a priority on ESA-listed species, including, without limitation, consideration for keeping redds watered, providing rearing habitat for wild fall Chinook, and pulse flows to assist in migration of juvenile fish if such pulse flows are shown to be effective; (2) the need to provide flood management benefits for down river areas; and (3) the desire to refill all Project reservoirs to achieve a combined target of 5 feet of available reservoir storage capacity by July 1, and a target of 15 feet of reservoir storage by Labor Day (to provide reasonable recreation uses between Memorial Day and Labor Day). The Counties and cities that are signatories to this Agreement may designate a local government liaison to the FCC. The liaison's purpose is to encourage communication between the FCC and local governments. PacifiCorp shall notify the local governments' liaison (a) when the FCC will be convened and (b) the general content of the agenda. The liaison may provide written comments to the FCC for its consideration.

Exhibit B

Definitions

7Q-10 – The high flow that is calculated to occur only once, for 7 consecutive days during any 10-year period.

BMPs – Best Management Practices to reduce pollution

CWQPP – Construction Water Quality Protection Plan – necessary for all construction projects in, over, or near water.

FERC – Federal Energy Regulatory Commission

FWPCA – Federal Water Pollution Control Act

HPA – Hydraulic Project Approval

IWPP – In Water Work Protection Plan. Part of the CWQPP as described above. This is for work in the water—such as boat ramps or cement work in the water. This does not apply inside the dam when before beginning the project, the water can be completely removed.

MSL – Mean Sea Level

NTU – Nephelometric Turbidity Units

Pesticide –

a) Any substance or mixture of substances intended to prevent, destroy, control, repel, or mitigate any insect, rodent, snail, slug, fungus, weed, and any other form of plant or animal life or virus, except virus on or in a living person or other animal which is normally considered to be a pest or which the director may declare to be a pest;

b) Any substance or mixture of substances intended to be used as a plant regulator, defoliant or desiccant; and

c) Any spray adjuvant, such as a wetting agent, spreading agent, deposit builder, adhesive, emulsifying agent, deflocculating agent, water modifier, or similar agent with or without toxic properties of its own intended to be used with any pesticide as an aid to the application or effect thereof, and sold in a package or container separate from that of the pesticide with which it is to be used. **RCW –** Revised Code of Washington

RM – River Mile

SWPPP – Stormwater Pollution Prevention Plan –Part of the CWQPP as described above. This is to prevent polluted stormwater from entering the reservoir or river.

TDG – Total Dissolved Gas

TMDL – Total Maximum Daily Load

TWQAP – Temperature Water Quality Attainment Plan

USC – United States Code

USDA-FS - Forest Service of the United States Department of Agriculture

USGS – United Stated Geological Survey

USFWS - United States Fish and Wildlife Service
WAC – Washington Administration Code
WDFW – Washington Department of Fish and Wildlife
WQAP – Water Quality Attainment Plan
WQMP – Water Quality Monitoring Plan
WQS – Water Quality Standards Rule, WAC 173 201A.

Exhibit C

Total Dissolved Gas Spill Monitoring Plan for Swift No 1, Yale, and Merwin Dams

This plan includes:

1. A quality assurance/quality control (QA/QC) plan;
2. A description of how spill events (including 7Q-10 events) will be anticipated;
3. A description of how equipment will be mobilized quickly prior to a spill event and timing of monitoring frequency and duration;
4. Location of monitoring equipment; and,
5. Reporting deadline.

1) Quality Assurance/Quality Control

Data Quality Objectives and Decision Criteria

Total Dissolved Gas meters can exhibit biased results depending on calibration, maintenance and/or field conditions. PacifiCorp staff will minimize bias by assuring proper maintenance and care of the TDG meters. Therefore, no Data Quality Objectives (DQOs) are being established.

TDG readings are expected to fall between 100% and 130% saturation. Washington State standard is 110% saturation. Measurement Quality Objectives (MQOs) are equivalent to DQOs and are equal to 1% saturation. MQOs will be met if the TDG meter readings are within 1 percent saturation or 5 mm HG of the expected value based on comparison to paired meters. If MQOs are not met for these pairs, the differences between paired data will be evaluated, including differences in the data quality procedures used, but the data will not be qualified or discarded unless other information indicates problems with the data.

Percent TDG measurements are dependent on barometric pressure readings, so secondary MQOs are also needed for the on-site barometric pressure readings. There are two weather stations at Yale and Swift so it is possible to obtain direct measurements of barometric pressure at those locations. A portable barometer will be employed at Merwin. The target for this monitoring effort will be an MQO of 5 mm HG for the field barometer readings. If the barometric pressure MQOs are exceeded, the data will be considered acceptable if the TDG percent saturation MQOs are met.

Temperature will also be collected during the monitoring periods. Since temperature is of secondary importance, DQOs will not be established but an MQO will be established to determine if data are acceptable for reporting. The MQO for temperature will be met and reported if post-calibration shows that the temperature is within 0.5 º C.

In terms of data quality the following acceptance criteria will be applied:

Data Reasonableness: Data will be reviewed to determine if the amount of variability is appropriate, based on expected values and comparison between data sets. Data with too much or reasonably too little variability will not be used.

Data Completeness: Data sets will be used that are reasonably complete during the period of sampling. Incomplete data sets will be used if they are considered representative of conditions during the sampling period.

Data Representation: Data will be used that are representative of the location or time period for sampling. Attention will be paid to the variations in meteorological conditions and to seasonal differences between high and low flow conditions.

Study Design and Field Procedures: All data will be collected using Hydrolab® Model MS5 remote TDG meters. Prior to deployment, instruments will be calibrated to ensure that total pressure (in air) equals barometric pressure. Meters will be attached to a streamside structure such as the Ariel USGS gage house below Merwin and existing cabling, or a large rock or tree below Yale and Swift No. l. The meters will be weighted such that they will maintain position in at least 10 feet of water (compensation depth) to prevent air bubble formation on the sensor membranes.

The Hydrolab® Model MS5 remote TDG meters will be checked for calibration before and after each deployment. Meters will be checked for performance at each site at the beginning and the end of each deployment.

Data Review, Quality Assessment, and Validation: Data will be downloaded from the Hydrolab® Model MS5 remote TDG meters to a spreadsheet and reviewed for reasonableness and any values exceeding the MQOs. Outliers will be evaluated for reasons behind unexpected deviation. Exceedances related to equipment malfunction result in rejection of the data.
Data sets will be considered complete if the data meet the MQOs at least 85 percent of the time. All data meeting MQOs will be accepted. Data will then be evaluated for compliance and acceptance criteria.

2) How spill events will be anticipated including 7Q-10 events
PacifiCorp Energy will use prediction tools described below to determine when to deploy TDG meters for any anticipated spill event.

The following is a description of how PacifiCorp Energy anticipates spill events, including 7Q-10 events, at Merwin Dam, Yale Dam and Swift No. 1 Dam. PacifiCorp Energy regularly monitors weather and inflow forecasts from the National Weather Service and River Forecast Center as well as a number of private forecasting vendors. Based on expected inflows and current reservoir elevations, PacifiCorp Energy will target total Project releases, typically 2 to 3 days in advance, so as to minimize the frequency and magnitude of Project spill. Since the Lewis River Project has a large amount of storage compared to typical inflow, PacifiCorp Energy is often able to manage and re-regulate natural high flow events so as not to spill at the Projects thereby saving water for such purposes as generation, fishery needs and refill. PacifiCorp Energy has real time reservoir elevation indication in each of its three reservoirs. With this data, total available Project storage is calculated on an hourly basis and made available to staff involved in Project operations. Reservoir elevations, available storage, and inflow forecasts are routinely monitored by Hydro Control Operators as well as technical water management staff. This information is scrutinized carefully particularly during actual and potential high run off situations.

During the high run off season (November 1 - April 1) PacifiCorp Energy is required to maintain an aggregate of at least 70,000 AF of storage in the Lewis River reservoirs. If there is a reasonable threat of encroaching on this storage, PacifiCorp Energy typically spills at Merwin dam as necessary to manage the available flood control storage. The rate at which inflow encroaches on required available storage is updated using existing Project telemetry and inflow forecasts provided by NOAA's National Weather Service River Forecast Center, and/or a third party consultant. Telemetered inflow and reservoir instrumentation currently includes:

- PacifiCorp Energy and USGS stream gages on the river mainstem and tributaries
- PacifiCorp Energy lake stage gages
- PacifiCorp Energy and National Weather Service weather stations
- PacifiCorp Energy and Natural Resource Conservation Service snow stations

Some spill events are not driven by high flow events, and these are typically planned with enough time to provide ample opportunity for the installation of monitoring equipment. Examples include spilling for required periodic testing of the spill gates as well as meeting some special water management needs, including minimum flow requirements, when the generation units are out of service.

Rainfall is but one factor considered in forecasting inflows. Other factors include air temperature (which will affect whether precipitation falls as rain or snow and at what elevations), wind, soil moisture and snowpack conditions. PacifiCorp Energy relies on the output of complex weather and streamflow models, typically managed by National Weather Service and third party consultants to assimilate these conditions as well as forecasted weather to predict streamflows, including 7Q-10 events.

3) Deployment, Timing of Monitoring, Frequency, and Duration
PacifiCorp Energy staff will have meters and deployment equipment at the ready at all times. A test deployment will take place at each site prior to the high run off season. During the high run off season (November 1 - April 1) staff will be on alert to be

prepared to deploy at any time. The MS5 meters will be programmed to record TDG and temperature on an hourly schedule. Meters will be deployed at approximately 24 hours before a spill event and continuing for 48 hours afterward. While the meters will be removed following spill events/periods, PacifiCorp Energy staff will be ready to deploy equipment as many times as needed to capture each event. Threat of vandalism or theft, and unwillingness to risk data loss drives the decision to remove equipment after each spill event.

4) Location of monitoring equipment

Three meters will be deployed in spill water at the following locations:

- Approximately ¼ mile downstream of Merwin dam near the Ariel gage site;
- Approximately ½ mile downstream of Yale dam and upstream of the confluence with Canyon Creek; and,
- Approximately ½ mile downstream of Swift No.1 dam.

Placement will be far enough downstream of the dams to be outside the aeration area below each spillway in order to avoid air bubble accumulation on the sensing membrane.

5) Reporting

Summary output of the streamflow forecast models, as well as inflow records, will be included in PacifiCorp Energy reports identifying and justifying periods of 7Q-10 exemptions identified in section 4.3.5.f. Likewise when Federal Energy Regulatory Commission license conditions or other safety and environmental requirements require spill not otherwise explicitly included in 7Q-10 exemptions, PacifiCorp Energy will document and report those events, including the basis of the operation. As called for in the Lewis River Settlement Agreement (Section 14.2.6), annual reporting of spill events and data analysis will be included in PacifiCorp Energy and Cowlitz PUD's Annual Aquatics Coordination Committee Report.

APPENDIX B

Modified Fishway Prescriptions filed by the Department of Commerce under Section 18 of the Federal Power Act for the Merwin Project No. 935

February 14, 2006

NMFS hereby prescribes the following license conditions for the construction, operation, and maintenance of upstream and downstream fishways to provide safe, timely, and effective passage around the Merwin, Yale, and Swift No. 1, and 2 Projects. Recognizing that the following prescriptions are consistent with the Settlement Agreement, NMFS respectfully requests, pursuant to its authority under Section 18 of the FPA, that the Commission incorporate into the Project licenses, in their entirety and without modification, the prescriptions included herein.

Article 1: Prescription for Anadromous Fish Reintroduction Outcome Goals

Regarding the stocks of Chinook, steelhead, and coho that are being transported under the Settlement Agreement, the Licensee must implement the relevant PM&E Measures that arc the Licensee's obligation in the Settlement Agreement and the Licensee, together with the licensees for the Yale, Swift No. 1 and Swift No. 2 projects must implement the relevant PM&E Measures that are shared obligations of the licensees in the Settlement Agreement to achieve the Reintroduction Outcome Goal as described in the Settlement Agreement. The "'Reintroduction Outcome Goal" is to achieve genetically viable, self-sustaining, naturally reproducing, harvestable populations above Merwin Dam greater than minimum viable populations. "Harvest" includes all forms of harvest including, without limitation, commercial, tribal, and recreational. Notwithstanding the previous sentences, the Licensee shall not be responsible for limiting factors that are not related to project effects, e.g. harvest. These Reintroduction Outcome Goals are separate from and have no relationship to the targets listed under Section 8 of the Settlement Agreement relating to numbers of returning hatchery fish.

1.1 Monitoring and Evaluation

The Licensee, together with the licensees for the Yale, Swift No. 1 and Swift No. 2 projects, in Consultation with the Aquatics Coordination Committee (ACC) (including at least the Services), and with the final approval of the Services, must monitor progress for achieving Reintroduction Outcome Goals periodically as set forth in Sections 3.2 and 9 of the Settlement Agreement. The results of such monitoring must be included in the reports on monitoring and evaluation to be provided to the Commission by the Licensee, together with the licensees for the Yale, Swift No. 1 and

Swift No. 2 projects, under Section 9.1 of the Settlement Agreement. The monitoring must rely on the work of regional recovery groups (e.g., the Technical Recovery Team and the Lower Columbia Fish Recovery Board) relating to North Fork Lewis River populations to the extent possible, in combination with the data gathered by the Licensee and the licensees for the Yale, Swift No. 1 and Swift No. 2 projects in accordance with the Settlement Agreement. As contemplated by the Settlement Agreement, the Licensee must supplement such work if needed to determine whether the Reintroduction Outcome Goals have been achieved or whether they are on track to being achieved on a timely basis.

1.2 Phase I Status Check

If the Services determine, on or after the later of (a) the 27th anniversary of Issuance of the last of the Licenses for Swift No. 1, Yale, Merwin, and Swift No. 2 projects, or (b) the 12th year after reintroduction of anadromous fish above Swift No. 1 Dam together with the operation of both the Merwin Upstream Transport Facility and the Swift Downstream Facility, as provided in the license for the Swift No. 1 project, using the approach developed pursuant to Section 3.1.1 of the Settlement Agreement (such determination process is referred to as the "Phase I Status Check"), that the Reintroduction Outcome Goal has been achieved for each North Fork Lewis River anadromous fish population that is being transported under the Settlement Agreement, the Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, shall continue to implement the relevant measures contained in Sections 4 through 9 of the Settlement Agreement for the remainder of the license terms, including adjusting and modifying fish passage facilities as needed to meet relevant performance standards as provided in Section 4.1.6 of the Settlement Agreement.

If the Services determine, on or after the later of (a) the 27th anniversary of issuance of the last of the Licenses for the Swift No. 1, Yale, Merwin, and Swift No. 2 projects, or (b) the 12th year after reintroduction of anadromous fish above Swift No. 1 Dam together with the operation of both the Merwin Upstream Transport Facility and the Swift Downstream Facility, as provided in the License for the Swift No. 1 project, using the approach developed pursuant to Section 3. 1.1 of the Settlement Agreement (such determination process is referred to as the "Phase I Status Check") that any of the Reintroduction Outcome Goals have not been met, the Licensee must perform a limiting factors analysis, in Consultation with the ACC (including at least the Services) and subject to final approval and acceptance of the Services. If the limiting factors analysis concludes, for all Reintroduction Outcome Goals that are not being met, that all significant limiting factors contributing to the failure to meet such goals are unrelated to Project effects, the Licensee, together with the licensees for the Yale, Swift No. 1 and Swift No. 2 projects, must continue carrying out the relevant measures contained in Sections 4 through 9 of the Settlement Agreement, including adjusting and modifying fish passage facilities as provided in Section 4.1.6 of the Settlement

Agreement, but shall not be obligated to implement any additional measures. Examples of factors unrelated to project effects include but are not limited to, harvest, upstream of Merwin off-Project habitat conditions (e.g. degradations in habitat due to forest management practices and natural catastrophic events), and ocean conditions. However, if the limiting factors analysis concludes that a Project effect is a significant limiting factor in any Reintroduction Outcome Goal not being met, then, in addition to continuing carrying out of the relevant measures contained in Sections 4 through 9 of the Settlement Agreement, including adjusting and modifying fish passage facilities as provided in Section 4.1.6 of the Settlement Agreement, the Licensee must complete any actions that the Services, informed by discussions with the ACC in a meeting that the Licensee must convene, determine would provide biological benefits adequate to thoroughly offset the impact of the identified Project-related limiting factor(s) for North Fork Lewis populations (e.g., habitat enhancement projects, continuing juvenile supplementation, etc.) provided the Licensee shall not be required to (1) make structural or operational changes with respect to its generating facilities or Project reservoirs to achieve standards, (2) replace any fish passage facility with another fish passage facility, or (3) install additional collection and transport facilities or alternative fish passage facilities.

1.3 Phase II Status Check

If the Services determine, on or after the later of (a) the 37th anniversary of Issuance of the last of the licenses for the Swift No. 1, Yale, Merwin, and Swift No. 2 projects, or (b) the seventh year after the Phase I Status Check, using the approach developed pursuant to Section 3.1.1 of the Settlement Agreement (such determination process is referred to as the "'Phase II Status Check"), that the Reintroduction Outcome Goals have been achieved, the Licensee, together with the licensees for the Yale, Swift No. 1 and Swift No. 2 projects, must continue to carry out the relevant measures provided in Sections 4 through 9 of the Settlement Agreement for the remainder the license terms, including adjusting and modifying fish passage facilities as needed to meet relevant performance standards as provided in Section 4.1.6 of the Settlement Agreement.

If the Services determine, on or after the later of (a) the 37th anniversary of issuance of the last of the licenses for the Swift No. 1, Yale, Merwin, and Swift No. 2 projects, or (b) the seventh year after the Phase I Status Check, using the approach developed pursuant to Section 3.1.1 of the Settlement Agreement (such determination process is referred to as the "Phase II Status Check"), that any of the Reintroduction Outcome Goals have not been achieved, the Licensee must perform a limiting factors analysis, in Consultation with the ACC (including at least the Services) and subject to the final approval and acceptance of the Services. If the limiting factors analysis concludes, for all Reintroduction Outcome Goals not being met, that all significant limiting factors contributing to the failure to meet such goals are unrelated to Project effects, the Licensee, together with the licensees for the Yale, Swift No. 1 and Swift No. 2 projects, must continue carrying out the relevant measures contained in Sections 4 through 9 of the Settlement Agreement including adjusting and modifying fish passage facilities as provided in Section 4.1.6 of 1he Settlement Agreement, but shall not be obligated to implement any additional measures. Examples of factors unrelated to project effects include but are not limited to harvest, upstream of Merwin off-Project habitat conditions (e.g. degradations in habitat due to forest management practices and natural catastrophic events), and ocean conditions. If the limiting factors analysis concludes that a Project effect is a significant limiting factor in any Reintroduction Outcome Goal not being met, then, in addition to continuing carrying out the relevant measures contained in Sections 4 through 9 of the Settlement Agreement, including Facility Adjustments and Facility Modifications as provided in Section 4.1.6 of the Settlement Agreement, the Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must Consult with the Services to determine what further actions by the Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, would be necessary to meet Reintroduction Outcome Goals pursuant to Section 3.5.2.b of the Settlement Agreement. Such actions may include, without limitation, consideration of structural or operational changes with respect to the generating facilities or Project reservoirs or construction of new or replacement passage facilities.

Article 2: Prescription for Fish Passage Facilities Design

To provide for the safe, timely and effective passage past the Project of upstream and downstream migrating salmonids, the Licensee shall develop and implement the Merwin Downstream Facility and Merwin Upstream Transport Facility in accordance with, and subject to the limitations included in, all of the relevant provisions of the Settlement Agreement.

2.1 Studies to Inform Design Decisions

The Licensee, in Consultation with the ACC (including at least the Services) and subject to the final approval of the Services, must develop and carry out studies to inform the design of upstream and downstream fish passage facilities described in the Settlement Agreement with the goal of improving the likelihood that the passage facilities will be successful as initially constructed. Needed information may include the hydraulic characteristics of the Swift No. 1, Yale, and Merwin forebays and tailraces (e.g., a three-dimensional numerical flow-field analysis) and the movement of adult and juvenile salmonids. The Licensee must complete these studies sufficiently in advance of the design decisions required by the Settlement Agreement so that the Licensee, the Services, and the ACC can take the resulting information into account when making final design decisions.

2.2 Design Review

Except as otherwise provided under Section 4.1.9 of the Settlement Agreement, the Licensee must design the Merwin Downstream Facility and the Merwin Upstream Transport Facility to meet the performance standard targets set out in Section 4.1.4.b of the Settlement Agreement, as applicable. The Licensee must use the best available technology for the type of passage facility being constructed, and design the passage facility to provide flexibility for subsequent expansion or Facility Adjustments, if needed, to meet performance standards. A fish passage facility may include duplication of some components (for example, multiple entrances) and still be considered a single passage facility. The Licensee must coordinate with and provide 30 percent and 60 percent completed preliminary designs for review and comment to the Services and WDFW. The Licensee must notify the ACC when design work has begun, and provide the 30 percent and 60 percent preliminary designs to any other Party to the Settlement Agreement at the Party's request. The Licensee must provide the Services and WDFW 45 days to provide their comments. The Licensee must submit the 90 percent preliminary designs with the relevant engineering, hydraulic, and biological work to the ACC (including at least the Services) at the times set forth in the Settlement Agreement. The Licensee must provide the ACC (including at least the Services) 45 days to provide its comments on the 90 percent preliminary design, and must finalize the designs in Consultation with the ACC (including at least the Services) and with the approval of the Services. The Licensee must consider and address in writing those written comments provided by the members of the ACC (including at least the Services) when submitting final designs to the Services for approval.

Article 3: Prescription for Permits and Time for Construction

Upon approval of passage facility designs by the Commission, the Licensee must diligently and expeditiously acquire all required Permits. The time by which each passage facility must be placed in operation is set forth in the Settlement Agreement.

Article 4: Prescription for Performance Standards for Fish Passage

The Licensee must provide for the safe, timely, and effective passage of salmonids being transported past the Project as described in the Settlement Agreement. The sole performance standard for kelts and downstream migration of adult sea-run cutthroat must be safe, timely, and effective passage. Specific life stages described below (not including kelts or downstream migrating sea-run cutthroat) have quantitative standards. The Licensee must construct and provide for the operation and maintenance of fish passage facilities that collect all life stages of salmonids that are present at the facility, and function during all flows and during all seasons; except for upstream passage facilities, to the extent it is infeasible due to flood events that require spill that could not be reasonably accommodated by the passage facility.

The Licensee must employ the following definitions in carrying out and monitoring the performance standards:

Adult Trap Efficiency ("ATE"): The percentage of adult Chinook, coho, steelhead, bull trout, and sea-run cutthroat that are actively migrating to a location above the trap and that are collected by the trap.

Collection efficiency ("CE"): The percentage of juvenile anadromous fish of each of the species to be transported, as described in Section 4.1.7 of the Settlement Agreement, that is available for collection and that is actually collected.

Collection Survival ("CS"): The percentage of juvenile anadromous fish of each of the species to he transported collected that leave Release Ponds alive.

Injury: Visible trauma (including, but not limited to, hemorrhaging, open wounds without fungus growth, gill damage, bruising greater than 0.5 cm in diameter, etc.), loss of equilibrium, or greater than 20 percent descaling. "Descaling" is defined as the sum of the area on one side of the fish that shows recent scale loss. This does not include areas where scales have regenerated or fungus has grown.

Overall Downstream Survival ("ODS"): The percentage of juvenile anadromous fish of each of the species to be transported that enter the reservoirs from natal streams and that survive to enter the Lewis River below Merwin Dam by collection, transport, and release via the juvenile fish passage system, passage via turbines, or some combination thereof, calculated as provided in Schedule 4.1.4 of the Settlement Agreement.

Upstream Passage Survival ("UPS"): Percentage of adult fish of each of the species to be transported that are collected that survive the upstream trapping-and-transport process. For sea-run cutthroat and bull trout, "adult" means fish greater than 13 inches in length.

4.1 Overall Fish Passage Performance Standards for Salmonids

For each species, the Licensee must achieve the following overall performance standards for fish passage: ODS of greater than or equal to 80 percent until such time as the Yale Downstream Facility is built as provided in the license for the Yale project (P-2071) or the funds from the In lieu Fund, as described in Section 7.6 of the Settlement Agreement, become available to the Services in lieu of constructing the Yale Downstream Facility, after which time ODS must be greater than or equal to 75 percent: UPS of greater than or equal to 99.5 percent and ATE to be established as described in the Settlement Agreement. ODS, as defined by the Settlement Agreement must include several components of juvenile passage, including reservoir survival, collection efficiency and collection survival, with the latter two terms having individual, quantitative performance standards, as described in Section 4.1.4 of the Settlement Agreement. Moreover, ODS must also incorporate estimates of juvenile survival rates for fish that elude collection but successfully navigate through Project turbines. For purposes of estimating ODS, until turbine survival studies are performed, the Licensee must assume that the turbine survival is equal to zero percent (0%). If the performance standards for ODS, UPS and ATE are not achieved within a reasonable time, the Licensee must make Facility Adjustments and Modifications, as described in Section 4.1.6 of the Settlement Agreement.

4.2 Passage Facility Design Performance Standards for Salmonids

The Licensee must design and construct downstream fish passage facilities to achieve, for each species, a CE of equal to or greater than 95 percent, a CS of equal to or greater than 99.5 percent for smolts and 98 percent for fry, and adult bull trout survival of equal to or greater than 99.5 percent. Design performance objectives for Injury are less than or equal to 2 percent. The Licensee must design and construct upstream fish passage facilities to achieve the UPS equal to or greater than 99.5 percent and the ATE to be established as described in the Settlement Agreement.

4.3 Adult Trap Efficiency for Salmonids

As soon as practicable, and following Consultation described by the Settlement Agreement, the Licensee must develop an ATE performance standard for the Merwin Upstream Transport Facility to ensure the safe, timely, and effective passage of adult salmonids, until such time as the standard has been developed, the Licensee must use NOAA Fisheries Service's fish passage guidelines (Anadromous Salmonid Passage Facility Guidelines and Criteria, NMFS (Jan. 31, 2004)). The Licensee must consider without limitation entry rate, fall back, crowding at the entrance, delay, and abandonment of the trap area. When performance standards for ATE have been developed, the Licensee must submit the standards to the Commission and such standards must be used to judge performance for the facilities when considering Facility Adjustments or Facility Modifications.

4.4 Monitoring and Evaluation of Performance Standards

As described in the Settlement Agreement, once the Merwin Upstream Transport Facility or Merwin Downstream Facility is constructed and placed in operation, and after each Facility Adjustment or Facility Modification, the Licensee must evaluate, in Consultation with the ACC (including at least the Services) and with the approval of the Services, whether performance standards are being, met for each of the species designated in the Settlement Agreement, in accordance with the monitoring and evaluation plan described in Section 9 of the Settlement Agreement.

4.5 Adjustments or Modifications to Passage Facilities to Achieve Performance Standards

A "Facility Adjustment" means a physical passage facility upgrade, improvement, or addition that was part of the original design of the passage facility, or an adjustment to the fish passage facility or its operations. A "'Facility Modification" means a physical alteration or addition to a physical passage facility that requires a new design. When making Facility Modifications, the Licensee must follow the design process set out in Section 4.1.2 of the Settlement Agreement, in Consultation with the ACC (including at least the Services). Whenever any Facility Adjustment or Facility Modification is completed, the Licensee must test the operation of the relevant facility for a reasonable time to determine the effectiveness of such adjustment or modification. At the direction of the Services and after any required Commission approvals and obtaining all required Permits, the Licensee must make Facility Adjustments and Facility Modifications to the relevant passage facility to achieve the relevant performance standards for each of the species designated in the Settlement Agreement as soon as practicable.

(a) If ODS is not being met, then the Licensee must make Facility Adjustments or Facility Modifications to downstream passage facilities as follows:

(1) If the CE is less than 95 percent and greater than or equal to 75 percent or the CS for smolts is less than 99.5 percent and greater than or equal to 98 percent, or the CS for fry is less than 98 percent and greater than or equal to 96 percent, or Injuries to juvenile Transported Anadromous Species caused by downstream collection and transport are greater than 2 percent but less than 4 percent, the Licensee must make Facility Adjustments directed by the Services to achieve the performance standard or standards that are not being met but is not required to make Facility Modifications or

(2) If the CE is less than 75 percent, or the CS for smolts is less than 98 percent. or the CS for fry is less than 96 percent, or injuries to juvenile Transported Anadromous Species caused by downstream collection and transport are greater than or equal to 4 percent, the Licensee must make the Facility Modifications directed by the Services to achieve the performance standard or standards that are not being met provided that if the Services believe a Facility Adjustment will likely achieve the performance standard or standards that are not being met, then the Licensee must first make Facility Adjustments as directed by the Services.

(b) If the ODS is being met but the CE is less than 95 percent, the CS for smolts is less than 99.5 percent, The CS for fry is less than 98 percent, or Injury to juvenile Transported Anadromous Species caused by downstream collection and transport is greater than 2 percent, the Licensee must make Facility Adjustments directed by the Services to downstream facilities but is not required to make Facility Modifications.

(c) [Reserved]

(d) For Transported Species, if UPS and/or ATE are not being met, then the Licensee will make Facility Adjustments or Facility Modifications to upstream passage facilities as directed by the Services consistent with the Settlement Agreement.

(e) Except as required in a proceeding initiated with Section 15.3.2 of the Settlement Agreement, or as provided in Section 3.5.2.b of the Settlement Agreement, the Licensee shall not be required to (1) make structural or operational changes with respect to its generating facilities or Project reservoir to achieve standards, (2) replace any fish passage facility with another passage facility, or (3) install additional collection and transport facilities or alternative fish passage facilities beyond those required by the Settlement Agreement. This Article is not intended to alter specific obligations provided under this License or the Settlement Agreement, including, without limitation, operational constraints required under Settlement Agreement Sections 4.2, 4.9.1, and 6.2.

Article 5: Prescription for Species to be Transported

For purposes of all fish passage provisions contained herein, the Licensee must only provide for the transport of spring Chinook, winter steelhead, coho, bull trout, and sea-run cutthroat. Notwithstanding the preceding sentence, the Licensee, after Consultation with the ACC (including at least the Services), and if directed by the Services, must also provide for the transport of fall Chinook or summer steelhead that enter the passage facilities.

Article 6: Prescription for Upstream Transport Before Full Adult Fish Passage

Unless and until alternative technologies are implemented, the Licensee must provide for the transport by truck of all Transported Species collected at the Merwin Upstream Transport Facility. Once the Merwin Upstream Transport Facility is completed, and for so long as trucks are used, the Licensee must provide for transport according to the Upstream Transport Plan described in Section 4.1.8.c of the Settlement Agreement.

Article 7: Prescription for Upstream Transport After Full Adult Fish Passage

On or before the 13th anniversary of the Issuance of the last of the Licenses for the Merwin (P-935), Yale (P-2071), Swift No. 1 (P-2111) and Swift No. 2 (P-2213) projects, the Licensee must evaluate alternative adult fish transport technologies (such as fish trams, cable lifts, or other new technologies) at the facility that allow transportation of the fish with the least practicable amount of handling or other stress-inducing actions, considering the need for sorting fish. The Licensee must implement such technologies provided that (1) alternative technologies are determined, by engineers qualified in fish passage and designated respectively by WDFW, USFWS, NOAA Fisheries Service, and the Licensee to be feasible and effective in transporting fish over dam facilities; (2) the Services determine that such technologies are suitable for meeting the Services' fish passage goals and the biological benefits are expected to be equal to or greater than the benefits of trap-and-transport by truck; and (3) the costs of the selected technology (considering both initial capital cost and ongoing operational and maintenance costs) do not significantly exceed the costs of transporting fish by truck. If there is a disagreement with the engineers' determination under (1) above, the Licensee shall allow for the resolution of disputes in accordance with the ADR Procedures in Section 15.10 of the Settlement Agreement. The Licensee must begin carrying out such technologies after acquisition of all required Permits according to the schedule set forth in the Settlement Agreement. The selection of such technologies and selection of final designs by the Licensee must be made with the approval of the Services after Consultation, with the ACC (including at least the Services) pursuant to Section 4.1.2 of the Settlement Agreement. The costs for such alternate technologies must be considered cumulatively for all of the Lewis River projects, so that a cost savings from alternate technology at one project could offset a cost increase for such technology at another Project, compared to trapping and transporting by truck. If costs are determined to significantly exceed the costs of transporting fish by truck, the Parties to the Settlement Agreement may make reasonable efforts to find more cost-effective facility designs that will achieve the same or greater biological benefit compared to trap-and-transport by truck. If (i) after due comparison of the costs of initial capital and ongoing operations and maintenance through the remaining term of the licenses of trapping and transporting by truck versus such costs of an alternative technology for upstream passage it appears that such alternate technologies would not be implemented because of increased costs; and (ii) any Party (other than the Licensee or the licensees for the Swift No. 1, Swift No. 2, and Yale projects): (A) identifies alternate sources of funding (B) provides a guarantee of payment acceptable to the Licensee of the difference in capital and ongoing operations and maintenance costs over the remaining term of the licenses between trap- and-transport and such alternative technology, and (C) provides such funding without additional conditions unacceptable to the Licensee, express or implied; then the Licensee, shall implement such technologies after acquisition of all required Permits for the Merwin Upstream Transport Facility after any required time for transition between truck and alternative transport facilities but no earlier than upon operation of both the Yale Upstream Facility and Swift Upstream Facility pursuant to the licenses for the Yale project and the Swift No. 1 and Swift No. 2 projects, respectively. If alternative methods are not used at any facility because they do not meet the standards of Section 4.1.8 of the Settlement Agreement, then the Licensee must continue to use trap and transport by truck at such facility.

7.1 Upstream Transport Plan

The Licensee must develop, in Consultation with the ACC (including at least the Services) and with the approval of the Services, subject to Section 15.14 of the Settlement Agreement, a plan that must describe the frequency and procedures to achieve safe, timely, and effective upstream passage (the "Upstream Transport Plan") from the Merwin Upstream Transport Facility. The Licensee must provide for the transport of fish at a minimum frequency of once daily, or more if necessary, to achieve safe, timely, and effective passage. The Licensee must submit the Upstream Transport Plan to the Commission before completion of the Merwin Upstream Transport Facility. The Licensee must modify the Upstream Transport Plan in Consultation with the ACC (including at least the Services) and with the approval of the Services, subject to Section 15.14 of the Settlement Agreement, to identify the distribution of adults transported to Yale lake and Swift Reservoir when the Yale Downstream Facility as provided in the License for the Yale project (P-2071) is completed and prior to completion of the Yale Upstream Facility as provided in the license for the Yale project (P-2071) and Swift Upstream Facility as provided in the Licenses for the Swift No. 1 (P-2111) and Swift No. 2 (P- 2213) projects. The Licensee, together with the licensees for the Yale, Swift No. 1 and Swift No. 2 projects, must modify the Upstream Transport Plan to address transport from the Yale Upstream Facility and the Swift Upstream Facility as provided in the licenses for the Yale, Swift No. 1, and Swift No 2 projects.

Article 8: Prescription for Downstream Transport

The Licensee must provide for the downstream transport of migrating Transported Species collected in the Merwin Downstream Facility by truck.

If the Licensee has not yet commenced construction of the Melvin Downstream Facility, the Licensee must construct and provide for the operation of a bypass passage system in lieu of trapping and transporting by truck if the Services determine that a salmonid bypass passage system would provide equal or greater biological benefit, and would not have unacceptable impacts on other fish, such as wild fall Chinook, between Merwin Dam and the Release Ponds which will be located further downstream.

If the Licensee has commenced construction of the Merwin Downstream Facility and the Services subsequently determine that a salmonid bypass passage system would provide equal or greater biological benefit and would not have unacceptable impacts on fish between Merwin Dam and the Release Ponds, and the Licensee does not determine that the capital, operation and maintenance costs of such bypass would be significantly greater than the capital, operation and maintenance costs of continued use of trap and transport by truck, then the Licensee must Consult with the ACC (including at least the Services) regarding a possible change in methods for downstream passage, in accordance with the Settlement Agreement.

8.1 Downstream Transport Plan

The Licensee together with the licensees for the Yale and Swift No. 1 projects, must modify the Downstream Transport Plan prepared in accordance with the Licensees for the Yale and Swift No. 1 projects, in Consultation with the ACC (including at least the Services), and with the approval of the Services subject to Section 15.14 of the Settlement Agreement, to address transport from the Merwin Downstream Facility. The plan must describe the frequency and procedures to achieve safe, timely, and effective downstream transport. The Licensee, together with the licensees for the Yale and Swift No. 1 projects, must submit the modified Downstream Transport Plan to the Commission before completion of the Merwin Downstream Facility.

Article 9: Prescription for the Merwin Trap

9.1 Merwin Trap Flow Restrictions

To the extent feasible, the Licensee must limit the discharge from the generation facilities at Merwin Dam for safety purposes to a maximum of 5,250 cubic feet per second ("cfs") or other flow level to be determined by the Licensee and the State of Washington Department of Fish and Wildlife (WDFW), measured at the Ariel gage, when personnel are working in the existing fish trap. This practice must continue until such time as upgrades to the Merwin Trap are made and the Licensee determines, in Consultation with WDFW, that such upgrades are effective in providing a greater margin of safety for such personnel. The Licensee must coordinate with WDFW on scheduling such flows and times when fish collection will occur.

9.2 Merwin Trap Upgrades

The Licensee must determine what information is required to improve operating conditions for personnel working in the Merwin Trap by providing a greater margin of safety. The Licensee must gather such information promptly to allow design of operating improvements. By the second anniversary of the Issuance of this License, the Licensee must modify the Merwin Trap as needed to improve the human working environment such that flow restrictions described above are no longer necessary, without introducing additional risk to fish. The Licensee must coordinate with and must provide 30 percent and 60 percent completed preliminary designs for review and comment to the Services and WDFW. The Licensee must provide the 90 percent preliminary designs for the improvements described in this article to the ACC (including at least the Services) within 30 days after the issuance of this License, in accordance with the Settlement Agreement. The Licensee must submit final designs to the Commission upon approval by the Services subject to Section 15.14 of the

Settlement Agreement, but not later than 90 days after Issuance of the Merwin license, or Aug. 31, 2006, whichever is later. Once the improvements are completed or beginning upon the second anniversary of the Issuance of this License, whichever is later, the Licensee must provide for fish to be sorted at the Lewis River Hatchery rather than at the Merwin Trap and must provide up to two additional staffers, if necessary, to clear the Merwin Trap once daily for the benefit of the fish in the facility.

9.3 Interim Merwin Trap Operations

Until construction of the Merwin Upstream Transport Facility, the Licensee must operate the upgraded Merwin Trap solely for the following purposes: to collect hatchery fish returning from the ocean and to transport any bull trout collected to Yale Lake, and fish other than hatchery fish and bull trout will be returned to the river below Merwin Dam. Until the Merwin Upstream Transport Facility is completed, the Licensee, in coordination with WDFW, must make reasonable efforts to operate the Merwin powerhouse to allow fish trapping operations at the Merwin Trap.

9.4 Merwin Upstream Collection and Transport Facility

By six months after the fourth anniversary of the Issuance of this License, the Licensee must construct and provide for the operation of an adult trap and transport facility for use to collect, sort and transport hatchery fish and upstream-migrating adult Transported Species. The Licensee must provide for the transport of adult Transported Anadromous Species as provided in the Settlement Agreement.

The Merwin Upstream Transport Facility must be designed by the Licensee, to the extent feasible, to be compatible both with truck transport and with alternate modes of transport that may be selected as described in Section 4.1.8 of the Settlement Agreement. When designing the Merwin Upstream Transport Facility, the Licensee must consider a wide range of design options for the trap and transport facility, including, without limitation, a complete new facility and incorporation of the Merwin Trap (as upgraded) into the new design. The Licensee must consider designs for the Merwin Upstream Transport Facility such that it would meet applicable performance standards regardless of the operational state of the hydroelectric generation facilities at Merwin Dam. The Licensee must provide for the operation of the passage facility year-round for the remaining term of this license. In Consultation with the Services, the Licensee must provide for safe, timely, and effective handling of all species entering the Merwin Upstream Transport Facility. The Licensee must ensure that all species that will not be transported above Merwin Dam or destined for the Hatchery Facilities shall be returned to the Lewis River below Merwin Dam in a manner and frequency that adequately protects them. The Licensee must provide the 90 percent preliminary designs to the ACC (including at least the Services) by the first anniversary of the Issuance of this License and must follow the procedures set forth in the Settlement Agreement. Subject to Section15.14 of the Settlement Agreement, the Licensee must submit final designs to the Commission upon approval by the Services but no later than six months after the first anniversary of the Merwin License.

Article 10: Prescription for Release Ponds

The Licensee, together with the licensees for the Swift No. 1 and Yale projects, must design and construct, in Consultation with the ACC (including at least the Services) and with the final approval of NOAA Fisheries Service, stress Release Ponds below the Merwin Project to be used for downstream migrating fish that are collected at the Swift Downstream Facility, the Yale Downstream Facility and the Merwin Downstream Facility, as described in Section 4.4.3 of the Settlement Agreement.

Article 11: Prescription for Downstream Passage at Merwin Dam

On or before the 17th anniversary of the Issuance of this License, the Licensee must construct and provide for the operation of a passage facility or facilities at Merwin Dam to collect, sort, tag, and transport downstream-migrating Transported Anadromous Species (the "Merwin Downstream Facility"), unless otherwise directed by the Services pursuant to Section 4.1.9 of the Settlement Agreement. Specifically, the Licensee must construct either a modular surface collector or, as directed by the Services, an alternate passage facility or set of facilities provided the detailed engineering estimate of the cost does not exceed the sum of factors described in Section 4.6 of the Settlement Agreement.

The Licensee must provide for the downstream transport of migrating transported anadromous juvenile and adult salmonids from Lake Merwin to the Release Ponds below Merwin Dam. Bull trout collected in the Merwin Downstream Facility shall be returned to Lake Merwin unless otherwise directed by the USFWS; provided that bull trout with a smolt-like appearance, as determined by the Licensee (using methods derived in consultation with the ACC including at least the USFWS), shall be transported in the same manner as Transported Anadromous Species, as described in Section 4.1.8 of the Settlement Agreement, and shall be transported to a location determined by the USFWS below Merwin Dam.

The Licensee must provide for the tagging of a statistically valid sample of the fish transported as appropriate to accomplish the monitoring and evaluation objectives set forth below, the methodology of such tagging to be determined by the Licensee in consultation with the ACC (including at least the Services) and approved by the Services. The Licensee must provide for the operation of the passage facility for the remaining term of this License unless the Services determine, after discussion with the ACC that operation of the Merwin Downstream Facility should not continue. If the Services make such determination after the passage facility has been operating, the Licensee shall notify the Commission of such decision. The Licensee must provide 90 percent preliminary designs to the ACC (including at least the Services) on or before the 13th anniversary of this License. Subject to Section 15.14 of the Settlement Agreement, the Licensee must submit final designs to the Commission upon approval by the Services, but not later than six months after providing preliminary designs to the ACC.

Article 12: Prescription for Monitoring and Evaluation Plan

Pursuant to Section 9.1 of the Settlement Agreement, the Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must complete a master monitoring and evaluation plan (the "M&E Plan") in Consultation with the ACC (including at least the Services) to carry out a program to monitor and evaluate the effectiveness of aquatic PM&E Measures contained in the Settlement Agreement and to assess achievement of the Reintroduction Outcome Goals as provided in the Settlement Agreement.

The M&E Plan must address the tasks, and the methods, frequency and duration of those tasks, necessary to accomplish the monitoring and evaluation items described below. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must provide a draft M&E Plan to the ACC (including at least the Services) as described in Section 9.1 of the Settlement Agreement. The Licensee must allow the ACC (including at least the Services) a period of 90 days to provide comments on the draft M&E Plan as part of such Consultation. The Services must have final approval authority over elements of the M&E Plan relating to fish passage or species listed under the ESA, subject to Section 15.14 of the Settlement Agreement. The Licensee, together with the licensees for the Yale, Swift No.1, and Swift No. 2 projects, shall finalize the M&E Plan and submit it to the Commission for approval within 90 days after the close of the ACC comment period and must implement the M&E Plan upon approval by the Commission. For the purposes of Section 9 of the Settlement Agreement, as provided in the license for the Swift No. 2 project, the Licensee for the Swift No. 2 project must prepare elements of the M&E Plan to be performed within the boundaries of Swift No. 2 and must implement such elements. As provided in the licenses for the Merwin, Yale and Swift No. 1 projects, the Licensee, together with the licensees for the Yale and Swift No. 1 projects must prepare and implement all other elements of the M&E Plan. As provided in the Settlement Agreement, the Licensee, and the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must cooperate to prepare a single M&E Plan and a single annual report to the Commission, but if that is not successful, the Licensee must submit its own plan and annual report as required under Section 9 of the Settlement Agreement.

The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must provide to the ACC (including at least the Services) the results of the monitoring and evaluations under the M&E Plan as part of the Licensee's annual report which must be prepared in accordance with the Settlement Agreement. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must also include in such annual report a description of the monitoring and evaluation tasks to be completed during the following year. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must consult with the ACC (including at least the Services) as necessary, but no less often than every five years, to determine if modifications to the M&E Plan are warranted. As a result of such consultation, the Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must propose changes to the M&E Plan to improve the effectiveness of monitoring and evaluation. The Services must have final approval of changes to the M&E Plan with respect to fish passage or species listed under the ESA, subject to Section 15.14 of the Settlement Agreement. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must carry out any changes to the M&E Plan as soon as they have been approved by the Commission

The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must amend the M&E Plan in Consultation with the ACC (including at least the Services), to incorporate newly constructed facilities and other aquatic PM&E Measures to be carried out during the term of this License. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must provide a draft revised M&E Plan relating to facilities to be constructed in the future, and other aquatic PM&E Measures to be carried out in the future, to the ACC (including at least the Services) not less than two years before completing construction of such facilities or implementation of such measures. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must allow the ACC (including at least the Services) a period of 90 days to provide comments on the draft revised M&E Plan as part of such consultation. The Services must have final approval authority for the revised M&E Plan relating to fish passage or species listed under the ESA, subject to Section 15.14 of the Settlement Agreement. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must finalize the revised M&E Plan and submit it to the Commission for approval within 90 days after the close of the ACC comment period. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must carry out any amendments to the M&E Plan as soon as they have been approved by the Commission.

The following provisions provide guidance regarding elements to be included in the original M&E Plan and in subsequent amendments to the M&E Plan, relating to specific passage facilities and other aquatic measures. The monitoring and evaluation tasks described in Section 9 of the Settlement Agreement shall be incorporated into and made part of the M&E Plan. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, may revise and adapt the monitoring and evaluation tasks described in Section 9 of the Settlement Agreement, in Consultation with the ACC (including at least the Services) and with the approval of the Services. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, shall allow the ACC a period of 90 days to provide comments on revisions to the draft

M&E Plan as part of such Consultation. The Services shall have final approval authority for the revisions to the M&E Plan relating to fish passage or species listed under the ESA, subject to Section 15.14 of the Settlement Agreement. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, shall finalize any revisions to the M&E Plan and submit them to the Commission for approval within 90 days after the close of the ACC comment period. The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, shall implement the revised M&E Plan upon approval by the Commission.

The Licensee, together with the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, must include in the M&E Plan elements to determine whether the Reintroduction Outcome Goals have been achieved, provided that for such purposes the licensee shall be required to monitor and evaluate only elements that are under the control of the Licensee (such as the functioning of fish passage facilities) and that are affected by the Project. The Licensee shall not be required, without its express written consent, to conduct monitoring that is the obligation of a third party under applicable law or permits (including, but not limited to, marine harvest).

Article 13: Prescription for Monitoring and Evaluation of Fish Passage Facilities

The Licensee must include in the M&E Plan the following monitoring and evaluation elements with respect to the Project and the Merwin Downstream Facility and Merwin Upstream Transport Facility for Chinook, steelhead, coho, bull trout and sea-run cutthroat.

(a) Juvenile migration timing and the estimated number of juveniles entering Lake Merwin;
(b) Reservoir Survival of juvenile fish migrating through Lake Merwin, determined by monitoring a statistically valid sample of fish entering the reservoir:
(c) Collection Efficiency and Collection Survival for the Merwin Downstream Facility:
(d) Injury to and mortality of juvenile fish collected at the Merwin Downstream Facility, and mortality measured at stress Release Ponds;
(e) Survival of, injury to, and mortality of kelts, bull trout and adult sea-run cutthroat collected at the Merwin Downstream Facility;
(f) Turbine Entrainment ("TE”), as contemplated by the Settlement Agreement, the percentage of juvenile anadromous fish of each of the species designated to be transported that are available for collection and that are not collected by the downstream passage facility, and enter the turbines;
(g) Turbine Survival ("TS"), the percentage of juvenile anadromous fish of each of the species to be transported that are entrained in turbines and that survive through turbines; provided that such monitoring must only be performed if and when fish passing through Project turbines may contribute materially to ODS; provided further

that prior to performing Turbine Survival studies, the Licensee must assume Turbine Survival equals zero;

(h) UPS at the Merwin Upstream Transport Facility;

(i) The ATE at the Merwin Upstream Transport Facility:

(j) The number by species of juvenile and adult fish being collected at the Project: and

(k) Hydraulic performance, such as attraction flows in cfs and water velocities in feet per second, to verify that each facility is operating according to its approved design.

Article 14: Prescription for Adult Migration/Spawning Assessment

As contemplated by the Settlement Agreement, the Licensee must identify the spawning timing, distribution, and spawning abundance for Transported Anadromous Species passed upstream by monitoring a statistically valid sample of each stock. The primary purpose is to identify preferred spawning areas to inform revisions to the Hatchery and Supplementation Plan and the Upstream Transport Plan, and to inform the decisions of the ACC in determining how to expend funds from the Aquatics Fund, but such identification must not otherwise create or increase obligations of the Licensee except as expressly set forth in the Settlement Agreement.

Article 15: Prescription for Adjustment in Monitoring Frequency

As contemplated by the Settlement Agreement, once any fish passage standard has been achieved, future monitoring of that standard would be limited to periodic checks to determine continued compliance with the standard.

Article 16: Prescription for Response to Fish Passage Monitoring Results

To the extent not set forth specifically in Section 9.2 of the Settlement Agreement, as contemplated by the Settlement Agreement, the obligations of the Licensee and the licensees for the Yale, Swift No. 1, and Swift No. 2 projects, based on the results of monitoring related to fish passage facilities, are set forth in Section 4 of the Settlement Agreement.

Article 17: Obligation to Consult

Notwithstanding any other provision of these Articles, and with respect to the requirements contained therein, the Licensee's obligation to convene the ACC shall be subject to Section 15.12 of the Settlement Agreement. Where Consultation is required by the Settlement Agreement, the Licensee shall not have an obligation to Consult regarding these Articles with Parties (other than the Services) which have withdrawn from the Settlement Agreement, or with any Party (other than the Services) if the

Settlement Agreement is terminated, except as described in Section 15.13 of the Settlement Agreement.

Article 18: Dispute Resolution

In implementing these Articles, the Licensee shall allow for the resolution of disputes, if any, among the Parties to the Settlement Agreement in accordance with the non-binding Alternative Dispute Resolution procedures set forth in the Settlement Agreement.

RESERVATION OF AUTHORITY

NOAA Fisheries Service reserves its right under Section 18 of the FPA to modify these fishway prescriptions and recommended terms and conditions based upon significant new information and conclusions developed in connection with the fulfillment of other statutory consultation and review requirements, including consultation under Section 7 of the ESA, 16 USC §1536, or Section 305(b) of the MSA, 16 USC § 1855, regarding essential fish habitat. NOAA Fisheries Service respectfully requests the Commission, upon issuance of any new license in this proceeding, retain by means of a specific reopener provision for fishway prescriptions, in accordance with Section 18 of the FPA, and other appropriate reservations of authority, sufficient discretionary involvement or control with respect to project construction, operation, maintenance, and modification under the new license, or any amendments thereto, so as to ensure full compliance with the requirements of Section 18 of the FPA and any new or modified fishway prescription issued thereunder.

In addition, NOAA Fisheries Service respectfully requests the Commission, upon issuance of any new license in this proceeding, retain by means of a specific ESA reopener provision and other appropriate reservations of authority (including authority to require license amendments or project modifications to comply with the ESA following reinitiation of ESA Section 7 consultation at the request *of* the NOAA Fisheries Service), sufficient discretionary involvement or control with respect to project construction, operation, maintenance, and modification under each new license, or any amendments thereto, so as to ensure full compliance with the requirements *of* the ESA, with respect to the carrying out *of* such actions during the term *of* the new license.

NOAA Fisheries Service's prescriptions for fishways presumes that the Licensee's obligations under the Settlement Agreement filed with FERC on December 1, 2004, are accepted in their entirety and without material modification. In addition to the descriptions contained herein, NOAA Fisheries Service's prescriptions rely on the Settlement Agreement and its attachments, as well as other documents in the record at FERC, as the basis and rationale for the construction, operation, and maintenance of fishways. If the Licensee's obligations under the Settlement Agreement are not accepted in their entirety, and without material modification by FERC, or are materially altered by court order or other review before becoming final, NOAA Fisheries Service reserves the right to revise and refile modified prescriptions and recommended terms and conditions within 90 days of notice indicating any such material modification or alteration.

APPENDIX C

Fishway Prescriptions filed by the Department of the Interior under Section 18 of the Federal Power Act for the Merwin Project No. 935

February 22, 2006

(For convenience and clarity, these prescriptions are numbered to match the numbers contained in the applicants revised draft license articles filed with the Commission on January 6, 2006)

2 Fish Passage Facilities Design

To provide for the safe, timely and effective passage past the Project of upstream and downstream migrating salmonids, the Licensee shall develop and implement the Merwin Downstream Facility and Merwin Upstream Transport Facility in accordance with, and subject to the limitations included in, all of the relevant provisions of the Settlement Agreement.

2.1 Studies to Inform Design Decisions

The Licensee, in Consultation with the ACC (including at least the Services) and subject to the final approval of the Services, must develop and carry out studies to inform the design of upstream and downstream fish passage facilities described in the Settlement Agreement with the goal of improving the likelihood that the passage facilities will be successful as initially constructed. Needed information may include the hydraulic characteristics of the Swift No. 1, Yale, and Merwin forebays and tailraces (e.g., a three-dimensional numerical flow-field analysis) and the movement of adult and juvenile salmonids. The Licensee must complete these studies sufficiently in advance of the design decisions required by the Settlement Agreement so that the Licensee, the Services, and the ACC can take the resulting information into account when making final design decisions.

2.2 Design Review

Except as otherwise provided under Section 4.1.9 of the Settlement Agreement, the Licensee must design the Merwin Downstream Facility and the Merwin Upstream Transport Facility~~,~~ to meet the performance standard targets set out in Section 4.1.4.b of the Settlement Agreement, as applicable. The Licensee must use the best available technology for the type of passage facility being constructed, and design the passage facility to provide flexibility for subsequent expansion or Facility Adjustments, if needed, to meet performance standards. A fish passage facility may include duplication of some components (for example, multiple entrances) and still be considered a single passage facility. The Licensee must coordinate with and provide 30 percent and 60 percent completed preliminary designs for review and comment to the Services and WDFW. The Licensee must notify the ACC when design work has begun, and provide the 30 percent and 60 percent preliminary designs to any other Party to the Settlement Agreement at the Party's request. The Licensee must provide the Services and WDFW 45 days to provide their comments. The Licensee must submit the 90 percent preliminary designs with the relevant engineering, hydraulic, and biological work to the ACC (including at least the Services) at the times set forth in the Settlement Agreement. The Licensee must provide the ACC (including at least the Services) 45 days to provide its comments on the 90 percent preliminary designs and must finalize the designs in Consultation with the ACC (including at least the Services) and with the approval of the Services. The Licensee must consider and address in writing those written comments provided by the members of the ACC (including at least the Services) when submitting final designs to the Services for approval.

3 Permits and Time for Construction

Upon approval of passage facility designs by the Commission, the Licensee must diligently and expeditiously acquire all required Permits. The time by which each passage facility must be placed in operation is set forth in the Settlement Agreement.

4 Performance Standards for Fish Passage

The Licensee must provide for the safe, timely, and effective passage of salmonids being transported past the Project as described in the Settlement Agreement. The sole performance standard for kelts and downstream migration of adult sea-run cutthroat must be safe, timely, and effective passage. Specific life stages described below (not including kelts or downstream migrating sea-run cutthroat) have quantitative standards. The Licensee must construct and provide for the operation and maintenance of fish passage facilities that collect all life stages of salmonids that are present at the facility, and function during all flows and during all seasons; except for upstream passage facilities, to the extent it is infeasible due to flood events that require spill that could not be reasonably accommodated by the passage facility.

The Licensee must employ the following definitions in carrying out and monitoring the performance standards:

- Adult Trap Efficiency ("ATE"): The percentage of adult Chinook, coho, steelhead, bull trout, and sea-run cutthroat that are actively migrating to a location above the trap and that are collected by the trap.
- Collection Efficiency ("CE"): The percentage of juvenile anadromous fish of each of the species to be transported, as described in Section 4.1.7 of the Settlement Agreement, that is available for collection and that is actually collected.

- Collection Survival ("CS"): The percentage of juvenile anadromous fish of each of the species to be transported collected that leave Release Ponds alive.
- Injury: Visible trauma (including, but not limited to, hemorrhaging, open wounds without fungus growth, gill damage, bruising greater than 0.5 cm in diameter, etc.), loss of equilibrium, or greater than 20 percent descaling. "Descaling" is defined as the sum of the area on one side of the fish that shows recent scale loss. This does not include areas where scales have regenerated or fungus has grown.
- Overall Downstream Survival ("ODS"): The percentage of juvenile anadromous fish of each of the species to be transported that enter the reservoirs from natal streams and that survive to enter the Lewis River below Merwin Dam by collection, transport, and release via the juvenile fish passage system, passage via turbines, or some combination thereof, calculated as provided in Schedule 4.1.4 of the Settlement Agreement.
- Upstream Passage Survival ("UPS"): Percentage of adult fish of each of the species to be transported that are collected that survive the upstream trapping-and-transport process. For sea-run cutthroat and bull trout, "adult" means fish greater than 13 inches in length.

4.1 Overall Fish Passage Performance Standards for Salmonids

For each species, the Licensee must achieve the following overall performance standards for fish passage: ODS of greater than or equal to 80 percent until such time as the Yale Downstream Facility is built as provided in the License for the Yale project (P-2071), or the funds from the In Lieu Fund, as described in Section 7.6 of the Settlement Agreement, become available to the Services in lieu of constructing the Yale Downstream Facility, after which time ODS must be greater than or equal to 75 percent; UPS of greater than or equal to 99.5 percent; and ATE to be established as described in the Settlement Agreement. ODS, as defined by the Settlement Agreement, must include several components of juvenile passage, including reservoir survival, collection efficiency and collection survival, with the latter two terms having individual, quantitative performance standards, as described in Section 4.1.4 of the Settlement Agreement. Moreover, ODS must also incorporate estimates of juvenile survival rates for fish that elude collection but successfully navigate through Project turbines. For purposes of estimating ODS, until turbine survival studies are performed, the Licensee must assume that the turbine survival is equal to zero percent (0%). If the performance standards for ODS, UPS and ATE are not achieved within a reasonable time, the Licensee must make Facility Adjustments and Modifications, as described in Section 4.1.6 of the Settlement Agreement.

4.2 Passage Facility Design Performance Standards for Salmonids

The Licensee must design and construct downstream fish passage facilities to achieve, for each species, a CE of equal to or greater than 95 percent, a CS of equal to or greater than 99.5 percent for smolts and 98 percent for fry, and adult bull trout survival of equal to or greater than 99.5 percent. Design performance objectives for Injury are less than or equal to 2 percent. The Licensee must design and construct upstream fish passage facilities to achieve the UPS equal to or greater than 99.5 percent and the ATE to be established as described in the Settlement Agreement.

4.3 Adult Trap Efficiency for Salmonids
As soon as practicable, and following Consultation described by the Settlement Agreement, the Licensee must develop an ATE performance standard for the Merwin Upstream Transport Facility to ensure the safe, timely, and effective passage of adult salmonids. Until such time as the standard has been developed, the Licensee must use NOAA Fisheries' fish passage guidelines (*Anadromous Salmonid Passage Facility Guidelines and Criteria*, NMFS (Jan. 31, 2004)). The Licensee must consider without limitation entry rate, fall back, crowding at the entrance, delay, and abandonment of the trap area. When performance standards for ATE have been developed, the Licensee must submit the standards to the Commission and such standards must be used to judge performance for the facilities when considering Facility Adjustments or Facility Modifications.

4.4 Monitoring and Evaluation of Performance Standards
As described in the Settlement Agreement, once the Merwin Upstream Transport Facility or Merwin Downstream Facility, is constructed and placed in operation, and after each Facility Adjustment or Facility Modification, the Licensee must evaluate, in Consultation with the ACC (including at least the Services) and with the approval of the Services, whether performance standards are being met for each of the species designated in the Settlement Agreement, in accordance with the monitoring and evaluation plan described in Section 9 of the Settlement Agreement.

4.5 Adjustments or Modifications to Passage Facilities to Achieve Performance Standards
A "Facility Adjustment" means a physical passage facility upgrade, improvement, or addition that was part of the original design of the passage facility, or an adjustment to the fish passage facility or its operations. A "Facility Modification" means a physical alteration or addition to a physical passage facility that requires a new design. When making Facility Modifications, the Licensee must follow the design process set out in Section 4.1.2 of the Settlement Agreement, in Consultation with the ACC (including at least the Services). Whenever any Facility Adjustment or Facility Modification is completed, the Licensee must test the operation of the relevant facility for a reasonable time to determine the effectiveness of such adjustment or modification. At the direction of the Services and after any required Commission approvals and obtaining all required Permits, the Licensee must make Facility Adjustments and Facility Modifications to the relevant passage facility to achieve the relevant performance standards for each of the species designated in the Settlement Agreement as soon as practicable.

(a) If ODS is not being met, then the Licensee must make Facility Adjustments or Facility Modifications to downstream passage facilities as follows:

(1) If the CE is less than 95 percent and greater than or equal to 75 percent or the CS for smolts is less than 99.5 percent and greater than or equal to 98 percent, or the CS for fry is less than 98 percent and greater than or equal to 96 percent, or Injuries to juvenile Transported Anadromous Species caused by downstream collection and transport are greater than 2 percent but less than 4 percent, the Licensee must make Facility Adjustments directed by the Services to achieve the performance standard or standards that are not being met but is not required to make Facility Modifications; or

(2) If the CE is less than 75 percent, or the CS for smolts is less than 98 percent, or the CS for fry is less than 96 percent, or Injuries to juvenile Transported Anadromous Species caused by downstream collection and transport are greater than or equal to 4 percent, the Licensee must make the Facility Modifications directed by the Services to achieve the performance standard or standards that are not being met; provided that if the Services believe a Facility Adjustment will likely achieve the performance standard or standards that are not being met, then the Licensee must first make Facility Adjustments as directed by the Services.

(b) If the ODS is being met but the CE is less than 95 percent, the CS for smolts is less than 99.5 percent, the CS for fry is less than 98 percent, or Injury to juvenile Transported Anadromous Species caused by downstream collection and transport is greater than 2 percent, the Licensee must make Facility Adjustments directed by the Services to downstream facilities but is not required to make Facility Modifications.

(c) For bull trout, the Licensee shall make Facility Adjustments or Facility Modifications to downstream passage facilities as follows:

(1) If the survival of bull trout is less than 99.5% and is greater than or equal to 98%, or Injuries caused by downstream collection and transport are greater than 2% but less than 4%, the Licensee shall make Facility Adjustments directed by USFWS to achieve the performance standard or standards that are not being met, but shall not be required to make Facility Modifications; or

(2) If the survival of bull trout is less than 98%, or Injuries caused by downstream collection and transport are greater than or equal to 4%, the Licensee shall make the Facility Modifications directed by USFWS to achieve the performance standard or standards that are not being met; provided that if USFWS determines that a Facility Adjustment will likely achieve the performance standard or standards that are not being met, then the Licensees shall make Facility Adjustments as directed by USFWS.

(d) For Transported Species, if UPS and/or ATE are not being met, then the Licensee will make Facility Adjustments or Facility Modifications to upstream passage facilities as directed by the Services, consistent with the Settlement Agreement.

(e) Except as required in a proceeding initiated with Section 15.3.2 of the Settlement Agreement, or as provided in Section 3.5.2.b of the Settlement Agreement, the Licensee shall not be required to (1) make structural or operational changes with respect to its generating facilities or Project reservoir to achieve standards, (2) replace any fish passage facility with another passage facility, or (3) install additional collection and transport facilities or alternative fish passage facilities beyond those required by the Settlement Agreement. This Article is not intended to alter specific obligations provided under this License or the Settlement Agreement, including, without limitation, operational constraints required under Settlement Agreement Sections 4.2, 4.9.1, and 6.2.

5 Species to be Transported

For purposes of all fish passage provisions contained herein, the Licensee must only provide for the transport of spring Chinook, winter steelhead, coho, bull trout, and sea-run cutthroat. Notwithstanding the preceding sentence, the Licensee, after Consultation with the ACC (including at least the Services), and if directed by the Services, must also provide for the transport of fall Chinook or summer steelhead that enter the passage facilities.

6 Upstream Transport Before Full Adult Fish Passage

Unless and until alternative technologies are implemented, the Licensee must provide for the transport by truck of all Transported Species collected at the Merwin Upstream Transport Facility. Once the Merwin Upstream Transport Facility is completed, and for so long as trucks are used, the Licensee must provide for transport according to the Upstream Transport Plan described in Section 4.1.8.c of the Settlement Agreement.

7 Upstream Transport After Full Adult Fish Passage

On or before the 13th anniversary of the Issuance of the last of the Licenses for the Merwin (P-935), Yale (P-2071), Swift No. 1 (P-2111), and Swift No. 2 (P-2213) projects, the Licensee must evaluate alternative adult fish transport technologies (such as fish trams, cable lifts, or other new technologies) at the facility that allow transportation of the fish with the least practicable amount of handling or other stress-inducing actions, considering the need for sorting fish. The Licensee must implement such technologies provided that (1) alternative technologies are determined, by engineers qualified in fish passage and designated respectively by WDFW, USFWS, NOAA Fisheries, and the Licensee to be feasible and effective in transporting fish over dam facilities; (2) the

Services determine that such technologies are suitable for meeting the Services' fish passage goals and the biological benefits are expected to be equal to or greater than the benefits of trap-and-transport by truck; and (3) the costs of the selected technology (considering both initial capital cost and ongoing operational and maintenance costs) do not significantly exceed the costs of transporting fish by truck. If there is a disagreement with the engineers' determination under (1) above, the Licensee shall allow for the resolution of disputes in accordance with the ADR Procedures in Section 15.10 of the Settlement Agreement. The Licensee must begin carrying out such technologies after acquisition of all required Permits according to the schedule set forth in the Settlement Agreement. The selection of such technologies and selection of final designs by the Licensee must be made with the approval of the Services after Consultation with the ACC (including at least the Services), pursuant to Section 4.1.2 of the Settlement Agreement. The costs for such alternate technologies must be considered cumulatively for all of the Lewis River projects, so that a cost savings from alternate technology at one Project could offset a cost increase for such technology at another Project, compared to trapping and transporting by truck. If costs are determined to significantly exceed the costs of transporting fish by truck, the Parties to the Settlement Agreement may make reasonable efforts to find more cost-effective facility designs that will achieve the same or greater biological benefit compared to trap-and-transport by truck. If (i) after due comparison of the costs of initial capital and ongoing operations and maintenance through the remaining term of the Licenses of trapping and transporting by truck versus such costs of an alternative technology for upstream passage it appears that such alternate technologies would not be implemented because of increased costs; and (ii) any Party (other than the Licensee or the licensees for the Swift No.1, Swift No. 2 and Yale projects): (A) identifies alternate sources of funding, (B) provides a guarantee of payment acceptable to the Licensee of the difference in capital and ongoing operations and maintenance costs over the remaining term of the Licenses between trap-and-transport and such alternative technology, and (C) provides such funding without additional conditions unacceptable to the Licensee, express or implied; then the Licensee, shall implement such technologies after acquisition of all required Permits for the Merwin Upstream Transport Facility after any required time for transition between truck and alternative transport facilities but no earlier than upon operation of both the Yale Upstream Facility and Swift Upstream Facility pursuant to the licenses for the Yale project and the Swift No. 1 and Swift No. 2 projects, respectively. If alternative methods are not used at any facility because they do not meet the standards of Section 4.1.8 of the Settlement Agreement, then the Licensee must continue to use trap and transport by truck at such facility.

7.1 Upstream Transport Plan

The Licensee must develop, in Consultation with the ACC and with the approval of the Services, subject to Section 15.14 of the Settlement Agreement, a plan that must describe the frequency and procedures to achieve safe, timely, and effective upstream passage (the "Upstream Transport Plan") from the Merwin Upstream Transport Facility. The

Licensee must provide for the transport of fish at a minimum frequency of once daily, or more if necessary, to achieve safe, timely, and effective passage. The Licensee must submit the Upstream Transport Plan to the Commission before completion of the Merwin Upstream Transport Facility. The Licensee, must modify the Upstream Transport Plan in Consultation with the ACC and with the approval of the Services, subject to Section 15.14 of the Settlement Agreement, to identify the distribution of adults transported to Yale Lake and Swift Reservoir when the Yale Downstream Facility as provided in the License for the Yale project (P-2071) is completed and prior to completion of the Yale Upstream Facility as provided in the License for the Yale project (P-2071) and Swift Upstream Facility as provided in the Licenses for the Swift No. 1 and Swift No. 2 projects. The Licensee, together with the licensees for the Yale, Swift No. 1 and Swift No. 2 projects, must modify the Upstream Transport Plan to address transport from the Yale Upstream Facility and the Swift Upstream Facility as provided in the licenses for the Yale, Swift No. 1 and Swift No. 2 projects.

8 Downstream Transport

The Licensee must provide for the downstream transport of migrating Transported Species collected in the Merwin Downstream Facility by truck.

If the Licensee has not yet commenced construction of the Merwin Downstream Facility, the Licensee must construct and provide for the operation of a bypass passage system in lieu of trapping and transporting by truck if the Services determine that a salmonid bypass passage system would provide equal or greater biological benefit, and would not have unacceptable impacts on other fish, such as wild fall Chinook, between Merwin Dam and the Release Ponds which will be located further downstream.

If the Licensee has commenced construction of the Merwin Downstream Facility and the Services subsequently determine that a salmonid bypass passage system would provide equal or greater biological benefit and would not have unacceptable impacts on fish between Merwin Dam and the Release Ponds, and the Licensee does not determine that the capital, operation and maintenance costs of such bypass would be significantly greater than the capital, operation and maintenance costs of continued use of trap and transport by truck, then the Licensee must Consult with the ACC (including at least the Services) regarding a possible change in methods for downstream passage, in accordance with the Settlement Agreement.

8.1 Downstream Transport Plan

The Licensee, together with the licensees for the Yale and Swift No. 1 projects, must modify the Downstream Transport Plan prepared in accordance with the License for the Yale and Swift No. 1 projects, in Consultation with the ACC, and with the approval of the Services subject to Section 15.14 of the Settlement Agreement, to address transport from the Merwin Downstream Facility. The plan must describe the frequency and procedures to achieve safe, timely, and effective downstream transport. The Licensee, together with the licensees for the Yale and Swift No. 1 projects must submit the modified Downstream Transport Plan to the Commission before completion of the Merwin Downstream Facility.

9.1 Merwin Trap Flow Restrictions
To the extent feasible, the Licensee must limit the discharge from the generation facilities at Merwin Dam for safety purposes to a maximum of 5,250 cubic feet per second ("cfs") or other flow level to be determined by the Licensee and the State of Washington Department of Fish and Wildlife (WDFW), measured at the Ariel gage, when personnel are working in the existing fish trap. This practice must continue until such time as upgrades to the Merwin Trap are made and the Licensee determines, in Consultation with WDFW, that such upgrades are effective in providing a greater margin of safety for such personnel. The Licensee must coordinate with WDFW on scheduling such flows and times when fish collection will occur.

9.2 Merwin Trap Upgrades
The Licensee must determine what information is required to improve operating conditions for personnel working in the Merwin Trap by providing a greater margin of safety. The Licensee must gather such information promptly to allow design of operating improvements. By the second anniversary of the Issuance of this License, the Licensee must modify the Merwin Trap as needed to improve the human working environment such that flow restrictions described above are no longer necessary, without introducing additional risk to fish. The Licensee must coordinate with and must provide 30 percent and 60 percent completed preliminary designs for review and comment to the Services and WDFW. The Licensee must provide the 90 percent preliminary designs for the improvements described in this article to the ACC (including at least the Services) within 30 days after the issuance of this License, in accordance with the Settlement Agreement. The Licensee must submit final designs to the Commission upon approval by the Services, subject to Section 15.14 of the Settlement Agreement, but not later than 90 days after Issuance of the Merwin License, or Aug. 31, 2006, whichever is later. Once the improvements are completed or beginning upon the second anniversary of the Issuance of this License, whichever is later, the Licensee must provide for fish to be sorted at the Lewis River Hatchery rather than at the Merwin Trap and must provide up to two additional staffers, if necessary, to clear the Merwin Trap once daily for the benefit of the fish in the facility.

9.3 Interim Merwin Trap Operations
Until construction of the Merwin Upstream Transport Facility, the Licensee must operate the upgraded Merwin Trap solely for the following purposes: to collect hatchery fish returning from the ocean and to transport any bull trout collected to Yale Lake, and fish other than hatchery fish and bull trout will be returned to the river below Merwin Dam. Until the Merwin Upstream Transport Facility is completed, the Licensee, in coordination

with WDFW, must make reasonable efforts to operate the Merwin powerhouse to allow fish trapping operations at the Merwin Trap.

9.4 Merwin Upstream Collection and Transport Facility

By six months after the fourth anniversary of the Issuance of this License, the Licensee must construct and provide for the operation of an adult trap and transport facility for use to collect, sort, and transport hatchery fish and upstream-migrating adult Transported Species. The Licensee must provide for the transport of adult Transported Anadromous Species as provided in the Settlement Agreement. The Licensee shall provide for the transport of any bull trout collected below Merwin Dam to Yale Lake unless otherwise directed by the USFWS.

The Merwin Upstream Transport Facility must be designed by the Licensee, to the extent feasible, to be compatible both with truck transport and with alternate modes of transport that may be selected as described in section 4.1.8 of the Settlement Agreement. When designing the Merwin Upstream Transport Facility, the Licensee must consider a wide range of design options for the trap and transport facility, including, without limitation, a complete new facility and incorporation of the Merwin Trap (as upgraded) into the new design. The Licensee must consider designs for the Merwin Upstream Transport Facility such that it would meet applicable performance standards regardless of the operational state of the hydroelectric generation facilities at Merwin Dam. The Licensee must provide for the operation of the passage facility year-round for the remaining term of this License. In Consultation with the Services, the Licensee must provide for safe, timely, and effective handling of all species entering the Merwin Upstream Transport Facility. The Licensee must ensure that all species that will not be transported above Merwin Dam or destined for the Hatchery Facilities shall be returned to the Lewis River below Merwin Dam in a manner and frequency that adequately protects them. The Licensee must provide the 90 percent preliminary designs to the ACC (including at least the Services) by the first anniversary of the Issuance of this License and must follow the procedures set forth in the Settlement Agreement. Subject to Section 15.14 of the Settlement Agreement, the Licensee must submit final designs to the Commission upon approval by the Services, but no later than six months after the first anniversary of the Merwin License.

10 Release Ponds

The Licensee, together with the licensees for the Swift No. 1 and Yale projects, must design and construct, in Consultation with the ACC and with the final approval of NOAA Fisheries, stress Release Ponds below the Merwin Project to be used for downstream migrating fish that are collected at the Swift Downstream Facility, the Yale Downstream Facility and the Merwin Downstream Facility, as described in Section 4.4.3 of the Settlement Agreement.

11 Downstream Passage at Merwin Dam

On or before the 17th anniversary of the Issuance of this License, the Licensee must construct and provide for the operation of a passage facility or facilities at Merwin Dam to collect, sort, tag, and transport downstream-migrating Transported Anadromous Species (the "Merwin Downstream Facility"), unless otherwise directed by the Services pursuant to Section 4.1.9 of the Settlement Agreement. Specifically, the Licensee must construct either a modular surface collector or, as directed by the Services, an alternate passage facility or set of facilities provided the detailed engineering estimate of the cost does not exceed the sum of factors described in Section 4.6 of the Settlement Agreement. The Licensee must provide for the downstream transport of migrating transported anadromous juvenile and adult salmonids from Lake Merwin to the Release Ponds below Merwin Dam. Bull trout collected in the Merwin Downstream Facility shall be returned to Lake Merwin unless otherwise directed by the USFWS; provided that bull trout with a smolt-like appearance, as determined by the Licensee (using methods derived in Consultation with the ACC including at least the USFWS), shall be transported in the same manner as Transported Anadromous Species, as described in Section 4.1.8 of the Settlement Agreement, and shall be transported to a location determined by the USFWS below Merwin Dam.

The Licensee must provide for the tagging of a statistically valid sample of the fish transported as appropriate to accomplish the monitoring and evaluation objectives set forth below, the methodology of such tagging to be determined by the Licensee in Consultation with the ACC (including at least the Services) and approved by the Services. The Licensee must provide for the operation of the passage facility for the remaining term of this License unless the Services determine, after discussion with the ACC, that operation of the Merwin Downstream Facility should not continue. If the Services make such determination after the passage facility has been operating, the Licensee shall notify the Commission of such decision. The Licensee must provide 90 percent preliminary designs to the ACC (including at least the Services) on or before the 13th anniversary of this License. Subject to Section 15.14 of the Settlement Agreement, the Licensee must submit final designs to the Commission upon approval by the Services, but not later than six months after providing preliminary designs to the ACC.

12 Bull Trout Entrainment Reduction

Unless already completed, the Licensee shall design and implement a study to evaluate bull trout entrainment reduction methods in Consultation with the ACC (including at least the USFWS). Potential entrainment reduction methods include installation of exclusion devices, such as strobe lights, and installation of barrier nets with submersible cork lines and designed to accommodate a Merwin-type floating trap. Due to the small numbers of bull trout in Yale Lake and Lake Merwin, any evaluation of strobe lights shall be performed in Swift Reservoir. Upon the request of the USFWS, the Licensee shall, in

Consultation with the ACC and subject to the approval of the USFWS, develop criteria to determine when entrainment reduction measures similar to those implemented at the Yale project as provided in the license for the Yale project (P-2111) should be implemented at Merwin Dam. The Licensee shall submit the criteria to the Commission for approval after obtaining approval by the USFWS subject to Section 15.14 of the Settlement Agreement, within 12 months after the USFWS request for criteria. Once approved by the Commission, if and when such criteria are met, the Licensee shall commence the entrainment reduction measures, and shall maintain such measures until commencing operation of the Merwin Downstream Facility.

13 Downstream Bull Trout Facilities

If, pursuant to Section 4.1.9 of the Settlement Agreement, the Licensee does not build the Merwin Downstream Facility, then when the Service determines that bull trout populations have increased sufficiently in Lake Merwin, but not sooner than the 17th anniversary of the Issuance of this License, the Licensee shall construct and provide for the operation of a passage facility similar to the Yale Downstream Bull Trout Facility at Merwin Dam (Merwin Downstream Bull Trout Facility).

The Merwin Downstream Bull Trout Facility shall be similar in magnitude and scale to modular floating Merwin-type collectors and are not intended to be passage facilities of the same magnitude and expense as the Merwin Downstream Facility. The Licensee shall provide for monitoring of performance as provided in the Monitoring and Evaluation Plan (M&E Plan) described in Section 9 of the Settlement Agreement, and make necessary and appropriate Facility Adjustments and Facility Modifications to the Merwin Downstream Bull Trout Facility, in Consultation with the ACC (including at least the USFWS) and with approval of the USFWS, subject to Section 15.14 of the Settlement Agreement, to achieve relevant performance standards, provided that such modifications shall not require installation of a different type of passage facility. The Licensee shall provide preliminary (30%) designs to the ACC for the Merwin Downstream Bull Trout Facility within 12 months after a determination by USFWS and NOAA Fisheries under Section 4.1.9 of the Settlement Agreement. The Licensee shall follow the provisions in Sections 4.1.1 through 4.1.3 of the Settlement Agreement, when developing designs for the facilities. The Licensee shall submit final designs to the Commission upon approval by USFWS, subject to 15.14 of the Settlement Agreement, but not later than 60 days after submission of the final design to USFWS.

14 Obligation to Consult

Notwithstanding any other provision of these prescriptions for Fishways, and with respect to the requirements contained therein, the Licensee's obligation to convene the ACC shall be subject to Section 15.12 of the Settlement Agreement. Where Consultation is required by the Settlement Agreement, the Licensee shall not have an obligation to Consult regarding these Fishway prescriptions with Parties (other than the Services) which have withdrawn from the Settlement Agreement, or with any Party (other than the Services) if the Settlement Agreement is terminated, except as described in Section 15.13 of the Settlement Agreement.

15 Dispute Resolution

In implementing these prescriptions for Fishways, the Licensee shall allow for the resolution of disputes, if any, among the Parties to the Settlement Agreement in accordance with the non-binding Alternative Dispute Resolution procedures set forth in the Settlement Agreement.

APPENDIX D

Terms and Conditions included in the National Marine Fisheries Service's Biological Opinion for Relicensing of the Lewis River Hydroelectric Projects: Merwin (No. 935), Yale (No. 2071), Swift No. 1 (No. 2111), and Swift No. 2 (No. 2213)

August 27, 2007

9.3.1 Terms and Conditions

To be exempt from the prohibitions of Section 9 of the ESA, FERC must fully comply with conservation measures described as part of the Proposed Action and the following terms and conditions that complete the reasonable and prudent measures (RPMs) described above. In order to be exempt from the take prohibitions of Section 9 of the ESA and regulations issued pursuant to Section 4(d) of the ESA, FERC must include in the licenses and PacifiCorp and Cowlitz PUD must implement the following terms and conditions, which implement the RPMs listed above. These terms and conditions are non-discretionary. NMFS may amend the provisions of this ITS consistent with its statutory and regulatory authorities.

1) All Settlement Agreement provisions that relate to anadromous fish (including, but not limited to, provisions related to passage, provisions that affect habitat conditions (e.g., flows) or provisions related to monitoring) for these Projects must be followed by PacifiCorp and Cowlitz PUD and enforced by FERC. This applies to those Settlement Agreement articles that relate to salmon, their habitat, and implementation of those measures including adaptive management. Some key provisions include, but are not limited to:
   Settlement Agreement:
      Section 3: Anadromous Fish Reintroduction Outcome Goals
      Section 4: Fish Passage Measures,
      Section 6: Flow Releases for Fish and Other Aquatic Species,
      Section 7: Aquatic Habitat Enhancement Actions,
      Section 8: Hatchery and Supplementation Program, and
      Section 9: Aquatic Monitoring and Evaluation.

2) In all proposed actions involving construction in or near waterways, FERC must require PacifiCorp and Cowlitz PUD to follow the construction best management practices described below to control sediment, disturbance, and other potential detrimental effects to listed salmonids.

   a. Minimum area. Construction impacts will be confined to the minimum area necessary to complete the project.

b. Alteration or disturbance of the streambanks and existing riparian vegetation will be minimized to the greatest extent possible.

c. No herbicide application should occur as part of this action. Mechanical removal of undesired vegetation and root nodes is permitted.

d. All existing vegetation within 150 ft of the edge of bank should be retained to the greatest extent possible.

e. Timing of inwater work. Work below the bankfull elevation will be completed during the State of Washington’s or the Corps’ preferred inwater work period as appropriate for the project area, unless otherwise approved in writing by NMFS.

f. Cessation of work. Construction project activities will cease under high flow conditions that may result in inundation of the project area, except for efforts to avoid or minimize resource damage. All materials, equipment, and fuel must be removed if flooding of the area is expected to occur within 24 hours.

g. Fish screens. All water intakes used for a construction project, including pumps used to isolate an inwater work area, will have a fish screen installed, operated, and maintained according to NMFS' fish screen criteria.

h. Fish passage. Passage must be provided for any adult or juvenile salmonid species present in the Project area during construction, unless otherwise approved in writing by NMFS, and maintained after construction for the life of the Project. Passage will be designed in accordance with NMFS’ "Anadromous Salmonid Passage Facility Guidelines and Criteria" (2004) (ATTACHMENT 1). Upstream passage is required during construction if it previously existed.

i. Construction activities associated with habitat enhancement and erosion control measures must meet or exceed best management practices and other performance standards contained in the applicable state and Federal permits.

j. Pollution and Erosion Control Plan. Prepare, in consultation with NMFS, and carry out a Pollution and Erosion Control Plan to prevent pollution caused by survey, construction, operation, and maintenance activities. The Plan will be available for inspection upon request by FERC or NMFS.
    i. Plan Contents. The Pollution and Erosion Control Plan will contain the pertinent elements listed below, and meet requirements of all applicable laws and regulations.

1. The name and address of the party(s) responsible for accomplishment of the Pollution and Erosion Control Plan.
2. Practices to prevent erosion and sedimentation associated with access roads, decommissioned roads, stream crossings, drilling sites, construction sites, borrow pit operations, haul roads, equipment and material storage sites, fueling operations, and staging areas.
3. Practices to confine, remove, and dispose of excess concrete, cement, and other mortars or bonding agents, including measures for washout facilities.
4. A description of any regulated or hazardous products or materials that will be used for the Project, including procedures for inventory, storage, handling, and monitoring.
5. A spill containment and control plan with notification procedures, specific cleanup and disposal instructions for different products, quick response containment and cleanup measures that will be available on the site, proposed methods for disposal of spilled materials, and employee training for spill containment.
6. Practices to prevent construction debris from dropping into any stream or water body, and to remove any material that does drop with a minimum disturbance to the streambed and water quality.
7. Erosion control materials (e.g., silt fence, straw bales, aggregate) in excess of those installed must be available on site for immediate use during emergency erosion control needs.
8. Temporary erosion and sediment controls will be used on all exposed slopes during any hiatus in work exceeding 7 days.

ii. Inspection of erosion controls. During construction, the operator must monitor instream turbidity and inspect all erosion controls daily, or as required by Washington Department of Ecology’s Construction stormwater general permit, or as determined by NMFS at the time of construction.
1. If monitoring or inspection shows that the erosion controls are ineffective, mobilize work crews immediately to make repairs, install replacements, or install additional controls as necessary.
2. Remove sediment from erosion controls once it has reached one-third of the exposed height of the control.

k. Construction discharge water. Treat all discharge water created by construction (e.g., concrete washout, pumping for work area isolation, vehicle wash water, drilling fluids) as follows:

i. Water quality. Design, build, and maintain facilities to collect and treat all construction discharge water using the best available technology applicable to site conditions. Provide treatment to remove debris, nutrients, sediment, petroleum hydrocarbons, metals, and other pollutants likely to be present.

ii. Discharge velocity. If construction discharge water is released using an outfall or diffuser port, velocities will not exceed 4 fps, and the maximum size of any aperture will not exceed 4 fps.

iii. Spawning areas, submerged estuarine vegetation. Do not release construction discharge water within 300 ft upstream of spawning areas or areas with submerged estuarine vegetation. Clean construction discharge may be released.

iv. Pollutants. Do not allow pollutants, including green concrete, contaminated water, silt, welding slag, or sandblasting abrasive to contact any wetland or the 2-year floodplain, except cement or grout when abandoning a drill boring or installing instrumentation in the boring.

l. During completion of habitat enhancement activities, no pollutants of any kind (sewage, waste spoils, petroleum products, etc.) should come in contact with the water body or wetlands nor their substrate below the mean high-high water elevation or 10-year flood elevation, whichever is greater.

m. Treated wood.

i. Projects using treated wood that may contact flowing water or that will be placed over water where it will be exposed to mechanical abrasion or where leachate may enter flowing water will not be used, except for pilings installed following NMFS' guidelines.

ii. Projects that require removal of treated wood will use the following precautions:

1. Treated wood debris. Use the containment necessary to prevent treated wood debris from falling into the water. If treated wood debris does fall into the water, remove it immediately.
2. Disposal of treated wood debris. Dispose of all treated wood debris removed during a project, including treated wood pilings, at an upland facility approved for hazardous materials of this classification. Do not leave treated wood pilings in the water or stacked on the streambank.

n. Preconstruction activity. Complete the following actions before significant alteration of the Project area:

i. Marking. Flag the boundaries of clearing limits associated with site access and construction to prevent ground disturbance of critical riparian vegetation, wetlands, and other sensitive sites beyond the flagged boundary. Construction activity or movement of equipment into existing vegetated areas must not begin until clearing limits are marked.

ii. Emergency erosion controls. Ensure that the following materials for emergency erosion control are on site: A supply of sediment control materials (e.g., silt fence, straw bales), and an oil-absorbing, floating boom whenever surface water is present.

iii. Temporary erosion controls. All temporary erosion controls will be in place and appropriately installed downslope of project activity within the riparian buffer area until site rehabilitation is complete.

o. Temporary access roads.
   i. Steep slopes. Do not build temporary roads mid-slope or on slopes steeper than 30 percent.
   ii. Minimizing soil disturbance and compaction. Low-impact, tracked drills will be walked to a survey site without the need for an access road. Minimize soil disturbance and compaction for other types of access whenever a new temporary road is necessary within 150 ft of a stream, water body, or wetland by clearing vegetation to ground level and placing clean gravel over geotextile fabric, unless otherwise approved in writing by NMFS.
   iii. Temporary stream crossings.
      1. Do not allow equipment in the flowing water portion of the stream channel where equipment activity could release sediment downstream, except at designated stream crossings.
      2. Minimize the number of temporary stream crossings.
      3. Design new temporary stream crossings as follows:
         a) Survey and map any potential spawning habitat within 300 ft downstream of a proposed crossing.
         b) Do not place stream crossings at known or suspected spawning areas, or within 300 ft upstream of such areas if spawning areas may be affected.
         c) Design the crossing to provide for foreseeable risks (e.g., flooding and associated bedload and debris) to prevent the diversion of stream flow out of the channel and down the road if the crossing fails.
         d) Vehicles and machinery will cross riparian buffer areas and streams at right angles to the main channel wherever possible.
      4. Obliteration. When the project is completed, obliterate all temporary access roads, stabilize the soil, and revegetate the site. Abandon and restore temporary roads in wet or flooded areas by the end of the inwater work period.

p. Vehicles.
   i. Choice of equipment. When heavy equipment will be used, the equipment selected will have the least adverse effects on the environment (e.g., minimally sized, low ground pressure equipment).
   ii. Vehicle staging. Fuel, operate, maintain, and store vehicles as follows:
      1. Complete vehicle staging, cleaning, maintenance, refueling, and fuel storage, except for that needed to service boats, in a vehicle staging area

placed 150 ft or more from any stream, water body, or wetland, unless otherwise approved in writing by NMFS.

2. Inspect all vehicles operated within 150 ft of any stream, water body, or wetland daily for fluid leaks before leaving the vehicle staging area. Repair any leaks detected in the vehicle staging area before the vehicle resumes operation. Document inspections in a record that is available for review on request by FERC or NMFS.
3. Before activities begin and as often as necessary during construction activities, steam clean all equipment that will be used below the bankfull elevation until all visible external oil, grease, mud, and other visible contaminates are removed. Any washing of equipment must be conducted in a location that will not contribute untreated wastewater to any flowing stream or drainage area.
4. Diaper all stationary power equipment (e.g., generators, cranes, stationary drilling equipment) operated within 150 ft of any stream, waterbody, or wetland to prevent leaks, unless suitable containment is provided to prevent potential spills from entering any stream or water body.
5. At the end of each work shift, vehicles must not be stored within or over the waterway.

q. Site preparation. Conserve native materials for site rehabilitation.
   i. If possible, leave native materials where they are found.
   ii. If materials are moved, damaged, or destroyed, replace them with a functional equivalent during site rehabilitation.
   iii. Stockpile any large wood, native vegetation, weed-free topsoil, and native channel material displaced by construction for use during site rehabilitation.

r. Isolation of inwater work area. If adult or juvenile fish are reasonably certain to be present, or if the work area is less than 300 ft upstream of spawning habitats, completely isolate the work area from the active flowing stream using inflatable bags, sandbags, sheet pilings, or similar materials, unless otherwise approved in writing by NMFS.

s. Capture and release. Before and intermittently during pumping to isolate an inwater work area, attempt to capture and release fish from the isolated area using trapping, seining, electrofishing, or other methods as are prudent to minimize risk of injury.
   i. The entire capture and release operation will be conducted or supervised by a fishery biologist experienced with work area isolation and competent to ensure the safe handling of all ESA-listed fish.
   ii. If electrofishing equipment is used to capture fish, comply with NMFS' electrofishing guidelines, listed below.

1. Do not electrofish near adult salmon in spawning condition or near redds containing eggs.
2. Keep equipment in good working condition. Complete manufacturers' preseason checks, follow all provisions, and record major maintenance work in a log.
3. Train the crew by a crew leader with at least 100 hours of electrofishing experience in the field using similar equipment. Document the crew leader's experience in a logbook. Complete training in waters that do not contain listed fish before an inexperienced crew begins any electrofishing.
4. Measure conductivity and set voltage as follows:

Conductivity (µS/cm)	Voltage
Less than 100	900 to 1100
100 to 300	500 to 800
Greater than 300	150 to 400

5. Use direct current (DC) at all times.
6. Begin each session with pulse width and rate set to the minimum needed to capture fish. These settings should be gradually increased only to the point where fish are immobilized and captured. Start with pulse width of 500µs and do not exceed 5 milliseconds. Pulse rate should start at 30Hz and work carefully upwards. In general, pulse rate should not exceed 40 Hz, to avoid unnecessary injury to the fish.
7. The zone of potential fish injury is 0.5 meters from the anode. Care should be taken in shallow waters, undercut banks, or where fish can be concentrated, because in such areas the fish are more likely to come into close contact with the anode.
8. Work the monitoring area systematically, moving the anode continuously in a herringbone pattern through the water. Do not electrofish one area for an extended period.
9. Have crew members carefully observe the condition of the sampled fish. Dark bands on the body and longer recovery times are signs of injury or handling stress. When such signs are noted, the settings for the electrofishing unit may need adjusting. End sampling if injuries occur or abnormally long recovery times persist.
10. Whenever possible, place a block net below the area being sampled to capture stunned fish that may drift downstream.
11. Record the electrofishing settings in a logbook along with conductivity, temperature, and other variables affecting efficiency. These notes, with observations on fish condition, will improve technique and form the basis for training new operators.

iii. Do not use seining or electrofishing if water temperatures exceed 18°C.
iv. Handle ESA-listed fish with extreme care, keeping fish in water to the maximum extent possible during seining and transfer procedures, to prevent

the added stress of out-of-water handling.

v. Transport fish in aerated buckets, tanks, or sanctuary nets that hold water during transfer. Release fish into a safe release site as quickly as possible, and as near as possible to capture sites.

vi. Do not transfer ESA-listed fish to anyone except NMFS or USFWS personnel, unless otherwise approved in writing by them.

vii. Obtain all other Federal, state, and local permits necessary to conduct the capture and release activity.

viii. Allow NMFS or the USFWS or its designated representative to accompany the capture team during the capture and release activity, and to inspect the team's capture and release records and facilities.

t. Earthwork. Complete earthwork (including drilling, excavation, dredging, filling, and compacting) as quickly as possible.

i. Excavation. Material removed during excavation will only be placed in locations where it cannot enter sensitive aquatic resources. Whenever topsoil is removed, it must be stored and reused on site to the greatest extent possible. If culvert inlet/outlet protecting riprap is used, it will be class 350 metric or larger, and topsoil will be placed over the rock and planted with native woody vegetation.

ii. Drilling and sampling. If drilling, boring, or jacking is used, the following conditions apply.

1. Isolate drilling activities in wetted stream channels using a steel pile, sleeve, or other appropriate isolation method to prevent drilling fluids from contacting water.
2. If it is necessary to drill through a bridge deck, use containment measures to prevent drilling debris from entering the channel.
3. If directional drilling is used, the drill, bore, or jack hole will span the channel migration zone and any associated wetland.
4. Sampling and directional drill recovery/recycling pits, and any associated waste or spoils, will be completely isolated from surface waters, off-channel habitats, and wetlands. All drilling fluids and waste will be recovered and recycled or disposed to prevent entry into flowing water.
5. If a drill boring conductor breaks and drilling fluid or waste is visible in water or a wetland, all drilling activity will cease, pending written approval from NMFS to resume drilling.

iii. Site stabilization. Stabilize all disturbed areas, including obliteration of temporary roads, following any break in work, unless construction will resume within 4 days.

iv. Source of materials. Obtain boulders, rock, woody materials, and other natural construction materials used for the project outside the riparian buffer area.

u. Implementation monitoring. For projects undertaken by or funded by PacifiCorp or Cowlitz PUD, PacifiCorp or Cowlitz PUD will include the status of a project or a description of the completed project in the annual report. This annual report will submitted to FERC and NMFS describing the success in meeting the RPMs and associated terms and conditions of the Opinion and will include the following.
   i. Project identification.
      1. Project implementor name, project name, detailed description of the project.
      2. Project location by 5th or 6th field HUC and by latitude and longitude as determined from the appropriate U.S. Geological Survey 7-minute quadrangle map.
      3. Starting and ending dates for the work completed.
   ii. Photo documentation. Photo documentation of habitat conditions at the project site before, during, and after project completion.
      1. Include general views and close-ups showing details of the project and project area, including pre- and post-construction.
      2. Label each photo with date, time, project name, photographer's name, and documentation of the subject activity.
   iii. Other data. Additional project-specific data, as appropriate, for individual projects.
      1. Work cessation. Dates work ceased because of high flows, if any.
      2. Fish screen. Compliance with NMFS' fish screen criteria.
      3. Pollution and Erosion Control Plan. A summary of pollution and erosion control inspections, including any erosion control failures, contaminant releases, and correction efforts.
      4. Description of site preparation.
      5. Isolation of inwater work area, capture, and release.
         a) Supervisory fish biologist's name and address.
         b) Methods of work area isolation and take minimization.
         c) Stream conditions before, during, and within 1 week after completion of work area isolation.
         d) Means of fish capture.
         e) Number of fish captured by species.
         f) Location and condition of all fish released.
         g) Any incidence of observed injury or mortality of listed species.
      6. Streambank protection.
         a) Type and amount of materials used.
         b) Project size - one bank or two, width, and linear feet.
      7. Site rehabilitation. Photo or other documentation that site rehabilitation performance standards were met.

NMFS will be reviewing the detailed construction plans submitted to advise FERC regarding whether or not those plans are likely to meet the "best management practices" articulated in this incidental take statement terms and conditions, or such additional best management practices that NMFS deems appropriate.

3) Conditions for research for the monitoring and evaluation identified in the November 30, 2004 Lewis River Settlement Agreement. Not all of these conditions may apply to the specific actions authorized by this ITS. Nonetheless, failure to adhere to any condition that does apply may cause NMFS to revoke the ITS.

a. All Monitoring and Evaluation plans associated with anadromous fish developed under the November 30, 2004 Lewis River Settlement Agreement must meet NMFS' satisfaction and must be approved by NMFS. Work will be conducted by PacifiCorp, Cowlitz PUD, or those hired by the Licensee(s) to conduct the work.
To ensure that the monitoring and evaluation plan will provide a benefit to listed species, and provide useful information on the effectiveness of various aquatic measures as well as achievement of the Reintroduction Outcome Goals, PacifiCorp and Cowlitz PUD will develop plan(s) and methods to monitor aspects of the various aquatic measures, including:

- Fish passage
- Adult anadromous salmonid migration, spawning, distribution, and abundance
- Water quality
- Hatchery supplementation programs
- Resident fish species

The Licensees' plan(s), among other items, will thoroughly describe of all methods that will be used to capture fish and how fish will be handled; details such as sampling locations and dates; and invasive procedures such as tagging, taking tissue samples, or sacrifice and will explain the purpose of each. Each plan will include estimates of the number of each species and life stage that will be handled and/or killed for that study. In addition, the plans will include methods by which they will be modified if empirical evidence indicates that negative effects on a species/life stage are greater than expected. The Licensees' will provide NMFS with annual reports, which NMFS will use to determine whether or not to authorize the next year's work under a multiyear plan. NMFS must approve all plans in writing before they are implemented.

b. The evaluator must ensure that listed species are taken only at the levels, by the means, in the areas, and for the purposes stated in the plans developed, and according to the conditions in this permit.

c. The evaluator must not intentionally kill or cause to be killed any listed species unless the plan specifically allows intentional lethal take.

d. The evaluator must handle listed fish with extreme care and keep them in cold water to the maximum extent possible during sampling and processing procedures. When fish are transferred or held, a healthy environment must be provided; e.g., the holding units must contain adequate amounts of well-circulated water. When using gear that captures a mix of species, the researcher must process listed fish first to minimize handling stress.

e. The evaluator must stop handling listed juvenile fish if the water temperature exceeds 70° F at the capture site. Under these conditions, listed fish may only be visually identified and counted.

f. If the evaluator anesthetizes listed fish to avoid injuring or killing them during handling, the fish must be allowed to recover before being released. Fish that are only counted must remain in water and not be anesthetized.

g. The evaluator must use a sterilized needle for each individual injection when PIT-tags are inserted into listed fish.

h. If the evaluator unintentionally captures any listed adult fish while sampling for juveniles, the adult fish must be released without further handling and such take must be reported.

i. The evaluator must exercise care during spawning ground surveys to avoid disturbing listed adult salmonids when they are spawning. Evaluators must avoid walking in salmon streams whenever possible, especially where listed salmonids are likely to spawn. Visual observation must be used instead of intrusive sampling methods, especially when just determining fish presence.

j. The evaluator must use the other applicable terms and conditions in this ITS including, but not limited to, term and condition 2.s.

k. The evaluator must obtain approval from NMFS before changing sampling locations or research protocols.

l. The evaluator must notify NMFS as soon as possible but no later than 2 days after any authorized level of take is exceeded or if such an event is likely. The evaluator must submit a written report detailing why the authorized take level was exceeded or is likely to be exceeded.

m. The evaluator is responsible for any biological samples collected from listed species as long as they are used for research purposes. The evaluator may not transfer biological samples to anyone not listed in the application without prior written approval from NMFS.

n. The person(s) actually doing the evaluation must carry a copy of this ITS and the applicable plan while conducting the authorized activities.

o. The evaluator must allow any NMFS employee or representative to accompany field personnel while they conduct the evaluation activities.

p. The evaluator must allow any NMFS employee or representative to inspect any records or facilities related to the permit activities.

q. The evaluator must obtain all other Federal, state, and local permits/authorizations needed for the evaluation activities.

r. Every year, the evaluator must submit to NMFS a post-season report in the prescribed form (ATTACHMENT 2) describing the evaluation activities, the number of listed fish taken and the location, the type of take, the number of fish intentionally killed and unintentionally killed, the take dates, and a brief summary of the monitoring results. This report may be included in the annual report identified in the SA and required by this ITS. Falsifying annual reports or permit records is a violation of this ITS.

s. If the evaluator violates any permit condition they will be subject to any and all penalties provided by the ESA. NMFS may revoke this permit if the authorized activities are not conducted in compliance with the permit and the requirements of the ESA or if NMFS determines that its ESA findings are no longer valid.

t. Listed fish mortalities and tissue samples will be returned to the capture site.

4) Within 2 days of observance, reports of dead or injured salmon or steelhead shall be sent to:

Lewis Hydro Projects Staff Lead
HydroPower Division
National Marine Fisheries Service
1201 NE Lloyd Blvd., Suite 1100
Portland, Oregon 97232

Include a concise description of the causative event (if known), and a description of any resultant corrective actions taken (if any) to reduce the likelihood of future mortalities or injuries.

APPENDIX E

Terms and Conditions included in the U.S. Fish and Wildlife Service's Biological Opinion for the Relicensing of the Lewis River Hydroelectric Projects: Merwin (No. 935), Yale (No. 2071), Swift No. 1 (No. 2111), and Swift No. 2 (No. 2213)

September 15, 2006

TERMS AND CONDITIONS

In order to be exempt from the prohibitions of section 9 of the ESA, the FERC or its applicant must comply with the following Terms and Conditions (T&C), which implement the Reasonable and Prudent Measures described above and outline required reporting/monitoring requirements. These Terms and Conditions are non-discretionary. Because no RPMs were identified to minimize the incidental take of spotted owls and bald eagles, there are no associated Terms and Conditions for these species.

Bull Trout

T&C 1.1: In restoring coho to Yale Lake, select for early spawners, if feasible, so that Cougar Creek bull trout will spawn at least partly after coho, thus reducing coho redd superimposition on bull trout.
T&C 2.1: Conduct annual bull trout surveys in the Swift No. 2 tailrace, Bypass Reach, and Lower and Upper Constructed Channels to document presence or absence of bull trout spawning and egg survival, if appropriate, in these locations. This will occur for a minimum of 3 years following completion of the Upper Release Point and implementation of the Bypass Reach flows (as directed by the WDOE) or until it is demonstrated that bull trout spawning does not occur in these areas.
T&C 3.1: If bull trout occur in the required random sample of mixed downstream migrant species in the Swift Creek Reservoir and Yale Lake traps, smolt-sized bull trout should be placed immediately in the recovery tank and transported to the next reservoir downstream. Bull trout fry should be separated from larger fish and be transferred to a separate fry tank. If possible, bull trout fry should be separated from other fry and released back into Swift Creek Reservoir away from the surface collector.
T&C 4.1: Determine the appropriate timing windows for instream construction in the Bypass Reach based on annual patterns of flow, temperature, and adult bull trout abundance, with a view toward minimizing suspended sediment impacts on bull trout and substrate embeddedness.
T&C 4.2: Where feasible and appropriate for the type, magnitude and duration of the instream activity, isolate instream construction from the flow during the work

period by installing temporary dams and pumping or diverting the water around the work zone. Dewatering may require fish rescue to avoid stranding.

T&C 5.1: The Licensees are authorized the direct take (harass by survey, capture, handle, and release) of bull trout while conducting annual monitoring activities and surveys for the purpose of enhancing bull trout survival, as well as to take bull trout in interim and permanent bull trout passage operations in accordance with the conditions stated below. Permitted activities are restricted to the Lewis River Subbasin, from the Columbia River to North Fork Lewis River Mile 72.5 (Lower Falls), including Lake Merwin, Yale Lake, and Swift Creek Reservoir, and all Lewis River tributaries up to Lower Falls.

T&C 5.2. The Utilities are responsible for assuring that the individuals conducting monitoring or collect and haul operations are properly trained and educated, and complying with the following Terms and Conditions. The Utilities shall retain a current list of such people and the list should include the following:

1) The name of each individual;
2) The resume or qualifications statement of each, detailing their experience with each species and type of activity for which they will be conducting; and
3) The names and phone numbers of a minimum of two references.

T&C 5.3: All capture, handling, and observation methods shall be implemented at times that will avoid temperature stress of bull trout being surveyed, collected, monitored, rescued, or relocated.

T&C 5.4: All live bull trout captured shall be released as soon as possible. Any bull trout captured and showing signs of stress or injury should only be released when able to maintain itself. Nurture such individuals in a holding tank until they have recovered. If bull trout are held in a tank, a healthy environment for the stressed bull trout must be provided, and the holding time must be minimized. Water-to-water transfers, the use of shaded, dark containers, and supplemental oxygen shall all be considered in designing bull trout handling operations. Any bull trout fry must be held in a separate container from other bull trout (including juvenile bull trout), to avoid predation by larger bull trout during captivity.

T&C 5.5: The period of time that captured bull trout are anesthetized shall be minimized. The number of bull trout that are anesthetized at one time shall be no more than what can be processed (biosampled) within several minutes.

T&C 5.6: Prior to conducting activities that involve handling of bull trout, the permittee shall ensure that hands are free of sunscreen, lotion, or insect repellent.

Reporting Requirements

In order to monitor the effectiveness of implementing the Reasonable and Prudent Measures, the FERC or its applicants will prepare a report describing their progress in implementing the Terms and Conditions and the licenses. An annual progress report should be sent to the FWS attention: Division Manager, Division of Conservation and Hydropower Planning. The report may be included in the Annual Report required under the SA and shall include, but not be limited to, the following:

1) Significant research results and its importance with regards to recovery of bull trout;
2) Maps or descriptions of locations sampled for each species;
3) The results of all sampling efforts including estimates of population size;
4) Quantification of take, including numbers of individuals incidentally killed, including dates, locations, and circumstances of lethal take, and an estimate of the numbers of individuals otherwise harmed or harassed (e.g., displaced during snorkeling surveys);
5) Other pertinent observations made during sampling efforts regarding the status and ecology of the bull trout, including size of individuals and presumed life-history form;
6) Progress with implementing the RPMs;
7) Activities carried out in the Conservation Covenants;
8) Activities conducted under the WHMPs;
9) Changes to dam operations that improve or protect the species or their habitat; and
10) Implementation of any Conservation Recommendations.

The FERC or its Licensees are to notify the FWS within 3 working days upon locating a dead, injured, or sick endangered or threatened species specimen. They must make initial notification at the nearest FWS Law Enforcement Office. Contact the FWS Law Enforcement Office at (425) 883-8122 or the FWS Western Washington Fish and Wildlife Office at (360) 753-9440. Notification must include the date, time, precise location of the injured animal or carcass, and any other pertinent information. Care should be taken in the handling of sick or injured specimens to preserve biological materials in the best possible state for later analysis of cause of death. In conjunction with the care of sick or injured endangered or threatened species or preservation of biological materials from a dead animal, the finder has the responsibility to ensure that evidence associated with the specimen is not unnecessarily disturbed. Reports of incidental injury or killing must include the date, time, precise location of the injured animal or carcass, and any other pertinent information such as cause of death or injury. In regards to bull trout, all incidental mortalities shall be preserved in a fashion to best provide maximum scientific information (otoliths, scales, genetic samples, general fisheries statistics, etc.). Any specimen killed shall be kept whole and put on ice or frozen, and a small sample of tissue (fin clip approximately 1 square centimeter) shall be preserved in a vial of 95 percent ethanol for genetic analysis.

Document Content(s)

Order On Rehearing

October 16, 2008

125 FERC ¶ 61,046
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

PacifiCorp | Project Nos. 2111-031, 2071-036, 935-082

ORDER ON REHEARING

(Issued October 16, 2008)

1. PacifiCorp has filed a request for rehearing of the June 26, 2008 Commission staff orders issuing new licenses for the continued operation and maintenance of the 240-megawatt (MW) Swift No. 1 Project No. 2111, the 134-MW Yale Project No. 2071, and the 136-MW Merwin Project No. 935, located on the North Fork Lewis River in Clark, Cowlitz and Skamania Counties, Washington.[1] PacifiCorp seeks modification or clarification and rehearing of its three licenses regarding (1) dead tree removal, (2) emergency telephone notification service, (3) the filing of amendment applications, (4) bull trout netting, (5) evaluation of kokanee, (6) lands for habitat management, (7) the South Merwin Trail access, (8) the Cougar Visitor Information Facility, (9) cost caps, (10) flood control, and (11) flow releases. In addition, the National Marine Fisheries Service (NMFS) filed a request for clarification and correction of the orders, and Washington Department of Fish and Wildlife (Washington DFW) filed a request for

[1] *PacifiCorp*, 123 FERC ¶ 62,260 (2008), *PacifiCorp*, 123 FERC ¶ 62,257 (2008) and *PacifiCorp*, 123 FERC ¶62,258 (2008).

rehearing regarding the boat launch at Swift No. 1.[2] For the reasons discussed below, we deny rehearing and grant the clarifications and corrections, in part.

<u>Background</u>

2. PacifiCorp is the licensee for three of the four licenses issued on June 26, 2008, for four projects located on the North Fork Lewis River. Public Utility District No. 1 of Cowlitz County (Cowlitz) is the licensee of the fourth project, the Swift No. 2 Project No. 2213 (located between the Swift No. 1 and Yale Projects).[3] PacifiCorp's Swift No. 1 Project is the furthest upstream and largest project in the Lewis River system. The project includes a 412-foot-high, 2,100-foot-long embankment structure, impounding an 11.5-mile-long, 4,600-acre reservoir. The Yale Project includes two zoned embankment dams -- the largest being 323 feet high and 1,500 feet long -- and a 10.5-mile-long reservoir with a surface area of 3,800 acres at full pool elevation. The oldest and most downstream project in the basin is PacifiCorp's Merwin Project. Its 313-foot-high concrete arch dam extends 1,300 feet across the Lewis River, impounding a 14.5-mile-long reservoir with a surface area of 4,000 acres at full pool.

3. The licenses incorporate almost all of the provisions of a comprehensive Settlement Agreement (Agreement) related to the relicensing of the four projects.[4] The provisions of the Agreement that are common to all four projects are discussed in the Order on Offer of Settlement and Issuing New License for the Swift No. 1 Project (Master Order).[5]

[2] On July 28, 2008, Clark Regional Emergency Services Agency (CRESA) filed a rehearing request concerning license requirements regarding emergency telephone notification service. The agency did not intervene in the relicensing proceedings, and because only parties to a proceeding may seek rehearing of an order on the merits, its rehearing request was rejected by notice issued on August 19, 2008. *PacifiCorp*, 124 FERC ¶ 61,172 (2008). Nevertheless, CRESA's concern is resolved in Paragraphs 8 and 9 of this order.

[3] *See Public Utility District No. 1 of Cowlitz County, Washington*, 3 FERC ¶ 62,259 (2008).

[4] The Agreement was filed on December 3, 2004.

[5] 123 FERC ¶ 62,260 (2008).

Discussion

A. **Preliminary Matters**

4. To the extent that PacifiCorp's and NMFS' pleadings seek rehearing of the relicenses, they are deficient because they fail to comply with the requirements of section 385.713(c)(2) of our regulations,[6] which requires that rehearing requests include a section, separate from the body of the rehearing order, entitled "Statement of Issues." The "Statement of Issues" section must list each issue in a separately enumerated paragraph that includes representative Commission and court precedent on which the participant is relying.[7] Section 375.713(c)(2) further provides that "any issue not so listed will be deemed waived." Neither PacifiCorp nor NMFS included a separate "Statement of Issues" section in its rehearing request.[8] Although their arguments are deemed waived, we will nevertheless address them.

B. **Boat Launch**

5. On rehearing, Washington DFW argues that the existing boat launch at the Swift No. 1 reservoir is not usable at low reservoir elevations and the license should instead include section 11.2.1.8 of the Agreement, which provides that, if during the license term, an entity other than the licensee constructs a new boat launch and related facilities that would allow access to the reservoir when water levels are low, the licensee must assume operation and maintenance responsibilities. However, if the boat launch is destroyed by vandalism or natural causes, the licensee's responsibilities would end.

[6] 18 C.F.R. § 385.713(c)(2) (2008).

[7] The purpose of this requirement is to benefit all participants in a proceeding by ensuring that the filer, the Commission, and all other participants understand the issues raised by the filer, and to enable the Commission to respond to these issues. Having a clearly articulated Statement of Issues ensures that issues are properly raised before the Commission and avoids the waste of time and resources involved in litigating appeals regarding which the courts of appeals lack jurisdiction because the issues on appeal were not clearly identified before the Commission.

[8] On August 20, 2008, PacifiCorp filed a pleading styled "Errata" in which it attempted to correct the omission merely by titling the body of the rehearing request "Statement of Issues." The revision came almost a month after the July 25 rehearing deadline. Even if it had been timely filed, it failed to cure the deficiency.

6. On rehearing, Washington DFW asserts that the existing boat ramp is not useable during periods of reservoir drawdown and cannot be extended sufficiently to allow reservoir use during the non-recreation season. Upon review of the information provided by Washington DFW, we find that the boat launch at Swift No. 1 reservoir is not useable during winter drawdown; however, it is accessible during the primary recreation season. Due to the location and steep terrain of this reservoir, Swift reservoir receives the fewest visitors of all the reservoirs at the project. Therefore, we do not believe that the use of the Swift reservoir outside of the summer recreation season warrants the construction of another boat launch. We accordingly deny Washington DFW's request for rehearing. At the same time, we do not oppose the construction of the boat launch if a party obtains funding, as envisioned in the Agreement. This is a facility that could be constructed and maintained outside of the license.

C. Requirements to Remove Dead Trees Along the Reservoir Peripheries

7. PacifiCorp requests that the Commission revise standard Article 20[9] to allow certain dead trees to be left for wildlife and aquatic habitat. The purpose of Article 20 is to require the removal from the reservoir and its perimeter of those dead trees that pose a hazard to project operations, public safety, or navigation; it does not require removal of dead trees that will not pose such hazards.[10] Thus, the licensee will not be required to remove dead trees that do not pose such hazards. If PacifiCorp has any further questions on this matter, it should consult with the Commission staff. Accordingly, we will not revise Article 20.

D. Emergency Telephone Notification

8. PacifiCorp requests that the emergency telephone notification service requirement of the license, Article 304(a), be revised to require PacifiCorp to only provide funding for the system, and not installation, operation, and maintenance of the system.[11] Both Clark

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[9] Article 20 is found in the three licenses in attached Form L-1.

[10] *See, e.g., Montana Power Company and Granite County, Montana*, 62 FERC ¶61,166, at p. 62,140 (1993); *Wisconsin Electric Power Company,* 75 FERC ¶ 61,011 (1996).

[11] Article 304 (a) of the three licenses requires that the licensee "acquire, install and maintain a new emergency telephone notification service for those portions of Clark County and Cowlitz County that are subject to inundation from the Lewis River projects."

and Cowlitz Counties have already installed the emergency telephone notification service called for in the Agreement.

9. As clarification, the Commission did not intend for PacifiCorp to develop a duplicate emergency telephone notification service, only to ensure that there is such a system. PacifiCorp, while ultimately responsible for such a system, may (as it has done here) delegate its responsibilities to the counties.[12]

E. Requirement to File Amendment Applications (License Article 401(b))

10. Article 401(b) requires PacifiCorp to file applications to amend its license prior to implementing "unspecified long-term changes to project operations, requirements, or facilities for the purpose of protecting and enhancing environmental resources." PacifiCorp and NMFS assert that this is unnecessary because the Agreement resolves all issues regarding the relicensing of the project, and the parties to the Agreement do not contemplate any measures that are not already included in the Agreement and the conditions of the license.

11. We agree that if measures are contemplated in the Agreement and incorporated in the license, then minor changes or adjustments to those requirements would not require an application to amend the license. However, in the event that the licensee wishes to implement unspecified, long-term, material changes to project operations, requirements, or facilities (i.e., not contemplated in the Agreement and not evaluated by staff prior to issuing the license order), then an amendment would be required. If the licensee is uncertain of whether an action requires an amendment, it should consult with Commission staff prior to undertaking the action.

12. Article 401(b)(1) requires that PacifiCorp file an application to amend the license for any "adjustments" to the upstream fish passage facility required by the license. PacifiCorp states that this will place an unnecessary burden on it to seek an amendment for any change to the facility, however minor. We clarify that this is not meant to require an amendment for minor changes to the facility, but rather for those material changes that were not contemplated by the license.

[12] Any other issues related to emergency communications will be handled under the projects' existing Emergency Action Plans.

F. Requirement to Net Bull Trout and Kokanee Evaluation

13. Article 402(a) in the Swift No. 1 and Yale licenses requires that PacifiCorp net bull trout from the projects' tailraces and haul them to a location determined by FWS. PacifiCorp contends that Article 402 should be deleted as unnecessary. These measures are already covered by other conditions of the license, respectively, the bull trout collection and transport plan required by NMFS's Biological Opinion (condition 1, which incorporates section 4.9 of the Agreement) and the hatchery and supplementation program that is also required by the Biological Opinion (condition 1, which incorporates section 8 of the Agreement). We agree that those requirements of the article should be deleted, but that Article 402 is necessary for requiring evaluation of bull trout annually for both the Swift No.1 and Yale Projects and for managing designated conservation lands on Cougar Creek for the protection of bull trout in the Yale Project. Accordingly, we will revise Article 402 in both the Swift No. 1 and Yale licenses.

14. Article 402(b) in the Swift No. 1, Yale and Merwin licenses require that the licensee evaluate bull trout and kokanee populations annually. Because kokanee reside only in the Yale and Merwin reservoirs, we will revise Article 402 of the Swift No. 1 license to require annual evaluation only of bull trout in the Swift No. 1 reservoir.

G. Incorporating Wildlife Habitat Lands into the Project Boundary

15. PacifiCorp requests rehearing of Article 403 in the three licenses, which requires that all land acquired for wildlife habitat under the Wildlife Habitat Management Plan must be included within the project boundaries.[13] PacifiCorp asserts that inclusion of theses lands alters the settlement and creates unnecessary additional expenses and processes. Furthermore, it states that incorporating these lands within the project boundaries does not serve project purposes or assure that the public interest is served.

16. We disagree. Acquisition and maintenance of lands for wildlife habitat has been determined by the Commission to satisfy a project purpose and has been included in the

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[13] Article 403 in the Merwin Project does not include wildlife habitat land acquisition, but rather requires filing a Wildlife Habitat Management Plan with the Commission for approval, as described in section 10.8 of the Agreement. For the Yale and Swift No. 1 licenses, lands acquired for wildlife habitat are required to be included in the project boundary. In the event that the Merwin Project acquires additional lands for wildlife habitat, those lands shall be included in the project boundary.

licenses.[14] Accordingly, the lands acquired for this purpose must be included within the project boundary. A project boundary serves the function of indicating that the lands within are used in some manner for project purposes. This helps to reduce ambiguity for purposes of license administration and compliance by clarifying the geographic scope of the licensee's responsibilities under its license (and the Commission's regulatory responsibilities).[15] Any lands managed pursuant to a license condition, or if used for "project purposes," should be included in the project boundary, regardless of existing management agreements by the applicant.

17. We will, however, modify Article 403 in the Swift No. 1 and Yale licenses, as PacifiCorp requests, to require that it update its project boundaries within five years of license issuance to reflect all lands acquired for wildlife habitat under that article during that period, rather than requiring a project boundary update upon each new parcel acquisition.

18. The second concern raised by PacifiCorp regarding wildlife habitat lands was the requirement to file annual plans that would describe the lands proposed to be acquired under the land acquisition and habitat enhancement funds. PacifiCorp is concerned about land speculation if the lands were delineated in the plan for approval before they would be purchased. To avoid such speculation, we will revise Article 403 in the Swift No. 1 and Yale licenses to require that the lands be described in the annual plans after they have been acquired.

H. South Merwin Trail Access

19. Article 406 of the Merwin license requires that PacifiCorp submit a plan to provide a trail easement to connect a proposed Clark County regional park to the south side of Lake Merwin, as outlined in section 11.2.3.4 of the Agreement. In 2007, Clark County finalized its comprehensive plan, which did not mention the Merwin location for a regional park. PacifiCorp requests that we clarify the obligation to provide a trail easement is contingent upon Clark County committing to develop the regional park near Merwin Lake.

20. We will revise Article 406 to require that the plan providing a trail easement to the regional park is contingent on Clark County developing the regional park.

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[14] *See* EIS at 5-29 to 5-31. Wildlife habitat lands acquisition and maintenance are discussed in each of the three licenses under Section B of Other Issues.

[15] *See PacifiCorp*, 80 FERC ¶ 61,334 (1997).

I. Cougar Visitor Information Facility

21. PacifiCorp requests that we eliminate the Cougar Visitor Information Facility because the facility is not necessary to carry out project purposes and reasonable alternatives exist for a visitor's facility and for a facility to curate artifacts.

22. In the EIS, Commission staff concluded that a visitor's center in Cougar would allow the licensees to provide general information on the projects to the public and more specific information on recreational opportunities or safety and security. Including the Cougar Visitor Information Facility in the project boundary would help ensure that the proposed facility would be used for project purposes for the term of the new license. The project area closest to Cougar is the Yale Project.[16] In response to comments on the draft EIS, staff stated that, as proposed in the Agreement, the visitor information facility would be developed immediately adjacent to the projects and would provide public information about recreational opportunities at the projects.

23. The four Lewis River projects are the primary recreational attraction in the vicinity of Cougar and, as acknowledged in the Joint Explanatory Statement of the Agreement, the visitor center would provide benefits to project visitors.[17] The Visitor Information Center would serve as a primary gateway to the upper Lewis River Basin by providing public information on its history and resources, including information about the Yale and Swift Creek reservoirs, project facilities and operations, environmental, recreational and cultural resources. We agree with staff that there is a clear nexus with the projects and we will continue to require that a Visitor Information Facility plan be filed within five years of the date of issuance of the license as set forth in Article 410 of the Yale license.

J. Cost Caps

24. The Master Order recognizes that the Agreement and many of the conditions of the four licenses establish limits on the licensee's responsibility to fund various resource mitigation measures and studies, but concludes that it is nevertheless the licensees' obligation to complete the measures required by the license articles, in the absence of Commission authorization to the contrary.[18]

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[16] EIS at 5-30.

[17] *Id*. at A-18.

[18] 123 FERC ¶ 62,260 at P 21.

25. On rehearing, PacifiCorp objects to this conclusion, and asks instead that the Commission approve the cost limits included in the Agreement.

26. We deny the request. We understand the licensee's desire to fix the costs that it may incur for resource protection and enhancement measures. As the order explains, it is likely that the specified funding will be sufficient for the measures in question. However, the Commission cannot constrain the fulfillment of its statutory responsibilities by agreeing to such spending caps.[19] We therefore affirm the conclusion in the Master Order that it is the licensee's obligation to complete the measures required by the license articles, in the absence of Commission authorization to the contrary. In addition, we are adding an additional license article to each license to so state.

K. <u>Flood Control Requirements</u>

27. PacifiCorp seeks clarification of Article 302 of the three licenses, which provides for flood management at the three projects. According to section 12.8 of the Settlement Agreement, PacifiCorp will seek an amendment of the FEMA agreement and Standard Operating Procedure Manual by the first anniversary of the license issuance. Once PacifiCorp obtains FEMA approval of the revised high runoff procedure, it then can seek an amendment to the licenses.

L. <u>Flow Release Requirements</u>

28. PacifiCorp requests that the Commission clarify whether the licenses require that the Commission be notified prior to adjustment of minimum flow for approval or whether the intent was for the Commission to be notified after a change in minimum flow. The Master Order, at paragraph 29, stated that the procedures should also include notification of the Commission regarding any deviations from the required minimum flows. We will include a new license article in the three licenses which clarifies the notification requirement.

M. <u>Corrections to License Articles and Appendices</u>

29. As discussed below, PacifiCorp points out a number of corrections that should be made to various conditions of the three licenses.

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[19] *See, e.g., Public Utility District No. 1 of Chelan County, Washington,* 119 FERC ¶ 61,055, at P 12-17 (2007).

30. We will correct the last sentence in standard Article 29 of the three licenses.

31. Appendix E of the Swift No. 1 Project license will be corrected to complete the last sentence in Article 2.

32. Ordering Paragraph (E) of the Yale Project license will be changed to refer to Appendix B.

33. Appendix A, Section 4.3(4)(a) of the Yale Project water quality certificate, references the 7Q10 year flow of 32,884 cfs for the Lewis River at Merwin Dam. As PacifiCorp states, it should reference the 7Q10 year flow of 27,088 cfs at the Yale Dam. We will make this correction. In addition, sections 4.4(2)(f) and 4.4(3) will be revised to conform to the language in the water quality certification.

34. NMFS pointed out six typographical errors in the Yale Project No. 2071 section 18 prescriptions (Appendix B), which we will correct.

N. Corrections to Discussion Section of License Order

35. PacifiCorp also seeks correction of some typographical errors and other items in the discussion section of the order. The requested corrections and edits are minor and do not affect the license articles or ordering paragraphs. We take note of them, but see no need to take any action.

The Commission orders:

(A) The request for rehearing filed on July 28, 2008, by the Washington Department of Fish and Wildlife is denied.

(B) The request for rehearing filed on July 28, 2008, by PacifiCorp is granted to the extent set forth in this order.

(C) The request for rehearing filed on July 25, 2008, by National Marine Fisheries Service is granted to the extent set forth in this order.

(D) The following technical corrections and clarifications are granted to the extent described above and the orders are revised to read as follows:

(1) Yale Project No. 2071, Ordering Paragraph (E) shall be revised to refer to Appendix B.

(2) Article 401(b)(1) of the Swift No.1 Project No. 2111, Yale Project No. 2071 and Merwin Project No. 935 are each revised as follows:

	Condition No.	Modification
1	Section 18 no. 4.5 and BO no. 1	Modifications to passage facilities to achieve performance standards

(3) Article 402 in the Swift No. 1 Project No. 2111 is revised to read as follows:

Article 402. *Aquatic Resources Management Measures*. The licensee shall continue to implement the following aquatic resources management measure:

(a) in conjunction with the licensees for the Yale Project No. 2071 and Merwin Project No. 935, evaluate bull trout populations annually.

The licensee shall include evidence of compliance with this measure in the annual reports filed with the Commission under section 14.2.6 of the Settlement Agreement (Agreement) filed on December 3, 2004.

In addition, the licensee shall file with the Commission within 2 years of license issuance, a bull trout limiting factor analysis, as described in section 5.5 of the Agreement filed on December 3, 2004.

(4) Article 402 in the Yale Project No. 2071 is revised to read as follows:

Article 402. *Aquatic Resources Management Measures*. The licensee shall continue to implement the following aquatic resources management measures:

(a) in conjunction with the Swift No. 1 Project No. 2111 and Merwin Project No. 935, evaluate bull trout and kokanee populations annually; and

(b) manage designated conservation lands on Cougar Creek for the protection of bull trout (section 5.2 of the Settlement Agreement filed on December 3, 2004).

The licensee shall include evidence of compliance with these measures in the annual reports filed with the Commission under section 14.2.6 of the Settlement Agreement.

(5) The second paragraph of Article 403 of the Swift No.1 Project No. 2111 is revised to read as follows:

All lands acquired for wildlife habitat under the Swift No. 1 and Swift No. 2 Land Acquisition and Habitat Protection Fund and the Lewis River Land Acquisition and Habitat Enhancement Fund shall be included within the project boundary and updated within five years of the issuance date of the license to reflect all lands acquired for wildlife habitat under the Wildlife Habitat Management Plan.

(6) The sixth paragraph of Article 403 of the Swift No. 1 Project No. 2111 is revised to read, in part, as follows:

…. The annual plans shall include: (a) a description of the lands acquired under the Swift No. 1 and Swift No. 2 Land Acquisition and Habitat Protection Fund; (b) a description of the lands acquired under the Lewis River Acquisition and Habitat Enhancement fund associated with the Swift No. 2 Project …..

(7) The second paragraph of Article 403 of the Yale Project No. 2071 is revised to read as follows:

All lands acquired for wildlife habitat under the Yale and Lewis River Land Acquisition and Habitat Protection Funds shall be included within the project boundary and updated within five years of the issuance date of the license to reflect all lands acquired for wildlife habitat under the Wildlife Habitat Management Plan.

(8) The sixth paragraph of Article 403 of the Yale Project No. 2071 is revised to read, in part, as follows:

…. The annual plans shall include: (a) a description of the lands acquired under the Yale Land Acquisition and Habitat Protection Funds; (b) a description of the lands acquired under the Lewis River Acquisition and Habitat Enhancement fund associated with the Yale Project; …..

(9) The first sentence of Article 406 of the Merwin Project No. 935 is revised to read as follows:

South Shore Merwin Trail Access Plan. Within one year of Clark County committing to develop a regional park near Merwin Lake, the licensee shall file with the Commission for approval, a plan to provide a trail easement to connect a proposed Clark County regional park to the south side of Lake Merwin, as outlined in section 11.2.3.4 of the Settlement Agreement filed on December 3, 2004.

(10) The following license Articles regarding cost caps are added to each of the licenses.

Swift No. 1 Project No. 2111: Article 413. *Funding*. Notwithstanding the limitation on expenditures as expressed in the mandatory conditions and included in this license, the Commission reserves the right to require the licensee to undertake such measures as may be appropriate and reasonable to implement approved plans and other requirements in this license.

Yale Project No. 2071: Article 415. *Funding*. Notwithstanding the limitation on expenditures as expressed in the mandatory conditions and included in this license, the Commission reserves the right to require the licensee to undertake such measures as may be appropriate and reasonable to implement approved plans and other requirements in this license.

Merwin Project No. 935: Article 414. *Funding*. Notwithstanding the limitation on expenditures as expressed in the mandatory conditions and included in this license, the Commission reserves the right to require the licensee to undertake such measures as may be appropriate and reasonable to implement approved plans and other requirements in this license.

(11) The following license Articles regarding modification of minimum flows are added to each of the licenses.

Swift No. 1 Project No. 2111 : Article 414. *Minimum Flow Modification.* The licensee may temporarily decrease minimum flows below Swift No. 1 Dam upon agreement between the licensee and the Flow Coordination Committee as defined in Section 6.2.5 of the Settlement Agreement. If the flow is so modified, the licensee shall notify the Commission as soon as possible, but no later than 10 days after each incident.

Yale Project No. 2071: Article 416. *Minimum Flow Modification.* The licensee may temporarily decrease minimum flows below Yale Dam upon agreement between the licensee and the Flow Coordination Committee as defined in Section 6.2.5 of the Settlement Agreement. If the flow is so modified, the licensee shall notify the Commission as soon as possible, but no later than 10 days after each incident.

Merwin Project No. 935: Article 415. *Minimum Flow Modification.* The licensee may temporarily decrease minimum flows below Merwin Dam pursuant to Sections 6.2.4 and 6.2.5 of the Settlement Agreement. If the flow is so modified, the licensee shall notify the Commission as soon as possible, but no later than 10 days after each incident.

(12) The last sentence in Form L-1, Article 29 of the Swift No.1 Project No. 2111, the Yale Project No. 2071 and the Merwin Project No. 935 are each revised as follows:

> Provided further, that in the event of disagreement, any question of unreasonable interference shall be determined by the Commission after notice and opportunity for hearing.

(13) The dates of the Settlement Agreement in the mandatory conditions are revised as follows:

Swift No. 1 Project No. 2111, Appendix C, Exhibit A, title shall read as: November 30, 2004;

Swift No. 1 Project No. 2111, Appendix D, first sentence shall read as: filed … on December 2, 2004;

Merwin Project No. 935, Appendix A, Section 4.2, first sentence shall read as: November 30, 2004, submitted to FERC on December 2, 2004; and

Merwin Project No. 935, Appendix A, Exhibit A, title shall read as: November 30, 2004.

(14) In Swift No. 1 Project No. 2111, the last sentence of Appendix E shall be revised to read as follows:

… Settlement Agreement concerning the relicensing of the Lewis River Hydroelectric Project Nos. 935, 2071, 2111 and 2213, Cowlitz and Skamania Counties, Washington, dated November 30, 2004, and filed with the Commission on December 3, 2004.

(15) Yale Project No. 2071, Appendix A, is revised as follows:

(a) Section 4.3(4)(a) ….. the 7Q10 flow for the Lewis River at Yale Dam is 27,088 cfs;

(b) Section 4.4(2)(f) : Identify adaptive management strategies to further improve the temperature fluctuation regime for the cold-water biota in the event that target temperatures are not achieved.

(c) Section 4.4(3) : If it is determined through the TWQAP that steps must be taken in order to protect the most sensitive beneficial uses, the Licensee shall employ all reasonable and feasible methods identified in response to condition 2(e and f) to ensure that the water temperature fluctuation regime in the Canyon remains below levels which would harm the aquatic biota or limit the potential healthy cold water habitat.

(16) Yale Project No. 2071, Appendix B, is revised as follows:

(1) On page 81, the acronym for Collection Efficiency is “CE”; (2) on page 82, in article 4.3, the third sentence shall read: “The Licensee must consider without limitation entry rate, fall back, crowding at the entrance, delay and abandonment of the trap area”; (3) on page 84, in article 6, the first sentence is revised to read as: “Unless and until

alternative technologies are implemented, the Licensee must provide for the transport by truck of all Transported Species collected at the Yale Upstream Facility"; (4) on page 87, in article 10, the first sentence of the second paragraph shall read: "Unless otherwise directed by the Services, the Licensee must provide for the marking of all the transported juvenile anadromous salmonids collected by the Yale Downstream Facility until such time as the Yale Upstream Facility is completed pursuant to this license and the Swift Upstream Facility is completed pursuant to the Swift No. 1 and Swift No. 2 licenses, and must provide for the tagging of a statistically valid sample of the fish transported as appropriate to accomplish the monitoring and evaluation objectives set forth below, the methodology of such tagging to be determined by the Licensee in Consultation with the ACC (including at least the Services) and approved by the Services"; (5) on page 88, in article 11, the last sentence shall read: "If these facilities do not function as well to collect bull trout as the interim collection method based on effectiveness monitoring, as determined by the USFWS, the Licensee shall continue the interim collection method"; and (6) on page 90, in article 13, the fourth paragraph, the third sentence shall read: "The Licensee, together with the licensees for the Merwin, Swift No. 1 and Swift No. 2 projects, must allow the ACC (including at least the Services) a period of 90 days to provide comments on the draft revised M&E Plan as part of such Consultation."

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Docket No. UE 263
Exhibit PAC/302
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark R. Tallman

FERC Order on Rehearing

March 2013

125 FERC ¶ 61,046
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

PacifiCorp — Project Nos. 2111-031, 2071-036, 935-082

ORDER ON REHEARING

(Issued October 16, 2008)

1. PacifiCorp has filed a request for rehearing of the June 26, 2008 Commission staff orders issuing new licenses for the continued operation and maintenance of the 240-megawatt (MW) Swift No. 1 Project No. 2111, the 134-MW Yale Project No. 2071, and the 136-MW Merwin Project No. 935, located on the North Fork Lewis River in Clark, Cowlitz and Skamania Counties, Washington.[1] PacifiCorp seeks modification or clarification and rehearing of its three licenses regarding (1) dead tree removal, (2) emergency telephone notification service, (3) the filing of amendment applications, (4) bull trout netting, (5) evaluation of kokanee, (6) lands for habitat management, (7) the South Merwin Trail access, (8) the Cougar Visitor Information Facility, (9) cost caps, (10) flood control, and (11) flow releases. In addition, the National Marine Fisheries Service (NMFS) filed a request for clarification and correction of the orders, and Washington Department of Fish and Wildlife (Washington DFW) filed a request for

[1] *PacifiCorp*, 123 FERC ¶ 62,260 (2008), *PacifiCorp*, 123 FERC ¶ 62,257 (2008) and *PacifiCorp*, 123 FERC ¶62,258 (2008).

rehearing regarding the boat launch at Swift No. 1.[2] For the reasons discussed below, we deny rehearing and grant the clarifications and corrections, in part.

Background

2. PacifiCorp is the licensee for three of the four licenses issued on June 26, 2008, for four projects located on the North Fork Lewis River. Public Utility District No. 1 of Cowlitz County (Cowlitz) is the licensee of the fourth project, the Swift No. 2 Project No. 2213 (located between the Swift No. 1 and Yale Projects).[3] PacifiCorp's Swift No. 1 Project is the furthest upstream and largest project in the Lewis River system. The project includes a 412-foot-high, 2,100-foot-long embankment structure, impounding an 11.5-mile-long, 4,600-acre reservoir. The Yale Project includes two zoned embankment dams -- the largest being 323 feet high and 1,500 feet long -- and a 10.5-mile-long reservoir with a surface area of 3,800 acres at full pool elevation. The oldest and most downstream project in the basin is PacifiCorp's Merwin Project. Its 313-foot-high concrete arch dam extends 1,300 feet across the Lewis River, impounding a 14.5-mile-long reservoir with a surface area of 4,000 acres at full pool.

3. The licenses incorporate almost all of the provisions of a comprehensive Settlement Agreement (Agreement) related to the relicensing of the four projects.[4] The provisions of the Agreement that are common to all four projects are discussed in the Order on Offer of Settlement and Issuing New License for the Swift No. 1 Project (Master Order).[5]

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[2] On July 28, 2008, Clark Regional Emergency Services Agency (CRESA) filed a rehearing request concerning license requirements regarding emergency telephone notification service. The agency did not intervene in the relicensing proceedings, and because only parties to a proceeding may seek rehearing of an order on the merits, its rehearing request was rejected by notice issued on August 19, 2008. *PacifiCorp*, 124 FERC ¶ 61,172 (2008). Nevertheless, CRESA's concern is resolved in Paragraphs 8 and 9 of this order.

[3] *See Public Utility District No. 1 of Cowlitz County, Washington*, 3 FERC ¶ 62,259 (2008).

[4] The Agreement was filed on December 3, 2004.

[5] 123 FERC ¶ 62,260 (2008).

Discussion

A. Preliminary Matters

4. To the extent that PacifiCorp's and NMFS' pleadings seek rehearing of the relicenses, they are deficient because they fail to comply with the requirements of section 385.713(c)(2) of our regulations,[6] which requires that rehearing requests include a section, separate from the body of the rehearing order, entitled "Statement of Issues." The "Statement of Issues" section must list each issue in a separately enumerated paragraph that includes representative Commission and court precedent on which the participant is relying.[7] Section 375.713(c)(2) further provides that "any issue not so listed will be deemed waived." Neither PacifiCorp nor NMFS included a separate "Statement of Issues" section in its rehearing request.[8] Although their arguments are deemed waived, we will nevertheless address them.

B. Boat Launch

5. On rehearing, Washington DFW argues that the existing boat launch at the Swift No. 1 reservoir is not usable at low reservoir elevations and the license should instead include section 11.2.1.8 of the Agreement, which provides that, if during the license term, an entity other than the licensee constructs a new boat launch and related facilities that would allow access to the reservoir when water levels are low, the licensee must assume operation and maintenance responsibilities. However, if the boat launch is destroyed by vandalism or natural causes, the licensee's responsibilities would end.

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[6] 18 C.F.R. § 385.713(c)(2) (2008).

[7] The purpose of this requirement is to benefit all participants in a proceeding by ensuring that the filer, the Commission, and all other participants understand the issues raised by the filer, and to enable the Commission to respond to these issues. Having a clearly articulated Statement of Issues ensures that issues are properly raised before the Commission and avoids the waste of time and resources involved in litigating appeals regarding which the courts of appeals lack jurisdiction because the issues on appeal were not clearly identified before the Commission.

[8] On August 20, 2008, PacifiCorp filed a pleading styled "Errata" in which it attempted to correct the omission merely by titling the body of the rehearing request "Statement of Issues." The revision came almost a month after the July 25 rehearing deadline. Even if it had been timely filed, it failed to cure the deficiency.

6. On rehearing, Washington DFW asserts that the existing boat ramp is not useable during periods of reservoir drawdown and cannot be extended sufficiently to allow reservoir use during the non-recreation season. Upon review of the information provided by Washington DFW, we find that the boat launch at Swift No. 1 reservoir is not useable during winter drawdown; however, it is accessible during the primary recreation season. Due to the location and steep terrain of this reservoir, Swift reservoir receives the fewest visitors of all the reservoirs at the project. Therefore, we do not believe that the use of the Swift reservoir outside of the summer recreation season warrants the construction of another boat launch. We accordingly deny Washington DFW's request for rehearing. At the same time, we do not oppose the construction of the boat launch if a party obtains funding, as envisioned in the Agreement. This is a facility that could be constructed and maintained outside of the license.

C. Requirements to Remove Dead Trees Along the Reservoir Peripheries

7. PacifiCorp requests that the Commission revise standard Article 20[9] to allow certain dead trees to be left for wildlife and aquatic habitat. The purpose of Article 20 is to require the removal from the reservoir and its perimeter of those dead trees that pose a hazard to project operations, public safety, or navigation; it does not require removal of dead trees that will not pose such hazards.[10] Thus, the licensee will not be required to remove dead trees that do not pose such hazards. If PacifiCorp has any further questions on this matter, it should consult with the Commission staff. Accordingly, we will not revise Article 20.

D. Emergency Telephone Notification

8. PacifiCorp requests that the emergency telephone notification service requirement of the license, Article 304(a), be revised to require PacifiCorp to only provide funding for the system, and not installation, operation, and maintenance of the system.[11] Both Clark

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[9] Article 20 is found in the three licenses in attached Form L-1.

[10] *See, e.g., Montana Power Company and Granite County, Montana*, 62 FERC ¶61,166, at p. 62,140 (1993); *Wisconsin Electric Power Company,* 75 FERC ¶ 61,011 (1996).

[11] Article 304 (a) of the three licenses requires that the licensee "acquire, install and maintain a new emergency telephone notification service for those portions of Clark County and Cowlitz County that are subject to inundation from the Lewis River projects."

and Cowlitz Counties have already installed the emergency telephone notification service called for in the Agreement.

9. As clarification, the Commission did not intend for PacifiCorp to develop a duplicate emergency telephone notification service, only to ensure that there is such a system. PacifiCorp, while ultimately responsible for such a system, may (as it has done here) delegate its responsibilities to the counties.[12]

E. Requirement to File Amendment Applications (License Article 401(b))

10. Article 401(b) requires PacifiCorp to file applications to amend its license prior to implementing "unspecified long-term changes to project operations, requirements, or facilities for the purpose of protecting and enhancing environmental resources." PacifiCorp and NMFS assert that this is unnecessary because the Agreement resolves all issues regarding the relicensing of the project, and the parties to the Agreement do not contemplate any measures that are not already included in the Agreement and the conditions of the license.

11. We agree that if measures are contemplated in the Agreement and incorporated in the license, then minor changes or adjustments to those requirements would not require an application to amend the license. However, in the event that the licensee wishes to implement unspecified, long-term, material changes to project operations, requirements, or facilities (i.e., not contemplated in the Agreement and not evaluated by staff prior to issuing the license order), then an amendment would be required. If the licensee is uncertain of whether an action requires an amendment, it should consult with Commission staff prior to undertaking the action.

12. Article 401(b)(1) requires that PacifiCorp file an application to amend the license for any "adjustments" to the upstream fish passage facility required by the license. PacifiCorp states that this will place an unnecessary burden on it to seek an amendment for any change to the facility, however minor. We clarify that this is not meant to require an amendment for minor changes to the facility, but rather for those material changes that were not contemplated by the license.

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[12] Any other issues related to emergency communications will be handled under the projects' existing Emergency Action Plans.

F. Requirement to Net Bull Trout and Kokanee Evaluation

13. Article 402(a) in the Swift No. 1 and Yale licenses requires that PacifiCorp net bull trout from the projects' tailraces and haul them to a location determined by FWS. PacifiCorp contends that Article 402 should be deleted as unnecessary. These measures are already covered by other conditions of the license, respectively, the bull trout collection and transport plan required by NMFS's Biological Opinion (condition 1, which incorporates section 4.9 of the Agreement) and the hatchery and supplementation program that is also required by the Biological Opinion (condition 1, which incorporates section 8 of the Agreement). We agree that those requirements of the article should be deleted, but that Article 402 is necessary for requiring evaluation of bull trout annually for both the Swift No.1 and Yale Projects and for managing designated conservation lands on Cougar Creek for the protection of bull trout in the Yale Project. Accordingly, we will revise Article 402 in both the Swift No. 1 and Yale licenses.

14. Article 402(b) in the Swift No. 1, Yale and Merwin licenses require that the licensee evaluate bull trout and kokanee populations annually. Because kokanee reside only in the Yale and Merwin reservoirs, we will revise Article 402 of the Swift No. 1 license to require annual evaluation only of bull trout in the Swift No. 1 reservoir.

G. Incorporating Wildlife Habitat Lands into the Project Boundary

15. PacifiCorp requests rehearing of Article 403 in the three licenses, which requires that all land acquired for wildlife habitat under the Wildlife Habitat Management Plan must be included within the project boundaries.[13] PacifiCorp asserts that inclusion of theses lands alters the settlement and creates unnecessary additional expenses and processes. Furthermore, it states that incorporating these lands within the project boundaries does not serve project purposes or assure that the public interest is served.

16. We disagree. Acquisition and maintenance of lands for wildlife habitat has been determined by the Commission to satisfy a project purpose and has been included in the

[13] Article 403 in the Merwin Project does not include wildlife habitat land acquisition, but rather requires filing a Wildlife Habitat Management Plan with the Commission for approval, as described in section 10.8 of the Agreement. For the Yale and Swift No. 1 licenses, lands acquired for wildlife habitat are required to be included in the project boundary. In the event that the Merwin Project acquires additional lands for wildlife habitat, those lands shall be included in the project boundary.

licenses.[14] Accordingly, the lands acquired for this purpose must be included within the project boundary. A project boundary serves the function of indicating that the lands within are used in some manner for project purposes. This helps to reduce ambiguity for purposes of license administration and compliance by clarifying the geographic scope of the licensee's responsibilities under its license (and the Commission's regulatory responsibilities).[15] Any lands managed pursuant to a license condition, or if used for "project purposes," should be included in the project boundary, regardless of existing management agreements by the applicant.

17. We will, however, modify Article 403 in the Swift No. 1 and Yale licenses, as PacifiCorp requests, to require that it update its project boundaries within five years of license issuance to reflect all lands acquired for wildlife habitat under that article during that period, rather than requiring a project boundary update upon each new parcel acquisition.

18. The second concern raised by PacifiCorp regarding wildlife habitat lands was the requirement to file annual plans that would describe the lands proposed to be acquired under the land acquisition and habitat enhancement funds. PacifiCorp is concerned about land speculation if the lands were delineated in the plan for approval before they would be purchased. To avoid such speculation, we will revise Article 403 in the Swift No. 1 and Yale licenses to require that the lands be described in the annual plans after they have been acquired.

H. <u>South Merwin Trail Access</u>

19. Article 406 of the Merwin license requires that PacifiCorp submit a plan to provide a trail easement to connect a proposed Clark County regional park to the south side of Lake Merwin, as outlined in section 11.2.3.4 of the Agreement. In 2007, Clark County finalized its comprehensive plan, which did not mention the Merwin location for a regional park. PacifiCorp requests that we clarify the obligation to provide a trail easement is contingent upon Clark County committing to develop the regional park near Merwin Lake.

20. We will revise Article 406 to require that the plan providing a trail easement to the regional park is contingent on Clark County developing the regional park.

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[14] *See* EIS at 5-29 to 5-31. Wildlife habitat lands acquisition and maintenance are discussed in each of the three licenses under Section B of Other Issues.

[15] *See PacifiCorp*, 80 FERC ¶ 61,334 (1997).

I. Cougar Visitor Information Facility

21. PacifiCorp requests that we eliminate the Cougar Visitor Information Facility because the facility is not necessary to carry out project purposes and reasonable alternatives exist for a visitor's facility and for a facility to curate artifacts.

22. In the EIS, Commission staff concluded that a visitor's center in Cougar would allow the licensees to provide general information on the projects to the public and more specific information on recreational opportunities or safety and security. Including the Cougar Visitor Information Facility in the project boundary would help ensure that the proposed facility would be used for project purposes for the term of the new license. The project area closest to Cougar is the Yale Project.[16] In response to comments on the draft EIS, staff stated that, as proposed in the Agreement, the visitor information facility would be developed immediately adjacent to the projects and would provide public information about recreational opportunities at the projects.

23. The four Lewis River projects are the primary recreational attraction in the vicinity of Cougar and, as acknowledged in the Joint Explanatory Statement of the Agreement, the visitor center would provide benefits to project visitors.[17] The Visitor Information Center would serve as a primary gateway to the upper Lewis River Basin by providing public information on its history and resources, including information about the Yale and Swift Creek reservoirs, project facilities and operations, environmental, recreational and cultural resources. We agree with staff that there is a clear nexus with the projects and we will continue to require that a Visitor Information Facility plan be filed within five years of the date of issuance of the license as set forth in Article 410 of the Yale license.

J. Cost Caps

24. The Master Order recognizes that the Agreement and many of the conditions of the four licenses establish limits on the licensee's responsibility to fund various resource mitigation measures and studies, but concludes that it is nevertheless the licensees' obligation to complete the measures required by the license articles, in the absence of Commission authorization to the contrary.[18]

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[16] EIS at 5-30.

[17] *Id*. at A-18.

[18] 123 FERC ¶ 62,260 at P 21.

25. On rehearing, PacifiCorp objects to this conclusion, and asks instead that the Commission approve the cost limits included in the Agreement.

26. We deny the request. We understand the licensee's desire to fix the costs that it may incur for resource protection and enhancement measures. As the order explains, it is likely that the specified funding will be sufficient for the measures in question. However, the Commission cannot constrain the fulfillment of its statutory responsibilities by agreeing to such spending caps.[19] We therefore affirm the conclusion in the Master Order that it is the licensee's obligation to complete the measures required by the license articles, in the absence of Commission authorization to the contrary. In addition, we are adding an additional license article to each license to so state.

K. Flood Control Requirements

27. PacifiCorp seeks clarification of Article 302 of the three licenses, which provides for flood management at the three projects. According to section 12.8 of the Settlement Agreement, PacifiCorp will seek an amendment of the FEMA agreement and Standard Operating Procedure Manual by the first anniversary of the license issuance. Once PacifiCorp obtains FEMA approval of the revised high runoff procedure, it then can seek an amendment to the licenses.

L. Flow Release Requirements

28. PacifiCorp requests that the Commission clarify whether the licenses require that the Commission be notified prior to adjustment of minimum flow for approval or whether the intent was for the Commission to be notified after a change in minimum flow. The Master Order, at paragraph 29, stated that the procedures should also include notification of the Commission regarding any deviations from the required minimum flows. We will include a new license article in the three licenses which clarifies the notification requirement.

M. Corrections to License Articles and Appendices

29. As discussed below, PacifiCorp points out a number of corrections that should be made to various conditions of the three licenses.

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[19] *See, e.g., Public Utility District No. 1 of Chelan County, Washington,* 119 FERC ¶ 61,055, at P 12-17 (2007).

30. We will correct the last sentence in standard Article 29 of the three licenses.

31. Appendix E of the Swift No. 1 Project license will be corrected to complete the last sentence in Article 2.

32. Ordering Paragraph (E) of the Yale Project license will be changed to refer to Appendix B.

33. Appendix A, Section 4.3(4)(a) of the Yale Project water quality certificate, references the 7Q10 year flow of 32,884 cfs for the Lewis River at Merwin Dam. As PacifiCorp states, it should reference the 7Q10 year flow of 27,088 cfs at the Yale Dam. We will make this correction. In addition, sections 4.4(2)(f) and 4.4(3) will be revised to conform to the language in the water quality certification.

34. NMFS pointed out six typographical errors in the Yale Project No. 2071 section 18 prescriptions (Appendix B), which we will correct.

N. **Corrections to Discussion Section of License Order**

35. PacifiCorp also seeks correction of some typographical errors and other items in the discussion section of the order. The requested corrections and edits are minor and do not affect the license articles or ordering paragraphs. We take note of them, but see no need to take any action.

The Commission orders:

(A) The request for rehearing filed on July 28, 2008, by the Washington Department of Fish and Wildlife is denied.

(B) The request for rehearing filed on July 28, 2008, by PacifiCorp is granted to the extent set forth in this order.

(C) The request for rehearing filed on July 25, 2008, by National Marine Fisheries Service is granted to the extent set forth in this order.

(D) The following technical corrections and clarifications are granted to the extent described above and the orders are revised to read as follows:

(1) Yale Project No. 2071, Ordering Paragraph (E) shall be revised to refer to Appendix B.

(2) Article 401(b)(1) of the Swift No.1 Project No. 2111, Yale Project No. 2071 and Merwin Project No. 935 are each revised as follows:

	Condition No.	Modification
1	Section 18 no. 4.5 and BO no. 1	Modifications to passage facilities to achieve performance standards

(3) Article 402 in the Swift No. 1 Project No. 2111 is revised to read as follows:

Article 402. *Aquatic Resources Management Measures*. The licensee shall continue to implement the following aquatic resources management measure:

(a) in conjunction with the licensees for the Yale Project No. 2071 and Merwin Project No. 935, evaluate bull trout populations annually.

The licensee shall include evidence of compliance with this measure in the annual reports filed with the Commission under section 14.2.6 of the Settlement Agreement (Agreement) filed on December 3, 2004.

In addition, the licensee shall file with the Commission within 2 years of license issuance, a bull trout limiting factor analysis, as described in section 5.5 of the Agreement filed on December 3, 2004.

(4) Article 402 in the Yale Project No. 2071 is revised to read as follows:

Article 402. *Aquatic Resources Management Measures*. The licensee shall continue to implement the following aquatic resources management measures:

(a) in conjunction with the Swift No. 1 Project No. 2111 and Merwin Project No. 935, evaluate bull trout and kokanee populations annually; and

(b) manage designated conservation lands on Cougar Creek for the protection of bull trout (section 5.2 of the Settlement Agreement filed on December 3, 2004).

The licensee shall include evidence of compliance with these measures in the annual reports filed with the Commission under section 14.2.6 of the Settlement Agreement.

(5) The second paragraph of Article 403 of the Swift No.1 Project No. 2111 is revised to read as follows:

All lands acquired for wildlife habitat under the Swift No. 1 and Swift No. 2 Land Acquisition and Habitat Protection Fund and the Lewis River Land Acquisition and Habitat Enhancement Fund shall be included within the project boundary and updated within five years of the issuance date of the license to reflect all lands acquired for wildlife habitat under the Wildlife Habitat Management Plan.

(6) The sixth paragraph of Article 403 of the Swift No. 1 Project No. 2111 is revised to read, in part, as follows:

…. The annual plans shall include: (a) a description of the lands acquired under the Swift No. 1 and Swift No. 2 Land Acquisition and Habitat Protection Fund; (b) a description of the lands acquired under the Lewis River Acquisition and Habitat Enhancement fund associated with the Swift No. 2 Project …..

(7) The second paragraph of Article 403 of the Yale Project No. 2071 is revised to read as follows:

All lands acquired for wildlife habitat under the Yale and Lewis River Land Acquisition and Habitat Protection Funds shall be included within the project boundary and updated within five years of the issuance date of the license to reflect all lands acquired for wildlife habitat under the Wildlife Habitat Management Plan.

(8) The sixth paragraph of Article 403 of the Yale Project No. 2071 is revised to read, in part, as follows:

…. The annual plans shall include: (a) a description of the lands acquired under the Yale Land Acquisition and Habitat Protection Funds; (b) a description of the lands acquired under the Lewis River Acquisition and Habitat Enhancement fund associated with the Yale Project; …..

(9) The first sentence of Article 406 of the Merwin Project No. 935 is revised to read as follows:

South Shore Merwin Trail Access Plan. Within one year of Clark County committing to develop a regional park near Merwin Lake, the licensee shall file with the Commission for approval, a plan to provide a trail easement to connect a proposed Clark County regional park to the south side of Lake Merwin, as outlined in section 11.2.3.4 of the Settlement Agreement filed on December 3, 2004.

(10) The following license Articles regarding cost caps are added to each of the licenses.

Swift No. 1 Project No. 2111: Article 413. *Funding*. Notwithstanding the limitation on expenditures as expressed in the mandatory conditions and included in this license, the Commission reserves the right to require the licensee to undertake such measures as may be appropriate and reasonable to implement approved plans and other requirements in this license.

Yale Project No. 2071: Article 415. *Funding*. Notwithstanding the limitation on expenditures as expressed in the mandatory conditions and included in this license, the Commission reserves the right to require the licensee to undertake such measures as may be appropriate and reasonable to implement approved plans and other requirements in this license.

Merwin Project No. 935: Article 414. *Funding*. Notwithstanding the limitation on expenditures as expressed in the mandatory conditions and included in this license, the Commission reserves the right to require the licensee to undertake such measures as may be appropriate and reasonable to implement approved plans and other requirements in this license.

(11) The following license Articles regarding modification of minimum flows are added to each of the licenses.

Swift No. 1 Project No. 2111 : Article 414. *Minimum Flow Modification.* The licensee may temporarily decrease minimum flows below Swift No. 1 Dam upon agreement between the licensee and the Flow Coordination Committee as defined in Section 6.2.5 of the Settlement Agreement. If the flow is so modified, the licensee shall notify the Commission as soon as possible, but no later than 10 days after each incident.

Yale Project No. 2071: Article 416. *Minimum Flow Modification.* The licensee may temporarily decrease minimum flows below Yale Dam upon agreement between the licensee and the Flow Coordination Committee as defined in Section 6.2.5 of the Settlement Agreement. If the flow is so modified, the licensee shall notify the Commission as soon as possible, but no later than 10 days after each incident.

Merwin Project No. 935: Article 415. *Minimum Flow Modification.* The licensee may temporarily decrease minimum flows below Merwin Dam pursuant to Sections 6.2.4 and 6.2.5 of the Settlement Agreement. If the flow is so modified, the licensee shall notify the Commission as soon as possible, but no later than 10 days after each incident.

(12) The last sentence in Form L-1, Article 29 of the Swift No.1 Project No. 2111, the Yale Project No. 2071 and the Merwin Project No. 935 are each revised as follows:

> Provided further, that in the event of disagreement, any question of unreasonable interference shall be determined by the Commission after notice and opportunity for hearing.

(13) The dates of the Settlement Agreement in the mandatory conditions are revised as follows:

Swift No. 1 Project No. 2111, Appendix C, Exhibit A, title shall read as: November 30, 2004;

Swift No. 1 Project No. 2111, Appendix D, first sentence shall read as: filed … on December 2, 2004;

Merwin Project No. 935, Appendix A, Section 4.2, first sentence shall read as: November 30, 2004, submitted to FERC on December 2, 2004; and

Merwin Project No. 935, Appendix A, Exhibit A, title shall read as: November 30, 2004.

(14) In Swift No. 1 Project No. 2111, the last sentence of Appendix E shall be revised to read as follows:

… Settlement Agreement concerning the relicensing of the Lewis River Hydroelectric Project Nos. 935, 2071, 2111 and 2213, Cowlitz and Skamania Counties, Washington, dated November 30, 2004, and filed with the Commission on December 3, 2004.

(15) Yale Project No. 2071, Appendix A, is revised as follows:

(a) Section 4.3(4)(a) ….. the 7Q10 flow for the Lewis River at Yale Dam is 27,088 cfs;

(b) Section 4.4(2)(f) : Identify adaptive management strategies to further improve the temperature fluctuation regime for the cold-water biota in the event that target temperatures are not achieved.

(c) Section 4.4(3) : If it is determined through the TWQAP that steps must be taken in order to protect the most sensitive beneficial uses, the Licensee shall employ all reasonable and feasible methods identified in response to condition 2(e and f) to ensure that the water temperature fluctuation regime in the Canyon remains below levels which would harm the aquatic biota or limit the potential healthy cold water habitat.

(16) Yale Project No. 2071, Appendix B, is revised as follows:

(1) On page 81, the acronym for Collection Efficiency is “CE”; (2) on page 82, in article 4.3, the third sentence shall read: “The Licensee must consider without limitation entry rate, fall back, crowding at the entrance, delay and abandonment of the trap area”; (3) on page 84, in article 6, the first sentence is revised to read as: “Unless and until

alternative technologies are implemented, the Licensee must provide for the transport by truck of all Transported Species collected at the Yale Upstream Facility"; (4) on page 87, in article 10, the first sentence of the second paragraph shall read: "Unless otherwise directed by the Services, the Licensee must provide for the marking of all the transported juvenile anadromous salmonids collected by the Yale Downstream Facility until such time as the Yale Upstream Facility is completed pursuant to this license and the Swift Upstream Facility is completed pursuant to the Swift No. 1 and Swift No. 2 licenses, and must provide for the tagging of a statistically valid sample of the fish transported as appropriate to accomplish the monitoring and evaluation objectives set forth below, the methodology of such tagging to be determined by the Licensee in Consultation with the ACC (including at least the Services) and approved by the Services"; (5) on page 88, in article 11, the last sentence shall read: "If these facilities do not function as well to collect bull trout as the interim collection method based on effectiveness monitoring, as determined by the USFWS, the Licensee shall continue the interim collection method"; and (6) on page 90, in article 13, the fourth paragraph, the third sentence shall read: "The Licensee, together with the licensees for the Merwin, Swift No. 1 and Swift No. 2 projects, must allow the ACC (including at least the Services) a period of 90 days to provide comments on the draft revised M&E Plan as part of such Consultation."

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Docket No. UE 263
Exhibit PAC/400
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Dana M. Ralston

March 2013

DIRECT TESTIMONY OF DANA M. RALSTON

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Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Dana M. Ralston. My business address is 1407 West North Temple, Suite 320, Salt Lake City, Utah 84116. My present position is Vice President of Thermal Generation. I am responsible for the coal, gas, and geothermal resources owned by the Company.

QUALIFICIATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science degree in Electrical Engineering from South Dakota State University. I have been the Vice President of Thermal Generation for PacifiCorp Energy since January 2010. Before 2010, I held a number of positions of increasing responsibility with MidAmerican Energy Company for 28 years in the generation organization, including the plant manager position at the Neal Energy Center, a 1600 megawatt generating complex. In my current role, I am responsible for the operation and maintenance of the thermal generation fleet.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information supporting the prudence of the turbine upgrade project at Unit 2 of the Jim Bridger generating plant located near Rock Springs, Wyoming. I discuss the scope, benefits, and economic analysis of the project.

PROJECT DESCRIPTION

Q. Please describe the Jim Bridger Unit 2 turbine upgrade project.

A. Recent advances to steam turbine design have resulted in increases in efficiency of new steam turbines. These improvements are transferable to existing power plants. The turbine upgrade project at Jim Bridger Unit 2 consists of installing a new steam turbine that includes the high pressure, intermediate pressure, and low pressure turbine sections with the new advanced design. The upgraded turbine is expected to produce 12 megawatts of additional generation with no increase in fuel input or emissions at full load.

Q. Did PacifiCorp conduct a competitive bidding process for the turbine replacement project?

A. Yes. In 2008, PacifiCorp solicited and competitively bid the procurement and installation of turbine upgrades for all units of the Jim Bridger generating plant. At the conclusion of the bidding process, the Company awarded the contract to Mechanical Dynamics and Analysis, LTD, a wholly owned subsidiary of Hitachi, Ltd.

Q. Were issues encountered during the project?

A. Yes. After the design had been finalized by the supplier and the manufacturing process started, the supplier provided engineering data that was used in a transmission study. The transmission study revealed that the mechanical resonance of the turbine would conflict with the transmission system electrical resonance. This phenomenon is called sub-synchronous resonance (SSR).

SSR has the potential to cause catastrophic damage to the turbine shaft requiring a lengthy outage to repair.

Q. What did PacifiCorp do when this information was discovered?

A. Due to the SSR issue, PacifiCorp suspended the fabrication of the Jim Bridger Unit 1 low pressure turbine in September 2009 and the high pressure, intermediate pressure, and low pressure turbines for Jim Bridger Units 2, 3, and 4 in February 2010, until a resolution to the SSR issue could be found. In December 2010, notice was sent to the vendor that the contracts for the high pressure, intermediate pressure, and low pressure turbines for Jim Bridger Units 2 and 4 and the low pressure turbine for Jim Bridger Unit 3 would be terminated.

Q. Did PacifiCorp solicit the assistance of third-party experts to study the SSR issue?

A. Yes. To fully study and understand what solutions could be applied to resolve the SSR issue, the Company hired General Electric to conduct a series of studies.

Q. Was a solution to the SSR issue found?

A. Yes. In November 2011, General Electric determined that installation of a blocking filter at the generator step up transformer would resolve the SSR issue. The estimate for the blocking filter for Jim Bridger Unit 2 is approximately $4.4 million and is part of the project costs used in the economic evaluation of the project discussed below.

Q. After a solution was found, what did PacifiCorp do?

A. PacifiCorp negotiated with the vendor to determine the feasibility and cost of finishing and installing the partially fabricated Jim Bridger Unit 1 low pressure turbine and the Jim Bridger Unit 3 high pressure and intermediate pressure turbines, and installing all three sections at Jim Bridger Unit 2. In October 2011, the vendor provided a proposal for the modified scope. PacifiCorp evaluated the total costs of the project to determine the current value to the customers with the updated costs and scope. PacifiCorp determined that with the new costs and scope, the project's PVRR(d) analysis showed a $28.9 million benefit to customers from the turbine upgrade project. The PVRR(d) analysis compares operation of the unit with the upgraded turbine to continued operation of the unit with the existing turbine.

PacifiCorp then finalized the termination of the Jim Bridger Unit 2 and 4 turbines and the low pressure section of the Jim Bridger Unit 3 turbine, and restated the contracts to complete the procurement and installation of the upgraded turbine for Jim Bridger Unit 2 in December 2011.

Q. What is the capital investment associated with the turbine upgrade project?

A. The turbine upgrade project is expected to cost approximately $31.0 million on a total-company basis. The capital costs are included in this case as a known and measurable change to the test period as detailed by Mr. Gary W. Tawwater in Exhibit PAC/1002, Tawwater/8.5.5.

Q. When will the turbine upgrade project be placed in service?

A. The project is expected to be placed in service in May 2013.

PROJECT BENEFITS

Q. What are the benefits of the turbine upgrade project?

A. Recent advances to steam turbine design have resulted in increases in efficiency of new steam turbines. These improvements are transferable to existing power plants and, when applied to Jim Bridger Unit 2, will improve efficiency and increase the maximum output with no increase in fuel input.

Q. What is the expected increase in maximum output?

A. The expected increase in maximum output is 12 megawatts. This is due to the increase in turbine efficiency. This increase will occur with no additional fuel input required at maximum output.

Q. Will there be efficiency gains over the entire normal operating range of the unit?

A. Yes, the new turbine will consume less fuel for the same megawatt output over the normal operating range of the unit when compared to the existing turbine. This improvement will average approximately 500 BTU/kwh over the normal operating range. This benefit was not included in the PVRR(d) benefit listed below because the total fuel savings benefit is very dependent on the operating load profile of the unit, which can change from year to year, and to add conservatism to the analysis.

PROJECT ECONOMICS

Q. Did the PVRR(d) analysis show a benefit to customers from this project?

A. Yes. The PVRR(d) analysis shows a $28.9 million benefit to customers from the turbine upgrade project when compared to continued operation of the existing turbine. The positive PVRR(d) results are from the capacity increase benefit only. To add conservatism, no benefit was included for the resulting lower fuel consumption at outputs below maximum load when compared to the existing turbine.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/500
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Richard A. Vail

March 2013

DIRECT TESTIMONY OF RICHARD A. VAIL

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Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Richard A. Vail. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. I am Vice President of Transmission for PacifiCorp.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science degree in Electrical Engineering (Electric Power Systems Focus) from Portland State University. My experience spans more than 18 years in the electric utility business and electric power industry in general. I have working experience and have had management responsibility for a number of functional organizations at PacifiCorp including Substation Engineering, Planning Technologies, Standards Engineering, Cost Estimating, Project Services, Capital Planning, Maintenance Policy, Maintenance Planning, Investment Planning, Risk Planning and Asset Strategy, Reliability Standards, Asset Management, and most recently Transmission Services and Transmission System and Area Planning.

Q. What are your responsibilities as Vice President of Transmission?

A. I am responsible for transmission planning activities required to support PacifiCorp's existing and future bulk transmission system and to ensure a safe and reliable transmission system that provides adequate service to our customers.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the mandatory system reliability and performance requirements with which the Company must comply, and to support the test year costs associated with capital investments in the Company's transmission system. These investments include the new Black Rock Substation in Millard County, Utah; the interconnection to the new Lake Side 2 natural gas-fired generating plant (Lake Side 2) near Vineyard, Utah; system reinforcements needed to interconnect new data facilities near Prineville, Oregon; and transmission system upgrades needed to provide voltage support to the system connected to the Carbon generating facility in central Utah.

Q. What is the capital investment for the projects described in your testimony?

A. The capital investment for the major transmission projects described in my testimony is $69.2 million on a total-company basis. These projects are included as part of the Oregon revenue requirement in this case and are referenced in the direct testimony and exhibits of Mr. Gary W. Tawwater.

Q. Will these investments be considered "used and useful" before the test period for this case?

A. Yes. My testimony will demonstrate that these were prudent investments that benefit our customers, the projects are on schedule for completion, and the projects will be used and useful before the test year for this proceeding.

RELIABILITY REQUIREMENTS

Q. Please describe the mandatory reliability standards and criteria with which the Company is required to comply.

A. PacifiCorp plans, designs, and operates its transmission system to meet or exceed North American Electric Reliability Corporation (NERC) standards for the Bulk Electric Systems and Western Electricity Coordinating Council (WECC) regional standards and criteria. The NERC standards are federal law stated in 18 CFR Part 40 (Mandatory Reliability Standards for Bulk-Power Systems). The WECC standards and criteria are deemed necessary for the WECC Region to meet or exceed NERC standards. There are currently more than 100 approved NERC standards with which the Company must comply. The following standards dictate the minimum levels of transmission system reliability, redundancy, and performance required for transmission facilities:

- NERC TPL-001 System Performance Under Normal Conditions[1]
- NERC TPL-002 System Performance Following Loss of a Single Bulk Electric System (BES) Element[2]
- NERC TPL-003 System Performance Following Loss of Two or More BES Elements[3]
- NERC TPL-004 System Performance Following Extreme BES Events[4]
- TPL 001-WECC-1-CR System Performance Criteria Normal Conditions[5]

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[1] NERC TPL-001 can be found at: http://www.nerc.com/files/TPL-001-0.pdf.
[2] NERC TPL-002 can be found at: http://www.nerc.com/files/TPL-002-0.pdf.
[3] NERC TPL-003 can be found at: http://www.nerc.com/files/TPL-003-0.pdf.
[4] NERC TPL-004 can be found at: http://www.nerc.com/files/TPL-004-0.pdf.
[5] TPL 001-WECC-1-CR – TPL 004-WECC -1-CR can be found at: http://www.wecc.biz/Standards/WECC%20Criteria/TPL-001%20thru%20004-WECC-1-CR%20-%20System%20Performance%20Criteria.pdf.

- TPL 002-WECC-1-CR System Performance Criteria Following Loss of a Single BES Element
- TPL 003-WECC-1-CR System Performance Criteria Following Loss of Two or More BES
- TPL 004-WECC-1-CR System Performance Criteria Following Extreme BES Events
- NERC TOP-002 Normal Operations Planning[6]
- NERC TOP-004 Transmission Operations[7]
- NERC TOP-007 Reporting SOL and IROL Violations[8]

Q. Please discuss further how these standards and criteria influence the timing of the investments included in this case.

A. These mandatory standards require the Company to have a forward-looking transmission plan of action to reliably serve current and anticipated customer demands under all expected operating conditions, including normal system operations (all system elements in service) and during system contingencies (where elements of the transmission system are out of service), both planned or otherwise. NERC Transmission Planning Standard TPL 002 states (emphasis added):

> **A. Introduction**
> **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that *meet specified performance requirements with sufficient lead time*, and continue to be modified or upgraded as <u>*necessary to meet present and future system needs.*</u>
>
> **B. Requirements**
> **R1.** The Planning Authority and Transmission Planner shall each demonstrate through valid assessment that its portion of the interconnected

[6] NERC TPL-002 can be found at: http://www.nerc.com/files/TPL-002-0.pdf.
[7] NERC TPL-004 can be found at: http://www.nerc.com/files/TPL-004-0.pdf.
[8] NERC TOP-007 can be found at: http://www.nerc.com/files/TOP-007-0.pdf.

> transmission *system is planned such that the Network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions* as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
>
> **R1.1.** Be made annually.
> **R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
>
> **R2.** When System simulations indicate an *inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1*, the Planning Authority and Transmission Planner shall each:
>
> **R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
> ***R2.1.1.*** *Including a schedule for implementation.*
> ***R2.1.2.*** *Including a discussion of expected required in-service dates of facilities.*
> ***R2.1.3.*** *Consider lead times necessary to implement plans.*

The Company is required to have both short-term and long-term transmission plans to reliably meet all expected current and forecasted customer electrical demands. The requirement to have these plans and meet current and forecasted customer demand is not optional for the Company. The Company is audited every three years by NERC and WECC. The next audit is scheduled for May 2013.

BLACK ROCK SUBSTATION

Q. Please describe the Black Rock Substation investment included in this case.

A. The Black Rock Substation is a new 230-69 kilovolt (kV) substation in Millard County, Utah, with a scheduled in-service date of May 1, 2013, and cost of $19.1 million on a total-company basis. This project consists of looping in and out the existing Pavant-Gonder 230 kV transmission line and the Delta-Graymont

69 kV transmission line, installing a 75 megavolt ampere (MVA) 230-69 kV load tap changing transformer, and changing the relay settings on the 46-46 kV regulator at the Delta Substation to enable forward and reverse power operation.

Q. Why is the Black Rock Substation investment needed?

A. The Black Rock Substation investment is needed to meet load growth and reliability needs and to maintain compliance with the mandatory system reliability and performance requirements described above. Currently, the Company's contractual obligation in the area served by the Pavant Substation exceeds what the system can provide. The Company performed a five-year study to address these contracted loads under multiple scenarios based on current and projected demand. This study showed that meeting current and projected maximum contracted load at the Pavant Substation resulted in a range of outcomes, including low voltages across the entire 46 and 69 kV systems during N-0 conditions, system deficiencies during summer peak beginning in 2012, and dropped loads during N-1 conditions (estimated for 2012 at approximately 47 MW of load served from Pavant in the Delta area). The Black Rock Substation was determined to be the least-cost option to provide voltage support to the area under N-0 conditions (i.e., normal system conditions) and to help solve problems under N-1 conditions (i.e., system performance following the loss of a single BES element).

Q. What are the system benefits associated with the Black Rock Substation?

A. The Black Rock Substation provides several system benefits, including:

- Decreased loading on the Pavant 230-46 kV transformers, providing redundancy in case of the loss of the other transformer;

- Improved voltage on the 46 and 69 kV systems to handle additional load growth in the area;
- Reduced loading on the Pavant to McCornick 46 kV line to 46 percent of its 25 MVA steady state rating, reducing the risk of load shedding in the Delta area; and
- Enabling of the 46 kV lines from Pavant to McCornick and Pavant to Delta to operate under N-1 operation upon the loss of one another.

Q. Will the Black Rock Substation investment be used and useful before the test period for this case?

A. Yes. When the Black Rock Substation is placed into service, in May 2013, the project will be part of the interconnected transmission system and will be fully used and useful.

LAKE SIDE 2 INTERCONNECTION

Q. Please describe the Lake Side 2 interconnection investment included in this case.

A. The investments included in this case for interconnection of Lake Side 2 (approximately $18.5 million total-company basis) consist primarily of the following:

- Construction of a new 345 kV point of interconnection substation (Steel Mill Substation);
- Looping in and out the existing 345 kV Camp Williams/Emery transmission line;
- Configuring the point of interconnection substation to accommodate a six breaker ring bus layout with three breakers installed for this project;
- Installing a control house, metering, communication, and protection and control equipment at the new point of interconnection substation; and
- Deploying required equipment replacement, control modifications, and communications upgrades at the Camp Williams, Emery, Sigurd, Dynamo,

and Timp substations, and at the Salt Lake City and Portland control centers.

Q. Why is the Lake Side 2 interconnection investment needed?

A. PacifiCorp Energy, the interconnection customer, made a formal request for interconnection of the new Lake Side 2 to PacifiCorp's existing Camp Williams-Hunter/Emery 345kV transmission line, which is adjacent to the existing Lake Side generating facility. The interconnection must be completed in May 2013 to provide electrical back feed approximately one year ahead of the generation plant in-service date. The interconnection substation must be engineered, designed, and constructed to meet all applicable PacifiCorp, NERC, and WECC mandatory reliability standards as described above.

Q. Is the Lake Side 2 interconnection investment in the Steel Mill Substation included in this case part of the interconnection facilities dedicated to Lake Side 2?

A. No. The Steel Mill Substation investment included in this case is located separately and remote from Lake Side 2 site and is an integral part of the 345kV transmission system serving both the generating unit and the Company's customers. Interconnection facilities that would be considered an integral part of the generating unit include those physically located on the Lake Side 2 site, such as the generator step up unit transformers (GSUs) and associated plant substation facilities and facilities interconnecting to the Steel Mill Substation included in this case. These facilities, installed and owned by PacifiCorp Energy, will be placed in service coincident with Lake Side 2 and are included as part of the costs included in the proposed separate tariff rider discussed in the testimony of Ms. Joelle R. Steward.

Q. What are the benefits associated with the Lake Side 2 interconnection investment?

A. The Company is required under its Federal Energy Regulatory Commission (FERC) approved Open Access Transmission Tariff to provide transmission service and generator interconnection service to all customers on a non-preferential, non-discriminatory basis. Per the Company's binding FERC interconnection agreement with PacifiCorp Energy, the Project must be completed in May 2013. Additionally, Lake Side 2 is part of the Company's acknowledged integrated resource plans and will provide benefits to all of PacifiCorp's native load customers.

Q. Will the Lake Side 2 interconnection investment be used and useful before the test period for this case?

A. Yes. When the Steel Mill Substation is placed into service in May 2013, the facility will be part of the interconnected transmission system and will be fully used and useful.

NEW OREGON DATA CENTER CUSTOMER SYSTEM REINFORCEMENTS

Q. Please describe the customer system reinforcements included in this case.

A. The customer's system reinforcements in this case are approximately $18.3 million on a total-company basis and consist primarily of the following:

- Expansion of 115 kV ring bus at Houston Lake Substation for 115 kV feed to the customer's new substation and new 115 kV transmission line between Ponderosa and Houston Lake Substations;

- Installation of metering equipment, 115 kV CT/PT combined metering units and metering bypass structure at Houston Lake Substation for feed to the customer's new substation;
- Construction of approximately 400 feet of 115 kV line from Houston Lake Substation to the customer's new substation;
- Installation of second 230-115 kV, 250 MVA transformer at Ponderosa Substation; expand Ponderosa Substation 115 kV ring bus to accommodate second transformer position and new Ponderosa-Houston Lake 115 kV line;
- Provision of funding to Bonneville Power Administration (BPA) for new 230 kV bus position at BPA Ponderosa Substation for interconnection of Company's new 230-115 kV transformer;
- Construction of new 115 kV line on a new right-of-way between Ponderosa and Houston Lake Substations, approximately 7.7 miles long;
- Modification of existing Ponderosa to Prineville 115 kV line at crossing with new line to achieve line separation and clearance;
- Replacement of 230 kV line relays at Pilot Butte Substation; and
- Replacement of four 12.47 kV circuit breakers and two sets of 115 kV fuses at Prineville Substation to accommodate increased system fault duty.

Q. Why are the new Oregon data center system reinforcements needed?

A. The customer has requested network service for its new Oregon Data Centers II and III, located adjacent to its existing Oregon Data Center I in the Tom McCall Industrial Park southwest of Prineville, Oregon. The customer system reinforcements are required to support interconnection of the new Oregon Data Centers II and III, which together represent 80 MVA of new customer load, and to maintain compliance with the mandatory system reliability and performance requirements described above, specifically NERC TPL-001 and TPL-002.

Q. What are the system benefits associated with these system reinforcements?

A. These investments are required for the interconnection and reliable service to the new data centers, absent these reinforcements, this new customer load could not be reliably interconnected or served and the Company would not meet its obligation to serve electric customers.

Q. Will the Oregon data center system reinforcements be used and useful to serve customers before the test period for this case?

A. Yes. When the project is placed into service in 2013, the facility will be part of the interconnected transmission system and will be fully used and useful.

CARBON VOLTAGE SUPPORT

Q. Please describe the Carbon voltage support investments included in this case.

A. The Carbon voltage support investments included in this case (approximately $13.2 million on a total-company basis), include the following:

- Removal of the 46 kV Carbon switching substation and replacement of the existing alternate station service feed to the 138 kV switching station with a new feed;
- Installation of two 138 kV 15 megavolt ampere reactive (MVAR) capacitor banks at the Mathington Substation;
- Expansion of the Mathington Substation for the static volt-ampere reactive (VAR) compensator (SVC); and
- Design/installation of one 138 kV +85 MVAR and -15 MVAR SVC; and modified communications and protection and control equipment at multiple locations across the Company's system.

Q. Why are the Carbon voltage support investments needed?

A. The Carbon generating facility is anticipated to be retired by April 15, 2015, to comply with the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards. To enable this facility to be retired as scheduled, and to maintain compliance with the mandatory system reliability and performance requirements described above, transmission system upgrades must be in place to provide voltage support necessary for continued reliable operation of the Carbon-Price-Vernal transmission grid area.

Q. What are the system benefits associated with the Carbon voltage support investments?

A. The Carbon voltage support investments will allow the Company to comply with NERC and WECC standards while continuing to provide reliable transmission service to the Carbon-Price-Vernal area following Carbon's retirement.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/600
Witness: Robert A. Ward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Robert A. Ward

March 2013

DIRECT TESTIMONY OF ROBERT A. WARD

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Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Robert Allen Ward. My business address is 825 NE Multnomah Street, Suite 700, Portland, Oregon 97232. My present position is Manager of Narrowband Compliance. I am responsible for ensuring that PacifiCorp complies with the recently enacted Federal Communications Commission (FCC) narrowband rules and, to that end, the delivery and implementation of a compliant two-way radio system for the Company.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I graduated with a Bachelor of Science degree in Electrical Engineering from the University of Miami. I have been PacifiCorp's Narrowband Compliance Program Manager since April 2010. Before that, I served as Manager of Network Engineering from January 2010 to April 2010, Director of Telecommunications from March 2001 to December 2009, and Manager of Network Engineering from July 1998 to March 2001.

Before joining PacifiCorp in July 1998, I worked at Florida Power and Light for 24 years in a variety of positions of increasing responsibility in the generation, transmission and distribution, and information technology organizations.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's narrowband compliance program. I will demonstrate why these plant additions are reasonable, prudent, and should be included in the Company's revenue requirement in this case.

Q. Please summarize your testimony.

A. My testimony describes the two-way radio system implemented to comply with FCC narrowband rules that took effect on January 1, 2013. In particular, I will describe those assets placed into service for the benefit of Oregon customers.

Q. Please provide a brief description of the purpose and necessity of these assets.

A. The Company uses two-way radio communications for efficient operations, remote system monitoring, reliable crew dispatch, and emergency response.

Q. Please explain why these business functions are unmet by commonly available commercial services such as cellular telephones.

A. The Company relies on two-way radio communications for power restoration and emergency response. Fulfilling these customer commitments is problematic when power is disrupted to the cellular infrastructure; for example, cellular service in Astoria was inoperative for three days following a coastal gale in December 2007.

Q. Please briefly describe the assets added to comply with the FCC narrowband rules.

A. Assets added to comply with the FCC narrowband rules include radio licenses, radio transmitter sites, supporting microwave transport facilities, electronic switching equipment, communications console equipment, monitoring and control equipment, mobile radios, portable radios, and peripheral devices.

Q. Please explain the necessity for replacing the Company's legacy two-way radio communications system.

A. The FCC has jurisdiction over the use of two-way radio communications systems in the United States. Seeking to obtain greater spectrum efficiency, the FCC released its Third Memorandum Opinion and Order in December 2004. This order mandated that all non-federal wideband radio systems licensed to operate on frequencies below 512 megahertz (MHz) convert to narrowband technology by January 1, 2013. Accordingly, the legacy wideband radio systems used by the Company and others would become obsolete. According to data provided by the FCC, a total of 107,665 licensees were affected.

Q. Please state the projected cost to comply with the FCC's order.

A. The projected capital cost to comply with the FCC's order on a total-company basis is $119.3 million. Assets totaling $64.4 million have been placed in service as of June 30, 2012, to comply with this order. The remaining total-company capital costs of $54.9 million, or $20 million Oregon-allocated, will be placed in service by October 2013 as shown in the exhibit of Mr. Gary W. Tawwater (Exhibit PAC/1002, Tawwater/8.5.10).

The projected capital cost to comply with this order on a total-company basis is $119.3 million. Assets totaling $80.0 million have been placed in service as of December 31, 2012, to comply with this order. The portion of this total-company expenditure attributable to Oregon customers is projected to be $36.1 million. A total of $26.3 million in assets that benefit the Company's Oregon customers have been placed in service as of December 31, 2012.

Q. Has PacifiCorp complied with the FCC's order?

A. Yes. The Company is currently compliant with the FCC's order. However, three legacy wideband transmitter sites continue to operate under waivers granted by the FCC. These waivers expire on October 31, 2013. Construction at each of the waivered sites has been seasonally delayed by lease or permit restriction.

Q. Do any of the transmitter sites operating under FCC waivers serve Oregon?

A. Yes. The transmitter site at Mt. Isabelle serves southwest Medford, Oregon. It will be constructed in summer 2013 and will also accommodate the State of Oregon's radio system. Incremental cost incurred to accommodate the State of Oregon will be offset by lease payments.

Q. What other post-compliance Oregon assets will be added under this program?

A. Two new Oregon transmitter installations are planned for 2013. The first will be located at the State of Oregon's facility on Saddlebag Mountain. It will provide supplemental and back-up communications for Oar Hill, which is currently the only transmitter site serving the Company's Lincoln City, Oregon customers. The second transmitter installation will be located at Howard Butte. It will provide supplemental and back-up communications for Sheep Ridge, which is currently the only transmitter site serving the Company's customers in Enterprise, Oregon. Other post-compliance assets will be added in 2013 to improve system reliability and control.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/700
Witness: Kelcey A. Brown

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Kelcey A. Brown

March 2013

DIRECT TESTIMONY OF KELCEY A. BROWN

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Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Kelcey A. Brown. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present title is Manager, Load Forecasting.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have been employed by PacifiCorp since May 2011. I have been the Manager of Load Forecasting since June 2012. Before that time, I worked as a Senior Consultant in the Regulatory Net Power Costs Department. Before joining PacifiCorp, I worked at the Public Utility Commission of Oregon (Commission) from 2007 through May 2011. During my time at the Commission, I sponsored testimony in several dockets involving net power costs, integrated resource planning, and various revenue and policy issues. From 2003 through 2007, I was the Economic Analyst with Blackfoot Telecommunications Group, where I was responsible for revenue forecasts, resource acquisition analysis, pricing, and regulatory support. I have a Bachelor of Science degree in Business Economics from the University of Wyoming, and I have completed all course work towards a Master’s degree in Economics from the University of Wyoming.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to explain how the Company developed the forecasts of the number of customers, kilowatt-hour (kWh) sales at the meter (sales), system loads and system peak loads at the system input level (loads), and number of bills by rate schedule for the 12-month period ending December 31, 2014.

OVERVIEW

Q. When did the Company prepare the sales and load forecast used in this filing?

A. The sales and load forecast used in this filing was completed in July 2012 and is the same forecast that is being used in the Company's 2013 Integrated Resource Plan (IRP). The July 2012 sales and load forecast is the most recent forecast of sales and loads prepared by the Company.

Q. How did the Company use the July 2012 sales and load forecast in this filing and in the Company's concurrent 2014 Transition Adjustment Mechanism (2014 TAM) filing?

A. The July 2012 load forecast was used to calculate net power costs in the 2014 TAM filing. The load forecast was also used by Mr. Gary W. Tawwater to calculate the inter-jurisdictional allocation factors. The sales forecast by rate schedule was used by Mr. C. Craig Paice and Ms. Joelle R. Steward to allocate costs between customer classes and to design rates that correctly reflect the cost of service, respectively.

Q. Is the forecast methodology used in this case the same as presented in the Company's 2012 general rate case, docket UE 246 (2012 Rate Case), and 2013 TAM, docket UE 245?

A. Yes. The updates to data and assumptions are discussed below.

Q. Please provide a general overview of the Company's sales and load forecast methodology.

A. The Company's methodology consists of first developing a forecast of monthly sales by customer class and monthly peak load by state. This sales forecast becomes the basis of the load forecast by adding line losses, meaning kWh sales levels are grossed-up to a generation or "input" level. The monthly loads are then spread to each hour based on the peak load forecast and typical hourly load patterns to produce the hourly load forecast.

Q. Please provide a summary of the forecasted energy sales for 2014.

A. Table 1 provides the forecasted energy sales for the 12-month period ending December 31, 2014.

Table 1 - Test Period Sales Forecast (MWh)

2013 GRC (CY 2014)		
	Total Company	**Oregon**
Residential	**15,912,619**	**5,381,873**
Commercial	**17,321,091**	**5,378,807**
Industrial	**19,825,363**	**2,133,140**
Irrigation	**1,245,400**	**238,210**
Public Authority	**276,500**	**-**
Lighting	**141,650**	**36,940**
Total	**54,722,623**	**13,168,971**

COMPARISONS TO PRIOR SALES FORECASTS

Q. How does the total-company sales forecast for 2014 compare to the sales forecast used in the 2012 Rate Case?

A. As shown in Table 2, total-company 2014 forecast sales are 0.8 percent lower than 2013 forecast sales used in the 2012 Rate Case. The difference in the forecasts is attributable to a decline in industrial load and a small level of growth in the commercial and residential load. The growth in the commercial class is related to data centers. The industrial class decrease in the forecast is attributable to prolonged recessionary impacts and additional self-generation elections by some of the Company's large industrial customers in Utah, Wyoming, and Oregon.

Table 2 - Total Company Sales Comparison (MWh)

	2012 GRC (CY 2013)	2013 GRC (CY 2014)	Change	Percentage Change
Residential	15,866,151	15,912,619	46,468	0.3%
Commercial	17,166,799	17,321,091	154,292	0.9%
Industrial	20,363,476	19,825,363	(538,113)	-2.6%
Irrigation	1,214,725	1,245,400	30,676	2.5%
Public Authority	406,610	276,500	(130,110)	-32.0%
Lighting	141,670	141,650	(20)	0.0%
Total	55,159,430	54,722,623	(436,807)	-0.8%

Q. How does the Oregon sales forecast for 2014 compare to the sales forecast for the 2012 GRC?

A. As shown in Table 3, the 2014 Oregon sales forecast has increased by approximately 0.5 percent from the 2013 sales forecast used in the 2012 Rate Case. On an Oregon basis, the commercial class increase reflects the planned expansion of data centers in Oregon. The declines in residential and industrial load reflect prolonged recessionary impacts, growth in energy efficiency and conservation programs, and self-generation elections by some of the Company's large industrial Oregon customers.

Table 3 - Oregon Sales Comparison (MWh)

	2012 GRC (CY 2013)	2013 GRC (CY 2014)	Change	Percentage Change
Residential	5,403,215	5,381,873	(21,341)	-0.4%
Commercial	5,165,190	5,378,807	213,617	4.1%
Industrial	2,274,055	2,133,140	(140,915)	-6.2%
Irrigation	217,560	238,210	20,650	9.5%
Lighting	37,720	36,940	(780)	-2.1%
Total	13,097,740	13,168,971	71,231	0.5%

FORECAST METHODOLOGY

Q. What aspects of the sales and load forecast methodology do you address?

A. First, I describe the updates to the data and assumptions used to produce the sales and load forecasts. Second, I describe the forecasting approach used to develop monthly sales for the residential, commercial, irrigation, and lighting customer classes, followed by a description of the forecasting approach for the industrial customer class. Third, I describe how the hourly load forecast is developed. Fourth, I describe how the forecast by rate schedule for sales and number of bills are developed.

SUMMARY OF CHANGES IN FORECAST DATA AND ASSUMPTIONS

Q. Please summarize major updates used to produce the 2014 forecast as compared to the forecast used in the 2012 Rate Case.

A. The Company updated many of its data inputs and assumptions compared to the forecast prepared for the 2012 Rate Case. For each of these updates, the Company used the most recent information available.

1. The Company expanded the historical data period used to develop the monthly retail sales forecasts by adding eight months of retail sales data. All classes, except the industrial class, use an historical data period of January 1997 through March 2012. The historical data period used to develop the industrial monthly sales is from January 2002 through March 2012.
2. The Company expanded the historical data period used to develop the monthly peak forecasts to include January 1997 through December 2011.

3. The Company updated the economic drivers from IHS Global Insight using the most recent information available for each of the Company's jurisdictions.
4. The Company updated the forecast of individual industrial customer usage based on the best information available as of March 2012.
5. The time period used to define normal weather was rolled forward to the 20-year time period of 1992 through 2011.
6. The Company rolled forward the line loss calculation to the five-year period ended December 2011.
7. The data used to develop temperature splines was rolled forward based on available customer class hourly data (2007 through 2011).
8. The Company continued to use the residential use per customer per day model with appliance saturation and efficiency results released in June 2010.

FORECASTS FOR NON-INDUSTRIAL CUSTOMER CLASSES

Q. How are monthly sales forecasts developed by customer class?

A. The Company develops monthly sales forecasts as a product of two separate forecasts: (1) the number of customers; and (2) sales per customer. The Company uses this methodology for residential and commercial customer classes.

Q. How are the forecasts for number of customers developed?

A. For the residential class, the Company forecasts the number of customers using IHS Global Insight's forecast of number of households as the major driver. For the commercial class, the Company forecasts the number of customers using the forecasted number of residential customers as the major economic driver. For the industrial, irrigation, and street lighting classes, the customer forecasts are fairly static and developed using time series or regression models without any economic drivers.

Q. How does the Company forecast sales per customer for each customer class?

A. The Company models sales per customer for the residential class through a Statistically Adjusted End-Use (SAE) model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling-related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income, and energy price.

For the commercial class, the Company forecasts sales per customer using regression analysis techniques with non-manufacturing employment used as the major economic driver, in addition to weather-related variables.

As already described, the sales forecast for the residential and commercial classes is the product of the number of customer forecast and the use per customer forecast. The development of the forecast of monthly commercial sales involves an additional step. To reflect the addition of a large "lumpy" change in sales such as a new data center, monthly commercial sales are increased based on input from the Company's customer account managers (CAMs). Although the scale is much smaller, the treatment of large commercial additions is similar to the previous methodology for large industrial customer sales, which is discussed below.

Monthly sales for irrigation and lighting are forecasted directly from historical sales volumes, not as a product of the use per customer and number of customers.

INDUSTRIAL CLASS FORECASTS

Q. How does the Company forecast sales for the industrial customer class?

A. The majority of industrial customers are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver. For a small number of industrial customers, the largest on the Company's system, the Company individually forecasts these customers based on input from the customer and information provided by the CAMs.

Q. Has the Company changed how it models its industrial forecast?

A. Yes. Previously, the Company separated the industrial class into three categories: (1) existing customers tracked by CAMs; (2) new large customers or expansions by existing large customers; and (3) industrial customers that are not monitored by CAMs. The Company developed the forecast for the first two categories through the usage data gathered by the CAMs based on direct input from the customers, forecasted load factors, and the probability of the project occurrence. The third category was forecasted using regression analysis consistent with how the total industrial class is now forecast.

Q. What was the reason for the change in methodology of the industrial forecast?

A. For existing large industrial customers and for new large industrial customers, the Company found that the inputs provided by customers for their existing loads and for new load tended to be overly optimistic and ultimately overstated. Therefore, the Company uses a regression analysis for the entire industrial class, excluding those largest industrial customers and taking into consideration historical patterns of industrial growth. The Company believes this is a reasonable means of forecasting existing customer load and future growth. The Company continues to monitor new load requests and planned expansions of existing customers for significant changes that would require an adjustment to the forecast.

Q. Why does the Company forecast industrial sales using total usage versus the use-per-customer methodology used for the other customer classes?

A. The Company forecasts the industrial class differently because of the diverse makeup of the customers within the class. In the industrial class, there are no "typical" customers. Large customers have very diverse usage patterns and power requirements. In contrast, customer classes that are made up of mostly smaller, homogeneous customers are best forecasted by multiplying use-per-customer by the number of customers. Those customer classes are generally composed of many smaller customers that have similar behaviors and usage patterns.

HOURLY LOAD FORECAST

Q. Please outline how the hourly load forecast is developed.

A. After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps.

First, monthly and seasonal peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. These weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the forecast. The peak forecast is based on average monthly historical peak-producing weather for the 20-year period 1992 through 2011.

Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly and seasonal peaks from the first step above. Also, the hourly loads are adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

Q. How are monthly system coincident peaks derived?

A. After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

FORECASTS BY RATE SCHEDULE

Q. Were any additional forecasts created for these proceedings?

A. Yes. As mentioned earlier, Ms. Steward and Mr. Paice require two additional forecasts that are based on the kWh sales forecast and the number of customers forecast. Once the kWh sales forecast is complete, it must be applied to individual rate schedules to forecast kWh sales by rate schedule. In addition, the forecast of number of customers must be expressed in number of bills.

Q. How are rate schedule level forecasts produced?

A. The Company develops this forecast in two steps. First, the Company forecasts test year sales by rate schedule. Then the Company proportionally adjusts the rate schedule sales forecasts so that the total matches the customer class forecast.

Q. How does the Company forecast the number of bills for each rate schedule?

A. The forecast of the number of bills for each rate schedule follows the same process as the sales forecast for each rate schedule. First, the Company forecasts the number of bills by class and by rate schedule. Then, the Company proportionally adjusts the forecasted number of bills by rate schedule so that the total number of bills matches the customer class forecasted number of bills.

Q. Does the Company plan to update its load forecast during the course of this proceeding?

A. The Company may need to update the 2014 load forecast for changes associated with interruptible contract changes with industrial customers. Updating the load forecast would impact net system loads used in the development of the Company's net power costs in the 2014 TAM, and inter-jurisdictional allocation factors applied in this proceeding and in the 2014 TAM. Inter-jurisdictional allocation factors are addressed in the direct testimony of Mr. Tawwater.

Mr. Gregory N. Duvall's direct testimony in the 2014 TAM proceeding discusses the potential impact of updating loads on total company net power costs.

Q. Does the Company intend to update the entire load forecast during this proceeding?

A. At this time, the Company does not intend to update all assumptions in the load forecast, such as the most recent actual load data, economic data, forecasts for large industrial and commercial customers, and incorporation of the class 2 demand-side management from the 2013 IRP preferred portfolio. However, the Company will evaluate any changes that occur in the load forecast assumptions that may significantly impact the TAM or rate case proceedings.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/800
Witness: Erich D. Wilson

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Erich D. Wilson

March 2013

DIRECT TESTIMONY OF ERICH D. WILSON

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Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Erich D. Wilson. My business address is 825 NE Multnomah Street, Suite 1800, Portland, Oregon 97232. My present position is Director, Human Resources.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Bachelor's degree in Economics (Business) from the University of California, San Diego, in 1992. In addition, I achieved Certified Compensation Professional status from the American Compensation Association in 1999 and have kept this certification current by attending various educational programs and seminars. Before coming to the Company, I held various positions in the area of human resources (operations, benefits, and staffing), but for the majority of my career I have directed the design and administration of compensation programs. I joined the Company in 2001 as Director of Compensation. I assumed my current position as Director of Human Resources in 2006.

Q. Please describe your current duties.

A. My primary responsibilities include managing the Company's human resource department, including compensation, benefits, compliance, staffing, training and development, employee and labor relations, and payroll. I focus on assisting the Company in attracting, retaining, and motivating qualified employees, along with the administration of all associated human resource programs and employee experiences.

PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the compensation and benefit plans provided to the Company's employees and to support the costs related to these areas included in the test period.

Q. Does your testimony address both union and non-union compensation and benefit plans?

A. The focus of my testimony is on the plans and programs provided to the Company's non-union workforce. The Company's union workforce and the compensation and benefit plans provided to them are governed by their respective collective bargaining agreements. These agreements are reached between the Company and each union to provide market-level competitive compensation, benefits, and work rules.

Q. Please provide an overview of your testimony.

A. This testimony focuses on the total compensation plan (consisting of base pay and annual incentive), pension plan, and health care benefit plans. These plans are designed to allow the Company to attract and retain the employee talent necessary to deliver safe and reliable service at a reasonable cost. I also demonstrate that the Company continues to control increases in labor and benefit costs. Moreover, increases in benefit costs have been maintained at a reasonable level that reflects the economic conditions and market.

TOTAL COMPENSATION

Q. What factors does the Company consider with respect to its compensation and benefit costs?

A. First, the Company is continually working to keep operations and maintenance and administrative and general costs under control to mitigate the impact on customer rates. Second, while it is important to keep compensation and benefit costs under control, it is still critical for the Company to be able to retain and attract competent and qualified personnel to manage and operate the system. To do so, the Company continues to align its wage levels with the labor market. The challenges facing the economy have resulted in wage increase levels below what had been seen in prior periods. This is evident by the Company's wage increase levels in 2009 of 1.0 percent to 1.75 percent, and in 2010 and 2011 of 2.0 percent, compared to previous levels in the 3.0 to 4.0 percent range. The level implemented in 2012 was 2.0 percent, and the actual level beginning in January 2013 is 2.22 percent. In addition, the market continues to see a shift to employees bearing more of the cost of benefits. Accordingly, the Company continues to shift a greater percentage of the cost of benefit plans to its employees.

Q. What is the Company's compensation philosophy?

A. Two fundamental principles underlie the Company's compensation philosophy. First, the Company's primary goal in determining employee compensation is to provide pay at or near the market average. Competitive compensation is critical to attracting and retaining qualified employees. The market for the skilled positions required to manage and operate a utility system is extremely competitive. Thus, the Company strives to provide the same general pay levels and benefits in its total compensation package as provided by others in the industry. The Company believes that providing total compensation at or near market levels results in reasonable total compensation costs.

The Company encourages superior performance, by placing a portion of each employee's total compensation "at risk." Receipt of the "at-risk" portion of total compensation is dependent upon individual performance and achievement of a limited number of specific business goals. I discuss in detail how this Annual Incentive Plan operates later in my testimony.

Q. How does the Company determine the total compensation package for each position?

A. Each of the Company's positions has been assigned a grade within the Company's overall salary structure. At least annually, the Company collects market data for comparable positions and calculates the average data point for total cash compensation for each grade. Market data is provided through a variety of compensation studies produced by experts and organizations, including Aon Hewitt, Towers Watson, and Mercer. The Company also uses an online tool called "MarketPay.com." MarketPay.com provides electronic access to all of the compensation studies the Company has traditionally used and some additional surveys, allowing the Company to more efficiently perform information searches and job and pay comparisons.

After the Company determines the appropriate level of total cash compensation for a specific grade, it then determines the at risk portion of the compensation for each grade. The Company sets the at-risk portion by reviewing market compensation using the various compensation studies described above. The at-risk portion is typically in the 10-25 percent range; however, incentive pay for a few employees is set as high as 75 percent. In general, the higher the position is within the Company, the higher the amount of pay at risk and thus the higher the percentage of potential incentive pay. The at-risk portion of compensation (referred to as "incentive compensation") is administered through the Annual Incentive Plan. The remaining percentage of total compensation is referred to as "base compensation." This base-plus-incentive compensation structure is the same as the structure presented in the Company's previous Oregon rate cases, including the Company's 2012 general rate case (docket UE 246).

Q. Has the Company made changes to the Annual Incentive Plan in response to Commission feedback?

A. Yes. In 2006, the Company adjusted its Annual Incentive Plan in response to feedback from the Commission. Before that time, the Company sought recovery of all awards made to employees under the plan, whether or not those awards resulted in total employee compensation that was above a target (competitive market) level. In response to the Commission's previous decisions on recovery of employee compensation, including incentives, the Company now seeks to recover only that portion of incentive payments that result in compensation at the target level.

ANNUAL INCENTIVE PLAN

Q. What is the objective of the Annual Incentive Plan?

A. The objective of the Annual Incentive Plan is to provide employees with an incentive to perform at an above-average level. The plan is not a bonus; the incentive compensation is not layered upon base compensation that is already at market levels. As discussed above, base compensation for each position is set at a level below the market level for total compensation for that position. Only if an employee performs at an acceptable level for the position will the employee earn total compensation at or near comparable positions in the market. If an employee fails to perform at an acceptable level, the employee will receive less than the target incentive or no incentive at all. When this occurs, the employee will be paid less than the comparable total cash compensation in the market for that year. Conversely, for exceptional performance, an employee may receive above his or her target incentive level.

The ability to earn a higher-than-target incentive payment provides the employee with an incentive to exceed average performance. This opportunity is an essential counterbalance to the risk the employee faces that his or her performance in a particular year will be less than acceptable, with the consequence that total compensation will be less than market in that year. The symmetry of the incentive element provides the Company with the financial tool to encourage exceptional performance and discourage less than acceptable performance.

Q. Does incentive compensation benefit customers?

A. Yes. Customers benefit from the higher level of overall employee performance that is achieved when a portion of employees' pay is at-risk. In addition, the Company's incentive compensation plan enables the Company to attract and retain talented employees in the increasingly competitive market for skilled labor, which also benefits customers. Therefore, while the total cost of the Company's compensation program (base plus incentive) is equal to average total cash compensation (just as a salary-only program would be), the benefit to customers is greater.

Q. How is the incentive compensation plan implemented?

A. First, before the distribution of the at-risk compensation dollars, senior Company management assesses the Company's achievement of certain critical business goals such as safety, customer satisfaction, and managing expenses in relation to revenues. Underperformance by the Company in satisfying critical business goals may result in a downward adjustment of the total pool of at-risk dollars available for distribution to all Company personnel. For example, the Company's underperformance in satisfying one or more of these goals resulted in reduction in the total amount of incentive compensation available for distribution to 85 percent in 2010, 87 percent in 2011, and 85 percent in 2012.

At approximately the same time as the evaluations of the Company's achievements are being performed, supervisors meet with each of the employees in their group to conduct an assessment of the employee's performance throughout the year against the employee's individual goals, the employee's performance against group goals (including safety goals), and the employee's success in addressing new issues and opportunities that may arise during the year. The results of these performance reviews and associated scores are reported to Human Resources.

Then, after the total pool of at-risk compensation has been determined by senior management, supervisors are informed of the amount of incentive compensation available for distribution within their group. Based on this information, each supervisor submits the recommended incentive payments for each employee in their group to Human Resources for review.

Q. What are an employee's individual goals and how are they set?

A. Individual goals start with the goals set for the Company as a whole. Each year, the Company's senior management, in conjunction with MidAmerican Energy Holdings Company, set the overall goals for the Company. All of these goals focus on delivering safe and reliable electricity to customers and providing excellent customer service. Goals include safety goals such as reducing lost time and recordable, preventable, and restricted duty incidents. Customer service goals include implementing local and regional customer service improvements, improving visibility and relations with industrial customers and consumer associations, and improving overall customer satisfaction. Some individual goals relate to operating within established budgets, including maintaining operating costs, controlling the cost of capital expenditures, and achieving operational efficiencies and financial targets that allow the Company to remain a low-cost utility. Other key goals relate to operational performance, major project delivery, organizational planning and development, and quality of service and regulatory commitments. The achievement of each and every one of these goals will benefit our customers.

Q. How do the Company goals relate to individual employee goals?

A. The Company-wide goals serve as the foundation for the goals set for each individual employee. Thus, when an individual employee establishes individual goals for the year, the employee focuses on how that employee's position can advance the overall goals of the Company. The employee's performance on individual goals accounts for approximately 70 percent of his or her overall evaluation. In addition to performance against individual goals, all employees are evaluated with reference to six performance factors. These performance factors describe the characteristics the Company believes are important to the success of all employees—customer focus, job knowledge, planning and decision making, productivity, building relationships, and leadership. The employee's performance with respect to these factors accounts for approximately 30 percent of the employee's overall evaluation.

Q. Are any of the employees judged on the financial performance of the Company?

A. No. While all employees are expected to operate within applicable budgets, corporate financial performance and returns are not a factor in determining the amount of incentive compensation awarded under the plan. The Company does maintain a separate plan for executives (the Long-Term Incentive Partnership

Plan) that bases awards on overall corporate performance; however, these costs are not recovered in customer rates.

Q. Please explain the level of incentive compensation that is included in this filing.

A. As shown in exhibit PAC/1002, Tawwater/4.2, the Company's filing includes annual incentive in the test year using a three-year average of the ratio of annual incentive expense to base wages. Based on this approach, annual incentive expense of $29.5 million ($20.3 after capitalization) is included in the test year on a total-company basis. The Oregon portion of this expense is approximately $8.5 million ($5.8 after capitalization). This amount recognizes that the pool of incentive compensation made available was reduced below 100 percent of the indicated market level in 2010, 2011, and 2012.

Q. Does the Company recommend including incentive compensation plus base compensation in rates?

A. Yes, for several reasons. First, customers should fully support the cost of incentive compensation because, as previously mentioned, it is an essential component of an overall market-based competitive compensation program. Reducing customer support for incentive pay would result in under-market salaries, making it impossible for the Company to recruit and maintain a qualified labor force, which would in turn make it impossible for the Company to provide safe and reliable service. Moreover, the goals of the plan are designed to encourage superior performance on the part of employees in pursuing the goals that directly benefit customers—safety, reliability, and customer service. This is precisely the type of prudently designed incentive plan program that provides direct benefits to customers and that customers should therefore support.

RETIREMENT PLANS

Q. Please describe the Company's retirement plan.

A. The Company strives to provide a competitive retirement plan offering with reduced expense volatility for the benefit of employees and customers. The Company provides non-represented employees hired before January 1, 2008, the ability to receive their retirement through either a cash balance or 401k only design. This choice was offered in 2008, and 41 percent of the eligible population elected the 401k design. All non-represented employees hired after January 1, 2008, receive retirement benefits through the 401k design approach. Retirement plan benefits for represented employees are determined through the collective bargaining process, through which the Company has maintained its focus to shift the retirement approach from the traditional defined benefit to defined contribution (401k) approach.

Q. Are there increases in costs related to retirement program offerings?

A. Yes. As shown in Exhibit PAC/1002, Tawwater/4.2, the Company has adjusted retirement plan costs consistent with the escalation applied to wages and salaries.

EMPLOYEE HEALTH BENEFITS

Q. Please describe the Company's health care benefits.

A. As with all benefits, the Company attempts to provide employees with the same level of health care benefits provided by the employers with whom the Company competes for labor. For the Company, this means offering employees market-average health benefits. The Company seeks to provide these benefits as economically as possible.

Q. How does the Company determine that it is providing these competitive benefits as economically as possible?

A. The Company relies on the advice of its consultant, Aon Hewitt, to confirm that it is securing market competitive benefits at the best possible rate. Aon Hewitt is a respected expert in the field, and the Company has relied on this expertise for many years. In consultation with Aon Hewitt, the Company periodically reviews and adjusts the sharing of health-care-related costs with employees in an effort to stabilize costs, manage volatility, and respond to changing market practices.

Q. Has the Company faced any particular challenges in the past several years relevant to its provision of health care benefits?

A. Yes. It is widely understood that health care costs have been rising over the past several years. As a result, the Company continues to experience increases in its health care benefit costs.

Q. Has the Company taken any action to contain these cost increases?

A. Yes. Beginning in 2008, the Company has been making adjustments to cost sharing and plan design to reduce costs and to align with market practices. Employees are shouldering a larger share of the costs. In particular, in 2012 and 2013, the Company had a base medical plan with a high deductible and a cost sharing of 84/16. The Company continues to offer other medical plan choices, but, except for a $600 deductible plan that is offered in rural areas, these plans are set at a cost sharing of 70/30. In addition, in 2012, the Company implemented a higher cost-sharing component for all covered dependants; in 2013 that level is further increased. All new hires as of January 1, 2008, have the option of selecting the high deductible plan or opting out of coverage.

Q. What is the Company's rationale for sharing health-care-related costs with employees?

A. This structural shift adheres to the Company's goal of providing competitive benefits to its employees, while doing so in a manner that is fair and helps to control costs.

Q. Please explain the level of health care costs included in this filing and compare that to previous fiscal year expenses.

A. As discussed above, there has been an upward trend in health care costs in recent years. For calendar years 2009, 2010, and 2011, actual total company health care expenses totaled $57.9, $57.9, and $61.8 million respectively. Consistent with this trend, the Company has included in this filing health care expenses on a total-company basis of $65.3 million ($44.9 million after capitalization), as shown in Exhibit PAC/1002, Tawwater/4.2. The Oregon allocated share of health care expense is $18.7 million ($12.9 million after capitalization).

Along with these increases, Aon Hewitt has informed the Company that current trends indicate the rates for the Company's health benefits are anticipated to increase annually by a range of eight to 10 percent. This is driven by the demographics and claims experience of our workforce. This projected increase is not included in the Company's filing. The Company continues to work to mitigate these increases through plan design and overall cost sharing with employees.

Q. Has the Company made changes to the retiree medical plan that affect the FAS 106 post-retirement benefits (other than pension costs) included in this case?

A. Yes. The Company implemented benefit design changes to the post-retirement welfare plans. These changes help to offset the other areas of cost increases that I have addressed, to the benefit of customers.

Q. Please explain the changes.

A. Health care reform legislation is causing many employers, including the Company, to change their approach to retiree health care benefits. With recent changes to Medicare, individual plans have become more widely available and affordable. These changes, which were effective January 1, 2012, not only provide savings to the customers through reduced expense, but also provide more flexibility to the retiree to choose from a variety of plan options to select the coverage that works best for them. Instead of the monthly subsidy structure, the Company now provides an annual contribution to a health reimbursement account that can be managed by the retiree and used to pay for the care and services received.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/900
Witness: Douglas K. Stuver

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Douglas K. Stuver

March 2013

DIRECT TESTIMONY OF DOUGLAS K. STUVER

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Douglas K. Stuver and my business address is 825 NE Multnomah Street, Suite 1900, Portland, Oregon 97232. My present position is Senior Vice President and Chief Financial Officer.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Arts degree in business administration from the University of Pittsburgh and am a Certified Public Accountant licensed in Pennsylvania. I worked for Ernst & Young for eight years in auditing and have since worked for Enserch Energy Services, CNG Energy Services, and Duke Energy Corporation in various accounting and risk management capacities. I joined PacifiCorp in 2004 as the controller for the commercial and trading division and moved into my current role as Senior Vice President and Chief Financial Officer in March 2008.

Q. What are your responsibilities as Senior Vice President and Chief Financial Officer?

A. My primary responsibilities include the accounting, treasury, tax, financial planning and analysis, external financial reporting, commodity risk management, and internal audit functions for PacifiCorp.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My direct testimony addresses the inclusion of PacifiCorp's prepaid pension asset and accrued other post-retirement liability, net of accumulated deferred income taxes, in rate base (see Exhibit PAC/901). My testimony supports inclusion of this balance in rate base as an appropriate means to recover the costs of financing cumulative contributions made to the Company's pension plan in excess of cumulative expense.

RATE TREATMENT OF PREPAID PENSION ASSET

Q. What is the Company's proposed rate treatment for its prepaid pension asset?

A. PacifiCorp seeks to recover its financing costs prospectively for the existing prepaid pension asset and accrued other post-retirement liability, net of accumulated deferred income taxes, by including the net balance as a component of rate base. The existing prepaid pension asset represents cumulative contributions made to the Company's pension plan in excess of cumulative expense. To date, the Company has borne the costs to finance the contributions in excess of expense without rate recovery.

Q. What method of recovery for the Company's pension and other post-retirement benefit plans is currently in place in Oregon?

A. Currently, recovery is provided based on expense for both the pension and other post-retirement benefits plans. The costs of financing the difference between contributions and pension and other post-retirement expense are not currently considered in the Oregon ratemaking process.

Q. What balance is the Company proposing to include in rate base associated with the prepaid pension asset and accrued other post-retirement liability?

A. Based on a 13-month average for the period ending December 31, 2014, the revenue requirement in this case reflects $176.5 million (total-company basis) in rate base as presented in Exhibit PAC/901. This amount reflects PacifiCorp's prepaid pension asset less its accrued other post-retirement liability and is net of accumulated deferred income tax liabilities (the "net prepaid pension asset").

Q. What is the rationale supporting the Company's proposal to include the net prepaid pension asset in rate base?

A. Historically, for ratemaking purposes in Oregon, the Company has recovered pension and other post-retirement costs based on the amount recorded to *expense*. Using this approach, investor capital is required to finance any difference between the amounts *contributed* to the plans and the amounts included in rates as *expense*.

For example, if the Company records $10.0 million of pension and other post-retirement benefits expense but contributes $15.0 million to the pension and other post-retirement benefit plans, customer rates reflect the $10.0 million in expense, and investor capital is used to finance the $5.0 million of contributions in excess of the amount expensed. Accordingly, it would be appropriate to include this $5.0 million in rate base to compensate investors for their cost of capital. Likewise, if the Company records $15.0 million of pension and other post-retirement benefits expense but contributes $10.0 million to the pension and other post-retirement benefit plans, customer rates reflect $5.0 million more than the Company has contributed. Accordingly, it would be appropriate to reduce rate base by $5.0 million for these customer-provided funds.

Q. Why do PacifiCorp's cumulative contributions exceed cumulative expense recognized?

A. PacifiCorp makes contributions to its plans based on funding requirements set forth in the Employee Retirement Income Security Act of 1974 (ERISA), which encompass the funding requirements of the federal Pension Protection Act of 2006, and in accordance with Company policy. In recent years, funding requirements have increased as a result of changes stemming from the Pension Protection Act and market conditions. As a result of the Pension Protection Act, PacifiCorp has been required to increase contributions to its pension plan to achieve both minimum ERISA funding requirements and funding targets established by the Pension Protection Act. These contributions have outpaced expense recognized to date for accounting purposes. Since the bases for determining expense and contributions are different—with expense driven by accounting guidance and contributions driven by ERISA funding requirements—the accounting expense differs from the amounts required to be contributed to the plans.

Expense is determined based on accounting guidance from the Financial Accounting Standards Board, which requires that expense be actuarially determined and reflect the service component of expense over the time period during which services are rendered by the employees. The accounting guidance was previously provided under Statement of Financial Accounting Standards No. 87, *Employers' Accounting for Pensions*, and Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement*

Benefits Other Than Pensions. This guidance was codified into Accounting Standards Codification Topic 715—*Compensation—Retirement Benefits*. Other post-retirement welfare plans are not subject to the same federal regulations as pension plans because there are no specific funding requirements. PacifiCorp's funding policy for its other post-retirement plan is to contribute an amount equal to expense plus estimated Medicare Part D subsidies to be received during the year. This policy has been consistently applied over time with the exception of certain one-time charges taken several years ago for which no matching contributions were made. This has resulted in a consistent accrued position (cumulative expense exceeds cumulative contributions) for the other post-retirement welfare plan from year to year.

Q. Please describe why the Company's proposed ratemaking treatment is based in sound regulatory principles.

A. The Company's proposed ratemaking treatment for its net prepaid pension asset appropriately recognizes the financing costs associated with the Company's pension and other post-retirement benefit plans in revenue requirements. PacifiCorp's net prepaid pension asset at any point in time represents the amount of cumulative contributions in excess of cumulative expense recognized to date. To the extent a prepaid balance exists, PacifiCorp incurs financing costs associated with these cumulative contributions in excess of cumulative expense. Those financing costs cease only when the prepaid balance goes to zero (i.e., when cumulative contributions equals cumulative expense) or moves into an accrual position. PacifiCorp is not seeking to recover past financing costs incurred on past prepaid balances. Instead, PacifiCorp is seeking to recover prospective financing costs on the prepaid balance that will exist during the forecast test period.

Q. Has the Commission opened a docket to investigate treatment of pension costs in utility rates?

A. Yes. The Commission opened docket UM 1633 to investigate the appropriate rate treatment of pension costs. The Company is actively participating in this docket, along with other utilities, Commission Staff, and various intervening parties. Although docket UM 1633 is in its early stages, the Company's proposal in this rate case is consistent with the position PacifiCorp has communicated to other parties during the workshops in docket UM 1633. Commission resolution of docket UM 1633 while this rate case is pending may provide additional guidance to the Company and may require modification of the Company's proposal in this case.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/901
Witness: Douglas K. Stuver

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Douglas K. Stuver

Pension and Other Postretirement Welfare Plan Balances

March 2013

Exhibit PAC/901
Stuver/1

Pension and Other Postretirement Welfare Plan Balances
13 Month Average December 2014 (a)
($Millions)

	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Dec-14	13 Month Average	
Prepaid Pension:																
Regulatory asset (unrecognized expense)	579.8													498.6		
Liability (underfunded status)	(273.1)													(144.9)		
Estimated cumulative excess of contributions over expense	306.7	313.5	320.3	327.2	334.0	340.8	347.6	354.4	361.2	359.3	357.4	355.5	353.6	353.7		
Accumulated deferred income tax liability (ADIT) **(b)**	(142.9)	(142.9)	(142.9)	(144.1)	(144.1)	(144.1)	(145.2)	(145.2)	(145.2)	(146.4)	(146.4)	(146.4)	(147.6)	(147.6)		
Prepaid pension asset net of ADIT	163.8	170.6	177.4	183.1	189.9	196.7	202.4	209.2	216.0	212.9	211.0	209.1	206.0	206.1	196.0	
Accrued Other Postretirement Welfare:																
Regulatory asset (unrecognized expense)	227.1													191.5		
Liability (underfunded status)	(256.2)													(221.1)		
Estimated cumulative excess of expense over contributions	(29.1)	(30.6)	(32.0)	(29.2)	(30.7)	(32.1)	(29.4)	(30.8)	(32.3)	(29.5)	(30.9)	(32.4)	(29.6)	(29.6)		
Accumulated deferred income tax asset (ADIT)	11.0	11.0	11.0	11.1	11.1	11.1	11.1	11.1	11.1	11.2	11.2	11.2	11.2	11.2		
Accrued other postretirement liability net of ADIT	(18.1)	(19.5)	(21.0)	(18.1)	(19.6)	(21.0)	(18.2)	(19.7)	(21.1)	(18.3)	(19.7)	(21.2)	(18.4)	(18.4)	(19.5)	
Net Prepaid Pension and Other Postretirement	**145.8**	**151.1**	**156.5**	**165.0**	**170.3**	**175.7**	**184.2**	**189.5**	**194.9**	**194.6**	**191.3**	**187.9**	**187.6**	**187.7**	**176.5**	**Ref. Adjustment # 8.15**

	YTD 2013	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	YTD 2014	YTD 2015
Pension:															
2013 Expense	34.8														
2013 Contributions	59.2														
2014 Expense		1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	22.9	
2014 Contributions		8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	-	-	-	-	69.8	
2015 Contributions															35.3
Change in ADIT during 2014		-	-	(1.2)	-	-	(1.2)	-	-	(1.2)	-	-	(1.2)		
Other Postretirement Welfare:															
2013 Expense	20.4														
2013 Contributions	20.4														
2014 Medicare Part D Subsidy Receipts		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.6)	
2014 Expense		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	16.8	
2014 Contributions		-	-	4.2	-	-	4.2	-	-	4.2	-	-	4.2	16.9	
Change in ADIT during 2014		-	-	0.0		-	0.0	-	-	0.0	-	-	0.0		

(a) All balances are based on Hewitt actuarial reports, other than ADIT, unless noted as otherwise.
All amounts are reflected net of regulatory adjustments.

(b) ADIT for pension reflects the tax benefit of contributions made within 8-1/2 months subsequent to year-end as such contributions are deductible in that preceding year.

Docket No. UE 263
Exhibit PAC/1000
Witness: Gary W. Tawwater

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Gary W. Tawwater

March 2013

DIRECT TESTIMONY OF GARY W. TAWWATER

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ATTACHED EXHIBITS

Exhibit PAC/1001 – Revenue Requirement Summary

Exhibit PAC/1002 – Oregon Results of Operations – December 2014

CONFIDENTIAL Exhibit PAC/1003 – PacifiCorp’s Property Tax Estimation Procedure

Exhibit PAC/1004 – Lake Side 2 Plant Investment

CONFIDENTIAL Exhibit PAC/1005 – IHS Global Insight Escalation Indices

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Gary W. Tawwater. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Manager, Revenue Requirement.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have been employed by PacifiCorp since March 2004. I was appointed to my current role as Manager of Revenue Requirement in August 2012. My primary responsibilities include the calculation and reporting of the Company's regulated earnings and revenue requirement, application of the inter-jurisdictional allocation methodologies, and the explanation of those calculations to regulators in the jurisdictions in which the Company operates. Before assuming my current position, I was the Manager of Regulatory Accounting, where I was responsible for overseeing the Company's Federal Energy Regulatory Commission (FERC) ledger, regulatory assets and liabilities, and other accounting activities. I received a Bachelor of Business Administration degree in finance with an emphasis in accounting from Stephen F. Austin State University in 1998. I have also attended various educational, professional, and electric-industry-related seminars.

PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. My direct testimony addresses the calculation of the Company's Oregon-allocated revenue requirement, excluding net power costs (NPC), and the revenue increase requested in the Company's filing. Specifically, I provide testimony on the following:

- The calculation of the $56.0 million revenue increase requested in this general rate case representing the increase over current rates required for the Company to recover its Oregon non-NPC revenue requirement of $901.1 million. As discussed by Ms. Joelle R. Steward, the revenue requirement increase will be reduced to $44.6 million if the Mona-to-Oquirrh tariff rider is approved once the project is placed in service in during 2013. The Company currently recovers its NPC through the Transition Adjustment Mechanism (TAM).
- The selection of the historical period of the 12 months ended June 2012 (Base Period) as the basis for the test period in this proceeding.
- The development of the forecast test year in this case, which is the 12 months ending December 31, 2014 (Test Period).
- Discussion of the 2010 Protocol inter-jurisdictional allocation methodology (2010 Protocol) used to determine Oregon-allocated results.
- The treatment of forecasted capital additions included in the revenue requirement calculations, which have been limited to projects placed in service before January 1, 2014, the beginning of the Test Period.
- The calculation of the revenue requirement associated with the Lake Side 2 natural gas-fired generating plant (Lake Side 2), which the Company is proposing to recover as a separate tariff once the project is complete and used and useful.

- The presentation of the normalized results of operations for the Test Period demonstrating that under current rates the Company will earn an overall return on equity (ROE) in Oregon of 7.9 percent, which is below the Company's authorized ROE.

REVENUE REQUIREMENT

Q. What is the revenue requirement to achieve the requested ROE in this case?

A. At current rate levels, the Company will earn an overall ROE in Oregon of 7.9 percent during the Test Period. This return is less than the 9.8 percent ROE authorized in the Company's 2012 general rate case, docket UE 246 (2012 Rate Case).[1] The Company is not proposing to change to the authorized ROE. A 9.8 percent ROE produces a non-NPC revenue requirement of $901.0 million based on the 2010 Protocol. Exhibit PAC/1001 provides a summary of the Company's Oregon-allocated results of operations for the Test Period. Exhibit PAC/1002 provides the supporting details and calculations and is discussed in greater detail later in my testimony.[2]

Q. Please explain how you have treated NPC in this filing.

A. As noted above, the Company recovers its NPC through the TAM, which was filed on March 1, 2013, for calendar year 2014 NPC. To model the non-NPC revenue requirement for this case, the Company first computed an overall Test Period revenue requirement including the NPC as filed in the TAM and then

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[1] *In the Matter of PacifiCorp d/b/a Pacific Power Request for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 (December 20, 2012). The parties to the partial stipulation in the 2012 Rate Case agreed to an overall rate of return of 7.655 percent and a 9.8 percent ROE for Oregon regulatory purposes. The stipulation was approved by the Commission in Order No. 12-493 on December 20, 2012.

[2] The revenue requirement impact of the Lake Side 2 is not included in Exhibits PAC/1001 or PAC/1002. As discussed later in my testimony, the revenue requirement associated with this investment is separately reflected in Exhibit PAC/1004 because the Company is not requesting rate recovery until the project is complete and used and useful.

removed the NPC components from the overall price change. This approach is required to compute certain non-NPC components of the Test Period revenue requirement that are impacted by NPC-related items, such as renewable energy tax credits, the hydro embedded cost differential (Hydro ECD), and the 2010 Protocol rate mitigation cap. Details supporting the overall revenue requirement and the breakout between the TAM and general rate case are provided in Exhibit PAC/1001. Page 1.0 of Exhibit PAC/1002 also shows the division of revenue requirement between the TAM and general rate case components, and the resulting general-rate-case-related price change requested in this case.

BASE PERIOD

Q. Why did the Company use July 2011 through June 2012 as the historical basis, or Base Period, for the Test Period?

A. The Company selected the 12-month period ended June 2012 as the historical basis for this case because it was the most recent total-company data available for inter-jurisdictional allocations to achieve a filing date of March 1, 2013. The Company audits and extracts total company accounting information with the data components necessary for state allocations on a semi-annual basis for the 12-month periods ending June and December each year. This semi-annual data extract and review procedure is a key control measure to ensure the accuracy and reliability of the data, which serves as the basis for each of the Company's results of operations and general rate case filings.

Q. Why was a March 1, 2013 filing date for this general rate case necessary?

A. In Order No. 09-274, the Commission adopted a stipulation establishing guidelines for future TAM filings, including the following provision:

> In all future filings after UE 207 in a year in which the Company files a general rate case, the TAM will be included in or processed concurrently with the general rate case filing. *In future filings after UE 207, the Company agrees that both filings will be made no later than March 1 to allow for a January 1 rate effective date*.[3]

Because of this agreement, a filing date later in the year is not possible.

Q. When will calendar year 2012 total-company data become available on an inter-jurisdictional allocation basis?

A. Only once total-company data is audited does it become available to begin analysis on an inter-jurisdictional allocation basis. Because of the unique complexities the Company faces as a multi-jurisdictional utility, additional time is necessary once total company financial data is finalized to ensure state-allocated data is accurate. Due to these complex steps, calendar year 2012 data will not be available for use as the basis of a forecast test period until the end of April 2013, approximately two months after the general rate case filing commitment date of March 1.

TEST PERIOD

Q. What Test Period did the Company use to determine revenue requirement in this case?

A. The forecast Test Period used by the Company in this proceeding is the 12 months ending December 31, 2014.

[3] *In the Matter of PacifiCorp dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at page 13 (July 16, 2009) (emphasis added).

Q. Why did the Company choose the year ending December 31, 2014, as the Test Period?

A. The Test Period in this case was selected to best reflect the conditions during the time the new rates will be in effect. Rates from this case will be effective no later than January 1, 2014, which matches the Test Period used by the Company in the calculation of the revenue requirement. The Test Period in this general rate case also matches the test period used in the development of the NPC filed in the concurrent TAM.

Q. Please explain how the Company developed the revenue requirement for the Test Period.

A. Revenue requirement preparation began with historical accounting information; in this case, the Company used the 12 months ended June 30, 2012. Each of the revenue requirement components in the Base Period was analyzed to determine if a normalizing ratemaking adjustment was warranted to reflect normal operating conditions. The historical information was adjusted to recognize known, measurable, and anticipated events.

Q. What is the significance of beginning with historical information?

A. The Company begins with historical accounting information and makes discrete adjustments to arrive at the Test Period revenue requirement. Beginning with historical information provides a solid foundation that is readily available for audit by all who wish to participate in the case. Individual adjustments are also available for review, and regulators and intervenors may determine each adjustment's relevance and accuracy.

Q. Please summarize the process used to adjust the historical accounting information to reflect Test Period revenues and costs.

A. Revenues are adjusted by applying the current Commission-approved tariff rates to the Test Period load projection. NPC are developed using the Generation & Regulation Initiative Decision (GRID) model. The results of the GRID run for the Test Period are embedded in the results for calculation purposes only; as previously mentioned, recovery of these costs is sought through the TAM filing. Historical operations and maintenance (O&M) expenses, excluding NPC, are split into labor and non-labor components. Non-labor costs are adjusted for inflation using inflation indices developed specifically for electric utilities provided by IHS Global Insight (Global Insight) and for other distinct changes required to reflect conditions expected during the Test Period. Historical labor costs are also adjusted for contractual increases through the end of the Test Period.

Q. Does the Company rely solely on its own projections of future cost increases?

A. No. For example, the adjustment made to account for inflation between the historical period and the Test Period relies on inflation indices published by Global Insight.

Q. How has the Company addressed areas where cost increases are different than inflation?

A. The Company's business units were asked to identify areas where budgets were significantly different than historical amounts, adjusted for wage increases and inflation. When differences were identified that needed to be adjusted in the rate case, the business units were asked to provide support for changes in the number, or frequency, of activities. An example of this type of adjustment is the incremental O&M adjustment (adjustment page 4.9). Adjustments of this nature are necessary because inflation indices account for cost increases on existing units of production, not changes in volume or processes.

INTER-JURISDICTIONAL ALLOCATIONS

Q. What methodology did the Company use to calculate the Oregon-allocated revenue requirement in this case?

A. The Company's Oregon-allocated revenue requirement is calculated using the 2010 Protocol as described in the stipulation approved by the Commission in Order No. 11-244 in docket UM 1050 on July 5, 2011. This is the Company's second Oregon rate case filing since the Commission's approval of the 2010 Protocol.

Q. Does the rate mitigation cap impact the Company's requested price increase in the current case?

A. No. As shown on Page 1.1 of Exhibit PAC/1002, Oregon's revenue requirement under the Revised Protocol methodology plus 0.30 percent is $1,268.7 million, which is greater than the Oregon revenue requirement of $1,264.2 million calculated using the 2010 Protocol.[4] Consequently, the rate mitigation cap is not triggered and does not affect the Company's requested price change in this case.

[4] 2010 Protocol and Revised Protocol figures reflect Oregon's total revenue requirement for the Test Period, including TAM and general rate case components.

FORECAST CAPITAL ADDITIONS

Q. How has the Company treated forecast capital additions to electric plant in service in this filing?

A. As mentioned in the direct testimony of Mr. Richard P. Reiten, the Company has included capital additions to plant in service through December 31, 2013, rather than through December 31, 2014, which is the end of the forecast Test Period and the rate effective period. This treatment is consistent with the Company's 2010 general rate case docket UE 217 (2010 Rate Case) and the 2012 Rate Case.

LAKE SIDE 2

Q. Please describe the revenue requirement associated with the Lake Side 2.

A. As discussed by Mr. Stefan A. Bird, the Company projects to complete Lake Side 2 in the second quarter of 2014. Exhibit PAC/1004 shows the projected capital investment, depreciation expense and reserve, O&M expense, and tax impacts associated with this project. Page two of this exhibit shows the overall Oregon annual revenue requirement of $22.7 million for this investment. The other pages in this exhibit provide supporting documentation for the figures used to determine the Oregon revenue requirement impact. The Company is requesting approval of a separate tariff rider to collect the revenue requirement of Lake Side 2.

Q. When is the Company requesting to begin recovery of the costs associated with this investment?

A. As discussed by Ms. Steward, the Company is proposing to recover the revenue requirement associated with this investment through a separate tariff, following a prudence review in this case, once the project becomes used and useful. This is consistent with the treatment of the Mona-to-Oquirrh transmission project tariff rider approved in Order No. 10-493 in the 2012 Rate Case.

OREGON RESULTS OF OPERATIONS

Q. Please describe Exhibit PAC/1002.

A. Exhibit PAC/1002, which was prepared under my direction, is the Company's Oregon results of operations report (Report). As previously explained, the Base Period for the Report is the 12 months ended June 30, 2012, which has been normalized and used to calculate the revenue requirement for the Test Period, the 12 months ending December 31, 2014. The Report provides totals for revenue, expenses, depreciation, NPC, taxes, rate base, and loads in the Test Period. The Report presents operating results for the Test Period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit PAC/1002 is organized.

A. The Report is organized into sections marked with tabs as follows:

- Tab 1 Summary contains a summary of Oregon-allocated results according to the 2010 Protocol. Page 1.0 breaks out the non-NPC results and calculates the revenue requirement the Company is requesting as part of this general rate case (column 5). Page 1.2 contains a summary of the general rate case request.
- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the Base Period and fully normalized results of operations for the Test Period by FERC account

and 2010 Protocol allocation factor.

- Tabs 3 through 8 provide supporting documentation for the normalizing adjustments required to reflect on-going costs of the Company.
- Tab 9 is a restatement of Tab 2 with the Oregon allocation based on the Revised Protocol method, as required by Commission Order No. 11-244.
- Tab 10 contains the calculation of the 2010 Protocol allocation factors. Factors in this case are based on the load forecast through December 2014 and pro forma account balances.
- Tab 11 contains the Company's most recent lead lag study, which is based on calendar year 2010 data.
- Tabs B1 through B20 contain the historical data for the Base Period and are organized by major FERC function.

Tab 3—Revenue Adjustments

Q. Please describe the information contained behind Tab 3 Revenue Adjustments.

A. Tab 3 begins with the Revenue Adjustment Index, which contains a brief overview of the assumptions used to project Test Period revenues and a list of each normalization adjustment included in this section of the exhibit. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenues and each adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a description of the adjustment.

Q. Please describe the adjustments made to revenue in Tab 3.

A. **Pro Forma Revenue (page 3.1)—**This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the Test Period based on forecasted loads. Page 3.1.4 shows a breakout of the TAM and general rate case revenues.

Wheeling Revenue (page 3.2)—This adjustment reflects the level of wheeling revenue for the Test Period by adjusting the actual revenue for normalizing, annualizing, and pro forma changes. Imbalance penalty revenue and expense is removed to avoid any impact on regulated results. The Company has not included any incremental Open Access Transmission Tariff (OATT) revenue associated with the Company's pending transmission rate case, Docket No. ER11-3643, at FERC. The Commission recently approved the Company's application to defer Oregon's allocated share of any incremental OATT revenues.[5]

Sulfur Dioxide (SO_2) Emission Allowances (page 3.3)—The Environmental Protection Agency (EPA) established guidelines that govern the volume of SO_2 that can be emitted from power plants and granted the issuance of SO_2 emission allowances. Plants that are not in compliance with EPA guidelines may purchase emission allowances from other companies that have excess allowances. This adjustment reflects the gain on sales of SO_2 allowances based on a four-year amortization period ending December 2014. This is the same methodology

[5] *In the Matter of PacifiCorp d/b/a Pacific Power Application for Deferred Accounting of Revenues Related to Open Access Transmission Tariff,* Docket No. UM 1639, Order No. 13-045 (February 12, 2013) (emphasis added).

included in the Company’s last four general rate cases, dockets UE 179, UE 210, the 2010 Rate Case, and the 2012 Rate Case.

Renewable Energy Credit (REC) Revenues (page 3.4)—This adjustment removes all REC revenue booked during the 12 months ended June 2012. Most of Oregon’s share of RECs is banked for compliance; however, not all RECs meet the Oregon Renewable Portfolio Standard (RPS) qualifications. Oregon’s revenue from RPS ineligible RECs that are sold are passed backed to customers through the Oregon property sales balancing account per Commission Order No. 10-210 in docket UP 260.

Ancillary Revenue (page 3.5)—In December 2011, the Company renewed its contract with Seattle City Light (SCL) to receive real time output from SCL’s share of the Stateline wind farm and return power two months later. The ancillary revenue booked in the 12 months ended June 2012 is adjusted to reflect the Test Period revenue expected per the terms of the new contract. The impact on NPC is included in adjustment 5.1 and in the TAM.

Tab 4—O&M Adjustments

Q. Please describe the information contained behind Tab 4 O&M Adjustments.

A. Tab 4 includes an O&M Expense Adjustment Index followed by a numerical summary and the specific adjustments. The O&M Expense Adjustment Index begins on page 4.0.1 with a brief overview of assumptions used to adjust operation, maintenance, administrative, and general expenses. The numerical summary (pages 4.0.2–4.0.3) identifies each adjustment made to actual expenses and that adjustment’s impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments made to O&M expense in Tab 4.

A. **Miscellaneous General Expense and Revenue (page 4.1)—**This adjustment removes certain miscellaneous expenses that should have been charged below the line to non-regulated expenses. It also reallocates certain gains and losses on property sales and regulatory expenses to reflect the appropriate allocation.

Wage and Employee Benefits (page 4.2)—Labor-related costs for the Test Period are computed by adjusting salaries, incentives, health benefits, and costs associated with pension, post-retirement benefits, and post-employment benefits for changes expected beyond the actual costs experienced in the period ended June 2012. Mr. Erich D. Wilson's testimony provides an overview of the compensation and benefit plans provided to employees at the Company and supports the costs related to these areas included in the Test Period.

Collective bargaining agreements are used to escalate union wages where increases are specified wage increases for non-union and exempt employees are based on the Company's actual merit increases or Global Insight's Consumer Price Forecast. Incentive compensation for non-union employees is included using a three-year average of the ratio of annual incentive expense to base wages. Pension expense and other employee benefit costs are adjusted to the planned expense for the Test Period, based on actuarial reports where available or by escalating actual costs.

Page 4.2.1 of the Report provides further description of the procedure used to compute Test Period labor costs. Page 4.2.2 contains a numerical summary of actual labor costs in the year ended June 2012 and summarizes the adjustments made to project costs through the Test Period. This summary is followed by detailed worksheets on pages 4.2.3 through 4.2.11.

Idaho Irrigation Load Control (page 4.3)—Incentive payments made to Idaho customers participating in the irrigation load control program and a portion of the program's administrative costs are initially system allocated in unadjusted accounting data. Consistent with the 2010 Protocol, demand side management (DSM) costs are situs assigned to the states in which the costs are incurred to match the benefit of reduced load reflected in the inter-jurisdictional allocation factors. This adjustment corrects the booked allocation to assign these costs directly to Idaho.

Remove Non-Recurring Entries (page 4.4)—A variety of accounting entries were made to expense accounts during the Base Period that are non-recurring in nature or relate to a prior period. These transactions are removed in this adjustment from the results of operations to normalize the Test Period results. Details on the specific items in the adjustment can be found on page 4.4.1 of the Report.

Uncollectible Accounts (page 4.5)—Uncollectible accounts expense is adjusted to the Test Period level by applying the historical uncollectible rate (Oregon uncollectible accounts expense in FERC Account 904 divided by Oregon general business revenues) to the normalized general business revenues in the Test Period.

DSM Revenue and Expense Removal (page 4.6)—This adjustment removes from regulated results revenues and expenses related to DSM programs in various states because the costs are recovered via separate surcharges and are not included in base rates.

Insurance Expense (page 4.7)—In the 2010 Rate Case, the Commission authorized the Company to establish monthly accruals and associated reserve balances for self-insurance for transmission and distribution property losses, non-transmission and distribution (Non-T&D) property losses, and third-party liability insurance. The Commission ordered the self-insurance accruals to begin on April 1, 2011, as a replacement for the expiration of the Company's captive insurance coverage with MidAmerican Energy Holdings Company. The Oregon-allocated monthly accrual for property related losses was based on a 10-year average of actual property losses, with each year escalated by the Consumer Price Index (CPI) to the Test Period. The Oregon-allocated monthly accrual for third-party liability insurance was established based on an annual average of historical insurance claim payments from April 2005 to December 2009.

The adjustment in this case uses the Commission-approved methodology for self-insurance accruals from the 2010 Rate Case, updated for known and measurable changes for both property and liability insurance. The adjustment also reduces both property and liability premiums for known and measurable changes in the Test Period and removes entries related to the captive insurance and a California regulatory asset.

Consistent with the treatment from the 2010 Rate Case, the Company is using a 10-year average of property damages for the self-insurance reserve accrual, using the most recent 10-year time period. Total company Non-T&D property premiums were $7.7 million for the 12 months ended June 2012 and will be reduced to $6.4 million for the Test Period.

In October 2012, the Company negotiated new liability coverage with a change in the per-event deductible to $10.0 million. Consistent with the treatment in the 2010 Rate Case, the third-party liability accrual in this case is calculated based on a five-year average of historical insurance events, from January 2008 through December 2012, with the events amounts adjusted to account for the change in the deductible.

Generation Overhaul Expense (page 4.8)—This adjustment normalizes generation overhaul expenses in the Base Period using a four-year average methodology. In this adjustment, overhaul expenses for the years ending June 2009 to June 2011 are restated to constant dollars to make them comparable prior to averaging.

Incremental O&M (page 4.9)—This adjustment adds incremental O&M to the Base Period to bring it to the projected O&M level for the 12 months ending December 2014, after accounting for Global Insight inflation escalation applied in adjustment page 4.12.

Naughton Unit 3 Write-Off Adjustment (page 4.10)—This adjustment removes expenses related to the Naughton Unit 3 write-off that occurred in June 2012.

Memberships and Subscriptions (page 4.11)—This adjustment removes expenses in excess of Commission policy as outlined by the Commission order in docket UE 94. National and regional trade organizations are recognized at 75 percent. The Company's mandated membership in the Western Electricity Coordinating Council (WECC) is included at 100 percent.

O&M Escalation (page 4.12)—This adjustment increases non-labor expenses for projected inflation through the Test Period. Projected increases or decreases in costs are based on Global Insight, which provide a detailed assessment of the electric market both historically and into the future. The indices used are based solely on electric utility costs for materials and services, which exclude labor expense, according to the Uniform System of Accounts defined by FERC for major electric utilities.

The Global Insight indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses. The Global Insight study used to prepare this filing was the third quarter 2012 forecast, released November 8, 2012. The Global Insight data is proprietary and subject to copyright protection, therefore the indices utilized in the Company’s case are provided in Confidential Exhibit PAC/1005.

O&M Efficiency (page 4.13)—This adjustment reduces the Company’s O&M expense levels in the Test Period for efficiency initiatives realized since the historical test period. This adjustment reduces Oregon-allocated O&M by $4.0 million.

Tab 5—Net Power Cost Adjustments

Q. Please describe the information contained behind Tab 5 Net Power Cost Adjustments.

A. Tab 5 includes adjustments to items that are generally related to NPC, but may or may not be addressed separately in the Company's TAM filing. Specifically, adjustment page 5.1, Net Power Costs relates solely to NPC and recovery of these costs is being sought in the TAM docket rather than the general rate case. This adjustment is included for modeling and computational purposes only. For example, Test Period revenue requirement includes a tax credit for renewable energy generated from renewable facilities (adjustment page 7.3). This tax credit is calculated based on the generation output of these facilities as modeled in GRID (adjustment page 5.1) for the Test Period. Adjustment pages 5.2 through 5.5 include items that are not addressed in the Company's TAM filing with the exception of the Black Cap Solar, LLC Project (adjustment page 5.5), which includes revenue requirement components in both the TAM and the general rate case.

The Net Power Cost Index on page 5.0.1 is a brief overview of assumptions used to adjust NPC-related items. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on overall revenue requirement. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **Net Power Cost Adjustment (page 5.1)—**This adjustment normalizes power costs by adjusting sales for resale, purchased power, wheeling, and fuel in a manner consistent with the contractual terms of sales and purchase agreements, as well as normal hydro and temperature conditions for the Test Period. The GRID study for this adjustment is based on forecasted loads for the period. As I previously described, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; NPC is not part of the revenue requirement for the general rate case.

James River Royalty Offset (page 5.2)—On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the 20-year operational term of the agreement as an offset to royalties paid to James River based on contract provisions. The contract costs of energy for the Camas unit are included in the Company's NPC as purchased power expense, but GRID does not include an offsetting revenue credit for the capital and maintenance cost recovery. This adjustment adds the royalty offset to FERC account 456, other electric revenue, for the Test Period.

Little Mountain (page 5.3)—The Company has provided both electricity and steam from its Little Mountain plant to the Great Salt Lake Minerals Company since 1968. The current contract associated with this arrangement expired on February 28, 2012. However, on August 1, 2011, the electrical generator at the Little Mountain plant experienced a significant electrical fault and has not produced energy since that time. In August 2011, the Company installed a mobile packaged boiler in order to provide enough steam for the Great Salt Lake Minerals Company to maintain its operations. Since the plant no longer produces energy due to the generator failure, this adjustment removes the steam revenue and plant O&M expense, and no energy from the plant is included in the NPC study or the TAM. The asset balance is removed in adjustment page 8.6, depreciation expense is removed in adjustment page 6.1, and the accumulated depreciation reserve is removed in adjustment page 6.2.

Bonneville Power Administration (BPA) Residential Exchange (page 5.4)— The Company receives a monthly purchase power credit from BPA. This credit is treated as a 100 percent pass-through to eligible customers. Both a revenue credit and a purchase power expense credit are posted to unadjusted results. This adjustment reverses the BPA purchase power expense credit recorded in unadjusted results. The revenue credit is removed from Test Period results in the Pro Forma Revenues adjustment, page 3.1.

Black Cap Solar LLC Project (page 5.5)—As stipulated and approved by the Commission in the 2012 Rate Case, this adjustment adds the O&M expense, the lease payment expense, and the land balance associated with the project to the Test Period. The NPC benefit associated with this project is included in adjustment page 5.1, NPC and is reflected in the TAM.

Tab 6—Depreciation and Amortization Expense Adjustments

Q. Please describe the information contained behind Tab 6 Depreciation and Amortization Adjustments.

A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 6.0.1 is a brief overview of assumptions used to adjust overall depreciation and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 6.

A. **Depreciation and Amortization Expense (page 6.1)**—This adjustment reflects the incremental depreciation expense associated with the capital additions included in the filing in the plant additions adjustment, page 8.6 and adjusting the depreciation expense for the proposed depreciation rates in docket UM 1647 effective January 1, 2014. The annualized level of depreciation and amortization expense for the Test Period is calculated by first applying the current composite depreciation and amortization rates to the December 2013 pro forma plant balances. The current composite rates used are those approved by the Commission in docket UM 1329, which became effective on January 1, 2008. The depreciation expense is then updated for the proposed depreciation rates filed in docket UM 1647, which the Company has requested become effective on

January 1, 2014, the beginning of the Test Period. The proposed rates in UM 1647 increase Oregon's allocated share of depreciation and amortization expense by $27.2 million. The detailed calculation of the depreciation and amortization expense is provided on pages 6.1 through 6.1.16.

Depreciation and Amortization Reserve (page 6.2)—This adjustment steps forward the depreciation and amortization reserve from the Base Period to a December 2013 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to Base Period balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2012, to December 31, 2013. An incremental reserve amount has been added to the December 31, 2013 balances to reflect the annualized level of depreciation and amortization expense included on page 6.1. The reserve balance calculations are detailed on pages 6.2 to 6.2.12.

Tab 7—Tax Adjustments

Q. Please describe the information contained behind Tab 7 Tax Adjustments.

A. Tab 7 includes the Tax Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index (page 7.0.1) contains a brief overview of the tax adjustments included in this case. The numerical summary on page 7.0.2 identifies each adjustment made to the various tax components and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 7.

A. **Interest True-Up (page 7.1)—**This adjustment details the adjustment to interest expense required to synchronize the Test Period interest expense with Test Period rate base. This is done by multiplying normalized net rate base by the Company's weighted cost of debt in this case.

Property Tax Expense (page 7.2)—Property tax expense for the Test Period is computed by adjusting accruals from the Base Period for known or anticipated changes in the assessed values of the Company's operating property and the corresponding effect such changes will have on property tax expense for the Test Period. For additional information on the Company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/1003.

Renewable Energy Tax Credit (page 7.3)—The Company is entitled to recognize federal and state income tax credits as a result of placing renewable generating plants in service. The federal tax credit is based on the kilowatt hours (kWh) generated by the plants, and the credit can be taken for the first 10 years of generation from qualifying property. This adjustment reflects the credit based on the qualifying production as modeled in GRID for the Test Period NPC study.

The Utah State Production Tax Credit expired in December 2011 and is not reflected in the Test Period. The Oregon Business Energy Tax Credit (BETC) is based on investment in qualifying plant, and the credit is used over a three to five year period on qualifying property.

Allowance for Funds Used During Construction (AFUDC) Equity (page 7.4)—This adjustment reflects the appropriate level of AFUDC equity into regulated results to align the tax schedule M with regulatory income. Per Commission Order No. 10-022, AFUDC equity in this case is included using flow-through tax treatment.

Medicare Deferred Accounting (page 7.5)—As established in dockets UM 1479 and the 2010 Rate Case, this adjustment recognizes the amortization of the Medicare deferral regulatory asset for the Test Period. This adjustment also normalizes the Base Period deferred income tax expense for a recent change in tax law. With the change in law, some of the costs related to other post-retirement benefits become non-deductible for income tax purposes.

Pro Forma Schedule M (page 7.6)—This adjustment normalizes the Schedule M to an estimated pro forma level of expense for the Test Period. The significant change in tax depreciation is primarily driven by the reduced bonus depreciation available in the Test Period as compared to the Base Period. Additional line item detail is included in the tax model that is provided with the Company's electronic work papers.

Pro Forma Deferred Income Taxes (page 7.7)—This adjustment normalizes the deferred tax expense to an estimated pro forma level of expense for the Test Period. Additional line item detail is included in the tax model that is provided with the Company's electronic work papers.

Pro Forma Accumulated Deferred Income Tax (ADIT) Balance (page 7.8)— This adjustment normalizes ADIT balances to an estimated pro forma level of rate base balance for the Test Period. Additional line item detail is included in the tax model that is provided with the Company's electronic work papers.

Wyoming Wind Generation Tax (page 7.9)—This adjustment normalizes the Wyoming Wind Generation Tax, which became effective January 1, 2012, into Test Period results. The Wyoming Wind Generation Tax is an excise tax levied upon production of electricity from wind resources in the state of Wyoming. The tax is on the production of any electricity produced from wind resources for sale or trade on or after January 1, 2012, and is to be paid by the entity producing the electricity. The tax is one dollar for each megawatt hour of electricity produced from wind resources at the point of interconnection with an electric transmission line.

Franchise and Resource Supplier Taxes (page 7.10)—This adjustment normalizes the Base Period Oregon franchise tax and the Oregon energy resource supplier assessment to the Test Period level based on pro forma revenues in adjustment page 3.1. Ms. Steward discusses how the franchise and energy resource supplier taxes are included as a new unbundled rate element in the Company's rate design in this case.

Tab 8—Rate Base Adjustments

Q. Please describe the information contained behind Tab 8 Rate Base Adjustments.

A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 8.0.1 begins with a brief overview of assumptions used to adjust rate base components.

The numerical summary (pages 8.0.2–8.0.3) identifies each adjustment made to actual rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe each of the adjustments to the historical rate base balances.

A. **Cash Working Capital (page 8.1)—**This adjustment supports the calculation of cash working capital balance included in rate base using the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on the lead lag study prepared by the Company using calendar year 2010 information. The Company is using the same lead lag study in this case that was used in the 2012 Rate Case. An electronic version of the lead lag study is included as part of the Company's workpapers.

Trapper Mine Rate Base (page 8.2)—The Company owns a 21.4 percent interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper includes all operating and maintenance costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine plant investment to the rate base and reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks the reclamation liability forward to December 2013. This adjustment was stipulated to and approved in docket UE 111 and has been included in all Oregon rate case filings since.

Jim Bridger Mine Rate Base (page 8.3)—The Company owns a two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The Company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base in order for the Company to earn a return on its investment. The normalized coal costs for Bridger Coal Company in NPC include the O&M costs of the mine but provide no return on investment. This adjustment adds the Company's portion of the pro forma December 31, 2013 net plant balance to rate base. This adjustment was stipulated to and approved in docket UE 111 and has been included in all Oregon rate case filings since.

Customer Advances for Construction (page 8.4)—Customer advances were recorded in the Base Period to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation factors of customer advances.

Plant Additions (page 8.5)—To reasonably represent the cost of system infrastructure required to serve customers, the Company has identified capital projects that will be used and useful by December 31, 2013.

Capital additions by FERC functional category are listed on pages 8.5.5 to 8.6.12, indicating the in-service date and amount by project. This adjustment is based on plant balances as of December 31, 2013. As described earlier in my testimony, the accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements. Projects over $5 million (total-company basis) are described on pages 8.6.13 through 8.6.18 of the Report.

This adjustment does not include the impact of Lake Side 2, which is reflected in Exhibit PAC/1004. As discussed earlier in my testimony, the Company is requesting recovery of the revenue requirement associated with this project through a separate tariff rider.

Plant Retirements (page 8.6)—Composite plant retirement rates were applied to pro forma plant balances included in this filing to reflect ongoing asset retirements through December 31, 2013. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of reserve balances in the Depreciation and Amortization Reserve Adjustment (page 6.2).

Miscellaneous Rate Base (page 8.7)—This adjustment reflects the change in the fuel stock balance from the Base Period to the Test Period. This adjustment also reflects the working capital deposits that are offsets to fuel stock costs. In addition, balances for prepaid overhauls at the Lake Side, Chehalis, and Currant Creek natural gas plants are walked forward to reflect payments and transfers of capital to electric plant in service through December 31, 2013.

Powerdale Hydro Removal (page 8.8)—This adjustment removes costs related to the Powerdale hydroelectric plant from results. Powerdale was decommissioned after it was damaged by a flood in November 2006. Deferred accounting for the unrecovered plant balance was authorized by the Commission in docket UM 1298 and was fully amortized December 2010. Consistent with dockets UE 210, the 2010 Rate Case, and the 2012 Rate Case, the Company amortized the decommissioning regulatory asset beginning January 1, 2010. This regulatory asset will be fully amortized before the beginning of the rate effective period in this case. Accordingly, this adjustment removes the O&M expense associated with the plant, the amortization expense related to the unrecovered plant regulatory asset, and the decommissioning regulatory asset balance.

Regulatory Asset Amortization (page 8.9)—This adjustment normalizes regulatory assets from the Base Period to the Test Period. In addition, in docket UE 210, the Company agreed to set up tariff riders to collect the balance of the Grid West, the 2000 Transition Plan, and the MidAmerican Energy Holdings Company (MEHC) Oregon Transition Plan regulatory assets. These separate tariff riders are credited to revenues when collected and removed from revenues in the Pro Forma Revenue adjustment page 3.1. These regulatory assets are amortized in unadjusted results by charging expense. This adjustment removes that expense.

Klamath Hydroelectric Settlement Agreement (KHSA) (page 8.10)—This adjustment accounts for the total Test Period costs related to the KHSA. As approved by the Commission in docket UE 219, effective January 1, 2011, the depreciation of existing Klamath facilities is being accelerated so that assets will be fully depreciated by December 31, 2019. Relicensing and settlement process costs are also amortized at a rate that will achieve a zero net book value by December 31, 2019.

Miscellaneous Asset Sales and Removals (page 8.11)—This adjusts the Company's Base Period for various assets that were sold or removed, including the sale of Snake Creek hydroelectric plant to Heber Light and Power Company, the removal of Deseret Power's portion of the Hunter unit two scrubber and turbine upgrade, the decommissioning of the Condit hydroelectric plant, and the removal of the Goose Creek switching station. Asset balances for Snake Creek and Condit are removed in the adjustment to plant retirements, page 8.7. The Oregon-allocated proceeds related to the gain on the sale of Snake Creek will be placed in the property sales balancing account and passed through to customers in Schedule 96, Property Sales Balancing Account Adjustment, as outlined in docket UP 275, Commission Order No. 11-331.

Remove Rolling Hills (page 8.12)—This adjustment removes the gross plant, accumulated depreciation, and O&M amounts related to the Rolling Hills wind resource from the Base Period. This treatment is consistent with Commission Order No. 08-548.

Plant Held for Future Use (PHFU) (page 8.13)—This adjustment removes all PHFU assets from FERC account 105. The Company is making this adjustment in compliance with Commission Order No. 01-787.

Carbon Plant Retirement (page 8.14)—This adjustment includes the impact of accelerated depreciation for the Carbon plant as stipulated and approved in the 2010 Rate Case. Depreciation of the Carbon plant is accelerated so that assets are fully depreciated by April 15, 2015. The Carbon plant is depreciated using Commission-approved rates from the end of the Base Period through

December 31, 2012. The level of expense reflected in the Test Period is based on an annualized level of depreciation expense using the proposed accelerated rate.

Pension and Other Postretirement Welfare Plan Balances (page 8.15)—This adjustment adds into rate base the Company's prepaid pension and other post-retirement welfare balance, net of the accumulated deferred income tax liability. This adjustment is discussed in detail in the direct testimony of Company witnesses Mr. Douglas K. Stuver.

Tab 9—Revised Protocol

Q. Please describe the information contained behind Tab 9.

A. Tab 9 is restatements of Tab 2 using the Revised Protocol allocation methodology. The Company is providing these restated results in compliance with Commission Order No. 11-244.

Tab 10—Allocation Factors

Q. Please describe the information contained behind Tab 10 Allocation Factors.

A. Tab 10 Allocation Factors summarizes the derivation of the jurisdictional allocation factors using the 2010 Protocol.

Q. Please explain how the inter-jurisdictional allocation factors applied in this case comply with the Commission order approving the 2010 Protocol.

A. Each of the inter-jurisdictional allocation factors included in this case is calculated in the same manner prescribed in the 2010 Protocol approved by the Commission in Order No. 11-244. Specifically, "Tab 2—Results of Operations of the Report" applies allocation factors to the revenue requirement components as outlined in Appendix B of the 2010 Protocol. In addition, the calculations of the allocation factors included in this case are consistent with the algebraic derivations approved by the Commission shown in Appendix C of the 2010 Protocol.

Q. What exhibits included in this filing demonstrate compliance with Order No. 11-244?

A. Two files are provided as part of this filing to demonstrate the Company's compliance with Order No. 11-244. First, "Tab 10—Allocation Factors" in the Report shows the calculation and derivation of each 2010 Protocol factor included in the filing. An electronic version of this section of my exhibit is provided with the Company's workpapers. In addition, the Company's revenue requirement model, the Jurisdictional Allocation Model (JAM), is provided as part of the Company's workpapers. The "Factors" tab within the Excel-based model shows the linked formulas and inputs used in the development of each of the allocation percentages. As noted above, the calculations in this section of the model were developed based on the algebraic derivations set forth in Appendix C of the 2010 Protocol.

Q. Are the forecast loads used to derive the inter-jurisdictional allocation factors the same as the forecast loads used to develop Test Period revenues and NPC?

A. Yes. The forecast loads used in the calculation of allocation factors are consistent with the loads used in the development of Test Period revenues and NPC. By using the same load forecast for each of these revenue requirement components, an appropriate matching is achieved. The load forecast applied in this case is described in detail in the testimony of Mr. Gregory N. Duvall.

Q. Although a consistent load forecast is used for inter-jurisdictional allocation factors, Test Period revenues, and NPC, are there any differences in the application of these loads?

A. Yes. NPC and inter-jurisdictional allocation factors are developed using forecasted loads at the system input level instead of the metered or sales level used in the development of Test Period revenues. The differences between the system input level and sales level are line losses. In addition, allocation factors are adjusted for load curtailments consistent with the 2010 Protocol.

Q. Will the Company need to update inter-jurisdictional allocation factors as part of this proceeding?

A. As described in the testimony of Mr. Duvall in the concurrent TAM filing, interruptible contracts with three large industrial customers expire in 2013 or 2014. Depending on the terms of new contracts, there is a possibility of an impact to the jurisdictional loads used to compute allocation factors under the 2010 Protocol. To the extent there is a change in how the contracts are structured such that curtailments for these contracts are reflected as reductions to jurisdictional loads, the Company would need to update the allocation factors in the TAM and in this proceeding to ensure an appropriate matching of costs and benefits. Accordingly, the Company may update 2010 Protocol allocation factors during the pendency of this proceeding.

Tabs B1–B20

Q. Please describe the information contained behind Tabs B1–B20.

A. Tabs B1 through B20 contain the historical results for the Base Period and are organized by major FERC function. The data contained in this section of the Report match the unadjusted data found under Tab 2—Results of Operations.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/1001
Witness: Gary W. Tawwater

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gary W. Tawwater

Revenue Requirement Summary

March 2013

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
December 2014

	(1) NPC-Related Results	(2) (3) - (1) Non-NPC Related Results	(3) Ref. Page 1.4 Total Adjusted Results	(4) Ref. Page 1.3 **TAM** NPC-Related Under Recovery	(5) Ref. Page 1.2 **GRC** Requested Non-NPC Related Price Change	(6) (3) + (4) + (5) Total Normalized Results with Price Change
1 Operating Revenues:						
2 General Business Revenues	364,107,266	845,069,214	1,209,176,480	(995,132)	55,986,989	1,264,168,337
3 Interdepartmental		-	-			-
4 Special Sales	123,005,658	1,024,807	124,030,465			124,030,465
5 Other Operating Revenues		39,567,427	39,567,427			39,567,427
6 Total Operating Revenues	487,112,923	885,661,449	1,372,774,372	(995,132)	55,986,989	1,427,766,229
7						
8 Operating Expenses:						
9 Steam Production	204,216,818	91,465,378	295,682,196			295,682,196
10 Nuclear Production		-	-			-
11 Hydro Production		11,123,151	11,123,151			11,123,151
12 Other Power Supply	244,574,932	30,873,006	275,447,938			275,447,938
13 Embedded Cost Differential (ECD)		(8,792,171)	(8,792,171)			(8,792,171)
14 Transmission	37,326,041	16,269,482	53,595,523			53,595,523
15 Distribution		71,951,511	71,951,511			71,951,511
16 Customer Accounting		35,929,744	35,929,744		329,519	36,259,263
17 Customer Service & Info		4,067,911	4,067,911			4,067,911
18 Sales		-	-			-
19 Administrative & General		47,652,982	47,652,982			47,652,982
20						
21 Total O&M Expenses	486,117,791	300,540,995	786,658,786	-	329,519	786,988,304
22						
23 Depreciation		211,121,763	211,121,763			211,121,763
24 Amortization		14,529,658	14,529,658			14,529,658
25 Taxes Other Than Income		67,523,836	67,523,836		1,308,806	68,832,642
26 Income Taxes - Federal	332,484	17,690,908	18,023,392	(332,484)	18,158,432	35,849,340
27 Income Taxes - State	45,179	4,631,479	4,676,658	(45,179)	2,467,429	7,098,908
28 Income Taxes - Def Net		44,337,342	44,337,342			44,337,342
29 Investment Tax Credit Adj.		-	-			-
30 Misc Revenue & Expense		(90,219)	(90,219)			(90,219)
31						
32 Total Operating Expenses:	486,495,454	660,285,761	1,146,781,214	(377,663)	22,264,186	1,168,667,738
33						
34 Operating Rev For Return:	617,470	225,375,688	225,993,158	(617,470)	33,722,803	259,098,491
35						
36 Rate Base:						
37 Electric Plant In Service		6,686,362,611	6,686,362,611			6,686,362,611
38 Plant Held for Future Use		-	-			-
39 Misc Deferred Debits		73,870,456	73,870,456			73,870,456
40 Elec Plant Acq Adj		10,072,737	10,072,737			10,072,737
41 Nuclear Fuel		-	-			-
42 Prepayments		7,197,975	7,197,975			7,197,975
43 Fuel Stock		60,471,050	60,471,050			60,471,050
44 Material & Supplies		58,580,887	58,580,887			58,580,887
45 Working Capital		29,005,460	29,005,460			29,005,460
46 Weatherization Loans		(1,219)	(1,219)			(1,219)
47 Misc Rate Base		-	-			-
48						
49 Total Electric Plant:	-	6,925,559,957	6,925,559,957			6,925,559,957
50						
51 Rate Base Deductions:						
52 Accum Prov For Deprec		(2,359,864,735)	(2,359,864,735)			(2,359,864,735)
53 Accum Prov For Amort		(152,115,135)	(152,115,135)			(152,115,135)
54 Accum Def Income Tax		(1,014,614,465)	(1,014,614,465)			(1,014,614,465)
55 Unamortized ITC		(593,249)	(593,249)			(593,249)
56 Customer Adv For Const		(5,758,640)	(5,758,640)			(5,758,640)
57 Customer Service Deposits		-	-			-
58 Misc Rate Base Deductions		(8,073,647)	(8,073,647)			(8,073,647)
59						
60 Total Rate Base Deductions	-	(3,541,019,871)	(3,541,019,871)			(3,541,019,871)
61						
62 Total Rate Base:	-	3,384,540,086	3,384,540,086			3,384,540,086
63						
64 Return on Rate Base			6.677%			7.655%
65						
66 Return on Equity			7.923%			9.800%

Exhibit PAC/1001
Tawwater/2

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
December 2014

GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) **GRC** Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	845,069,214	55,986,989	901,056,204
3	Interdepartmental	-		-
4	Special Sales	1,024,807		1,024,807
5	Other Operating Revenues	39,567,427		39,567,427
6	Total Operating Revenues	885,661,449	55,986,989	941,648,438
7				
8	Operating Expenses:			
9	Steam Production	91,465,378		91,465,378
10	Nuclear Production	-		-
11	Hydro Production	11,123,151		11,123,151
12	Other Power Supply	30,873,006		30,873,006
13	Embedded Cost Differential (ECD)	(8,792,171)		(8,792,171)
14	Transmission	16,269,482		16,269,482
15	Distribution	71,951,511		71,951,511
16	Customer Accounting	35,929,744	329,519	36,259,263
17	Customer Service & Info	4,067,911		4,067,911
18	Sales	-		-
19	Administrative & General	47,652,982		47,652,982
20				
21	Total O&M Expenses	300,540,995	329,519	300,870,513
22				
23	Depreciation	211,121,763		211,121,763
24	Amortization	14,529,658		14,529,658
25	Taxes Other Than Income	67,523,836	1,308,806	68,832,642
26	Income Taxes - Federal	17,690,908	18,158,432	35,849,340
27	Income Taxes - State	4,631,479	2,467,429	7,098,908
28	Income Taxes - Def Net	44,337,342		44,337,342
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(90,219)		(90,219)
31				
32	Total Operating Expenses:	660,285,761	22,264,186	682,549,947
33				
34	Operating Rev For Return:	225,375,688	33,722,803	259,098,491
35				
36	Rate Base:			
37	Electric Plant In Service	6,686,362,611		6,686,362,611
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	73,870,456		73,870,456
40	Elec Plant Acq Adj	10,072,737		10,072,737
41	Nuclear Fuel	-		-
42	Prepayments	7,197,975		7,197,975
43	Fuel Stock	60,471,050		60,471,050
44	Material & Supplies	58,580,887		58,580,887
45	Working Capital	29,005,460		29,005,460
46	Weatherization Loans	(1,219)		(1,219)
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	6,925,559,957	-	6,925,559,957
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,359,864,735)		(2,359,864,735)
53	Accum Prov For Amort	(152,115,135)		(152,115,135)
54	Accum Def Income Tax	(1,014,614,465)		(1,014,614,465)
55	Unamortized ITC	(593,249)		(593,249)
56	Customer Adv For Const	(5,758,640)		(5,758,640)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(8,073,647)		(8,073,647)
59				
60	Total Rate Base Deductions	(3,541,019,871)	-	(3,541,019,871)
61				
62	Total Rate Base:	3,384,540,086	-	3,384,540,086
63				
64	Return on Rate Base	6.659%		7.655%
65				
66	Return on Equity	7.888%		9.800%
67				
68	TAX CALCULATION:			
69	Operating Revenue	292,035,417	54,348,664	346,384,081
70	Other Deductions			
71	Interest (AFUDC)	(16,809,094)	-	(16,809,094)
72	Interest	85,739,606	-	85,739,606
73	Schedule "M" Additions	259,848,068	-	259,848,068
74	Schedule "M" Deductions	378,729,222	-	378,729,222
75	Income Before Tax	104,223,749	54,348,664	158,572,413
76				
77	State Income Taxes	4,631,479	2,467,429	7,098,908
78	Taxable Income	99,592,270	51,881,235	151,473,505
79				
80	Federal Income Taxes + Other	17,690,908	18,158,432	35,849,340

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
December 2014

TAM RESULTS

		(1) Total Adjusted Results	(2) **TAM** Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	364,107,266	(995,132)	363,112,133
3	Interdepartmental	-		-
4	Special Sales	123,005,658		123,005,658
5	Other Operating Revenues	-		-
6	Total Operating Revenues	487,112,923	(995,132)	486,117,791
7				
8	Operating Expenses:			
9	Steam Production	204,216,818		204,216,818
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	244,574,932		244,574,932
13	Embedded Cost Differential (ECD)	-		-
14	Transmission	37,326,041		37,326,041
15	Distribution	-		-
16	Customer Accounting	-	-	-
17	Customer Service & Info	-		-
18	Sales	-		-
19	Administrative & General	-		-
20				
21	Total O&M Expenses	486,117,791	-	486,117,791
22				
23	Depreciation	-		-
24	Amortization	-		-
25	Taxes Other Than Income	-	-	-
26	Income Taxes - Federal	332,484	(332,484)	(0)
27	Income Taxes - State	45,179	(45,179)	(0)
28	Income Taxes - Def Net	-		-
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	-		-
31				
32	Total Operating Expenses:	486,495,454	(377,663)	486,117,791
33				
34	Operating Rev For Return:	617,470	(617,470)	-
35				
36	Rate Base:			
37	Electric Plant In Service	-		-
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	-		-
40	Elec Plant Acq Adj	-		-
41	Nuclear Fuel	-		-
42	Prepayments	-		-
43	Fuel Stock	-		-
44	Material & Supplies	-		-
45	Working Capital	-		-
46	Weatherization Loans	-		-
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	-	-	-
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	-		-
53	Accum Prov For Amort	-		-
54	Accum Def Income Tax	-		-
55	Unamortized ITC	-		-
56	Customer Adv For Const	-		-
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	-		-
59				
60	Total Rate Base Deductions	-	-	-
61				
62	Total Rate Base:	-	-	-
63				
64	Return on Rate Base	N/A		N/A
65				
66	Return on Equity	N/A		N/A
67				
68	TAX CALCULATION:			
69	Operating Revenue	995,132	(995,132)	-
70	Other Deductions	-		
71	Interest (AFUDC)	-	-	-
72	Interest	-	-	-
73	Schedule "M" Additions	-	-	-
74	Schedule "M" Deductions	-	-	-
75	Income Before Tax	995,132	(995,132)	-
76				
77	State Income Taxes	45,179	(45,179)	(0)
78	Taxable Income	949,953	(949,953)	0
79				
80	Federal Income Taxes + Other	332,484	(332,484)	(0)

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
December 2014

COMBINED TAM AND GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,209,176,480	54,991,857	1,264,168,337
3	Interdepartmental	-		-
4	Special Sales	124,030,465		124,030,465
5	Other Operating Revenues	39,567,427		39,567,427
6	Total Operating Revenues	1,372,774,372	54,991,857	1,427,766,229
7				
8	Operating Expenses:			
9	Steam Production	295,682,196		295,682,196
10	Nuclear Production	-		-
11	Hydro Production	11,123,151		11,123,151
12	Other Power Supply	275,447,938		275,447,938
13	Embedded Cost Differential (ECD)	(8,792,171)		(8,792,171)
14	Transmission	53,595,523		53,595,523
15	Distribution	71,951,511		71,951,511
16	Customer Accounting	35,929,744	329,519	36,259,263
17	Customer Service & Info	4,067,911		4,067,911
18	Sales	-		-
19	Administrative & General	47,652,982		47,652,982
20				
21	Total O&M Expenses	786,658,786	329,519	786,988,304
22				
23	Depreciation	211,121,763		211,121,763
24	Amortization	14,529,658		14,529,658
25	Taxes Other Than Income	67,523,836	1,308,806	68,832,642
26	Income Taxes - Federal	18,023,392	17,825,948	35,849,340
27	Income Taxes - State	4,676,658	2,422,250	7,098,908
28	Income Taxes - Def Net	44,337,342		44,337,342
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(90,219)		(90,219)
31				
32	Total Operating Expenses:	1,146,781,214	21,886,524	1,168,667,738
33				
34	Operating Rev For Return:	225,993,158	33,105,333	259,098,491
35				
36	Rate Base:			
37	Electric Plant In Service	6,686,362,611		6,686,362,611
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	73,870,456		73,870,456
40	Elec Plant Acq Adj	10,072,737		10,072,737
41	Nuclear Fuel	-		-
42	Prepayments	7,197,975		7,197,975
43	Fuel Stock	60,471,050		60,471,050
44	Material & Supplies	58,580,887		58,580,887
45	Working Capital	29,005,460		29,005,460
46	Weatherization Loans	(1,219)		(1,219)
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	6,925,559,957	-	6,925,559,957
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,359,864,735)		(2,359,864,735)
53	Accum Prov For Amort	(152,115,135)		(152,115,135)
54	Accum Def Income Tax	(1,014,614,465)		(1,014,614,465)
55	Unamortized ITC	(593,249)		(593,249)
56	Customer Adv For Const	(5,758,640)		(5,758,640)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(8,073,647)		(8,073,647)
59				
60	Total Rate Base Deductions	(3,541,019,871)	-	(3,541,019,871)
61				
62	Total Rate Base:	3,384,540,086	-	3,384,540,086
63				
64	Return on Rate Base	6.677%		7.655%
65				
66	Return on Equity	7.923%		9.800%
67				
68	TAX CALCULATION:			
69	Operating Revenue	293,030,549	53,353,532	346,384,081
70	Other Deductions			
71	Interest (AFUDC)	(16,809,094)	-	(16,809,094)
72	Interest	85,739,606	-	85,739,606
73	Schedule "M" Additions	259,848,068	-	259,848,068
74	Schedule "M" Deductions	378,729,222	-	378,729,222
75	Income Before Tax	105,218,882	53,353,532	158,572,413
76				
77	State Income Taxes	4,676,658	2,422,250	7,098,908
78	Taxable Income	100,542,224	50,931,281	151,473,505
79				
80	Federal Income Taxes + Other	18,023,392	17,825,948	35,849,340
81				

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2014

	Exhibit PAC/1002		Exhibit PAC/1002			
			Tab 3	Tab 4	Tab 5	Tab 6
	TOTAL COMPANY ACTUAL RESULTS JUNE 2012	OREGON ALLOCATED ACTUAL RESULTS JUNE 2012	Revenue Adjustments	O&M Adjustments	NPC Adjustments	Deperciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	4,092,063,041	1,128,512,328	80,664,152	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	339,615,342	86,880,114	-	-	37,150,351	-
5 Other Operating Revenues	249,987,732	56,502,980	(6,866,375)	(10,204,815)	135,638	-
6 Total Operating Revenues	4,681,666,114	1,271,895,421	73,797,777	(10,204,815)	37,285,989	-
7						
8 Operating Expenses:						
9 Steam Production	1,033,981,927	259,370,846	-	5,193,310	31,191,424	(73,384)
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	38,494,364	10,028,937	-	1,077,115	-	(15,541)
12 Other Power Supply	958,605,486	225,879,311	-	369,279	49,279,783	(12,522)
13 Embedded Cost Differential (ECD)	-	(8,792,171)	-	-	-	-
13 Transmission	205,329,189	53,364,883	(197,987)	(222,688)	657,728	(6,413)
14 Distribution	208,601,621	65,912,168	-	6,074,891	-	(35,547)
15 Customer Accounting	94,659,859	35,169,515	-	1,170,262	-	(21,361)
16 Customer Service & Info	109,993,566	27,253,445	-	(23,182,913)	-	(2,621)
17 Sales	-	-	-	-	-	-
18 Administrative & General	152,548,405	47,477,959	-	1,498,449	-	(29,318)
19						
20 Total O&M Expenses	2,802,214,417	715,664,893	(197,987)	(8,022,295)	81,128,935	(196,707)
21						
22 Depreciation	549,502,550	154,054,000	-	-	-	46,509,009
23 Amortization	52,427,146	14,064,994	-	-	-	644,345
24 Taxes Other Than Income	157,778,830	62,043,915	-	-	-	-
25 Income Taxes - Federal	(117,200,416)	(14,847,617)	24,717,985	(760,168)	(14,659,982)	(13,555,340)
26 Income Taxes - State	(6,488,596)	440,987	3,358,764	(103,294)	(1,992,048)	(1,841,946)
27 Income Taxes - Def Net	368,714,954	93,550,467	19,311	-	-	-
28 Investment Tax Credit Adj.	(1,862,752)	-	-	-	-	-
29 Misc Revenue & Expense	(764,772)	(188,071)	(50,436)	148,288	-	-
30						
31 Total Operating Expenses:	3,804,321,362	1,024,783,568	27,847,637	(8,737,469)	64,476,904	31,559,361
32						
33 Operating Rev For Return:	877,344,752	247,111,853	45,950,141	(1,467,346)	(27,190,915)	(31,559,361)
34						
35 Rate Base:						
36 Electric Plant In Service	23,253,605,964	6,371,400,760	-	-	75,000	-
37 Plant Held for Future Use	46,178,566	13,855,477	-	-	-	-
38 Misc Deferred Debits	281,108,847	23,474,662	-	-	-	-
39 Elec Plant Acq Adj	49,044,288	12,777,509	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	26,323,174	7,197,975	-	-	-	-
42 Fuel Stock	264,151,338	65,210,335	-	-	-	-
43 Material & Supplies	200,372,004	58,580,887	-	-	-	-
44 Working Capital	83,829,274	26,812,692	560,970	(178,797)	1,297,390	(313,779)
45 Weatherization Loans	(5,877,664)	(1,219)	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	24,198,735,790	6,579,309,078	560,970	(178,797)	1,372,390	(313,779)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(7,170,108,718)	(2,107,464,837)	-	-	-	(243,039,682)
52 Accum Prov For Amort	(501,645,416)	(140,183,768)	-	-	-	(8,698,357)
53 Accum Def Income Tax	(3,458,822,902)	(913,623,771)	11,405	(2,016,181)	-	-
54 Unamortized ITC	(3,233,092)	(1,997,073)	-	-	-	-
55 Customer Adv For Const	(22,790,686)	(6,632,669)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(62,558,327)	(8,043,594)	(30,052)	-	-	-
58						
59 Total Rate Base Deductions	(11,219,159,141)	(3,177,945,714)	(18,647)	(2,016,181)	-	(251,738,039)
60						
61 Total Rate Base:	12,979,576,648	3,401,363,365	542,323	(2,194,978)	1,372,390	(252,051,818)
62						
63 Return on Rate Base	6.759%	7.265%	1.350%	-0.038%	-0.803%	-0.380%
64						
65 Return on Equity	8.080%	9.051%	2.590%	-0.072%	-1.541%	-0.729%
66						
67 TAX CALCULATION:						
68 Operating Revenue		326,255,690	74,046,200	(2,330,808)	(43,842,946)	(46,956,647)
69 Other Deductions			-	-	-	-
70 Interest (AFUDC)		(14,356,107)	-	-	-	-
71 Interest		86,165,786	13,739	(55,605)	34,766	(6,385,158)
72 Schedule "M" Additions		222,280,382	-	-	-	-
73 Schedule "M" Deductions		466,054,294	50,884	-	-	-
74 Income Before Tax		10,672,100	73,981,577	(2,275,203)	(43,877,712)	(40,571,489)
75						
76 State Income Taxes		440,987	3,358,764	(103,294)	(1,992,048)	(1,841,946)
77 Taxable Income		10,231,113	70,622,814	(2,171,909)	(41,885,664)	(38,729,543)
78						
79 Federal Income Taxes + Other		(14,847,617)	24,717,985	(760,168)	(14,659,982)	(13,555,340)
80						
81 PRICE CHANGE		22,050,540	(76,259,631)	2,158,311	45,341,832	20,371,790
82						
83 NET POWER COST		347,871,955	-	-	15,240,178	-

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2014

		Exhibit PAC/1002		
		Tab 7	Tab 8	
		Tax Adjustments	Rate Base Adjustments	Oregon Normalized Results December 2013
1	Operating Revenues:			
2	General Business Revenues	-	-	1,209,176,480
3	Interdepartmental	-	-	-
4	Special Sales	-	-	124,030,465
5	Other Operating Revenues	-	-	39,567,427
6	Total Operating Revenues	-	-	1,372,774,372
7				
8	Operating Expenses:			
9	Steam Production	-	-	295,682,196
10	Nuclear Production	-	-	-
11	Hydro Production	-	32,640	11,123,151
12	Other Power Supply	-	(67,913)	275,447,938
13	Embedded Cost Differential (ECD)	-	-	(8,792,171)
13	Transmission	-	-	53,595,523
14	Distribution	-	-	71,951,511
15	Customer Accounting	-	(388,671)	35,929,744
16	Customer Service & Info	-	-	4,067,911
17	Sales	-	-	-
18	Administrative & General	894,328	(2,188,437)	47,652,982
19				
20	Total O&M Expenses	894,328	(2,612,381)	786,658,786
21			-	-
22	Depreciation	-	10,558,754	211,121,763
23	Amortization	-	(179,681)	14,529,658
24	Taxes Other Than Income	5,479,921	-	67,523,836
25	Income Taxes - Federal	41,946,976	(4,818,461)	18,023,392
26	Income Taxes - State	5,468,944	(654,749)	4,676,658
27	Income Taxes - Def Net	(48,414,852)	(817,585)	44,337,342
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	(90,219)
30				
31	Total Operating Expenses:	5,375,316	1,475,897	1,146,781,214
32				
33	Operating Rev For Return:	(5,375,316)	(1,475,897)	225,993,158
34				
35	Rate Base:			
36	Electric Plant In Service	-	314,886,851	6,686,362,611
37	Plant Held for Future Use	-	(13,855,477)	-
38	Misc Deferred Debits	-	50,395,795	73,870,456
39	Elec Plant Acq Adj	-	(2,704,773)	10,072,737
40	Nuclear Fuel	-	-	-
41	Prepayments	-	-	7,197,975
42	Fuel Stock	-	(4,739,285)	60,471,050
43	Material & Supplies	-	-	58,580,887
44	Working Capital	1,082,354	(255,371)	29,005,460
45	Weatherization Loans	-	-	(1,219)
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	1,082,354	343,727,740	6,925,559,957
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-	(9,360,216)	(2,359,864,735)
52	Accum Prov For Amort	-	(3,233,009)	(152,115,135)
53	Accum Def Income Tax	(115,102,825)	16,116,906	(1,014,614,465)
54	Unamortized ITC	1,403,824	-	(593,249)
55	Customer Adv For Const	-	874,029	(5,758,640)
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	-	-	(8,073,647)
58				
59	Total Rate Base Deductions	(113,699,001)	4,397,710	(3,541,019,871)
60				
61	Total Rate Base:	(112,616,646)	348,125,450	3,384,540,086
62				
63	Return on Rate Base	0.097%	-0.814%	6.677%
64				
65	Return on Equity	0.187%	-1.563%	7.923%
66				
67	TAX CALCULATION:			
68	Operating Revenue	(6,374,249)	(7,766,692)	293,030,549
69	Other Deductions	-	-	
70	Interest (AFUDC)	(2,452,986)	-	(16,809,094)
71	Interest	(2,852,886)	8,818,965	85,739,606
72	Schedule "M" Additions	37,567,685	-	259,848,068
73	Schedule "M" Deductions	(85,212,080)	(2,163,876)	378,729,222
74	Income Before Tax	121,711,389	(14,421,781)	105,218,882
75				
76	State Income Taxes	5,468,944	(654,749)	4,676,658
77	Taxable Income	116,242,445	(13,767,032)	100,542,224
78				
79	Federal Income Taxes + Other	41,946,976	(4,818,461)	18,023,392
80				
81	PRICE CHANGE	(5,391,799)	46,720,813	54,991,857
82				
83	NET POWER COST	-	-	-

Docket No. UE 263
Exhibit PAC/1002
Witness: Gary W. Tawwater

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gary W. Tawwater

Oregon Results of Operations
December 2014

March 2013

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
December 2014

		(1)	(2) (3) - (1)	(3) Ref. Page 1.4	(4) Ref. Page 1.3 **TAM**	(5) Ref. Page 1.2 **GRC**	(6) (3) + (4) + (5)
		NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1	Operating Revenues:						
2	General Business Revenues	364,107,266	845,069,214	1,209,176,480	(995,132)	55,986,989	1,264,168,337
3	Interdepartmental		-	-			-
4	Special Sales	123,005,658	1,024,807	124,030,465			124,030,465
5	Other Operating Revenues		39,567,427	39,567,427			39,567,427
6	Total Operating Revenues	487,112,923	885,661,449	1,372,774,372	(995,132)	55,986,989	1,427,766,229
7							
8	Operating Expenses:						
9	Steam Production	204,216,818	91,465,378	295,682,196			295,682,196
10	Nuclear Production		-	-			-
11	Hydro Production		11,123,151	11,123,151			11,123,151
12	Other Power Supply	244,574,932	30,873,006	275,447,938			275,447,938
13	Embedded Cost Differential (ECD)		(8,792,171)	(8,792,171)			(8,792,171)
14	Transmission	37,326,041	16,269,482	53,595,523			53,595,523
15	Distribution		71,951,511	71,951,511			71,951,511
16	Customer Accounting		35,929,744	35,929,744		329,519	36,259,263
17	Customer Service & Info		4,067,911	4,067,911			4,067,911
18	Sales		-	-			-
19	Administrative & General		47,652,982	47,652,982			47,652,982
20							
21	Total O&M Expenses	486,117,791	300,540,995	786,658,786	-	329,519	786,988,304
22							
23	Depreciation		211,121,763	211,121,763			211,121,763
24	Amortization		14,529,658	14,529,658			14,529,658
25	Taxes Other Than Income		67,523,836	67,523,836		1,308,806	68,832,642
26	Income Taxes - Federal	332,484	17,690,908	18,023,392	(332,484)	18,158,432	35,849,340
27	Income Taxes - State	45,179	4,631,479	4,676,658	(45,179)	2,467,429	7,098,908
28	Income Taxes - Def Net		44,337,342	44,337,342			44,337,342
29	Investment Tax Credit Adj.		-	-			-
30	Misc Revenue & Expense		(90,219)	(90,219)			(90,219)
31							
32	Total Operating Expenses:	486,495,454	660,285,761	1,146,781,214	(377,663)	22,264,186	1,168,667,738
33							
34	Operating Rev For Return:	617,470	225,375,688	225,993,158	(617,470)	33,722,803	259,098,491
35							
36	Rate Base:						
37	Electric Plant In Service		6,686,362,611	6,686,362,611			6,686,362,611
38	Plant Held for Future Use		-	-			-
39	Misc Deferred Debits		73,870,456	73,870,456			73,870,456
40	Elec Plant Acq Adj		10,072,737	10,072,737			10,072,737
41	Nuclear Fuel		-	-			-
42	Prepayments		7,197,975	7,197,975			7,197,975
43	Fuel Stock		60,471,050	60,471,050			60,471,050
44	Material & Supplies		58,580,887	58,580,887			58,580,887
45	Working Capital		29,005,460	29,005,460			29,005,460
46	Weatherization Loans		(1,219)	(1,219)			(1,219)
47	Misc Rate Base		-	-			-
48							
49	Total Electric Plant:	-	6,925,559,957	6,925,559,957			6,925,559,957
50							
51	Rate Base Deductions:						
52	Accum Prov For Deprec		(2,359,864,735)	(2,359,864,735)			(2,359,864,735)
53	Accum Prov For Amort		(152,115,135)	(152,115,135)			(152,115,135)
54	Accum Def Income Tax		(1,014,614,465)	(1,014,614,465)			(1,014,614,465)
55	Unamortized ITC		(593,249)	(593,249)			(593,249)
56	Customer Adv For Const		(5,758,640)	(5,758,640)			(5,758,640)
57	Customer Service Deposits		-	-			-
58	Misc Rate Base Deductions		(8,073,647)	(8,073,647)			(8,073,647)
59							
60	Total Rate Base Deductions	-	(3,541,019,871)	(3,541,019,871)			(3,541,019,871)
61							
62	Total Rate Base:	-	3,384,540,086	3,384,540,086			3,384,540,086
63							
64	Return on Rate Base			6.677%			7.655%
65							
66	Return on Equity			7.923%			9.800%
				Ref. Page 2.2			Ref. Page 1.4

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
12 Months Ended December 31, 2014

(1) Test Period Revised Protocol Revenue Requirement	1,264,884,865	
(2) Rate Mitigation Cap	100.30%	
(3) Capped Revenue Requirement	1,268,679,520	
(4) Normalized General Business Revenues	1,209,176,480	Page 1.0
(5) Capped Revised Protocol Price Change*	**59,503,040**	

2010 Protocol

(6) Test Period 2010 Protocol Revenue Requirement	1,264,168,337	Page 1.0
(7) Normalized General Business Revenues	1,209,176,480	Page 1.0
(8) 2010 Protocol Price Change*	**54,991,857**	Page 1.0

*Includes TAM and GRC

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
December 2014

GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) GRC Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	845,069,214	55,986,989	901,056,204
3	Interdepartmental	-		-
4	Special Sales	1,024,807		1,024,807
5	Other Operating Revenues	39,567,427		39,567,427
6	Total Operating Revenues	885,661,449	55,986,989	941,648,438
7				
8	Operating Expenses:			
9	Steam Production	91,465,378		91,465,378
10	Nuclear Production	-		-
11	Hydro Production	11,123,151		11,123,151
12	Other Power Supply	30,873,006		30,873,006
13	Embedded Cost Differential (ECD)	(8,792,171)		(8,792,171)
14	Transmission	16,269,482		16,269,482
15	Distribution	71,951,511		71,951,511
16	Customer Accounting	35,929,744	329,519	36,259,263
17	Customer Service & Info	4,067,911		4,067,911
18	Sales	-		-
19	Administrative & General	47,652,982		47,652,982
20				
21	Total O&M Expenses	300,540,995	329,519	300,870,513
22				
23	Depreciation	211,121,763		211,121,763
24	Amortization	14,529,658		14,529,658
25	Taxes Other Than Income	67,523,836	1,308,806	68,832,642
26	Income Taxes - Federal	17,690,908	18,158,432	35,849,340
27	Income Taxes - State	4,631,479	2,467,429	7,098,908
28	Income Taxes - Def Net	44,337,342		44,337,342
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(90,219)		(90,219)
31				
32	Total Operating Expenses:	660,285,761	22,264,186	682,549,947
33				
34	Operating Rev For Return:	225,375,688	33,722,803	259,098,491
35				
36	Rate Base:			
37	Electric Plant In Service	6,686,362,611		6,686,362,611
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	73,870,456		73,870,456
40	Elec Plant Acq Adj	10,072,737		10,072,737
41	Nuclear Fuel	-		-
42	Prepayments	7,197,975		7,197,975
43	Fuel Stock	60,471,050		60,471,050
44	Material & Supplies	58,580,887		58,580,887
45	Working Capital	29,005,460		29,005,460
46	Weatherization Loans	(1,219)		(1,219)
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	6,925,559,957	-	6,925,559,957
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,359,864,735)		(2,359,864,735)
53	Accum Prov For Amort	(152,115,135)		(152,115,135)
54	Accum Def Income Tax	(1,014,614,465)		(1,014,614,465)
55	Unamortized ITC	(593,249)		(593,249)
56	Customer Adv For Const	(5,758,640)		(5,758,640)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(8,073,647)		(8,073,647)
59				
60	Total Rate Base Deductions	(3,541,019,871)	-	(3,541,019,871)
61				
62	Total Rate Base:	3,384,540,086	-	3,384,540,086
63				
64	Return on Rate Base	6.659%		7.655%
65				
66	Return on Equity	7.888%		9.800%
67				
68	TAX CALCULATION:			
69	Operating Revenue	292,035,417	54,348,664	346,384,081
70	Other Deductions			
71	Interest (AFUDC)	(16,809,094)	-	(16,809,094)
72	Interest	85,739,606	-	85,739,606
73	Schedule "M" Additions	259,848,068	-	259,848,068
74	Schedule "M" Deductions	378,729,222	-	378,729,222
75	Income Before Tax	104,223,749	54,348,664	158,572,413
76				
77	State Income Taxes	4,631,479	2,467,429	7,098,908
78	Taxable Income	99,592,270	51,881,235	151,473,505
79				
80	Federal Income Taxes + Other	17,690,908	18,158,432	35,849,340

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
December 2014

TAM RESULTS

		(1) Total Adjusted Results	(2) TAM Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	364,107,266	(995,132)	363,112,133
3	Interdepartmental	-		-
4	Special Sales	123,005,658		123,005,658
5	Other Operating Revenues	-		-
6	Total Operating Revenues	487,112,923	(995,132)	486,117,791
7				
8	Operating Expenses:			
9	Steam Production	204,216,818		204,216,818
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	244,574,932		244,574,932
13	Embedded Cost Differential (ECD)	-		-
14	Transmission	37,326,041		37,326,041
15	Distribution	-		-
16	Customer Accounting	-	-	-
17	Customer Service & Info	-		-
18	Sales	-		-
19	Administrative & General	-		-
20				
21	Total O&M Expenses	486,117,791	-	486,117,791
22				
23	Depreciation	-		-
24	Amortization	-		-
25	Taxes Other Than Income	-	-	-
26	Income Taxes - Federal	332,484	(332,484)	(0)
27	Income Taxes - State	45,179	(45,179)	(0)
28	Income Taxes - Def Net	-		-
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	-		-
31				
32	Total Operating Expenses:	486,495,454	(377,663)	486,117,791
33				
34	Operating Rev For Return:	617,470	(617,470)	-
35				
36	Rate Base:			
37	Electric Plant In Service	-		-
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	-		-
40	Elec Plant Acq Adj	-		-
41	Nuclear Fuel	-		-
42	Prepayments	-		-
43	Fuel Stock	-		-
44	Material & Supplies	-		-
45	Working Capital	-		-
46	Weatherization Loans	-		-
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	-	-	-
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	-		-
53	Accum Prov For Amort	-		-
54	Accum Def Income Tax	-		-
55	Unamortized ITC	-		-
56	Customer Adv For Const	-		-
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	-		-
59				
60	Total Rate Base Deductions	-	-	-
61				
62	Total Rate Base:	-	-	-
63				
64	Return on Rate Base	N/A		N/A
65				
66	Return on Equity	N/A		N/A
67				
68	TAX CALCULATION:			
69	Operating Revenue	995,132	(995,132)	-
70	Other Deductions	-		
71	Interest (AFUDC)	-	-	-
72	Interest	-	-	-
73	Schedule "M" Additions	-	-	-
74	Schedule "M" Deductions	-	-	-
75	Income Before Tax	995,132	(995,132)	-
76				
77	State Income Taxes	45,179	(45,179)	(0)
78	Taxable Income	949,953	(949,953)	0
79				
80	Federal Income Taxes + Other	332,484	(332,484)	(0)

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
December 2014
COMBINED TAM AND GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,209,176,480	54,991,857	1,264,168,337
3	Interdepartmental	-		-
4	Special Sales	124,030,465		124,030,465
5	Other Operating Revenues	39,567,427		39,567,427
6	Total Operating Revenues	1,372,774,372	54,991,857	1,427,766,229
7				
8	Operating Expenses:			
9	Steam Production	295,682,196		295,682,196
10	Nuclear Production	-		-
11	Hydro Production	11,123,151		11,123,151
12	Other Power Supply	275,447,938		275,447,938
13	Embedded Cost Differential (ECD)	(8,792,171)		(8,792,171)
14	Transmission	53,595,523		53,595,523
15	Distribution	71,951,511		71,951,511
16	Customer Accounting	35,929,744	329,519	36,259,263
17	Customer Service & Info	4,067,911		4,067,911
18	Sales	-		-
19	Administrative & General	47,652,982		47,652,982
20				
21	Total O&M Expenses	786,658,786	329,519	786,988,304
22				
23	Depreciation	211,121,763		211,121,763
24	Amortization	14,529,658		14,529,658
25	Taxes Other Than Income	67,523,836	1,308,806	68,832,642
26	Income Taxes - Federal	18,023,392	17,825,948	35,849,340
27	Income Taxes - State	4,676,658	2,422,250	7,098,908
28	Income Taxes - Def Net	44,337,342		44,337,342
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(90,219)		(90,219)
31				
32	Total Operating Expenses:	1,146,781,214	21,886,524	1,168,667,738
33				
34	Operating Rev For Return:	225,993,158	33,105,333	259,098,491
35				
36	Rate Base:			
37	Electric Plant In Service	6,686,362,611		6,686,362,611
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	73,870,456		73,870,456
40	Elec Plant Acq Adj	10,072,737		10,072,737
41	Nuclear Fuel	-		-
42	Prepayments	7,197,975		7,197,975
43	Fuel Stock	60,471,050		60,471,050
44	Material & Supplies	58,580,887		58,580,887
45	Working Capital	29,005,460		29,005,460
46	Weatherization Loans	(1,219)		(1,219)
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	6,925,559,957	-	6,925,559,957
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,359,864,735)		(2,359,864,735)
53	Accum Prov For Amort	(152,115,135)		(152,115,135)
54	Accum Def Income Tax	(1,014,614,465)		(1,014,614,465)
55	Unamortized ITC	(593,249)		(593,249)
56	Customer Adv For Const	(5,758,640)		(5,758,640)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(8,073,647)		(8,073,647)
59				
60	Total Rate Base Deductions	(3,541,019,871)	-	(3,541,019,871)
61				
62	Total Rate Base:	3,384,540,086	-	3,384,540,086
63				
64	Return on Rate Base	6.677%		7.655%
65				
66	Return on Equity	7.923%		9.800%
67				
68	TAX CALCULATION:			
69	Operating Revenue	293,030,549	53,353,532	346,384,081
70	Other Deductions			
71	Interest (AFUDC)	(16,809,094)	-	(16,809,094)
72	Interest	85,739,606	-	85,739,606
73	Schedule "M" Additions	259,848,068	-	259,848,068
74	Schedule "M" Deductions	378,729,222	-	378,729,222
75	Income Before Tax	105,218,882	53,353,532	158,572,413
76				
77	State Income Taxes	4,676,658	2,422,250	7,098,908
78	Taxable Income	100,542,224	50,931,281	151,473,505
79				
80	Federal Income Taxes + Other	18,023,392	17,825,948	35,849,340
81		Ref. Page 2.2		

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
December 2014

Net Rate Base	$	3,384,540,086	Ref. Page 2.2
Return on Rate Base Requested		7.655%	Ref. Page 2.1
Revenues Required to Earn Requested Return		259,098,491	
Less Current Operating Revenues		(225,993,158)	
Increase to Current Revenues		33,105,333	
Net to Gross Bump-up		166.11%	
Price Change Required for Requested Return	$	54,991,857	
Requested Price Change	$	54,991,857	
Uncollectible Percent		0.599%	Ref. Page 1.6
Increased Uncollectible Expense	$	329,519	
Requested Price Change	$	54,991,857	
Franchise Tax		2.300%	Ref. Page 1.6
Revenue Tax		0.000%	Ref. Page 1.6
Resource Supplier Tax		0.080%	Ref. Page 1.6
Gross Receipts		0.000%	Ref. Page 1.6
Increase Taxes Other Than Income	$	1,308,806	
Requested Price Change	$	54,991,857	
Uncollectible Expense		(329,519)	
Taxes Other Than Income		(1,308,806)	
Income Before Taxes	$	53,353,532	
State Effective Tax Rate		4.54%	Ref. Page 2.1
State Income Taxes	$	2,422,250	
Taxable Income	$	50,931,281	
Federal Income Tax Rate		35.00%	Ref. Page 2.1
Federal Income Taxes	$	17,825,948	
Operating Income		100.000%	
Net Operating Income		60.200%	Ref. Page 1.6
Net to Gross Bump-Up		166.11%	

PacifiCorp
OREGON
Normalized Results of Operations - 2010 PROTOCOL
December 2014

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.599%	See Note (1) Below
Taxes Other - Franchise Tax	2.300%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.080%	
Taxes Other - Gross Receipts	0.000%	
Sub-Total	97.021%	
State Income Tax @ 4.54%	4.405%	
Sub-Total	92.616%	
Federal Income Tax @ 35.00%	32.416%	
Net Operating Income	60.200%	

(1) Uncollectible Accounts =	6,762,199	Pg. 4.5.1
	1,128,512,328	Pg. 2.2, General Business Revenues

PacifiCorp
Oregon General Rate Case - December 2014
Adjustment Summary

		TOTAL COMPANY ACTUAL RESULTS JUNE 2012	OREGON ALLOCATED ACTUAL RESULTS JUNE 2012	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 NPC Adjustments	Tab 6 Deperciation & Amortization Adjustments
1	Operating Revenues:						
2	General Business Revenues	4,092,063,041	1,128,512,328	80,664,152	-	-	-
3	Interdepartmental	-	-	-	-	-	-
4	Special Sales	339,615,342	86,880,114	-	-	37,150,351	-
5	Other Operating Revenues	249,987,732	56,502,980	(6,866,375)	(10,204,815)	135,638	-
6	Total Operating Revenues	4,681,666,114	1,271,895,421	73,797,777	(10,204,815)	37,285,989	-
7							
8	Operating Expenses:						
9	Steam Production	1,033,981,927	259,370,846	-	5,193,310	31,191,424	(73,384)
10	Nuclear Production	-	-	-	-	-	-
11	Hydro Production	38,494,364	10,028,937	-	1,077,115	-	(15,541)
12	Other Power Supply	958,605,486	225,879,311	-	369,279	49,279,783	(12,522)
13	Embedded Cost Differential (ECD)	-	(8,792,171)	-	-	-	-
13	Transmission	205,329,189	53,364,883	(197,987)	(222,688)	657,728	(6,413)
14	Distribution	208,601,621	65,912,168	-	6,074,891	-	(35,547)
15	Customer Accounting	94,659,859	35,169,515	-	1,170,262	-	(21,361)
16	Customer Service & Info	109,993,566	27,253,445	-	(23,182,913)	-	(2,621)
17	Sales	-	-	-	-	-	-
18	Administrative & General	152,548,405	47,477,959	-	1,498,449	-	(29,318)
19							
20	Total O&M Expenses	2,802,214,417	715,664,893	(197,987)	(8,022,295)	81,128,935	(196,707)
21							
22	Depreciation	549,502,550	154,054,000	-	-	-	46,509,009
23	Amortization	52,427,146	14,064,994	-	-	-	644,345
24	Taxes Other Than Income	157,778,830	62,043,915	-	-	-	-
25	Income Taxes - Federal	(117,200,416)	(14,847,617)	24,717,985	(760,168)	(14,659,982)	(13,555,340)
26	Income Taxes - State	(6,488,596)	440,987	3,358,764	(103,294)	(1,992,048)	(1,841,946)
27	Income Taxes - Def Net	368,714,954	93,550,467	19,311	-	-	-
28	Investment Tax Credit Adj.	(1,862,752)	-	-	-	-	-
29	Misc Revenue & Expense	(764,772)	(188,071)	(50,436)	148,288	-	-
30							
31	Total Operating Expenses:	3,804,321,362	1,024,783,568	27,847,637	(8,737,469)	64,476,904	31,559,361
32							
33	Operating Rev For Return:	877,344,752	247,111,853	45,950,141	(1,467,346)	(27,190,915)	(31,559,361)
34							
35	Rate Base:						
36	Electric Plant In Service	23,253,605,964	6,371,400,760	-	-	75,000	-
37	Plant Held for Future Use	46,178,566	13,855,477	-	-	-	-
38	Misc Deferred Debits	281,108,847	23,474,662	-	-	-	-
39	Elec Plant Acq Adj	49,044,288	12,777,509	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-
41	Prepayments	26,323,174	7,197,975	-	-	-	-
42	Fuel Stock	264,151,338	65,210,335	-	-	-	-
43	Material & Supplies	200,372,004	58,580,887	-	-	-	-
44	Working Capital	83,829,274	26,812,692	560,970	(178,797)	1,297,390	(313,779)
45	Weatherization Loans	(5,877,664)	(1,219)	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-
47							
48	Total Electric Plant:	24,198,735,790	6,579,309,078	560,970	(178,797)	1,372,390	(313,779)
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec	(7,170,108,718)	(2,107,464,837)	-	-	-	(243,039,682)
52	Accum Prov For Amort	(501,645,416)	(140,183,768)	-	-	-	(8,698,357)
53	Accum Def Income Tax	(3,458,822,902)	(913,623,771)	11,405	(2,016,181)	-	-
54	Unamortized ITC	(3,233,092)	(1,997,073)	-	-	-	-
55	Customer Adv For Const	(22,790,686)	(6,632,669)	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-
57	Misc Rate Base Deductions	(62,558,327)	(8,043,594)	(30,052)	-	-	-
58							
59	Total Rate Base Deductions	(11,219,159,141)	(3,177,945,714)	(18,647)	(2,016,181)	-	(251,738,039)
60							
61	Total Rate Base:	12,979,576,648	3,401,363,365				
62							
63	Return on Rate Base	6.759%	7.265%	1.350%	-0.038%	-0.803%	-0.380%
64							
65	Return on Equity	8.080%	9.051%	2.590%	-0.072%	-1.541%	-0.729%
66							
67	TAX CALCULATION:						
68	Operating Revenue		326,255,690	74,046,200	(2,330,808)	(43,842,946)	(46,956,647)
69	Other Deductions						
70	Interest (AFUDC)		(14,356,107)	-	-	-	-
71	Interest		86,165,786	13,739	(55,605)	34,766	(6,385,158)
72	Schedule "M" Additions		222,280,382	-	-	-	-
73	Schedule "M" Deductions		466,054,294	50,884	-	-	-
74	Income Before Tax		10,672,100	73,981,577	(2,275,203)	(43,877,712)	(40,571,489)
75							
76	State Income Taxes		440,987	3,358,764	(103,294)	(1,992,048)	(1,841,946)
77	Taxable Income		10,231,113	70,622,814	(2,171,909)	(41,885,664)	(38,729,543)
78							
79	Federal Income Taxes + Other		(14,847,617)	24,717,985	(760,168)	(14,659,982)	(13,555,340)
80							
81	PRICE CHANGE		22,050,540	(76,259,631)	2,158,311	45,341,832	20,371,790

PacifiCorp
Oregon General Rate Case - December 2014
Adjustment Summary

	Tab 7	Tab 8	
	Tax Adjustments	Rate Base Adjustments	Oregon Normalized Results December 2014
1 Operating Revenues:			
2 General Business Revenues	-	-	1,209,176,480
3 Interdepartmental	-	-	-
4 Special Sales	-	-	124,030,465
5 Other Operating Revenues	-	-	39,567,427
6 Total Operating Revenues	-	-	1,372,774,372
7			
8 Operating Expenses:			
9 Steam Production	-	-	295,682,196
10 Nuclear Production	-	-	-
11 Hydro Production	-	32,640	11,123,151
12 Other Power Supply	-	(67,913)	275,447,938
13 Embedded Cost Differential (ECD)	-	-	(8,792,171)
13 Transmission	-	-	53,595,523
14 Distribution	-	-	71,951,511
15 Customer Accounting	-	(388,671)	35,929,744
16 Customer Service & Info	-	-	4,067,911
17 Sales	-	-	-
18 Administrative & General	894,328	(2,188,437)	47,652,982
19			
20 Total O&M Expenses	894,328	(2,612,381)	786,658,786
21		-	-
22 Depreciation	-	10,558,754	211,121,763
23 Amortization	-	(179,681)	14,529,658
24 Taxes Other Than Income	5,479,921	-	67,523,836
25 Income Taxes - Federal	41,946,976	(4,818,461)	18,023,392
26 Income Taxes - State	5,468,944	(654,749)	4,676,658
27 Income Taxes - Def Net	(48,414,852)	(817,585)	44,337,342
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	(90,219)
30			
31 Total Operating Expenses:	5,375,316	1,475,897	1,146,781,214
32			
33 Operating Rev For Return:	(5,375,316)	(1,475,897)	225,993,158
34			
35 Rate Base:			
36 Electric Plant In Service	-	314,886,851	6,686,362,611
37 Plant Held for Future Use	-	(13,855,477)	-
38 Misc Deferred Debits	-	50,395,795	73,870,456
39 Elec Plant Acq Adj	-	(2,704,773)	10,072,737
40 Nuclear Fuel	-	-	-
41 Prepayments	-	-	7,197,975
42 Fuel Stock	-	(4,739,285)	60,471,050
43 Material & Supplies	-	-	58,580,887
44 Working Capital	1,082,354	(255,371)	29,005,460
45 Weatherization Loans	-	-	(1,219)
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	1,082,354	343,727,740	6,925,559,957
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	(9,360,216)	(2,359,864,735)
52 Accum Prov For Amort	-	(3,233,009)	(152,115,135)
53 Accum Def Income Tax	(115,102,825)	16,116,906	(1,014,614,465)
54 Unamortized ITC	1,403,824	-	(593,249)
55 Customer Adv For Const	-	874,029	(5,758,640)
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	-	-	(8,073,647)
58			
59 Total Rate Base Deductions	(113,699,001)	4,397,710	(3,541,019,871)
60			
61 Total Rate Base:			3,401,363,365
62			
63 Return on Rate Base	0.097%	-0.814%	6.677%
64			
65 Return on Equity	0.187%	-1.563%	7.923%
66			
67 TAX CALCULATION:			
68 Operating Revenue	(6,374,249)	(7,766,692)	293,030,549
69 Other Deductions	-	-	
70 Interest (AFUDC)	(2,452,986)	-	(16,809,094)
71 Interest	(2,852,886)	8,818,965	85,739,606
72 Schedule "M" Additions	37,567,685	-	259,848,068
73 Schedule "M" Deductions	(85,212,080)	(2,163,876)	378,729,222
74 Income Before Tax	121,711,389	(14,421,781)	105,218,882
75			
76 State Income Taxes	5,468,944	(654,749)	4,676,658
77 Taxable Income	116,242,445	(13,767,032)	100,542,224
78			
79 Federal Income Taxes + Other	41,946,976	(4,818,461)	18,023,392
80			
81 PRICE CHANGE	(5,391,799)	46,720,813	54,991,857

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	DECEMBER 2014
FILE:	OR JAM Dec 2014 GRC
PREPARED BY:	Revenue Requirement Department
DATE:	2/12/2013
TIME:	6:04:14 PM
TYPE OF RATE BASE:	Year End
ALLOCATION METHOD:	**2010 PROTOCOL**
FERC JURISDICTION:	Separate Jurisdiction
8 OR 12 CP:	12 Coincidental Peaks
DEMAND %	75% Demand
ENERGY %	25% Energy

TAX INFORMATION

TAX RATE ASSUMPTIONS:	TAX RATE
FEDERAL RATE	35.00%
STATE EFFECTIVE RATE	4.54%
TAX GROSS UP FACTOR	1.661
FEDERAL/STATE COMBINED RATE	37.951%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	47.60%	5.322%	2.533%
PREFERRED	0.30%	5.427%	0.016%
COMMON	52.10%	9.800%	5.106%
	100.00%		7.655%

OTHER INFORMATION

The stipulated capital structure and cost of capital from UE-246 was used to develop the results and subsequent revenue requirement for this case.

2010 PROTOCOL
Year End

RESULTS OF OPERATIONS SUMMARY

			JUNE 2012 UNADJUSTED RESULTS		DECEMBER 2014 PRO FORMA RESULTS	
	Description of Account Summary:	**Ref**	**TOTAL**	**OREGON**	**TOTAL**	**OREGON**
1	Operating Revenues					
2	General Business Revenues	2.3	4,092,063,041	1,128,512,328	4,462,720,886	1,209,176,480
3	Interdepartmental	2.3	0	0	0	0
4	Special Sales	2.3	339,615,342	86,880,114	482,210,526	124,030,465
5	Other Operating Revenues	2.4	249,987,732	56,502,980	172,625,748	39,567,427
6	Total Operating Revenues	2.4	4,681,666,114	1,271,895,421	5,117,557,160	1,372,774,372
7						
8	Operating Expenses:					
9	Steam Production	2.5	1,033,981,927	259,370,846	1,179,365,066	295,682,196
10	Nuclear Production	2.6	0	0	0	0
11	Hydro Production	2.7	38,494,364	10,028,937	42,694,317	11,123,151
12	Other Power Supply	2.9	958,605,486	225,879,311	1,085,961,655	275,447,938
13	Embedded Cost Differential (ECD)		0	(8,792,171)	0	(8,792,171)
14	Transmission	2.10	205,329,189	53,364,883	205,984,992	53,595,523
15	Distribution	2.12	208,601,621	65,912,168	217,864,397	71,951,511
16	Customer Accounting	2.12	94,659,859	35,169,515	97,119,698	35,929,744
17	Customer Service & Infor	2.13	109,993,566	27,253,445	18,895,566	4,067,911
18	Sales	2.13	0	0	0	0
19	Administrative & General	2.14	152,548,405	47,477,959	141,901,957	47,652,982
20						
21	Total O & M Expenses	2.14	2,802,214,417	715,664,893	2,989,787,648	786,658,786
22						
23	Depreciation	2.16	549,502,550	154,054,000	779,010,766	211,121,763
24	Amortization	2.17	52,427,146	14,064,994	54,063,663	14,529,658
25	Taxes Other Than Income	2.17	157,778,830	62,043,915	173,216,287	67,523,836
26	Income Taxes - Federal	2.20	(117,200,416)	(14,847,617)	71,410,664	18,023,392
27	Income Taxes - State	2.20	(6,488,596)	440,987	18,253,831	4,676,658
28	Income Taxes - Def Net	2.19	368,714,954	93,550,467	169,493,895	44,337,342
29	Investment Tax Credit Adj.	2.17	(1,862,752)	0	(1,862,752)	0
30	Misc Revenue & Expense	2.4	(764,772)	(188,071)	(364,815)	(90,219)
31						
32	Total Operating Expenses	2.20	3,804,321,362	1,024,783,568	4,253,009,187	1,146,781,214
33						
34	Operating Revenue for Return		877,344,752	247,111,853	864,547,973	225,993,158
35						
36	Rate Base:					
37	Electric Plant in Service	2.30	23,253,605,964	6,371,400,760	24,416,813,071	6,686,362,611
38	Plant Held for Future Use	2.31	46,178,566	13,855,477	0	0
39	Misc Deferred Debits	2.33	281,108,847	23,474,662	465,228,507	73,870,456
40	Elec Plant Acq Adj	2.31	49,044,288	12,777,509	38,662,480	10,072,737
41	Nuclear Fuel	2.31	0	0	0	0
42	Prepayments	2.32	26,323,174	7,197,975	26,323,174	7,197,975
43	Fuel Stock	2.32	264,151,338	65,210,335	244,953,638	60,471,050
44	Material & Supplies	2.32	200,372,004	58,580,887	200,372,004	58,580,887
45	Working Capital	2.33	83,829,274	26,812,692	89,719,796	29,005,460
46	Weatherization Loans	2.31	(5,877,664)	(1,219)	(5,877,664)	(1,219)
47	Miscellaneous Rate Base	2.34	0	0	0	0
48						
49	Total Electric Plant		24,198,735,790	6,579,309,078	25,476,195,005	6,925,559,957
50						
51	Rate Base Deductions:					
52	Accum Prov For Depr	2.38	(7,170,108,718)	(2,107,464,837)	(8,071,766,363)	(2,359,864,735)
53	Accum Prov For Amort	2.39	(501,645,416)	(140,183,768)	(544,774,074)	(152,115,135)
54	Accum Def Income Taxes	2.35	(3,458,822,902)	(913,623,771)	(3,812,324,071)	(1,014,614,465)
55	Unamortized ITC	2.35	(3,233,092)	(1,997,073)	(1,084,972)	(593,249)
56	Customer Adv for Const	2.34	(22,790,686)	(6,632,669)	(22,790,686)	(5,758,640)
57	Customer Service Deposits	2.34	0	0	0	0
58	Misc. Rate Base Deductions	2.34	(62,558,327)	(8,043,594)	(62,680,062)	(8,073,647)
59						
60	Total Rate Base Deductions		(11,219,159,141)	(3,177,945,714)	(12,515,420,228)	(3,541,019,871)
61						
62	Total Rate Base		12,979,576,648	3,401,363,365	12,960,774,777	3,384,540,086
63						
64	Return on Rate Base		6.759%	7.265%	6.670%	6.677%
65						
66	Return on Equity		8.080%	9.051%	7.910%	7.923%
67	Net Power Costs		1,393,001,321	347,871,955	1,457,051,989	363,112,133
68	100 Basis Points in Equity:					
69	Revenue Requirement Impact		108,984,181	28,559,853	108,826,309	28,418,595
70	Rate Base Decrease		(928,841,298)	(227,599,736)	(938,965,076)	(244,969,673)

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	 OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	 OREGON
71	Sales to Ultimate Customers								
72	440	Residential Sales							
73			0	S		1,538,606,880	548,352,337	1,680,851,141	583,299,297
74									
75					B1	1,538,606,880	548,352,337	1,680,851,141	583,299,297
76									
77	442	Commercial & Industrial Sales							
78			0	S		2,514,992,419	573,646,675	2,747,001,471	621,158,232
79			P	SE		-	-	-	-
80			PT	SG		-	-	-	-
81									
82									
83					B1	2,514,992,419	573,646,675	2,747,001,471	621,158,232
84									
85	444	Public Street & Highway Lighting							
86			0	S		20,929,527	6,513,316	18,254,607	4,718,952
87			0	SO		-	-	-	-
88					B1	20,929,527	6,513,316	18,254,607	4,718,952
89									
90	445	Other Sales to Public Authority							
91			0	S		17,534,215	-	16,613,667	-
92									
93					B1	17,534,215	-	16,613,667	-
94									
95	448	Interdepartmental							
96			DPW	S		-	-	-	-
97			GP	SO		-	-	-	-
98					B1	-	-	-	-
99									
100	**Total Sales to Ultimate Customers**				**B1**	**4,092,063,041**	**1,128,512,328**	**4,462,720,886**	**1,209,176,480**
101									
102									
103									
104	447	Sales for Resale-Non NPC							
105			P	S		10,074,303	1,024,807	10,074,303	1,024,807
106						10,074,303	1,024,807	10,074,303	1,024,807
107									
108	447NPC	Sales for Resale-NPC							
109			P	SG		329,539,169	85,854,845	472,136,224	123,005,658
110			P	SE		1,870	462	-	-
111			P	SG		-	-	-	-
112						329,541,039	85,855,307	472,136,224	123,005,658
113									
114		Total Sales for Resale			B1	339,615,342	86,880,114	482,210,526	124,030,465
115									
116	449	Provision for Rate Refund							
117			P	S		-	-	-	-
118			P	SG		-	-	-	-
119									
120									
121					B1	-	-	-	-
122									
123	**Total Sales from Electricity**				**B1**	**4,431,678,382**	**1,215,392,442**	**4,944,931,412**	**1,333,206,945**
124	450	Forfeited Discounts & Interest							
125			CUST	S		8,704,074	3,713,451	8,704,074	3,713,451
126			CUST	SO		-	-	-	-
127					B1	8,704,074	3,713,451	8,704,074	3,713,451
128									
129	451	Misc Electric Revenue							
130			CUST	S		6,239,419	1,449,104	6,239,419	1,449,104
131			CUST	SG		-	-	-	-
132			CUST	SO		4,129	1,131	4,129	1,131
133					B1	6,243,548	1,450,235	6,243,548	1,450,235
134									
135	453	Water Sales							
136			P	SG		12,096	3,151	12,096	3,151
137					B1	12,096	3,151	12,096	3,151
138									
139	454	Rent of Electric Property							
140			DPW	S		10,740,536	5,032,337	10,740,536	5,032,337
141			T	SG		5,635,964	1,468,338	5,635,964	1,468,338
142			GP	SO		3,624,836	992,634	3,624,836	992,634
143					B1	20,001,336	7,493,310	20,001,336	7,493,310
144									
145									

2010 PROTOCOL

Line	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
146									
147	456	Other Electric Revenue							
148			DMSC	S		85,315,923	10,204,815	33,788,726	-
149			CUST	CN		-	-	-	-
150			OTHSE	SE		11,357,475	2,803,790	11,357,475	2,803,790
151			OTHSO	SO		(26,572)	(7,277)	(26,572)	(7,277)
152			OTHSGR	SG		118,379,851	30,841,505	92,545,065	24,110,767
153									
154									
155					B1	215,026,677	43,842,832	137,664,694	26,907,280
156									
157	**Total Other Electric Revenues**				**B1**	**249,987,732**	**56,502,980**	**172,625,748**	**39,567,427**
158									
159	**Total Electric Operating Revenues**				**B1**	**4,681,666,114**	**1,271,895,421**	**5,117,557,160**	**1,372,774,372**
160									
161	Summary of Revenues by Factor								
162		S				4,213,137,296	1,149,936,843	4,532,267,943	1,220,396,180
163		CN				-	-	-	-
164		SE				11,359,345	2,804,251	11,357,475	2,803,790
165		SO				3,602,393	986,488	3,602,393	986,488
166		SG				453,567,081	118,167,839	570,329,349	148,587,915
167		DGP				-	-	-	-
168									
169	Total Electric Operating Revenues					4,681,666,114	1,271,895,421	5,117,557,160	1,372,774,372
170	Miscellaneous Revenues								
171	41160	Gain on Sale of Utility Plant - CR							
172			DPW	S		-	-	-	-
173			T	SG		-	-	-	-
174			G	SO		-	-	-	-
175			T	SG		-	-	-	-
176			P	SG		-	-	-	-
177					B1	-	-	-	-
178									
179	41170	Loss on Sale of Utility Plant							
180			DPW	S		-	-	-	-
181			T	SG		-	-	-	-
182					B1	-	-	-	-
183									
184	4118	Gain from Emission Allowances							
185			P	S		-	-	-	-
186			P	SE		(1,814)	(448)	(206,119)	(50,884)
187					B1	(1,814)	(448)	(206,119)	(50,884)
188									
189	41181	Gain from Disposition of NOX Credits							
190			P	SE		-	-	-	-
191					B1	-	-	-	-
192									
193	4194	Impact Housing Interest Income							
194			P	SG		-	-	-	-
195					B1	-	-	-	-
196									
197	421	(Gain) / Loss on Sale of Utility Plant							
198			DPW	S		(4,903)	11,947	(5,126)	165
199			T	SG		-	-	-	-
200			T	SG		(26,947)	(7,020)	(26,947)	(7,020)
201			CUST	CN		-	-	-	-
202			PTD	SO		(155,792)	(42,662)	38,278	10,482
203			P	SG		(575,317)	(149,887)	(164,901)	(42,962)
204					B1	(762,958)	(187,623)	(158,696)	(39,335)
205									
206	**Total Miscellaneous Revenues**					**(764,772)**	**(188,071)**	**(364,815)**	**(90,219)**
207	Miscellaneous Expenses								
208	4311	Interest on Customer Deposits							
209			CUST	S		-	-	-	-
210					B1	-	-	-	-
211	**Total Miscellaneous Expenses**					-	-	-	-
212									
213	**Net Misc Revenue and Expense**				**B1**	**(764,772)**	**(188,071)**	**(364,815)**	**(90,219)**
214									

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
500	Operation Supervision & Engineering							
		P	SG		17,858,424	4,652,656	16,479,062	4,293,290
		P	SG		2,065,704	538,178	2,162,093	563,290
				B2	19,924,129	5,190,834	18,641,155	4,856,580
501	Fuel Related-Non NPC							
		P	SE		16,121,513	3,979,875	16,760,530	4,137,627
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SE		3,257,603	804,196	3,409,608	841,721
				B2	19,379,116	4,784,070	20,170,138	4,979,348
501NPC	Fuel Related-NPC							
		P	S		659,235	-	-	-
		P	SE		642,970,169	158,728,328	764,151,498	188,644,039
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SE		53,938,291	13,315,602	59,706,693	14,739,632
				B2	697,567,695	172,043,930	823,858,191	203,383,671
	Total Fuel Related				716,946,810	176,828,000	844,028,329	208,363,019
502	Steam Expenses							
		P	SG		29,033,421	7,564,078	30,372,100	7,912,844
		P	SG		8,911,067	2,321,601	9,326,871	2,429,930
				B2	37,944,489	9,885,678	39,698,972	10,342,774
503	Steam From Other Sources-Non-NPC							
		P	SE		-	-	(109)	(27)
				B2	-	-	(109)	(27)
503NPC	Steam From Other Sources-NPC							
		P	SE		3,975,674	981,464	3,374,877	833,147
				B2	3,975,674	981,464	3,374,877	833,147
505	Electric Expenses							
		P	SG		3,101,340	807,992	3,244,154	845,200
		P	SG		1,014,290	264,253	1,061,618	276,583
				B2	4,115,629	1,072,245	4,305,772	1,121,783
506	Misc. Steam Expense							
		P	SG		56,484,552	14,715,921	59,070,240	15,389,570
		P	SE		-	-	-	-
		P	SG		1,824,538	475,347	1,909,674	497,527
				B2	58,309,091	15,191,268	60,979,914	15,887,098
507	Rents							
		P	SG		333,631	86,921	349,199	90,977
		P	SG		-	-	-	-
				B2	333,631	86,921	349,199	90,977
510	Maint Supervision & Engineering							
		P	SG		4,264,472	1,111,023	(2,772,454)	(722,307)
		P	SG		2,038,200	531,012	2,089,967	544,499
				B2	6,302,672	1,642,035	(682,486)	(177,808)
511	Maintenance of Structures							
		P	SG		23,163,124	6,034,689	24,106,297	6,280,414
		P	SG		858,103	223,562	891,395	232,235
				B2	24,021,227	6,258,251	24,997,692	6,512,649
512	Maintenance of Boiler Plant							
		P	SG		106,024,128	27,622,468	125,319,889	32,649,593
		P	SG		5,320,169	1,386,064	5,525,830	1,439,645
				B2	111,344,298	29,008,532	130,845,719	34,089,237
513	Maintenance of Electric Plant							
		P	SG		37,946,481	9,886,197	39,494,978	10,289,627
		P	SG		610,812	159,135	634,517	165,311
				B2	38,557,293	10,045,332	40,129,495	10,454,938
514	Maintenance of Misc. Steam Plant							
		P	SG		9,839,461	2,563,475	10,237,147	2,667,084
		P	SG		2,367,524	616,811	2,459,391	640,745
				B2	12,206,985	3,180,286	12,696,538	3,307,829
Total Steam Power Generation				**B2**	**1,033,981,927**	**259,370,846**	**1,179,365,066**	**295,682,196**

2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
517	Operation Super & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
518	Nuclear Fuel Expense							
		P	SE		-	-	-	-
				B2	-	-	-	-
519	Coolants and Water							
		P	SG		-	-	-	-
				B2	-	-	-	-
520	Steam Expenses							
		P	SG		-	-	-	-
				B2	-	-	-	-
523	Electric Expenses							
		P	SG		-	-	-	-
				B2	-	-	-	-
524	Misc. Nuclear Expenses							
		P	SG		-	-	-	-
				B2	-	-	-	-
528	Maintenance Super & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
529	Maintenance of Structures							
		P	SG		-	-	-	-
				B2	-	-	-	-
530	Maintenance of Reactor Plant							
		P	SG		-	-	-	-
				B2	-	-	-	-
531	Maintenance of Electric Plant							
		P	SG		-	-	-	-
				B2	-	-	-	-
532	Maintenance of Misc Nuclear							
		P	SG		-	-	-	-
				B2	-	-	-	-
Total Nuclear Power Generation				**B2**	-	-	-	-
535	Operation Super & Engineering							
		P	DGP		-	-	-	-
		P	SG		5,037,384	1,312,390	7,628,533	1,987,462
		P	SG		(845,964)	(220,399)	(569,127)	(148,275)
				B2	4,191,420	1,091,991	7,059,406	1,839,187
536	Water For Power							
		P	DGP		-	-	-	-
		P	SG		222,131	57,872	230,128	59,955
		P	SG		-	-	-	-
				B2	222,131	57,872	230,128	59,955

2010 PROTOCOL
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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
359	537	Hydraulic Expenses							
360			P	DGP		-	-	-	-
361			P	SG		3,539,452	922,133	3,901,253	1,016,394
362			P	SG		302,079	78,701	312,451	81,403
363									
364					B2	3,841,530	1,000,834	4,213,704	1,097,796
365									
366	538	Electric Expenses							
367			P	DGP		-	-	-	-
368			P	SG		-	-	-	-
369			P	SG		-	-	-	-
370									
371					B2	-	-	-	-
372									
373	539	Misc. Hydro Expenses							
374			P	DGP		-	-	-	-
375			P	SG		14,672,822	3,822,711	15,120,579	3,939,365
376			P	SG		6,989,478	1,820,969	7,238,455	1,885,835
377									
378									
379					B2	21,662,300	5,643,679	22,359,034	5,825,200
380									
381	540	Rents (Hydro Generation)							
382			P	DGP		-	-	-	-
383			P	SG		(165,850)	(43,209)	(174,996)	(45,592)
384			P	SG		33,495	8,726	34,519	8,993
385									
386					B2	(132,355)	(34,482)	(140,477)	(36,599)
387									
388	541	Maint Supervision & Engineering							
389			P	DGP		-	-	-	-
390			P	SG		388	101	404	105
391			P	SG		-	-	-	-
392									
393					B2	388	101	404	105
394									
395	542	Maintenance of Structures							
396			P	DGP		-	-	-	-
397			P	SG		926,329	241,336	966,108	251,700
398			P	SG		205,962	53,659	215,029	56,022
399									
400					B2	1,132,291	294,996	1,181,137	307,722
401									
402									
403									
404									
405	543	Maintenance of Dams & Waterways							
406			P	DGP		-	-	-	-
407			P	SG		1,709,562	445,392	1,781,414	464,112
408			P	SG		568,608	148,139	593,510	154,627
409									
410					B2	2,278,170	593,532	2,374,924	618,739
411									
412	544	Maintenance of Electric Plant							
413			P	DGP		-	-	-	-
414			P	SG		2,013,460	524,567	2,100,959	547,363
415			P	SG		476,270	124,083	497,279	129,556
416									
417					B2	2,489,730	648,649	2,598,239	676,919
418									
419	545	Maintenance of Misc. Hydro Plant							
420			P	DGP		-	-	-	-
421			P	SG		2,022,348	526,882	2,028,465	528,476
422			P	SG		786,410	204,884	789,352	205,650
423									
424					B2	2,808,758	731,766	2,817,818	734,126
425									
426	**Total Hydraulic Power Generation**				**B2**	**38,494,364**	**10,028,937**	**42,694,317**	**11,123,151**

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
546	Operation Super & Engineering							
		P	SG		474,373	123,588	509,659	132,781
		P	SG		-	-	-	-
				B2	474,373	123,588	509,659	132,781
547	Fuel-Non-NPC							
		P	SE		-	-	-	-
		P	SE		-	-	-	-
				B2	-	-	-	-
547NPC	Fuel-NPC							
		P	SE		385,597,558	95,191,439	334,359,033	82,542,321
		P	SE		9,132,801	2,254,590	7,134,120	1,761,181
				B2	394,730,359	97,446,029	341,493,153	84,303,502
548	Generation Expense							
		P	SG		17,018,069	4,433,718	15,042,752	3,919,088
		P	SG		726,180	189,192	772,387	201,230
				B2	17,744,249	4,622,910	15,815,139	4,120,318
549	Miscellaneous Other							
		P	S		-	-	-	-
		P	SG		14,405,059	3,752,950	13,032,903	3,395,462
		P	SG		-	-	-	-
				B2	14,405,059	3,752,950	13,032,903	3,395,462
550	Rents							
		P	S		-	-	384,295	384,295
		P	SG		4,241,932	1,105,151	4,557,470	1,187,358
		P	SG		-	-	-	-
				B2	4,241,932	1,105,151	4,941,764	1,571,652
551	Maint Supervision & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
552	Maintenance of Structures							
		P	SG		1,423,389	370,836	1,481,480	385,970
		P	SG		83,600	21,780	87,182	22,713
				B2	1,506,988	392,616	1,568,662	408,684
553	Maint of Generation & Electric Plant							
		P	SG		14,021,506	3,653,023	16,804,413	4,378,054
		P	SG		948,421	247,092	986,877	257,111
				B2	14,969,927	3,900,115	17,791,290	4,635,165
554	Maintenance of Misc. Other							
		P	SG		4,146,189	1,080,207	4,312,762	1,123,604
		P	SG		238,501	62,137	248,401	64,716
				B2	4,384,691	1,142,344	4,561,162	1,188,320
Total Other Power Generation				**B2**	**452,457,579**	**112,485,703**	**399,713,732**	**99,755,885**
555	Purchased Power-Non NPC							
		DMSC	S		(39,697,756)	(29,094,524)	-	-
					(39,697,756)	(29,094,524)	-	-
555NPC	Purchased Power-NPC							
		P	S		-	-	(138,381)	(138,381)
		P	SG		501,391,831	130,627,622	591,180,527	154,020,272
		P	SE		(16,365,455)	(4,040,096)	25,882,481	6,389,539
	Seasonal Co	P	SG		-	-	-	-
			DGP		-	-	-	-
					485,026,376	126,587,526	616,924,627	160,271,430
	Total Purchased Power			B2	445,328,620	97,493,002	616,924,627	160,271,430
556	System Control & Load Dispatch							
		P	SG		1,766,410	460,203	1,869,969	487,183
				B2	1,766,410	460,203	1,869,969	487,183

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
557	Other Expenses							
		P	S		(183,792)	(53,813)	9,937,337	(53,813)
		P	SG		62,527,920	16,290,400	56,512,684	14,723,251
		P	SGCT		1,122,425	293,409	1,122,425	293,409
		P	SE		(4,413,675)	(1,089,592)	(119,119)	(29,407)
		P	SG		-	-	-	-
		P	TROJP		-	-	-	-
				B2	59,052,877	15,440,404	67,453,327	14,933,440
Total Other Power Supply				**B2**	**506,147,907**	**113,393,609**	**686,247,922**	**175,692,053**
Total Production Expense				**B2**	**2,031,081,777**	**495,279,094**	**2,308,021,038**	**582,253,285**
Embedded Cost Differentials								
	Company Owned Hy(	P	DGP		-	-	-	-
	Company Owned Hy(	P	SG		-	-	-	-
	Mid-C Contract	P	MC		-	-	-	-
	Mid-C Contract	P	SG		-	-	-	-
	Existing QF Contract:	P	S		-	-	-	-
	Existing QF Contract:	P	SG		-	-	-	-
				B2	-	-	-	-
2010 Protocol Stipulated Embedded Cost Differential and Adjustment								
	Company Owned Hy(	P	DGP		(21,878,231)	(11,925,675)	(21,878,231)	(11,925,675)
	Company Owned Hy(	P	SG		21,878,231	5,699,936	21,878,231	5,699,936
	Mid-C Contract	P	MC		(16,420,299)	(6,844,413)	(16,420,299)	(6,844,413)
	Mid-C Contract	P	SG		16,420,299	4,277,981	16,420,299	4,277,981
					-	(8,792,171)	-	(8,792,171)
Summary of Production Expense by Factor								
	S				(39,222,314)	(29,148,337)	10,183,250	192,101
	SG				1,013,265,717	263,986,134	1,120,354,281	291,885,919
	SE				1,094,214,479	270,125,805	1,214,659,611	299,859,773
	SNPPH				-	-	-	-
	TROJP				-	-	-	-
	SGCT				1,122,425	293,409	1,122,425	293,409
	DGP				(21,878,231)	(11,925,675)	(21,878,231)	(11,925,675)
	DEU				-	-	-	-
	DEP				-	-	-	-
	SNPPS				-	-	-	-
	SNPPO				-	-	-	-
	DGU				-	-	-	-
	MC				(16,420,299)	(6,844,413)	(16,420,299)	(6,844,413)
	SSGCT				-	-	-	-
	SSECT				-	-	-	-
	SSGC				-	-	-	-
	SSGCH				-	-	-	-
	SSECH				-	-	-	-
Total Production Expense by Factor					2,031,081,777	486,486,924	2,308,021,038	573,461,114
560	Operation Supervision & Engineering							
		T	SG		4,908,370	1,278,778	4,697,736	1,223,901
				B2	4,908,370	1,278,778	4,697,736	1,223,901
561	Load Dispatching							
		T	SG		9,118,261	2,375,581	9,550,236	2,488,123
				B2	9,118,261	2,375,581	9,550,236	2,488,123
562	Station Expense							
		T	SG		2,627,632	684,577	2,779,785	724,217
				B2	2,627,632	684,577	2,779,785	724,217
563	Overhead Line Expense							
		T	SG		339,363	88,414	359,594	93,685
				B2	339,363	88,414	359,594	93,685
564	Underground Line Expense							
		T	SG		-	-	-	-
				B2	-	-	-	-

2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
565	Transmission of Electricity by Others							
		T	SG		-	-	-	-
		T	SE		-	-	-	-
					-	-	-	-
565NPC	Transmission of Electricity by Others-NPC							
		T	SG		131,761,383	34,327,795	138,432,164	36,065,734
		T	SE		9,480,873	2,340,518	5,105,200	1,260,307
					141,242,257	36,668,313	143,537,364	37,326,041
	Total Transmission of Electricity by Others			B2	141,242,257	36,668,313	143,537,364	37,326,041
566	Misc. Transmission Expense							
		T	SG		2,907,403	757,466	2,284,500	595,181
				B2	2,907,403	757,466	2,284,500	595,181
567	Rents - Transmission							
		T	SG		2,203,116	573,978	2,343,169	610,466
				B2	2,203,116	573,978	2,343,169	610,466
568	Maint Supervision & Engineering							
		T	SG		2,208,687	575,429	2,304,521	600,397
				B2	2,208,687	575,429	2,304,521	600,397
569	Maintenance of Structures							
		T	SG		4,505,090	1,173,711	4,677,117	1,218,529
				B2	4,505,090	1,173,711	4,677,117	1,218,529
570	Maintenance of Station Equipment							
		T	SG		10,419,175	2,714,508	10,838,960	2,823,874
				B2	10,419,175	2,714,508	10,838,960	2,823,874
571	Maintenance of Overhead Lines							
		T	SG		23,045,623	6,004,076	20,749,618	5,405,898
				B2	23,045,623	6,004,076	20,749,618	5,405,898
572	Maintenance of Underground Lines							
		T	SG		95,533	24,889	99,206	25,846
				B2	95,533	24,889	99,206	25,846
573	Maint of Misc. Transmission Plant							
		T	SG		1,708,680	445,162	1,763,187	459,363
				B2	1,708,680	445,162	1,763,187	459,363
Total Transmission Expense				**B2**	**205,329,189**	**53,364,883**	**205,984,992**	**53,595,523**
Summary of Transmission Expense by Factor								
	SE				9,480,873	2,340,518	5,105,200	1,260,307
	SG				195,848,316	51,024,365	200,879,792	52,335,215
	SNPT				-	-	-	-
Total Transmission Expense by Factor					205,329,189	53,364,883	205,984,992	53,595,523
580	Operation Supervision & Engineering							
		DPW	S		779,159	247,019	126,342	(3,245)
		DPW	SNPD		13,635,673	3,664,124	13,365,989	3,591,656
				B2	14,414,832	3,911,143	13,492,332	3,588,411
581	Load Dispatching							
		DPW	S		-	-	1	1
		DPW	SNPD		13,180,858	3,541,908	13,784,196	3,704,034
				B2	13,180,858	3,541,908	13,784,196	3,704,035
582	Station Expense							
		DPW	S		4,005,727	1,107,778	4,202,153	1,162,254
		DPW	SNPD		36,385	9,777	38,099	10,238
				B2	4,042,112	1,117,555	4,240,252	1,172,492

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
657	583	Overhead Line Expenses							
658			DPW	S		6,383,357	2,918,711	6,680,976	3,054,562
659			DPW	SNPD		17,871	4,802	18,709	5,027
660					B2	6,401,228	2,923,514	6,699,685	3,059,589
661									
662	584	Underground Line Expense							
663			DPW	S		135	-	142	-
664			DPW	SNPD		1,041	280	1,095	294
665					B2	1,175	280	1,236	294
666									
667	585	Street Lighting & Signal Systems							
668			DPW	S		-	-	-	-
669			DPW	SNPD		220,491	59,250	230,460	61,928
670					B2	220,491	59,250	230,460	61,928
671									
672	586	Meter Expenses							
673			DPW	S		6,547,433	3,146,157	6,853,656	3,293,344
674			DPW	SNPD		1,235,796	332,078	1,293,869	347,683
675					B2	7,783,229	3,478,236	8,147,525	3,641,027
676									
677	587	Customer Installation Expenses							
678			DPW	S		12,971,313	4,500,312	13,577,719	4,710,389
679			DPW	SNPD		-	-	-	-
680					B2	12,971,313	4,500,312	13,577,719	4,710,389
681									
682	588	Misc. Distribution Expenses							
683			DPW	S		1,544,650	83,894	1,620,234	89,574
684			DPW	SNPD		3,476,291	934,135	3,634,283	976,590
685					B2	5,020,941	1,018,029	5,254,517	1,066,164
686									
687	589	Rents							
688			DPW	S		2,900,913	1,691,500	3,050,785	1,778,965
689			DPW	SNPD		48,772	13,106	51,303	13,786
690					B2	2,949,685	1,704,606	3,102,088	1,792,751
691									
692	590	Maint Supervision & Engineering							
693			DPW	S		827,494	304,836	861,973	317,553
694			DPW	SNPD		3,490,454	937,941	3,657,608	982,858
695					B2	4,317,947	1,242,777	4,519,582	1,300,411
696									
697	591	Maintenance of Structures							
698			DPW	S		2,074,458	922,370	2,127,932	946,146
699			DPW	SNPD		144,949	38,950	148,685	39,954
700					B2	2,219,407	961,320	2,276,617	986,101
701									
702	592	Maintenance of Station Equipment							
703			DPW	S		10,509,327	3,064,090	10,891,081	3,168,320
704			DPW	SNPD		1,707,646	458,872	1,786,706	480,116
705					B2	12,216,973	3,522,962	12,677,786	3,648,436
706	593	Maintenance of Overhead Lines							
707			DPW	S		87,421,162	28,563,973	93,316,113	33,549,409
708			DPW	SNPD		1,288,093	346,131	1,078,853	289,905
709					B2	88,709,255	28,910,105	94,394,966	33,839,314
710									
711	594	Maintenance of Underground Lines							
712			DPW	S		21,126,297	5,759,231	21,927,613	5,981,807
713			DPW	SNPD		6,367	1,711	6,612	1,777
714					B2	21,132,664	5,760,942	21,934,225	5,983,583
715									
716	595	Maintenance of Line Transformers							
717			DPW	S		-	-	-	-
718			DPW	SNPD		870,008	233,785	905,592	243,347
719					B2	870,008	233,785	905,592	243,347
720									
721	596	Maint of Street Lighting & Signal Sys.							
722			DPW	S		3,933,543	1,185,321	4,073,638	1,233,766
723			DPW	SNPD		-	-	-	-
724					B2	3,933,543	1,185,321	4,073,638	1,233,766
725									

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
597	Maintenance of Meters							
		DPW	S		4,982,631	1,192,317	5,190,585	1,242,254
		DPW	SNPD		1,180,007	317,087	1,230,074	330,540
				B2	6,162,638	1,509,404	6,420,659	1,572,794
598	Maint of Misc. Distribution Plant							
		DPW	S		2,615,897	481,896	2,685,425	495,575
		DPW	SNPD		(562,577)	(151,173)	(554,104)	(148,897)
				B2	2,053,320	330,722	2,131,321	346,679
Total Distribution Expense				**B2**	**208,601,621**	**65,912,168**	**217,864,397**	**71,951,511**
Summary of Distribution Expense by Factor								
	S				168,623,497	55,169,405	177,186,367	61,020,673
	SNPD				39,978,124	10,742,763	40,678,029	10,930,839
Total Distribution Expense by Factor					208,601,621	65,912,168	217,864,397	71,951,511
901	Supervision							
		CUST	S		10	162	11	169
		CUST	CN		2,902,463	880,177	3,034,419	920,192
				B2	2,902,474	880,339	3,034,430	920,362
902	Meter Reading Expense							
		CUST	S		18,436,323	9,515,684	19,274,515	9,948,404
		CUST	CN		2,345,596	711,306	2,452,213	743,637
				B2	20,781,919	10,226,989	21,726,728	10,692,042
903	Customer Receipts & Collections							
		CUST	S		8,281,326	2,310,850	8,027,410	2,108,965
		CUST	CN		47,182,937	14,308,301	48,356,661	14,664,234
				B2	55,464,262	16,619,151	56,384,071	16,773,200
904	Uncollectible Accounts							
		CUST	S		15,054,589	7,300,290	15,497,299	7,394,970
		P	SG		-	-	-	-
		CUST	CN		269,596	81,756	281,697	85,425
				B2	15,324,186	7,382,046	15,778,995	7,480,395
905	Misc. Customer Accounts Expense							
		CUST	S		6,138	6,138	6,413	6,413
		CUST	CN		180,880	54,852	189,061	57,333
				B2	187,018	60,990	195,475	63,747
Total Customer Accounts Expense				**B2**	**94,659,859**	**35,169,515**	**97,119,698**	**35,929,744**
Summary of Customer Accts Exp by Factor								
	S				41,778,387	19,133,124	42,805,648	19,458,922
	CN				52,881,472	16,036,391	54,314,050	16,470,822
	SG				-	-	-	-
Total Customer Accounts Expense by Factor					94,659,859	35,169,515	97,119,698	35,929,744
907	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		298,102	90,400	311,563	94,482
				B2	298,102	90,400	311,563	94,482
908	Customer Assistance							
		CUST	S		103,173,557	25,032,153	12,107,194	1,857,183
		CUST	CN		1,579,122	478,871	1,580,386	479,255
				B2	104,752,679	25,511,024	13,687,581	2,336,438

2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
909	Informational & Instructional Adv							
		CUST	S		1,483,391	602,954	1,537,383	618,357
		CUST	CN		3,341,512	1,013,319	3,236,360	981,431
				B2	4,824,903	1,616,273	4,773,744	1,599,789
910	Misc. Customer Service							
		CUST	S		-	-	-	-
		CUST	CN		117,882	35,748	122,679	37,203
				B2	117,882	35,748	122,679	37,203
Total Customer Service Expense				**B2**	**109,993,566**	**27,253,445**	**18,895,566**	**4,067,911**
Summary of Customer Service Exp by Factor								
	S				104,656,948	25,635,107	13,644,578	2,475,541
	CN				5,336,618	1,618,338	5,250,988	1,592,371
Total Customer Service Expense by Factor				B2	109,993,566	27,253,445	18,895,566	4,067,911
911	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
912	Demonstration & Selling Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
913	Advertising Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
916	Misc. Sales Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
Total Sales Expense				**B2**	**-**	**-**	**-**	**-**
Total Sales Expense by Factor								
	S				-	-	-	-
	CN				-	-	-	-
Total Sales Expense by Factor					-	-	-	-
Total Customer Service Exp Including Sales				**B2**	**109,993,566**	**27,253,445**	**18,895,566**	**4,067,911**
920	Administrative & General Salaries							
		PTD	S		(2,954,533)	1,088,137	(5,264,131)	(843,151)
		CUST	CN		-	-	-	-
		PTD	SO		73,783,837	20,205,155	74,311,413	20,349,628
				B2	70,829,304	21,293,292	69,047,282	19,506,477
921	Office Supplies & expenses							
		PTD	S		250,630	59,631	263,411	62,672
		CUST	CN		71,100	21,561	74,726	22,661
		PTD	SO		8,831,411	2,418,416	9,226,866	2,526,709
				B2	9,153,141	2,499,608	9,565,003	2,612,041
922	A&G Expenses Transferred							
		PTD	S		-	-	-	-
		CUST	CN		-	-	-	-
		PTD	SO		(25,112,617)	(6,876,903)	(27,588,760)	(7,554,977)
				B2	(25,112,617)	(6,876,903)	(27,588,760)	(7,554,977)

2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
923	Outside Services							
		PTD	S		299,393	125,132	316,387	132,235
		CUST	CN		-	-	-	-
		PTD	SO		6,903,286	1,890,414	6,530,965	1,788,456
				B2	7,202,679	2,015,546	6,847,352	1,920,691
924	Property Insurance							
		DPW	S		7,962,669	5,285,806	9,570,157	6,959,234
		PT	SG		-	-	-	-
		PTD	SO		8,814,109	2,413,678	6,818,574	1,867,216
				B2	16,776,778	7,699,484	16,388,731	8,826,450
925	Injuries & Damages							
		PTD	S		-	-	3,369,178	3,369,178
		PTD	SO		15,065,328	4,125,528	3,939,183	1,078,716
				B2	15,065,328	4,125,528	7,308,360	4,447,894
926	Employee Pensions & Benefits							
		LABOR	S		-	-	-	-
		CUST	CN		-	-	-	-
		LABOR	SO		-	-	-	-
				B2	-	-	-	-
927	Franchise Requirements							
		DMSC	S		-	-	-	-
		DMSC	SG		-	-	-	-
				B2	-	-	-	-
928	Regulatory Commission Expense							
		DMSC	S		17,601,734	4,700,388	18,572,681	4,961,857
		CUST	CN		-	-	-	-
		DMSC	SO		2,550,990	698,570	2,692,485	737,317
		FERC	SG		3,702,587	964,635	3,916,240	1,020,298
				B2	23,855,311	6,363,593	25,181,406	6,719,472
929	Duplicate Charges							
		LABOR	S		-	-	-	-
		LABOR	SO		(6,339,512)	(1,736,028)	(8,107,044)	(2,220,054)
				B2	(6,339,512)	(1,736,028)	(8,107,044)	(2,220,054)
930	Misc General Expenses							
		PTD	S		136,067	41,387	1,089,835	919,899
		CUST	CN		-	-	-	-
		CUST	SG		1,449	378	1,521	396
		LABOR	SO		11,354,504	3,109,346	11,194,601	3,065,558
				B2	11,492,021	3,151,112	12,285,956	3,985,854
931	Rents							
		PTD	S		1,154,787	1,098,296	1,296,945	1,233,499
		PTD	SO		5,580,226	1,528,103	6,267,168	1,716,217
				B2	6,735,013	2,626,399	7,564,113	2,949,716
935	Maintenance of General Plant							
		G	S		347,662	142,394	356,125	145,770
		CUST	CN		21,160	6,417	21,654	6,566
		G	SO		22,522,137	6,167,520	23,031,778	6,307,081
				B2	22,890,959	6,316,330	23,409,557	6,459,418
Total Administrative & General Expense				**B2**	**152,548,405**	**47,477,959**	**141,901,957**	**47,652,982**
Summary of A&G Expense by Factor								
	S				24,798,409	12,541,170	29,570,588	16,941,193
	SO				123,953,700	33,943,798	108,317,229	29,661,867
	SG				3,704,036	965,013	3,917,760	1,020,694
	CN				92,261	27,978	96,380	29,227
Total A&G Expense by Factor					152,548,405	47,477,959	141,901,957	47,652,982
Total O&M Expense				**B2**	**2,802,214,417**	**715,664,893**	**2,989,787,648**	**786,658,786**

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	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
927	403SP	Steam Depreciation							
928			P	SG		20,827,113	5,426,088	47,878,880	12,473,885
929			P	SG		23,906,020	6,228,236	43,283,377	11,276,619
930			P	SG		83,869,689	21,850,572	245,246,369	63,894,040
931			P	SG		7,904,603	2,059,386	24,650,417	6,422,173
932					B3	136,507,425	35,564,282	361,059,042	94,066,718
933									
934	403NP	Nuclear Depreciation							
935			P	SG		-	-	-	-
936					B3	-	-	-	-
937									
938	403HP	Hydro Depreciation							
939			P	SG		3,604,046	938,962	4,963,572	1,293,159
940			P	SG		984,010	256,364	1,361,340	354,670
941			P	SG		13,197,864	3,438,440	20,792,015	5,416,944
942			P	SG		4,042,573	1,053,212	5,477,288	1,426,998
943					B3	21,828,493	5,686,978	32,594,215	8,491,771
944									
945	403OP	Other Production Depreciation							
946			P	S		-	-	-	-
947			P	SG		87,069	22,684	-	-
948			P	SG		113,016,274	29,444,132	98,899,230	25,766,218
949			P	SG		2,646,606	689,520	3,163,767	824,256
950			P	SG		-	-	-	-
951					B3	115,749,949	30,156,336	102,062,997	26,590,474
952									
953	403TP	Transmission Depreciation							
954			T	S		-	-	-	-
955			T	SG		10,907,803	2,841,810	10,013,919	2,608,927
956			T	SG		12,462,921	3,246,965	11,497,556	2,995,458
957			T	SG		62,098,401	16,178,497	73,484,839	19,145,006
958					B3	85,469,125	22,267,273	94,996,315	24,749,391
959									
960									
961									
962	403	Distribution Depreciation							
963	360	Land & Land Rights	DPW	S		342,296	71,413	317,677	35,535
964	361	Structures	DPW	S		1,357,638	324,407	1,321,871	272,282
965	362	Station Equipment	DPW	S		19,217,105	4,522,423	18,854,076	3,993,370
966	363	Storage Battery Eq	DPW	S		-	-	-	-
967	364	Poles & Towers	DPW	S		36,253,454	12,926,373	35,836,121	12,318,181
968	365	OH Conductors	DPW	S		19,946,377	7,060,332	19,665,761	6,651,382
969	366	UG Conduit	DPW	S		8,124,531	2,202,698	7,992,242	2,009,910
970	367	UG Conductor	DPW	S		18,059,095	3,838,524	17,747,746	3,384,785
971	368	Line Trans	DPW	S		28,738,900	11,311,787	28,261,086	10,615,455
972	369	Services	DPW	S		12,278,603	4,627,852	12,021,335	4,252,927
973	370	Meters	DPW	S		6,092,819	2,168,342	6,019,302	2,061,203
974	371	Inst Cust Prem	DPW	S		484,777	119,333	481,095	113,968
975	372	Leased Property	DPW	S		-	-	-	-
976	373	Street Lighting	DPW	S		2,160,196	676,460	2,134,520	639,042
977					B3	153,055,790	49,849,943	150,652,831	46,348,040
978									
979	403GP	General Depreciation							
980			G-SITUS	S		13,171,446	4,075,918	13,855,709	4,416,126
981			G-DGP	SG		155,614	40,542	48,207	12,559
982			G-DGU	SG		178,000	46,374	30,059	7,831
983			P	SE		15,835	3,909	17,457	4,309
984			CUST	CN		1,748,089	530,111	1,617,486	490,505
985			G-SG	SG		6,534,978	1,702,558	7,451,965	1,941,461
986			PTD	SO		14,944,608	4,092,470	14,456,988	3,958,939
987			P	SG		6,010	1,566	5,947	1,549
988			P	SG		137,187	35,741	161,548	42,088
989					B3	36,891,768	10,529,189	37,645,366	10,875,368
990									
991	403GV0	General Vehicles							
992			G-SG	SG		-	-	-	-
993					B3	-	-	-	-
994									
995	403MP	Mining Depreciation							
996			P	SE		-	-	-	-
997					B3	-	-	-	-
998									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
999	403EP	Experimental Plant Depreciation							
1000			P	SG		-	-	-	-
1001			P	SG		-	-	-	-
1002					B3	-	-	-	-
1003	4031	ARO Depreciation							
1004			P	S		-	-	-	-
1005					B3	-	-	-	-
1006									
1007									
1008	**Total Depreciation Expense**				**B3**	**549,502,550**	**154,054,000**	**779,010,766**	**211,121,763**
1009									
1010	Summary	S				166,227,236	53,925,861	164,508,540	50,764,166
1011		DGP				-	-	-	-
1012		DGU				-	-	-	-
1013		SG				366,566,781	95,501,649	598,410,295	155,903,844
1014		SO				14,944,608	4,092,470	14,456,988	3,958,939
1015		CN				1,748,089	530,111	1,617,486	490,505
1016		SE				15,835	3,909	17,457	4,309
1017		SSGCH				-	-	-	-
1018		SSGCT				-	-	-	-
1019	Total Depreciation Expense By Factor					549,502,550	154,054,000	779,010,766	211,121,763
1020									
1021	404GP	Amort of LT Plant - Capital Lease Gen							
1022			I-SITUS	S		1,337,374	445,579	705,903	231,371
1023			I-SG	SG		-	-	-	-
1024			PTD	SO		1,270,053	347,794	1,278,904	350,218
1025			I-DGU	SG		-	-	-	-
1026			CUST	CN		273,367	82,899	273,367	82,899
1027			I-DGP	SG		-	-	-	-
1028					B4	2,880,793	876,272	2,258,174	664,488
1029									
1030	404SP	Amort of LT Plant - Cap Lease Steam							
1031			P	SG		-	-	-	-
1032			P	SG		-	-	-	-
1033					B4	-	-	-	-
1034									
1035	404IP	Amort of LT Plant - Intangible Plant							
1036			I-SITUS	S		190,856	13,810	189,210	11,762
1037			P	SE		55,997	13,824	336,152	82,985
1038			I-SG	SG		10,083,201	2,626,976	6,787,294	1,768,294
1039			PTD	SO		15,468,250	4,235,865	21,183,084	5,800,830
1040			CUST	CN		6,015,598	1,824,240	6,419,226	1,946,640
1041			I-SG	SG		10,888,019	2,836,656	10,822,615	2,819,616
1042			I-SG	SG		307,800	80,191	301,628	78,583
1043			I-DGP	SG		-	-	-	-
1044			I-SG	SG		-	-	-	-
1045			I-SG	SG		156,748	40,838	-	-
1046			I-DGU	SG		16,758	4,366	16,101	4,195
1047					B4	43,183,227	11,676,766	46,055,309	12,512,905
1048									
1049	404MP	Amort of LT Plant - Mining Plant							
1050			P	SE		-	-	-	-
1051					B4	-	-	-	-
1052									
1053	404OP	Amort of LT Plant - Other Plant							
1054			P	SG		-	-	-	-
1055					B4	-	-	-	-
1056									
1057									
1058	404HP	Amortization of Other Electric Plant							
1059			P	SG		232,997	60,703	311,610	81,184
1060			P	SG		46,417	12,093	44,532	11,602
1061			P	SG		-	-	-	-
1062					B4	279,414	72,796	356,143	92,786
1063									
1064	**Total Amortization of Limited Term Plant**				**B4**	**46,343,434**	**12,625,834**	**48,669,626**	**13,270,179**
1065									
1066									
1067	405	Amortization of Other Electric Plant							
1068			GP	S		-	-	-	-
1069									
1070					B4	-	-	-	-
1071									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1072	406	Amortization of Plant Acquisition Adj							
1073			P	S		-	-	-	-
1074			P	SG		-	-	-	-
1075			P	SG		-	-	-	-
1076			P	SG		5,523,970	1,439,160	4,834,296	1,259,479
1077			P	SO		-	-	-	-
1078					B4	5,523,970	1,439,160	4,834,296	1,259,479
1079	407	Amort of Prop Losses, Unrec Plant, etc							
1080			DPW	S		559,742	-	559,742	-
1081			GP	SO		-	-	-	-
1082			P	SG		-	-	-	-
1083			P	SE		-	-	-	-
1084			P	SG		-	-	-	-
1085			P	TROJP		-	-	-	-
1086					B4	559,742	-	559,742	-
1087									
1088	**Total Amortization Expense**				**B4**	**52,427,146**	**14,064,994**	**54,063,663**	**14,529,658**
1089									
1090									
1091									
1092	Summary of Amortization Expense by Factor								
1093		S				2,087,972	459,389	1,454,855	243,132
1094		SE				55,997	13,824	336,152	82,985
1095		TROJP				-	-	-	-
1096		DGP				-	-	-	-
1097		SG-P				-	-	-	-
1098		SO				16,738,303	4,583,660	22,461,988	6,151,048
1099		SSGCT				-	-	-	-
1100		SSGCH				-	-	-	-
1101		CN				6,288,965	1,907,138	6,692,593	2,029,539
1102		SG				27,255,910	7,100,983	23,118,076	6,022,953
1103	Total Amortization Expense by Factor					52,427,146	14,064,994	54,063,663	14,529,658
1104	408	Taxes Other Than Income							
1105			DMSC	S		30,702,755	27,276,225	32,446,766	29,020,236
1106			GP	GPS		116,729,123	31,965,402	129,375,528	35,428,526
1107			GP	SO		8,848,595	2,423,122	8,848,595	2,423,122
1108			P	SE		819,813	202,385	819,813	202,385
1109			P	SG		678,544	176,781	1,725,585	449,567
1110			DMSC	OPRV-ID		-	-	-	-
1111			GP	EXCTAX		-	-	-	-
1112			GP	SG		-	-	-	-
1113									
1114									
1115									
1116	**Total Taxes Other Than Income**				**B5**	**157,778,830**	**62,043,915**	**173,216,287**	**67,523,836**
1117									
1118									
1119	41140	Deferred Investment Tax Credit - Fed							
1120			PTD	DGU		(1,862,752)	-	(1,862,752)	-
1121									
1122					B7	(1,862,752)	-	(1,862,752)	-
1123									
1124	41141	Deferred Investment Tax Credit - Idaho							
1125			PTD	DGU		-	-	-	-
1126									
1127					B7	-	-	-	-
1128									
1129	**Total Deferred ITC**				**B7**	**(1,862,752)**	**-**	**(1,862,752)**	**-**
1130									

2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
427	Interest on Long-Term Debt							
		GP	S		327,928,239	86,165,786	326,446,716	85,739,606
		GP	SNP		-	-	-	-
				B6	327,928,239	86,165,786	326,446,716	85,739,606
428	Amortization of Debt Disc & Exp							
		GP	SNP		-	-	-	-
				B6	-	-	-	-
429	Amortization of Premium on Debt							
		GP	SNP		-	-	-	-
				B6	-	-	-	-
431	Other Interest Expense							
		NUTIL	OTH		-	-	-	-
		GP	SO		-	-	-	-
		GP	SNP		-	-	-	-
				B6	-	-	-	-
432	AFUDC - Borrowed							
		GP	SNP		-	-	-	-
					-	-	-	-
	Total Elec. Interest Deductions for Tax			B6	327,928,239	86,165,786	326,446,716	85,739,606
	Non-Utility Portion of Interest							
	427	NUTIL	NUTIL		-	-	-	-
	428	NUTIL	NUTIL		-	-	-	-
	429	NUTIL	NUTIL		-	-	-	-
	431	NUTIL	NUTIL		-	-	-	-
	Total Non-utility Interest				-	-	-	-
	Total Interest Deductions for Tax			B6	327,928,239	86,165,786	326,446,716	85,739,606
419	Interest & Dividends							
		GP	S		-	-	-	-
		GP	SNP		(54,338,671)	(14,356,107)	(63,623,361)	(16,809,094)
	Total Operating Deductions for Tax			B6	(54,338,671)	(14,356,107)	(63,623,361)	(16,809,094)
41010	Deferred Income Tax - Federal-DR							
		GP	S		37,958,773	249,502	4,156,555	20,423
		P	SCHMDEXP		-	-	-	-
		PT	SG		37,085	9,662	37,085	9,662
		LABOR	SO		7,353,797	2,013,783	(922,006)	(252,484)
		GP	SNP		29,910,347	7,902,220	36,302,668	9,591,052
		P	SE		12,842,500	3,170,394	1,788,676	441,566
		PT	SG		76,326,248	19,885,279	54,677,938	14,245,244
		GP	GPS		39,932,361	10,935,180	21,918,549	6,002,232
		TAXDEPR	TAXDEPR		496,822,238	131,149,417	430,161,791	113,552,622
		CUST	BADDEBT		-	-	-	-
		CUST	CN		18,276	5,542	-	-
		IBT	IBT		-	-	-	-
		DPW	SNPD		986,927	265,203	-	-
				B7	702,188,552	175,586,181	548,121,256	143,610,316

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1190									
1191									
1192	41110	Deferred Income Tax - Federal-CR							
1193			GP	S		(33,964,770)	(925,515)	(13,742,118)	(597,475)
1194			P	SE		(9,872,333)	(2,437,156)	-	-
1195			CUST	BADDEBT		(1,670,977)	(792,165)	(0)	(0)
1196			GP	SNP		(20,189,415)	(5,333,980)	(26,012,957)	(6,872,542)
1197			PT	SG		150,392	39,182	2,308	601
1198			DPW	CIAC		(15,616,054)	(4,196,284)	(17,653,569)	(4,743,797)
1199			LABOR	SO		(8,378,162)	(2,294,297)	(5,146,197)	(1,409,248)
1200			PT	SNPD		(3,627,116)	(974,664)	-	-
1201			P	GPS		(1,739,033)	(476,221)	-	-
1202			P	SGCT		(425,972)	(111,352)	(425,972)	(111,352)
1203			GP	SCHMDEXP		(237,594,428)	(64,391,093)	(315,108,180)	(85,398,299)
1204			P	TROJD		(5,054)	(1,304)	-	-
1205			IBT	IBT		-	-	-	-
1206			0	SG		-	-	-	-
1207			0	SG		-	-	-	-
1208			0	SG		-	-	-	-
1209			0	SG		(540,676)	(140,862)	(540,676)	(140,862)
1210			0	SG		-	-	-	-
1211					B7	(333,473,598)	(82,035,714)	(378,627,361)	(99,272,974)
1212									
1213	**Total Deferred Income Taxes**				**B7**	**368,714,954**	**93,550,467**	**169,493,895**	**44,337,342**
1214	SCHMAF	Additions - Flow Through							
1215			SCHMAF	S		-	-	-	-
1216			SCHMAF	SNP		-	-	-	-
1217			SCHMAF	SO		-	-	-	-
1218			SCHMAF	SE		-	-	-	-
1219			SCHMAF	TROJP		-	-	-	-
1220			SCHMAF	SG		-	-	-	-
1221					B6	-	-	-	-
1222									
1223	SCHMAP	Additions - Permanent							
1224			P	S		(7,137)	-	-	-
1225			P	SE		82,060	20,258	18,000	4,444
1226			LABOR	SNP		-	-	-	-
1227			SCHMAP-SO	SO		7,528,967	2,061,752	679,971	186,205
1228			SCHMAP	SG		-	-	-	-
1229			DPW	SCHMDEXP		-	-	71,461	19,367
1230					B6	7,603,890	2,082,010	769,432	210,015
1231									
1232	SCHMAT	Additions - Temporary							
1233			SCHMAT-SITUS	S		83,565,307	7,491,514	36,228,455	-
1234			P	SG		-	-	-	-
1235			DPW	CIAC		41,147,935	11,057,110	46,516,739	12,499,794
1236			SCHMAT-SNP	SNP		53,198,636	14,054,914	68,543,531	18,108,987
1237			P	TROJD		13,316	3,437	-	-
1238			CUST	BADDEBT		4,402,986	2,087,337	0	0
1239			SCHMAT-SE	SE		26,031,778	6,426,395	-	-
1240			P	SG		(1,993,526)	(519,373)	-	-
1241			SCHMAT-GPS	CN		-	-	-	-
1242			SCHMAT-SO	SO		21,222,244	5,811,554	13,560,110	3,713,335
1243			SCHMAT-SNP	SNPD		9,557,365	2,568,217	-	-
1244			P	SGCT		1,122,425	293,409	1,122,425	293,409
1245			TAXDEPR	SG		-	-	-	-
1246			BOOKDEPR	SCHMDEXP		626,055,776	169,669,028	830,302,706	225,022,527
1247			0	SG		-	-	-	-
1248			0	GPS		4,582,312	1,254,832	-	-
1249			0	SG		-	-	-	-
1250			0	SG		-	-	-	-
1251					B6	868,906,554	220,198,373	996,273,966	259,638,052
1252									
1253	TOTAL SCHEDULE - M ADDITIONS				B6	876,510,444	222,280,382	997,043,398	259,848,068
1254									

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	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1255	SCHMDF	Deductions - Flow Through							
1256			SCHMDF	S		-	-	-	-
1257			SCHMDF	SG		-	-	-	-
1258			SCHMDF	SG		-	-	-	-
1259					B6	-	-	-	-
1260	SCHMDP	Deductions - Permanent							
1261			SCHMDP	S		-	-	-	-
1262			P	SE		474,854	117,226	493,869	121,920
1263			PTD	SNP		382,696	101,107	381,062	100,675
1264			SCHMDEXP	SCHMDEXP		257,021	69,656	357,168	96,797
1265			P	SG		-	-	-	-
1266			SCHMDP-SO	SO		11,495,969	3,148,086	-	-
1267					B6	12,610,540	3,436,075	1,232,099	319,393
1268									
1269	SCHMDT	Deductions - Temporary							
1270			GP	S		100,020,473	657,429	10,952,419	53,813
1271			CUST	BADDEBT		-	-	-	-
1272			SCHMDT-SNP	SNP		78,813,067	20,822,166	95,656,684	25,272,198
1273			SCHMDT	CN		48,156	14,603	-	-
1274			SCHMDT	SG		97,718	25,458	97,718	25,458
1275			P	SG		-	-	-	-
1276			P	SE		33,648,216	8,306,645	4,713,119	1,163,515
1277			SCHMDT-SG	SG		201,117,881	52,397,245	144,075,093	37,535,886
1278			SCHMDT-GPS	GPS		105,220,837	28,813,943	57,754,860	15,815,739
1279			SCHMDT-SO	SO		19,377,084	5,306,270	(2,429,465)	(665,291)
1280			TAXDEPR	TAXDEPR		1,309,115,012	345,575,654	1,133,466,288	299,208,512
1281			DPW	SNPD		2,600,530	698,804	-	-
1282					B6	1,850,058,974	462,618,220	1,444,286,716	378,409,830
1283									
1284	TOTAL SCHEDULE - M DEDUCTIONS				B6	1,862,669,514	466,054,294	1,445,518,815	378,729,222
1285									
1286	**TOTAL SCHEDULE - M ADJUSTMENTS**				**B6**	**(986,159,070)**	**(243,773,912)**	**(448,475,417)**	**(118,881,155)**
1287									
1288									
1289									
1290	40911	State Income Taxes							
1291			IBT	S		(6,321,528)	484,513	18,638,736	4,776,937
1292			IBT	IBT		-	-	-	-
1293		REC	P	SG		(167,068)	(43,526)	(384,905)	(100,279)
1294			IBT	IBT		-	-	-	-
1295	**Total State Tax Expense**					**(6,488,596)**	**440,987**	**18,253,831**	**4,676,658**
1296									
1297									
1298	Calculation of Taxable Income:								
1299		Operating Revenues				4,681,666,114	1,271,895,421	5,117,557,160	1,372,774,372
1300		Operating Deductions:							
1301		O & M Expenses				2,802,214,417	715,664,893	2,989,787,648	786,658,786
1302		Depreciation Expense				549,502,550	154,054,000	779,010,766	211,121,763
1303		Amortization Expense				52,427,146	14,064,994	54,063,663	14,529,658
1304		Taxes Other Than Income				157,778,830	62,043,915	173,216,287	67,523,836
1305		Interest & Dividends (AFUDC-Equity)				(54,338,671)	(14,356,107)	(63,623,361)	(16,809,094)
1306		Misc Revenue & Expense				(764,772)	(188,071)	(364,815)	(90,219)
1307		Total Operating Deductions				3,506,819,500	931,283,624	3,932,090,188	1,062,934,730
1308		Other Deductions:							
1309		Interest Deductions				327,928,239	86,165,786	326,446,716	85,739,606
1310		Interest on PCRBS				-	-	-	-
1311		Schedule M Adjustments				(986,159,070)	(243,773,912)	(448,475,417)	(118,881,155)
1312									
1313		Income Before State Taxes				(139,240,694)	10,672,100	410,544,838	105,218,882
1314									
1315		State Income Taxes				(6,488,596)	440,987	18,253,831	4,676,658
1316									
1317	Total Taxable Income					(132,752,099)	10,231,113	392,291,008	100,542,224
1318									
1319	Tax Rate					35.0%	35.0%	35.0%	35.0%
1320									
1321	Federal Income Tax - Calculated					(46,463,235)	3,580,889	137,301,853	35,189,778
1322									
1323	Adjustments to Calculated Tax:								
1324	40910	PMI	P	SE		(75,871)	(18,730)	(18,000)	(4,444)
1325	40910	REC	P	SG		(70,632,447)	(18,401,873)	(65,873,189)	(17,161,943)
1326	40911	State Energy Cr	P	SO		(28,863)	(7,904)	-	-
1327	40910	IRS Settle	LABOR	S		-	-	-	-
1328	**Federal Income Tax Expense**					**(117,200,416)**	**(14,847,617)**	**71,410,664**	**18,023,392**
1329									
1330	**Total Operating Expenses**					**3,804,321,362**	**1,024,783,568**	**4,253,009,187**	**1,146,781,214**

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
310	Land and Land Rights							
		P	SG		2,328,228	606,573	2,328,228	606,573
		P	SG		34,798,446	9,066,040	34,798,446	9,066,040
		P	SG		53,412,167	13,915,473	53,412,167	13,915,473
		P	S		-	-	-	-
		P	SG		2,468,743	643,182	2,468,743	643,182
				B8	93,007,584	24,231,267	93,007,584	24,231,267
311	Structures and Improvements							
		P	SG		233,321,135	60,787,159	233,321,135	60,787,159
		P	SG		324,156,573	84,452,517	324,156,573	84,452,517
		P	SG		351,799,294	91,654,276	351,799,294	91,654,276
		P	SG		60,162,131	15,674,041	60,162,131	15,674,041
				B8	969,439,133	252,567,993	969,439,133	252,567,993
312	Boiler Plant Equipment							
		P	SG		626,136,118	163,127,253	582,279,218	151,701,214
		P	SG		563,119,063	146,709,419	523,643,651	136,424,889
		P	SG		2,642,215,151	688,376,356	2,754,131,841	717,534,013
		P	SG		326,012,913	84,936,150	327,514,876	85,327,456
				B8	4,157,483,245	1,083,149,177	4,187,569,587	1,090,987,572
314	Turbogenerator Units							
		P	SG		121,781,725	31,727,795	121,781,725	31,727,795
		P	SG		134,947,365	35,157,839	134,947,365	35,157,839
		P	SG		645,203,132	168,094,782	637,274,246	166,029,069
		P	SG		66,201,616	17,247,508	66,201,616	17,247,508
				B8	968,133,838	252,227,924	960,204,952	250,162,212
315	Accessory Electric Equipment							
		P	SG		86,687,072	22,584,584	86,687,072	22,584,584
		P	SG		137,089,386	35,715,900	137,089,386	35,715,900
		P	SG		162,218,902	42,262,893	162,218,902	42,262,893
		P	SG		67,334,063	17,542,545	67,334,063	17,542,545
				B8	453,329,423	118,105,922	453,329,423	118,105,922
316	Misc Power Plant Equipment							
		P	SG		4,633,610	1,207,194	4,633,610	1,207,194
		P	SG		5,085,197	1,324,846	5,085,197	1,324,846
		P	SG		19,683,635	5,128,178	19,683,635	5,128,178
		P	SG		4,155,009	1,082,504	4,155,009	1,082,504
				B8	33,557,450	8,742,723	33,557,450	8,742,723
317	Steam Plant ARO							
		P	S		-	-	-	-
				B8	-	-	-	-
SP	Unclassified Steam Plant - Account 300							
		P	SG		(22,737,202)	(5,923,724)	(22,737,202)	(5,923,724)
				B8	(22,737,202)	(5,923,724)	(22,737,202)	(5,923,724)
Total Steam Production Plant				**B8**	**6,652,213,470**	**1,733,101,283**	**6,674,370,926**	**1,738,873,965**
Summary of Steam Production Plant by Factor								
	S				-	-	-	-
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				6,652,213,470	1,733,101,283	6,674,370,926	1,738,873,965
	SSGCH				-	-	-	-
Total Steam Production Plant by Factor					6,652,213,470	1,733,101,283	6,674,370,926	1,738,873,965
320	Land and Land Rights							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
321	Structures and Improvements							
		P	SG		-	-	-	-
		P	SG	B8	-	-	-	-
					-	-	-	-

2010 PROTOCOL
Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1404									
1405	322	Reactor Plant Equipment							
1406			P	SG		-	-	-	-
1407			P	SG		-	-	-	-
1408					B8	-	-	-	-
1409									
1410	323	Turbogenerator Units							
1411			P	SG		-	-	-	-
1412			P	SG		-	-	-	-
1413					B8	-	-	-	-
1414									
1415	324	Land and Land Rights							
1416			P	SG		-	-	-	-
1417			P	SG		-	-	-	-
1418					B8	-	-	-	-
1419									
1420	325	Misc. Power Plant Equipment							
1421			P	SG		-	-	-	-
1422			P	SG		-	-	-	-
1423					B8	-	-	-	-
1424									
1425									
1426	NP	Unclassified Nuclear Plant - Acct 300							
1427			P	SG		-	-	-	-
1428					B8	-	-	-	-
1429									
1430									
1431	**Total Nuclear Production Plant**				**B8**	-	-	-	-
1432									
1433									
1434									
1435	Summary of Nuclear Production Plant by Factor								
1436		DGP				-	-	-	-
1437		DGU				-	-	-	-
1438		SG				-	-	-	-
1439									
1440	Total Nuclear Plant by Factor					-	-	-	-
1441									
1442	330	Land and Land Rights							
1443			P	SG		10,551,027	2,748,859	10,551,027	2,748,859
1444			P	SG		5,266,732	1,372,142	5,266,732	1,372,142
1445			P	SG		15,039,610	3,918,270	15,039,610	3,918,270
1446			P	SG		672,873	175,304	672,873	175,304
1447					B8	31,530,243	8,214,575	31,530,243	8,214,575
1448									
1449	331	Structures and Improvements							
1450			P	SG		20,523,158	5,346,899	20,523,158	5,346,899
1451			P	SG		5,241,539	1,365,578	5,241,539	1,365,578
1452			P	SG		107,540,371	28,017,495	107,540,371	28,017,495
1453			P	SG		8,830,412	2,300,587	8,830,412	2,300,587
1454					B8	142,135,480	37,030,559	142,135,480	37,030,559
1455									
1456	332	Reservoirs, Dams & Waterways							
1457			P	SG		147,899,455	38,532,247	143,429,363	37,367,654
1458			P	SG		19,502,638	5,081,023	18,250,810	4,754,884
1459			P	SG		137,824,060	35,907,305	339,248,611	88,384,446
1460			P	SG		53,789,787	14,013,854	72,634,834	18,923,555
1461					B8	359,015,940	93,534,429	573,563,619	149,430,539
1462									
1463	333	Water Wheel, Turbines, & Generators							
1464			P	SG		30,070,051	7,834,151	30,070,051	7,834,151
1465			P	SG		8,441,577	2,199,284	8,441,577	2,199,284
1466			P	SG		50,067,352	13,044,048	50,067,352	13,044,048
1467			P	SG		30,405,968	7,921,667	30,405,968	7,921,667
1468					B8	118,984,948	30,999,150	118,984,948	30,999,150
1469									
1470	334	Accessory Electric Equipment							
1471			P	SG		4,102,459	1,068,814	4,102,459	1,068,814
1472			P	SG		3,495,538	910,693	3,495,538	910,693
1473			P	SG		51,337,502	13,374,960	51,337,502	13,374,960
1474			P	SG		7,490,384	1,951,470	7,490,384	1,951,470
1475					B8	66,425,883	17,305,936	66,425,883	17,305,936
1476									

2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
335	Misc. Power Plant Equipment							
		P	SG		1,145,017	298,311	1,145,017	298,311
		P	SG		157,719	41,091	157,719	41,091
		P	SG		1,043,475	271,857	1,043,475	271,857
		P	SG		12,582	3,278	12,582	3,278
				B8	2,358,793	614,536	2,358,793	614,536
336	Roads, Railroads & Bridges							
		P	SG		4,597,710	1,197,841	4,597,710	1,197,841
		P	SG		822,766	214,355	822,766	214,355
		P	SG		10,714,114	2,791,348	10,714,114	2,791,348
		P	SG		726,716	189,331	726,716	189,331
				B8	16,861,306	4,392,876	16,861,306	4,392,876
337	Hydro Plant ARO							
		P	S		-	-	-	-
				B8	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300							
		P	S		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
Total Hydraulic Production Plant				**B8**	**737,312,593**	**192,092,062**	**951,860,271**	**247,988,172**
Summary of Hydraulic Plant by Factor								
	S				-	-	-	-
	SG				737,312,593	192,092,062	951,860,271	247,988,172
	DGP				-	-	-	-
	DGU				-	-	-	-
Total Hydraulic Plant by Factor					737,312,593	192,092,062	951,860,271	247,988,172
340	Land and Land Rights							
		P	S		-	-	75,000	75,000
		P	SG		28,894,615	7,527,915	28,894,615	7,527,915
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	28,894,615	7,527,915	28,969,615	7,602,915
341	Structures and Improvements							
		P	SG		159,580,327	41,575,465	156,480,034	40,767,746
		P	SG		163,512	42,600	163,512	42,600
		P	SG		4,240,304	1,104,727	4,240,304	1,104,727
				B8	163,984,143	42,722,791	160,883,850	41,915,072
342	Fuel Holders, Producers & Accessories							
		P	SG		8,424,526	2,194,842	8,424,526	2,194,842
		P	SG		-	-	-	-
		P	SG		2,462,148	641,463	2,462,148	641,463
				B8	10,886,674	2,836,305	10,886,674	2,836,305
343	Prime Movers							
		P	S		-	-	-	-
		P	SG		242,141	63,085	43,906	11,439
		P	SG		2,441,616,585	636,114,408	2,290,268,983	596,683,815
		P	SG		54,729,341	14,258,636	53,842,912	14,027,695
				B8	2,496,588,068	650,436,130	2,344,155,801	610,722,949
344	Generators							
		P	S		-	-	-	-
		P	SG		-	-	-	-
		P	SG		336,222,815	87,596,135	330,372,442	86,071,938
		P	SG		15,944,197	4,153,942	15,944,197	4,153,942
				B8	352,167,012	91,750,077	346,316,639	90,225,880

2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
345	Accessory Electric Plant							
		P	SG		246,082,037	64,111,757	233,870,087	60,930,177
		P	SG		156,586	40,795	156,586	40,795
		P	SG		3,007,064	783,430	3,007,064	783,430
				B8	249,245,687	64,935,983	237,033,737	61,754,403
346	Misc. Power Plant Equipment							
		P	SG		12,474,935	3,250,095	11,815,438	3,078,276
		P	SG		11,813	3,078	11,813	3,078
				B8	12,486,748	3,253,173	11,827,251	3,081,354
347	Other Production ARO							
		P	S		-	-	-	-
				B8	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300							
		P	S		-	-	-	-
		P	SG		-	-	-	-
					-	-	-	-
Total Other Production Plant				**B8**	**3,314,252,948**	**863,462,374**	**3,140,073,567**	**818,138,877**
Summary of Other Production Plant by Factor								
	S				-	-	75,000	75,000
	DGU				-	-	-	-
	SG				3,314,252,948	863,462,374	3,139,998,567	818,063,877
	SSGCT				-	-	-	-
Total of Other Production Plant by Factor					3,314,252,948	863,462,374	3,140,073,567	818,138,877
Experimental Plant								
103	Experimental Plant							
		P	SG		-	-	-	-
Total Experimental Production Plant				**B8**	**-**	**-**	**-**	**-**
Total Production Plant				**B8**	**10,703,779,011**	**2,788,655,718**	**10,766,304,764**	**2,805,001,014**
350	Land and Land Rights							
		T	SG		21,116,232	5,501,412	21,116,232	5,501,412
		T	SG		48,469,541	12,627,770	48,469,541	12,627,770
		T	SG		125,199,107	32,618,125	125,199,107	32,618,125
				B8	194,784,879	50,747,308	194,784,879	50,747,308
352	Structures and Improvements							
		T	S		-	-	-	-
		T	SG		7,433,421	1,936,629	7,433,421	1,936,629
		T	SG		18,083,218	4,711,221	18,083,218	4,711,221
		T	SG		129,700,598	33,790,899	129,700,598	33,790,899
				B8	155,217,238	40,438,749	155,217,238	40,438,749
353	Station Equipment							
		T	SG		121,389,908	31,625,715	121,389,908	31,625,715
		T	SG		179,206,263	46,688,610	179,206,263	46,688,610
		T	SG		1,361,438,651	354,695,634	1,360,515,549	354,455,138
				B8	1,662,034,821	433,009,959	1,661,111,719	432,769,463
354	Towers and Fixtures							
		T	SG		155,435,933	40,495,726	155,435,933	40,495,726
		T	SG		133,295,649	34,727,518	133,295,649	34,727,518
		T	SG		695,554,276	181,212,767	695,554,276	181,212,767
				B8	984,285,858	256,436,010	984,285,858	256,436,010
355	Poles and Fixtures							
		T	S		-	-	-	-
		T	SG		65,808,250	17,145,025	57,511,821	14,983,556
		T	SG		116,294,040	30,298,088	109,861,355	28,622,181
		T	SG		474,042,596	123,502,325	1,181,959,906	307,936,033
				B8	656,144,886	170,945,438	1,349,333,082	351,541,770

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Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
356	Clearing and Grading							
		T	SG		185,272,868	48,269,143	185,272,868	48,269,143
		T	SG		157,446,338	41,019,497	157,446,338	41,019,497
		T	SG		560,225,539	145,955,569	560,225,539	145,955,569
				B8	902,944,745	235,244,209	902,944,745	235,244,209
357	Underground Conduit							
		T	SG		6,371	1,660	6,371	1,660
		T	SG		91,651	23,878	91,651	23,878
		T	SG		3,170,534	826,019	3,170,534	826,019
				B8	3,268,556	851,557	3,268,556	851,557
358	Underground Conductors							
		T	SG		-	-	-	-
		T	SG		1,087,552	283,340	1,087,552	283,340
		T	SG		6,389,533	1,664,665	6,389,533	1,664,665
				B8	7,477,085	1,948,005	7,477,085	1,948,005
359	Roads and Trails							
		T	SG		1,863,032	485,376	1,863,032	485,376
		T	SG		440,513	114,767	440,513	114,767
		T	SG		9,283,137	2,418,536	9,283,137	2,418,536
				B8	11,586,681	3,018,678	11,586,681	3,018,678
TP	Unclassified Trans Plant - Acct 300							
		T	SG		6,334,193	1,650,247	6,334,193	1,650,247
				B8	6,334,193	1,650,247	6,334,193	1,650,247
TS0	Unclassified Trans Sub Plant - Acct 300							
		T	SG		-	-	-	-
				B8	-	-	-	-
Total Transmission Plant				**B8**	**4,584,078,943**	**1,194,290,161**	**5,276,344,037**	**1,374,645,997**
Summary of Transmission Plant by Factor								
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				4,584,078,943	1,194,290,161	5,276,344,037	1,374,645,997
Total Transmission Plant by Factor					4,584,078,943	1,194,290,161	5,276,344,037	1,374,645,997
360	Land and Land Rights							
		DPW	S		58,999,246	13,164,238	60,834,094	13,747,277
				B8	58,999,246	13,164,238	60,834,094	13,747,277
361	Structures and Improvements							
		DPW	S		85,716,168	22,195,790	88,381,900	23,042,848
				B8	85,716,168	22,195,790	88,381,900	23,042,848
362	Station Equipment							
		DPW	S		869,991,777	212,939,062	897,048,109	221,536,435
				B8	869,991,777	212,939,062	897,048,109	221,536,435
363	Storage Battery Equipment							
		DPW	S		-	-	-	-
				B8	-	-	-	-
364	Poles, Towers & Fixtures							
		DPW	S		1,000,131,154	332,414,679	1,031,234,760	342,298,106
				B8	1,000,131,154	332,414,679	1,031,234,760	342,298,106
365	Overhead Conductors							
		DPW	S		672,490,564	237,217,176	693,404,702	243,862,816
				B8	672,490,564	237,217,176	693,404,702	243,862,816

2010 PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
366	Underground Conduit							
		DPW	S		317,027,620	85,675,877	326,887,029	88,808,786
				B8	317,027,620	85,675,877	326,887,029	88,808,786
367	Underground Conductors							
		DPW	S		746,144,068	159,274,223	769,348,795	166,647,716
				B8	746,144,068	159,274,223	769,348,795	166,647,716
368	Line Transformers							
		DPW	S		1,145,072,411	396,579,456	1,180,683,621	407,895,211
				B8	1,145,072,411	396,579,456	1,180,683,621	407,895,211
369	Services							
		DPW	S		616,539,518	228,911,524	635,713,605	235,004,248
				B8	616,539,518	228,911,524	635,713,605	235,004,248
370	Meters							
		DPW	S		176,183,046	59,644,428	181,662,255	61,385,492
				B8	176,183,046	59,644,428	181,662,255	61,385,492
371	Installations on Customers' Premises							
		DPW	S		8,822,755	2,506,290	9,097,139	2,593,477
				B8	8,822,755	2,506,290	9,097,139	2,593,477
372	Leased Property							
		DPW	S		-	-	-	-
				B8	-	-	-	-
373	Street Lights							
		DPW	S		61,531,317	22,303,399	63,444,912	22,911,460
				B8	61,531,317	22,303,399	63,444,912	22,911,460
DP	Unclassified Dist Plant - Acct 300							
		DPW	S		28,945,772	5,984,241	28,945,772	5,984,241
				B8	28,945,772	5,984,241	28,945,772	5,984,241
DS0	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		-	-	-	-
				B8	-	-	-	-
Total Distribution Plant				**B8**	**5,787,595,414**	**1,778,810,385**	**5,966,686,693**	**1,835,718,113**
Summary of Distribution Plant by Factor								
	S				5,787,595,414	1,778,810,385	5,966,686,693	1,835,718,113
Total Distribution Plant by Factor					5,787,595,414	1,778,810,385	5,966,686,693	1,835,718,113

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Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1727	389	Land and Land Rights							
1728			G-SITUS	S		12,748,785	4,601,321	12,748,785	4,601,321
1729			CUST	CN		1,128,506	342,221	1,128,506	342,221
1730			G-DGU	SG		332	87	332	87
1731			G-SG	SG		1,228	320	1,228	320
1732			PTD	SO		5,596,700	1,532,615	5,596,700	1,532,615
1733					B8	19,475,551	6,476,563	19,475,551	6,476,563
1734									
1735	390	Structures and Improvements							
1736			G-SITUS	S		114,694,304	33,734,032	114,694,304	33,734,032
1737			G-DGP	SG		355,153	92,528	355,153	92,528
1738			G-DGU	SG		1,633,901	425,680	1,633,901	425,680
1739			CUST	CN		12,317,880	3,735,417	12,317,880	3,735,417
1740			G-SG	SG		5,353,435	1,394,731	5,353,435	1,394,731
1741			PTD	SO		103,108,968	28,235,624	103,108,968	28,235,624
1742					B8	237,463,641	67,618,011	237,463,641	67,618,011
1743									
1744	391	Office Furniture & Equipment							
1745			G-SITUS	S		11,227,878	3,217,356	11,227,878	3,217,356
1746			G-DGP	SG		-	-	-	-
1747			G-DGU	SG		5,295	1,380	5,295	1,380
1748			CUST	CN		8,637,133	2,619,224	8,637,133	2,619,224
1749			G-SG	SG		4,566,605	1,189,738	4,557,892	1,187,468
1750			P	SE		33,537	8,279	33,537	8,279
1751			PTD	SO		55,298,622	15,143,116	55,298,622	15,143,116
1752			P	SG		90,667	23,622	90,667	23,622
1753			P	SG		-	-	-	-
1754					B8	79,859,736	22,202,714	79,851,023	22,200,445
1755									
1756	392	Transportation Equipment							
1757			G-SITUS	S		78,250,993	23,846,950	78,250,993	23,846,950
1758			PTD	SO		7,379,542	2,020,833	7,379,542	2,020,833
1759			G-SG	SG		17,816,559	4,641,748	17,816,559	4,641,748
1760			CUST	CN		-	-	-	-
1761			G-DGU	SG		779,129	202,986	779,129	202,986
1762			P	SE		448,363	110,686	448,363	110,686
1763			G-DGP	SG		119,116	31,033	119,116	31,033
1764			P	SG		343,984	89,618	343,984	89,618
1765			P	SG		44,655	11,634	44,655	11,634
1766					B8	105,182,341	30,955,489	105,182,341	30,955,489
1767									
1768	393	Stores Equipment							
1769			G-SITUS	S		8,551,583	2,815,609	8,551,583	2,815,609
1770			G-DGP	SG		69,750	18,172	69,750	18,172
1771			G-DGU	SG		144,970	37,769	144,970	37,769
1772			PTD	SO		318,705	87,275	318,705	87,275
1773			G-SG	SG		4,887,374	1,273,308	4,887,374	1,273,308
1774			P	SG		53,971	14,061	53,971	14,061
1775					B8	14,026,352	4,246,193	14,026,352	4,246,193

2010 PROTOCOL

Line	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1776									
1777	394	Tools, Shop & Garage Equipment							
1778			G-SITUS	S		33,591,288	10,862,111	33,591,288	10,862,111
1779			G-DGP	SG		1,077,687	280,770	1,077,687	280,770
1780			G-SG	SG		21,609,243	5,629,856	21,609,243	5,629,856
1781			PTD	SO		3,774,723	1,033,680	3,774,723	1,033,680
1782			P	SE		5,617	1,387	5,617	1,387
1783			G-DGU	SG		558,757	145,573	558,757	145,573
1784			P	SG		1,842,348	479,987	1,842,348	479,987
1785			P	SG		89,913	23,425	89,913	23,425
1786					B8	62,549,577	18,456,788	62,549,577	18,456,788
1787									
1788	395	Laboratory Equipment							
1789			G-SITUS	S		24,502,509	9,673,147	24,502,509	9,673,147
1790			G-DGP	SG		1,518	395	1,518	395
1791			G-DGU	SG		5,371	1,399	5,371	1,399
1792			PTD	SO		5,280,671	1,446,072	5,280,671	1,446,072
1793			P	SE		7,593	1,875	7,593	1,875
1794			G-SG	SG		6,447,255	1,679,703	6,447,255	1,679,703
1795			P	SG		253,001	65,914	253,001	65,914
1796			P	SG		14,022	3,653	14,022	3,653
1797					B8	36,511,939	12,872,160	36,511,939	12,872,160
1798									
1799	396	Power Operated Equipment							
1800			G-SITUS	S		114,772,768	34,331,104	114,772,768	34,331,104
1801			G-DGP	SG		845,108	220,176	845,108	220,176
1802			G-SG	SG		34,189,753	8,907,457	34,189,753	8,907,457
1803			PTD	SO		1,919,236	525,569	1,919,236	525,569
1804			G-DGU	SG		1,574,205	410,128	1,574,205	410,128
1805			P	SE		45,031	11,117	45,031	11,117
1806			P	SG		-	-	-	-
1807			P	SG		999,837	260,488	999,837	260,488
1808					B8	154,345,939	44,666,038	154,345,939	44,666,038
1809	397	Communication Equipment							
1810			DPW	S		131,979,895	45,080,205	171,472,150	59,628,025
1811			G-DGP	SG		1,301,936	339,193	(1,027,955)	(267,813)
1812			G-DGU	SG		1,544,068	402,276	(3,242,763)	(844,837)
1813			PTD	SO		58,258,262	15,953,592	48,146,596	13,184,587
1814			CUST	CN		2,855,125	865,821	790,311	239,663
1815			G-SG	SG		110,649,879	28,827,615	125,597,831	32,722,005
1816			P	SE		232,898	57,495	109,139	26,943
1817			G-SG	SG		619,180	161,315	1,684,406	438,838
1818			G-SG	SG		1,590	414	(21,704)	(5,655)
1819					B8	307,442,833	91,687,926	343,508,011	105,121,757
1820									
1821	398	Misc. Equipment							
1822			G-SITUS	S		2,121,606	1,082,798	2,121,606	1,082,798
1823			G-DGP	SG		-	-	-	-
1824			G-DGU	SG		-	-	-	-
1825			CUST	CN		215,589	65,378	215,589	65,378
1826			PTD	SO		2,960,972	810,840	2,960,972	810,840
1827			P	SE		1,668	412	1,668	412
1828			G-SG	SG		2,069,905	539,272	2,069,905	539,272
1829			G-SG	SG		-	-	-	-
1830					B8	7,369,740	2,498,700	7,369,740	2,498,700
1831									
1832	399	Coal Mine							
1833			P	SE		292,563,015	72,224,250	482,121,148	119,019,960
1834	MP		P	SE		-	-	-	-
1835					B8	292,563,015	72,224,250	482,121,148	119,019,960
1836									
1837	399L	WIDCO Capital Lease							
1838			P	SE	Tab 8	-	-	-	-
1839						-	-	-	-
1840									
1841		Remove Capital Leases				-	-	-	-
1842					Tab 8	-	-	-	-
1843									

2010 PROTOCOL

	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1844	1011390	General Capital Leases							
1845			G-SITUS	S		18,984,156	5,882,166	18,984,156	5,882,166
1846			P	SG		33,744,912	8,791,562	33,744,912	8,791,562
1847			PTD	SO		12,664,054	3,467,957	12,664,054	3,467,957
1848					B9	65,393,121	18,141,686	65,393,121	18,141,686
1849									
1850		Remove Capital Leases				(65,393,121)	(18,141,686)	(65,393,121)	(18,141,686)
1851						-	-	-	-
1852									
1853	1011346	General Gas Line Capital Leases							
1854			P	SG		-	-	-	-
1855					B9	-	-	-	-
1856									
1857		Remove Capital Leases				-	-	-	-
1858						-	-	-	-
1859									
1860	GP	Unclassified Gen Plant - Acct 300							
1861			G-SITUS	S		-	-	-	-
1862			PTD	SO		7,401,397	2,026,818	7,401,397	2,026,818
1863			CUST	CN		-	-	-	-
1864			G-SG	SG		-	-	-	-
1865			G-DGP	SG		-	-	-	-
1866			G-DGU	SG		-	-	-	-
1867					B8	7,401,397	2,026,818	7,401,397	2,026,818
1868									
1869	399G	Unclassified Gen Plant - Acct 300							
1870			G-SITUS	S		-	-	-	-
1871			PTD	SO		-	-	-	-
1872			G-SG	SG		-	-	-	-
1873			G-DGP	SG		-	-	-	-
1874			G-DGU	SG		-	-	-	-
1875					B8	-	-	-	-
1876									
1877	**Total General Plant**				**B8**	**1,324,192,060**	**375,931,651**	**1,549,806,658**	**436,158,921**
1878									
1879	Summary of General Plant by Factor								
1880		S				551,425,763	175,126,799	590,918,018	189,674,619
1881		DGP				-	-	-	-
1882		DGU				-	-	-	-
1883		SG				255,705,611	66,618,987	264,570,061	68,928,442
1884		SO				263,961,851	72,283,989	253,850,185	69,514,985
1885		SE				293,337,722	72,415,500	482,772,097	119,180,658
1886		CN				25,154,232	7,628,061	23,089,418	7,001,903
1887		DEU				-	-	-	-
1888		SSGCT				-	-	-	-
1889		SSGCH				-	-	-	-
1890		Less Capital Leases				(65,393,121)	(18,141,686)	(65,393,121)	(18,141,686)
1891	Total General Plant by Factor					1,324,192,060	375,931,651	1,549,806,658	436,158,921
1892	301	Organization							
1893			I-SITUS	S		-	-	-	-
1894			PTD	SO		-	-	-	-
1895			I-SG	SG		-	-	-	-
1896					B8	-	-	-	-
1897	302	Franchise & Consent							
1898			I-SITUS	S		1,000,000	-	1,000,000	-
1899			I-SG	SG		10,419,206	2,714,516	5,558,601	1,448,182
1900			I-SG	SG		173,622,224	45,233,801	171,139,925	44,587,087
1901			I-SG	SG		9,189,363	2,394,105	9,035,229	2,353,948
1902			I-DGP	SG		-	-	(956,836)	(249,285)
1903			I-DGU	SG		600,993	156,577	577,415	150,434
1904					B8	194,831,786	50,498,998	186,354,334	48,290,368
1905									

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	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1906	303	Miscellaneous Intangible Plant							
1907			I-SITUS	S		10,757,522	3,994,986	10,738,312	3,992,922
1908			I-SG	SG		138,585,578	36,105,703	138,585,578	36,105,703
1909			PTD	SO		383,331,947	104,972,602	395,971,206	108,433,769
1910			P	SE		3,666,461	905,129	3,554,385	877,462
1911			CUST	CN		122,787,241	37,235,426	122,467,102	37,138,343
1912			P	SG		-	-	-	-
1913			I-DGP	SG		-	-	-	-
1914					B8	659,128,750	183,213,847	671,316,583	186,548,199
1915	303	Less Non-Utility Plant							
1916			I-SITUS	S		-	-	-	-
1917						659,128,750	183,213,847	671,316,583	186,548,199
1918	IP	Unclassified Intangible Plant - Acct 300							
1919			I-SITUS	S		-	-	-	-
1920			I-SG	SG		-	-	-	-
1921			I-DGU	SG		-	-	-	-
1922			PTD	SO		-	-	-	-
1923						-	-	-	-
1924									
1925	**Total Intangible Plant**				**B8**	**853,960,537**	**233,712,845**	**857,670,918**	**234,838,566**
1926									
1927	Summary of Intangible Plant by Factor								
1928		S				11,757,522	3,994,986	11,738,312	3,992,922
1929		DGP				-	-	-	-
1930		DGU				-	-	-	-
1931		SG				332,417,365	86,604,701	323,939,913	84,396,071
1932		SO				383,331,947	104,972,602	395,971,206	108,433,769
1933		CN				122,787,241	37,235,426	122,467,102	37,138,343
1934		SSGCT				-	-	-	-
1935		SSGCH				-	-	-	-
1936		SE				3,666,461	905,129	3,554,385	877,462
1937	Total Intangible Plant by Factor					853,960,537	233,712,845	857,670,918	234,838,566
1938	Summary of Unclassified Plant (Account 106)								
1939		DP				28,945,772	5,984,241	28,945,772	5,984,241
1940		DS0				-	-	-	-
1941		GP				7,401,397	2,026,818	7,401,397	2,026,818
1942		HP				-	-	-	-
1943		NP				-	-	-	-
1944		OP				-	-	-	-
1945		TP				6,334,193	1,650,247	6,334,193	1,650,247
1946		TS0				-	-	-	-
1947		IP				-	-	-	-
1948		MP							
1949		SP				(22,737,202)	(5,923,724)	(22,737,202)	(5,923,724)
1950	Total Unclassified Plant by Factor					19,944,160	3,737,583	19,944,160	3,737,583
1951									
1952	**Total Electric Plant In Service**				**B8**	**23,253,605,964**	**6,371,400,760**	**24,416,813,071**	**6,686,362,611**

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	 OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	 OREGON
1953	Summary of Electric Plant by Factor								
1954		S				6,350,778,700	1,957,932,171	6,569,418,023	2,029,460,653
1955		SE				297,004,184	73,320,629	486,326,482	120,058,119
1956		DGU				-	-	-	-
1957		DGP				-	-	-	-
1958		SG				15,875,980,929	4,136,169,568	16,631,083,775	4,332,896,524
1959		SO				647,293,799	177,256,591	649,821,391	177,948,754
1960		CN				147,941,474	44,863,487	145,556,521	44,140,246
1961		DEU				-	-	-	-
1962		SSGCH				-	-	-	-
1963		SSGCT				-	-	-	-
1964		Less Capital Leases				(65,393,121)	(18,141,686)	(65,393,121)	(18,141,686)
1965						23,253,605,964	6,371,400,760	24,416,813,071	6,686,362,611
1966	105	Plant Held For Future Use							
1967			DPW	S		7,945,429	4,254,106	-	-
1968			P	SG		-	-	-	-
1969			P	SG		2,996,636	780,714	-	-
1970			P	SG		8,923,302	2,324,788	-	-
1971			P	SE		26,313,198	6,495,869	-	-
1972			G	SG		-	-	-	-
1973									
1974									
1975	**Total Plant Held For Future Use**				**B10**	**46,178,566**	**13,855,477**	**-**	**-**
1976									
1977	114	Electric Plant Acquisition Adjustments							
1978			P	S		-	-	-	-
1979			P	SG		144,614,797	37,676,495	144,614,797	37,676,495
1980			P	SG		14,560,711	3,793,502	14,560,711	3,793,502
1981	**Total Electric Plant Acquisition Adjustment**				**B15**	**159,175,508**	**41,469,998**	**159,175,508**	**41,469,998**
1982									
1983	115	Accum Provision for Asset Acquisition Adjustments							
1984			P	S		-	-	-	-
1985			P	SG		(96,250,428)	(25,076,125)	(106,632,236)	(27,780,898)
1986			P	SG		(13,880,792)	(3,616,363)	(13,880,792)	(3,616,363)
1987					B15	(110,131,220)	(28,692,489)	(120,513,028)	(31,397,261)
1988									
1989	120	Nuclear Fuel							
1990			P	SE		-	-	-	-
1991	**Total Nuclear Fuel**				**B15**	**-**	**-**	**-**	**-**
1992									
1993	124	Weatherization							
1994			DMSC	S		1,714,949	0	1,714,949	0
1995			DMSC	SO		(4,454)	(1,220)	(4,454)	(1,220)
1996					B16	1,710,495	(1,219)	1,710,495	(1,219)
1997									
1998	182W	Weatherization							
1999			DMSC	S		(7,588,159)	-	(7,588,159)	-
2000			DMSC	SG		-	-	-	-
2001			DMSC	SG		-	-	-	-
2002			DMSC	SO		-	-	-	-
2003					B16	(7,588,159)	-	(7,588,159)	-
2004									
2005	186W	Weatherization							
2006			DMSC	S		-	-	-	-
2007			DMSC	CN		-	-	-	-
2008			DMSC	CNP		-	-	-	-
2009			DMSC	SG		-	-	-	-
2010			DMSC	SO		-	-	-	-
2011					B16	-	-	-	-
2012									
2013	**Total Weatherization**				**B16**	**(5,877,664)**	**(1,219)**	**(5,877,664)**	**(1,219)**

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Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2014									
2015	151	Fuel Stock							
2016			P	DEU		-	-	-	-
2017			P	SE		259,761,148	64,126,541	240,567,099	59,388,157
2018			P	SE		-	-	-	-
2019			P	SE		10,115,124	2,497,094	10,795,211	2,664,985
2020	**Total Fuel Stock**				**B13**	**269,876,272**	**66,623,634**	**251,362,310**	**62,053,142**
2021									
2022	152	Fuel Stock - Undistributed							
2023			P	SE		-	-	-	-
2024						-	-	-	-
2025									
2026	25316	DG&T Working Capital Deposit							
2027			P	SE		(3,235,000)	(798,616)	(3,549,923)	(876,360)
2028					B13	(3,235,000)	(798,616)	(3,549,923)	(876,360)
2029									
2030	25317	DG&T Working Capital Deposit							
2031			P	SE		(2,489,934)	(614,683)	(2,858,749)	(705,732)
2032					B13	(2,489,934)	(614,683)	(2,858,749)	(705,732)
2033									
2034	25319	Provo Working Capital Deposit							
2035			P	SE		-	-	-	-
2036						-	-	-	-
2037									
2038		Total Fuel Stock			B13	264,151,338	65,210,335	244,953,638	60,471,050
2039	154	Materials and Supplies							
2040			MSS	S		91,436,270	30,297,434	91,436,270	30,297,434
2041			MSS	SG		4,700,056	1,224,506	4,700,056	1,224,506
2042			MSS	SE		5,973,797	1,474,735	5,973,797	1,474,735
2043			MSS	SO		203,687	55,778	203,687	55,778
2044			MSS	SG		93,226,734	24,288,363	93,226,734	24,288,363
2045			MSS	SG		1,563	407	1,563	407
2046			MSS	SNPD		(2,280,591)	(612,831)	(2,280,591)	(612,831)
2047			MSS	SG		-	-	-	-
2048			MSS	SG		-	-	-	-
2049			MSS	SG		-	-	-	-
2050			MSS	SG		-	-	-	-
2051			MSS	SG		7,383,487	1,923,620	7,383,487	1,923,620
2052			MSS	SG		-	-	-	-
2053	**Total Materials and Supplies**				**B13**	**200,645,004**	**58,652,012**	**200,645,004**	**58,652,012**
2054									
2055	163	Stores Expense Undistributed							
2056			MSS	SO		-	-	-	-
2057									
2058					B13	-	-	-	-
2059									
2060	25318	Provo Working Capital Deposit							
2061			MSS	SG		(273,000)	(71,125)	(273,000)	(71,125)
2062									
2063					B13	(273,000)	(71,125)	(273,000)	(71,125)
2064									
2065		Total Materials & Supplies			B13	200,372,004	58,580,887	200,372,004	58,580,887
2066									
2067	165	Prepayments							
2068			DMSC	S		8,415,026	2,425,369	8,415,026	2,425,369
2069			GP	GPS		216,127	59,185	216,127	59,185
2070			PT	SG		3,397,261	885,088	3,397,261	885,088
2071			P	SE		3,194,786	788,688	3,194,786	788,688
2072			PTD	SO		11,099,974	3,039,645	11,099,974	3,039,645
2073	**Total Prepayments**				**B15**	**26,323,174**	**7,197,975**	**26,323,174**	**7,197,975**
2074									

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	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2075	182M	Misc Regulatory Assets							
2076			DDS2	S		171,580,102	(273,550)	171,687,728	(165,924)
2077			DEFSG	SG		-	-	-	-
2078			P	SGCT		5,705,661	1,491,496	3,460,811	904,678
2079			DEFSG	SG		-	-	-	-
2080			P	SE		-	-	-	-
2081			P	SG		-	-	-	-
2082			DDSO2	SO		10,028,834	2,746,321	186,514,834	51,075,700
2083					B11	187,314,597	3,964,268	361,663,373	51,814,454
2084									
2085	186M	Misc Deferred Debits							
2086			LABOR	S		18,192,572	-	18,192,572	-
2087			P	SG		-	-	-	-
2088			P	SG		-	-	-	-
2089			DEFSG	SG		61,941,029	16,137,497	71,711,913	18,683,106
2090			LABOR	SO		19,594	5,366	19,594	5,366
2091			P	SE		13,641,055	3,367,531	13,641,055	3,367,531
2092			P	SG		-	-	-	-
2093			GP	EXCTAX		-	-	-	-
2094	**Total Misc. Deferred Debits**				**B11**	**93,794,250**	**19,510,394**	**103,565,134**	**22,056,002**
2095									
2096	Working Capital								
2097	CWC	Cash Working Capital							
2098			CWC	S		43,897,857	15,535,918	50,163,782	17,821,360
2099			CWC	SO		-	-	-	-
2100			CWC	SE		-	-	-	-
2101					B14	43,897,857	15,535,918	50,163,782	17,821,360
2102									
2103	OWC	Other Work. Cap.							
2104	131	Cash	GP	SNP		-	-	-	-
2105	135	Working Funds	P	SG		-	-	-	-
2106	141	Notes Receivabl	GP	SO		-	-	-	-
2107	143	Other A/R	GP	SO		57,855,649	15,843,339	57,855,649	15,843,339
2108	232	A/P	PTD	S		(6,379)	-	(6,379)	-
2109	232	A/P	PTD	SO		(5,265,990)	(1,442,052)	(5,265,990)	(1,442,052)
2110	232	A/P	P	SE		(2,204,099)	(544,120)	(2,204,099)	(544,120)
2111	232	A/P	T	SG		(86,375)	(22,503)	(86,375)	(22,503)
2112	2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2113	2533	Other Msc. Df. Crd.	P	SE		(6,534,614)	(1,613,183)	(6,910,016)	(1,705,857)
2114	230	Asset Retir. Oblig.	P	SE		(2,849,851)	(703,535)	(2,849,851)	(703,535)
2115	230	Asset Retir. Oblig.	P	S		-	-	-	-
2116	254105	ARO Reg Liability	P	S		-	-	-	-
2117	254105	ARO Reg Liability	P	SE		(976,925)	(241,171)	(976,925)	(241,171)
2118	2533	Cholla Reclamation	P	SE		-	-	-	-
2119					B14	39,931,417	11,276,775	39,556,014	11,184,100
2120									
2121	**Total Working Capital**				**B14**	**83,829,274**	**26,812,692**	**89,719,796**	**29,005,460**
2122	Miscellaneous Rate Base								
2123	18221	Unrec Plant & Reg Study Costs							
2124			P	S		-	-	-	-
2125									
2126					B15	-	-	-	-
2127									
2128	18222	Nuclear Plant - Trojan							
2129			P	S		-	-	-	-
2130			P	TROJP		-	-	-	-
2131			P	TROJD		-	-	-	-
2132					B15	-	-	-	-
2133									
2134									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2135									
2136	1869	Misc Deferred Debits-Trojan							
2137			P	S		-	-	-	-
2138			P	SG		-	-	-	-
2139					B15	-	-	-	-
2140									
2141	**Total Miscellaneous Rate Base**				**B15**	**-**	**-**	**-**	**-**
2142									
2143	**Total Rate Base Additions**				**B15**	**945,129,825**	**207,908,318**	**1,059,381,935**	**239,197,347**
2144	235	Customer Service Deposits							
2145			CUST	S		-	-	-	-
2146			CUST	CN		-	-	-	-
2147	**Total Customer Service Deposits**				B15	-	-	-	-
2148									
2149	2281	Prop Ins	PTD	SO		-	-	-	-
2150	2282	Inj & Dam	PTD	SO		(12,639,000)	(3,461,096)	(12,639,000)	(3,461,096)
2151	2283	Pen & Ben	PTD	SO		(3,057,213)	(837,195)	(3,057,213)	(837,195)
2152	254	Ins Prov	PTD	SO		-	-	-	-
2153	254	Reg Liabilitie	P	SE		-	-	-	-
2154					B15	(15,696,213)	(4,298,291)	(15,696,213)	(4,298,291)
2155									
2156	22844	Accum Hydro Relicensing Obligation							
2157			P	S		-	-	-	-
2158			P	SG		-	-	-	-
2159					B15	-	-	-	-
2160									
2161	22841	Chehalis Rat	P	SG		(1,479,562)	(385,470)	(1,479,562)	(385,470)
2162	230	ARO	P	TROJP		-	-	-	-
2163	254105	ARO	P	TROJP		(3,236,234)	(836,419)	(3,236,234)	(836,419)
2164	254		P	S		(31,648,165)	298,028	(31,648,165)	298,028
2165					B15	(36,363,961)	(923,862)	(36,363,961)	(923,862)
2166									
2167	252	Customer Advances for Construction							
2168			DPW	S		(4,145,233)	(1,774,969)	(8,116,990)	(1,935,702)
2169			DPW	SE		-	-	-	-
2170			T	SG		(18,645,453)	(4,857,700)	(14,673,696)	(3,822,938)
2171			DPW	SO		-	-	-	-
2172			CUST	CN		-	-	-	-
2173	**Total Customer Advances for Construction**				**B19**	**(22,790,686)**	**(6,632,669)**	**(22,790,686)**	**(5,758,640)**
2174									
2175	25398	SO2 Emissions							
2176			P	SE		-	-	(121,735)	(30,052)
2177					B19	-	-	(121,735)	(30,052)
2178									
2179	25399	Other Deferred Credits							
2180			P	S		(809,095)	(297,151)	(809,095)	(297,151)
2181			LABOR	SO		-	-	-	-
2182			P	SG		(9,689,058)	(2,524,291)	(9,689,058)	(2,524,291)
2183			P	SE		-	-	-	-
2184					B19	(10,498,153)	(2,821,441)	(10,498,153)	(2,821,441)

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2185									
2186	190	Accumulated Deferred Income Taxes							
2187			P	S		32,624,509	5,571,396	20,838,367	1,681,887
2188			CUST	CN		28,936	8,775	10,661	3,233
2189			LABOR	SO		78,367,323	21,460,308	81,133,803	22,217,888
2190			P	GPS		-	-	-	-
2191			IBT	IBT		-	-	-	-
2192			P	SG		-	-	-	-
2193			P	SG		-	-	-	-
2194			CUST	BADDEBT		5,515,134	2,614,576	4,215,846	1,998,619
2195			P	TROJD		1,917,975	495,006	1,880,194	485,256
2196			P	SG		44,555,610	11,608,074	3,409,554	888,291
2197			P	SE		5,811,555	1,434,683	(31,493,628)	(7,774,748)
2198			PTD	SNP		-	-	-	-
2199			DPW	SNPD		806,637	216,756	1,988,128	534,242
2200			P	SG		-	-	-	-
2201	**Total Accum Deferred Income Taxes**				**B19**	**169,627,679**	**43,409,575**	**81,982,925**	**20,034,667**
2202									
2203	281	Accumulated Deferred Income Taxes							
2204			P	S		-	-	-	-
2205			PT	SG		(178,288,826)	(46,449,591)	-	-
2206			T	SG		-	-	-	-
2207					B19	(178,288,826)	(46,449,591)	-	-
2208									
2209	282	Accumulated Deferred Income Taxes							
2210			GP	S		-	-	(3,865,514,515)	(1,033,679,794)
2211			GP	CN		-	-	-	-
2212			TAXDEPR	SG		-	-	-	-
2213			ACCMDIT	DITBAL		(3,360,555,483)	(909,311,178)	6	2
2214			P	SG		-	-	-	-
2215			DPW	SG-P		-	-	-	-
2216			P	SG		-	-	-	-
2217			PT	SG-U		-	-	-	-
2218			LABOR	SO		22,811,348	6,246,718	21,089,899	5,775,312
2219			GP	SG		-	-	-	-
2220			P	SE		(5,108,635)	(1,261,155)	(5,832,388)	(1,439,826)
2221			P	SG		(4,458,160)	(1,161,484)	12,848,905	3,347,526
2222					B19	(3,347,310,930)	(905,487,099)	(3,837,408,093)	(1,025,996,781)
2223									
2224	283	Accumulated Deferred Income Taxes							
2225			GP	S		(76,689,057)	1,894,728	(26,514,301)	(471,523)
2226			P	SG		(2,807,889)	(731,539)	(1,873,877)	(488,201)
2227			P	SE		(2,611,320)	(644,650)	(2,605,290)	(643,161)
2228			LABOR	SO		(8,742,187)	(2,393,983)	(14,278,359)	(3,910,022)
2229			GP	GPS		(5,949,550)	(1,629,240)	(7,389,065)	(2,023,440)
2230			PTD	SNP		(3,672,481)	(970,258)	(2,924,599)	(772,670)
2231			P	TROJD		-	-	-	-
2232			P	SG		-	-	-	-
2233			P	SGCT		(2,378,341)	(621,714)	(1,313,412)	(343,334)
2234			P	IBT		-	-	-	-
2235					B19	(102,850,825)	(5,096,656)	(56,898,902)	(8,652,352)
2236									
2237	**Total Accum Deferred Income Tax**				**B19**	**(3,458,822,902)**	**(913,623,771)**	**(3,812,324,071)**	**(1,014,614,465)**
2238	255	Accumulated Investment Tax Credit							
2239			PTD	S		-	-	-	-
2240			PTD	ITC84		(290,837)	(206,424)	-	-
2241			PTD	ITC85		(1,347,412)	(912,063)	(190,006)	(128,615)
2242			PTD	ITC86		(863,199)	(557,696)	(388,922)	(251,275)
2243			PTD	ITC88		(148,176)	(90,684)	(91,199)	(55,814)
2244			PTD	ITC89		(339,502)	(191,329)	(226,217)	(127,487)
2245			PTD	ITC90		(243,966)	(38,877)	(188,628)	(30,059)
2246			PTD	DGU		-	-	-	-
2247	**Total Accumlated ITC**				**B19**	(3,233,092)	(1,997,073)	(1,084,972)	(593,249)
2248									
2249	**Total Rate Base Deductions**					**(3,547,405,008)**	**(930,297,108)**	**(3,898,879,791)**	**(1,029,040,001)**
2250									

	2010 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2251									
2252									
2253	108SP	Steam Prod Plant Accumulated Depr							
2254			P	S		-	-	-	-
2255			P	SG		(755,843,347)	(196,919,879)	(775,000,005)	(201,910,764)
2256			P	SG		(814,203,937)	(212,124,565)	(831,327,873)	(216,585,864)
2257			P	SG		(675,402,811)	(175,962,705)	(1,105,123,069)	(287,917,731)
2258			P	SG		(172,395,851)	(44,914,294)	(197,909,136)	(51,561,270)
2259					B17	(2,417,845,946)	(629,921,443)	(2,909,360,083)	(757,975,629)
2260									
2261	108NP	Nuclear Prod Plant Accumulated Depr							
2262			P	SG		-	-	-	-
2263			P	SG		-	-	-	-
2264			P	SG		-	-	-	-
2265					B17	-	-	-	-
2266									
2267									
2268	108HP	Hydraulic Prod Plant Accum Depr							
2269			P	S		-	-	-	-
2270			P	SG		(154,655,295)	(40,292,347)	(155,927,854)	(40,623,886)
2271			P	SG		(29,281,162)	(7,628,622)	(29,864,357)	(7,780,561)
2272			P	SG		(57,986,251)	(15,107,159)	(77,056,297)	(20,075,478)
2273			P	SG		(21,132,737)	(5,505,712)	(26,946,882)	(7,020,472)
2274					B17	(263,055,446)	(68,533,840)	(289,795,388)	(75,500,397)
2275									
2276	108OP	Other Production Plant - Accum Depr							
2277			P	S		-	-	-	-
2278			P	SG		(1,000,886)	(260,761)	(829,117)	(216,010)
2279			P	SG		-	-	-	-
2280			P	SG		(512,725,603)	(133,580,410)	(626,071,697)	(163,110,469)
2281			P	SG		(22,545,768)	(5,873,849)	(25,970,172)	(6,766,009)
2282					B17	(536,272,257)	(139,715,020)	(652,870,986)	(170,092,488)
2283									
2284	108EP	Experimental Plant - Accum Depr							
2285			P	SG		-	-	-	-
2286			P	SG		-	-	-	-
2287						-	-	-	-
2288									
2289	**Total Production Plant Accum Depreciation**				**B17**	**(3,217,173,648)**	**(838,170,303)**	**(3,852,026,457)**	**(1,003,568,515)**
2290									
2291	Summary of Prod Plant Depreciation by Factor								
2292		S				-	-	-	-
2293		DGP				-	-	-	-
2294		DGU				-	-	-	-
2295		SG				(3,217,173,648)	(838,170,303)	(3,852,026,457)	(1,003,568,515)
2296		SSGCH				-	-	-	-
2297		SSGCT				-	-	-	-
2298	Total of Prod Plant Depreciation by Factor					(3,217,173,648)	(838,170,303)	(3,852,026,457)	(1,003,568,515)
2299									
2300									
2301	108TP	Transmission Plant Accumulated Depr							
2302			T	S		-	-	-	-
2303			T	SG		(369,658,339)	(96,307,093)	(376,788,696)	(98,164,765)
2304			T	SG		(398,638,323)	(103,857,249)	(409,900,684)	(106,791,432)
2305			T	SG		(483,569,188)	(125,984,288)	(565,124,573)	(147,231,914)
2306	**Total Trans Plant Accum Depreciation**				**B17**	**(1,251,865,849)**	**(326,148,630)**	**(1,351,813,952)**	**(352,188,111)**

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Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
108360	Land and Land Rights							
		DPW	S		(7,638,160)	(2,439,164)	(9,198,016)	(3,036,579)
				B17	(7,638,160)	(2,439,164)	(9,198,016)	(3,036,579)
108361	Structures and Improvements							
		DPW	S		(15,519,872)	(3,885,172)	(17,786,085)	(4,753,117)
				B17	(15,519,872)	(3,885,172)	(17,786,085)	(4,753,117)
108362	Station Equipment							
		DPW	S		(216,923,165)	(60,646,672)	(239,924,509)	(69,456,044)
				B17	(216,923,165)	(60,646,672)	(239,924,509)	(69,456,044)
108363	Storage Battery Equipment							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108364	Poles, Towers & Fixtures							
		DPW	S		(569,064,966)	(219,323,380)	(595,507,011)	(229,450,519)
				B17	(569,064,966)	(219,323,380)	(595,507,011)	(229,450,519)
108365	Overhead Conductors							
		DPW	S		(306,896,598)	(132,370,285)	(324,676,291)	(139,179,797)
				B17	(306,896,598)	(132,370,285)	(324,676,291)	(139,179,797)
108366	Underground Conduit							
		DPW	S		(128,927,979)	(37,892,880)	(137,309,739)	(41,103,042)
				B17	(128,927,979)	(37,892,880)	(137,309,739)	(41,103,042)
108367	Underground Conductors							
		DPW	S		(294,642,008)	(62,560,236)	(314,368,995)	(70,115,550)
				B17	(294,642,008)	(62,560,236)	(314,368,995)	(70,115,550)
108368	Line Transformers							
		DPW	S		(387,610,097)	(175,369,931)	(417,884,183)	(186,964,718)
				B17	(387,610,097)	(175,369,931)	(417,884,183)	(186,964,718)
108369	Services							
		DPW	S		(186,188,983)	(72,184,238)	(202,489,410)	(78,427,201)
				B17	(186,188,983)	(72,184,238)	(202,489,410)	(78,427,201)
108370	Meters							
		DPW	S		(69,851,398)	(33,197,639)	(74,509,427)	(34,981,635)
				B17	(69,851,398)	(33,197,639)	(74,509,427)	(34,981,635)
108371	Installations on Customers' Premises							
		DPW	S		(7,545,086)	(2,526,538)	(7,778,347)	(2,615,875)
				B17	(7,545,086)	(2,526,538)	(7,778,347)	(2,615,875)
108372	Leased Property							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108373	Street Lights							
		DPW	S		(27,313,402)	(8,973,182)	(28,940,203)	(9,596,236)
				B17	(27,313,402)	(8,973,182)	(28,940,203)	(9,596,236)
108D00	Unclassified Dist Plant - Acct 300							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		1,741,637	817,585	1,741,637	817,585
				B17	1,741,637	817,585	1,741,637	817,585
Total Distribution Plant Accum Depreciation				**B17**	**(2,216,380,077)**	**(810,551,730)**	**(2,368,630,579)**	**(868,862,729)**
Summary of Distribution Plant Depr by Factor								
	S				(2,216,380,077)	(810,551,730)	(2,368,630,579)	(868,862,729)
Total Distribution Depreciation by Factor					(2,216,380,077)	(810,551,730)	(2,368,630,579)	(868,862,729)

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	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2384	108GP	General Plant Accumulated Depr							
2385			G-SITUS	S		(166,793,901)	(50,557,550)	(173,802,498)	(51,479,635)
2386			G-DGP	SG		(2,572,738)	(670,276)	(402,915)	(104,971)
2387			G-DGU	SG		(3,676,496)	(957,838)	814,832	212,288
2388			G-SG	SG		(59,966,753)	(15,623,139)	(67,440,897)	(17,570,378)
2389			CUST	CN		(8,786,738)	(2,664,592)	(9,220,436)	(2,796,112)
2390			PTD	SO		(78,928,937)	(21,614,102)	(72,319,411)	(19,804,133)
2391			P	SE		(310,133)	(76,562)	(257,640)	(63,603)
2392			P	SG		(51,569)	(13,435)	(41,478)	(10,806)
2393			P	SG		(2,102,292)	(547,710)	(1,837,545)	(478,736)
2394					B17	(323,189,557)	(92,725,203)	(324,507,988)	(92,096,086)
2395									
2396									
2397	108MP	Mining Plant Accumulated Depr.							
2398			P	S		-	-	-	-
2399			P	SE		(161,499,586)	(39,868,971)	(174,787,386)	(43,149,295)
2400					B17	(161,499,586)	(39,868,971)	(174,787,386)	(43,149,295)
2401	108MP	Less Centralia Situs Depreciation							
2402			P	S		-	-	-	-
2403					B17	(161,499,586)	(39,868,971)	(174,787,386)	(43,149,295)
2404									
2405	1081390	Accum Depr - Capital Lease							
2406			PTD	SO	B17	-	-	-	-
2407						-	-	-	-
2408									
2409		Remove Capital Leases				-	-	-	-
2410					B17	-	-	-	-
2411									
2412	1081399	Accum Depr - Capital Lease							
2413			P	S		-	-	-	-
2414			P	SE	B17	-	-	-	-
2415						-	-	-	-
2416									
2417		Remove Capital Leases				-	-	-	-
2418					B17	-	-	-	-
2419									
2420									
2421	**Total General Plant Accum Depreciation**				**B17**	**(484,689,143)**	**(132,594,175)**	**(499,295,374)**	**(135,245,381)**
2422									
2423									
2424									
2425	Summary of General Depreciation by Factor								
2426		S				(166,793,901)	(50,557,550)	(173,802,498)	(51,479,635)
2427		DGP				-	-	-	-
2428		DGU				-	-	-	-
2429		SE				(161,809,718)	(39,945,533)	(175,045,026)	(43,212,898)
2430		SO				(78,928,937)	(21,614,102)	(72,319,411)	(19,804,133)
2431		CN				(8,786,738)	(2,664,592)	(9,220,436)	(2,796,112)
2432		SG				(68,369,849)	(17,812,398)	(68,908,002)	(17,952,603)
2433		DEU				-	-	-	-
2434		SSGCT				-	-	-	-
2435		SSGCH				-	-	-	-
2436		Remove Capital Leases				-	-	-	-
2437	Total General Depreciation by Factor					(484,689,143)	(132,594,175)	(499,295,374)	(135,245,381)
2438									
2439									
2440	**Total Accum Depreciation - Plant In Service**				**B17**	**(7,170,108,718)**	**(2,107,464,837)**	**(8,071,766,363)**	**(2,359,864,735)**
2441	111SP	Accum Prov for Amort-Steam							
2442			P	SG		-	-	-	-
2443			P	SG		-	-	-	-
2444					B18	-	-	-	-
2445									
2446									
2447	111GP	Accum Prov for Amort-General							
2448			G-SITUS	S		(10,105,921)	(3,943,245)	(11,164,775)	(4,290,302)
2449			CUST	CN		(3,134,593)	(950,570)	(3,544,644)	(1,074,919)
2450			I-SG	SG		-	-	-	-
2451			PTD	SO		(12,094,200)	(3,311,907)	(14,012,557)	(3,837,234)
2452			P	SE		-	-	-	-
2453					B18	(25,334,715)	(8,205,722)	(28,721,975)	(9,202,455)
2454									

2010 PROTOCOL

	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2012 PRO FORMA RESULTS TOTAL	JUNE 2012 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2455									
2456	111HP	Accum Prov for Amort-Hydro							
2457			P	SG		-	-	-	-
2458			P	SG		-	-	-	-
2459			P	SG		(473,877)	(123,459)	(941,292)	(245,235)
2460			P	SG		(506,676)	(132,004)	(573,475)	(149,407)
2461					B18	(980,553)	(255,464)	(1,514,767)	(394,642)
2462									
2463									
2464	111IP	Accum Prov for Amort-Intangible Plant							
2465			I-SITUS	S		(1,263,532)	(61,511)	(1,528,757)	(77,091)
2466			I-DGP	SG		-	-	956,836	249,285
2467			I-DGU	SG		(374,534)	(97,577)	(375,381)	(97,798)
2468			P	SE		(1,794,223)	(442,935)	(2,190,791)	(540,835)
2469			I-SG	SG		(52,567,449)	(13,695,398)	(50,513,331)	(13,160,239)
2470			I-SG	SG		(30,399,471)	(7,919,975)	(44,178,273)	(11,509,766)
2471			I-SG	SG		(3,831,411)	(998,197)	(4,131,863)	(1,076,474)
2472			CUST	CN		(103,869,877)	(31,498,705)	(113,185,569)	(34,323,704)
2473			P	SG		-	-	-	-
2474			P	SG		(327,836)	(85,411)	(327,836)	(85,411)
2475			PTD	SO		(280,901,816)	(76,922,873)	(299,062,366)	(81,896,004)
2476					B18	(475,330,148)	(131,722,582)	(514,537,332)	(142,518,037)
2477	111IP	Less Non-Utility Plant							
2478			NUTIL	OTH		-	-	-	-
2479						(475,330,148)	(131,722,582)	(514,537,332)	(142,518,037)
2480									
2481	111390	Accum Amtr - Capital Lease							
2482			G-SITUS	S		(5,325,839)	(2,469,170)	(5,325,839)	(2,469,170)
2483			P	SG		(5,217,177)	(1,359,231)	(5,217,177)	(1,359,231)
2484			PTD	SO		428,996	117,477	428,996	117,477
2485						(10,114,020)	(3,710,924)	(10,114,020)	(3,710,924)
2486									
2487		Remove Capital Lease Amtr				10,114,020	3,710,924	10,114,020	3,710,924
2488									
2489	**Total Accum Provision for Amortization**				**B18**	**(501,645,416)**	**(140,183,768)**	**(544,774,074)**	**(152,115,135)**
2490									
2491									
2492									
2493									
2494	Summary of Amortization by Factor								
2495		S				(16,695,291)	(6,473,926)	(18,019,371)	(6,836,562)
2496		DGP				-	-	-	-
2497		DGU				-	-	-	-
2498		SE				(1,794,223)	(442,935)	(2,190,791)	(540,835)
2499		SO				(292,567,021)	(80,117,302)	(312,645,927)	(85,615,761)
2500		CN				(107,004,470)	(32,449,276)	(116,730,213)	(35,398,622)
2501		SSGCT				-	-	-	-
2502		SSGCH				-	-	-	-
2503		SG				(93,698,430)	(24,411,253)	(105,301,792)	(27,434,278)
2504		Less Capital Lease				10,114,020	3,710,924	10,114,020	3,710,924
2505	Total Provision For Amortization by Factor					(501,645,416)	(140,183,768)	(544,774,074)	(152,115,135)

The Company used actual revenue for the 12 months ended June 30, 2012 as the starting point for the calculation of pro forma revenue. Actual revenue was adjusted using the normalizing and pro forma adjustments below to calculate the revenue for the December 2014 test period.

3.1 Pro Forma Revenue
3.2 Wheeling Revenue
3.3 SO2 Emission Allowances
3.4 REC Revenue
3.5 Ancillary Revenue

PacifiCorp
Oregon General Rate Case - December 2014
Tab 3 Adjustment Summary

	Total Adjustments	3.1 Pro Forma Revenue	3.2 Wheeling Revenue	3.3 SO2 Emission Allowances	3.4 REC Revenue	3.5 Ancillary Revenue
1 Operating Revenues:						
2 General Business Revenues	80,664,152	80,664,152	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-
5 Other Operating Revenues	(6,866,375)	-	(395,012)	-	(6,855,522)	384,158
6 Total Operating Revenues	73,797,777	80,664,152	(395,012)	-	(6,855,522)	384,158
7						
8 Operating Expenses:						
9 Steam Production	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-	-
13 Embedded Cost Differential (ECD)	-	-	-	-	-	-
13 Transmission	(197,987)	-	(197,987)	-	-	-
14 Distribution	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	-	-	-	-	-	-
19						
20 Total O&M Expenses	(197,987)	-	(197,987)	-	-	-
21						
22 Depreciation	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-
25 Income Taxes - Federal	24,717,985	26,945,487	(65,782)	8	(2,290,055)	128,326
26 Income Taxes - State	3,358,764	3,661,444	(8,939)	1	(311,180)	17,437
27 Income Taxes - Def Net	19,311	-	-	19,311	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-
29 Misc Revenue & Expense	(50,436)	-	-	(50,436)	-	-
30						
31 Total Operating Expenses:	27,847,637	30,606,931	(272,707)	(31,116)	(2,601,236)	145,764
32						
33 Operating Rev For Return:	45,950,141	50,057,221	(122,305)	31,116	(4,254,286)	238,395
34						
35 Rate Base:						
36 Electric Plant In Service	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-
44 Working Capital	560,970	615,866	(5,487)	0	(52,342)	2,933
45 Weatherization Loans	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	560,970	615,866	(5,487)	0	(52,342)	2,933
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-
53 Accum Def Income Tax	11,405	-	-	11,405	-	-
54 Unamortized ITC	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(30,052)	-	-	(30,052)	-	-
58						
59 Total Rate Base Deductions	(18,647)	-	-	(18,647)	-	-
60						
61 Total Rate Base:	542,323	615,866	(5,487)	(18,647)	(52,342)	2,933
62						
63 Return on Rate Base	1.350%	1.470%	-0.004%	0.001%	-0.125%	0.007%
64						
65 Return on Equity	2.590%	2.822%	-0.007%	0.002%	-0.240%	0.013%
66						
67 TAX CALCULATION:						
68 Operating Revenue	74,046,200	80,664,152	(197,025)	50,436	(6,855,522)	384,158
69 Other Deductions						
70 Interest (AFUDC)	-	-	-	-	-	-
71 Interest	13,739	15,602	(139)	(472)	(1,326)	74
72 Schedule "M" Additions	-	-	-	-	-	-
73 Schedule "M" Deductions	50,884	-	-	50,884	-	-
74 Income Before Tax	73,981,577	80,648,551	(196,886)	25	(6,854,196)	384,084
75						
76 State Income Taxes	3,358,764	3,661,444	(8,939)	1	(311,180)	17,437
77 Taxable Income	70,622,814	76,987,106	(187,947)	23	(6,543,015)	366,647
78						
79 Federal Income Taxes + Other	24,717,985	26,945,487	(65,782)	8	(2,290,055)	128,326
80						
81 PRICE CHANGE	(76,259,631)	(83,072,622)	202,465	(54,059)	7,060,214	(395,628)

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Income:							
Residential	440	3	34,946,960	OR	100.000%	34,946,960	3.1.1
Commercial	442	3	29,746,803	OR	100.000%	29,746,803	3.1.1
Industrial	442	3	9,226,432	OR	100.000%	9,226,432	3.1.1
Irrigation	442	3	8,538,322	OR	100.000%	8,538,322	3.1.1
Public Street & Hwy	444	3	(1,794,365)	OR	100.000%	(1,794,365)	3.1.1
			80,664,152			80,664,152	
Adjustment to Income - All States Other Than Oregon							
Residential	440	3	107,297,301	Situs	0.000%	-	3.1.3
Commerical/Industrial	442	3	184,497,495	Situs	0.000%	-	3.1.3
Public Street & Hwy	444	3	(880,555)	Situs	0.000%	-	3.1.3
Other Sales to Public Auth	445	3	(920,548)	Situs	0.000%	-	3.1.3
			289,993,693			-	

Description of Adjustment:

This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the 12 months ending December 2014 based on forecasted loads. Page 3.1.4 shows a breakout between the TAM and general rate case revenues.

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Revenue
Actual 12 Months Ended June 2012
Forecast 12 Months Ending December 2014

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Total Revenue	Normalizing Adjustments[1] (305 Report)	Unadjusted Revenues	Remove Tariff Riders[2]	Base Rate Revenues	Normalizing Adjustments[3]	Temperature Normalization	Total Type 1 Adjusted Revenue	Type 2 Annualized Price Change[4]	Total Type 2 Adjusted Revenue	Type 3 Pro Forma Price Change[5]	Total Oregon Forecast Revenue	**Total Adjustment**
Residential	$550,106,777	($1,754,442)	$548,352,335	$20,096,540	$568,448,874	($8,586,281)	($6,013,373)	$553,849,221	$9,991,946	$563,841,167	$19,458,128	$583,299,295	**$34,946,960**
Commercial	$416,491,025	($1,477,689)	$415,013,336	($3,001,685)	$412,011,651	($222,796)	($433,130)	$411,355,725	$14,023,577	$425,379,302	$19,380,836	$444,760,138	**$29,746,803**
Industrial	$141,674,875	($541,949)	$141,132,926	($200,021)	$140,932,905	$7,394,175	$0	$148,327,080	$5,120,834	$153,447,915	($3,088,557)	$150,359,358	**$9,226,432**
Irrigation	$17,503,217	($2,802)	$17,500,416	$616,993	$18,117,409	$2,235,511	$394,928	$20,747,848	$1,898,382	$22,646,230	$3,392,508	$26,038,738	**$8,538,322**
Public St & Hwy	$6,187,968	$325,348	$6,513,316	($165,051)	$6,348,265	($1,112,745)	$0	$5,235,520	$52,279	$5,287,799	($568,848)	$4,718,952	**($1,794,365)**
Total Oregon	$1,131,963,862	($3,451,534)	**$1,128,512,328**	$17,346,777	$1,145,859,104	($292,135)	($6,051,575)	$1,139,515,394	$31,087,018	$1,170,602,413	$38,574,067	**$1,209,176,480**	**$80,664,152**
Source / Formula	305 Report		Report Pg. 2, Line 2	Ref. 3.1.7 - B	C + D	Ref. 3.1.7	Ref. 3.1.7	E + F + G	Ref. 3.1.7	H + I	Ref. 3.1.7	J + K	L - C **To. 3.1**

[1] Includes the removal of items not included in regulatory unadjusted results.
[2] Removal of SB838 Recovery, Revenue Accounting Adjustments, Gain on Sale of Asset, Other Rev - Deferred, Other Rev - Realized, DSM, Blue Sky, Revenue Adjust Property, Merger Credit, BPA (Sch 98), Independent Evaluator Adj (Sch 93), Property Sales Adj (Sch 96), MEHC Change-in-Control Severance Reg Asset Adj (Sch 194), Grid West Reg Asset Adj (Sch 195), RAC Deferral (Sch 203), Oregon Solar Incentive Program (Sch 204), and 2010 Protocol (Sch 291)
[3] Removal of SMUD Revenue Imputations, Demand Charge Accrual, RMA (Sch 299) and Out of Period adjustment.
[4] TAM rate change Effective January 1, 2012; Klamath rate change Effective April 17, 2012 (Schedule 33). Includes adjustment bringing direct access consumers to cost of service.
[5] GRC rate change Effective January 1, 2013; TAM rate change Effective January 1, 2013; Klamath rate change Effective April 17, 2013 (Schedule 33); transition to forecast.

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Revenue
Actual 12 Months Ended June 2012
Forecast 12 Months Ending December 2014

	A	B	C	D	E	F	G	H
	Total MWhs	Normalizing Adjustments MWhs[1]	Temperature Adjustments MWhs	Type 1 Adjusted MWhs	Type 2 Adjustments MWhs[2]	Total Oregon Adjusted MWhs	Type 3 Adjustment MWhs[3]	Total Oregon Forecast MWhs
Residential	5,481,239	937	(65,070)	5,417,107	(4,766)	5,412,341	(30,468)	5,381,873
Commercial	4,959,656	11,619	(4,613)	4,966,662	114,987	5,081,649	297,158	5,378,807
Industrial	2,165,393	1,656	0	2,167,048	27,216	2,194,264	(61,124)	2,133,140
Irrigation	228,054	2,087	4,215	234,355	0	234,355	3,855	238,210
Public St & Hwy	38,833	(137)	0	38,696	(0)	38,696	(1,756)	36,940
Total Oregon	12,873,176	16,161	(65,468)	12,823,869	137,437	12,961,306	207,665	13,168,971
Source / Formula	305 Report	Ref. 3.1.6	Ref. 3.1.6	A + B + C	Ref. 3.1.6	D + E	Ref. 3.1.6	F + G

[1] Out of period adjustment.
[2] Adjustment made to reconcile booked kWh's with blocking kWh's. Includes adjustment to move Residential Schedule 23 to Commercial class. Includes adjustment to incorporate direct access kWh.
[3] Difference between actual and forecast.

PacifiCorp
Summary of Revenue Adjustments
Oregon General Rate Case - December 2014
All States Other Than Oregon

Unadjusted Revenue - 12 Months Ended June 2012	Residential 440	Commercial/Industrial 442	Public Street & Hwy 444	OSPA 445	TOTAL REVENUE
California	51,379,016	48,010,528	428,379		99,817,923
Idaho	67,482,373	181,662,015	504,795		249,649,183
Utah	642,783,365	1,038,802,653	10,135,150	17,534,215	1,709,255,383
Washington	126,577,406	164,154,929	1,142,077		291,874,412
Wyoming	101,213,984	508,183,232	2,205,809		611,603,025
TOTAL	989,436,144	1,940,813,358	14,416,210	17,534,215	2,962,199,927

Pro Forma Revenue - 12 Months Ending December 2014	Residential 440	Commercial/Industrial 442	Public Street & Hwy 444	OSPA 445	TOTAL REVENUE
California	49,786,966	47,571,285	407,858		97,766,109
Idaho	74,081,255	185,606,658	497,693		260,185,607
Utah	725,172,190	1,167,680,282	9,172,631	16,613,667	1,918,638,770
Washington	133,959,213	164,830,862	1,250,273		300,040,348
Wyoming	113,733,821	559,621,765	2,207,200		675,562,785
TOTAL	1,096,733,445	2,125,310,853	13,535,655	16,613,667	3,252,193,619

Adjustment to Revenue	Residential 440	Commercial/Industrial 442	Public Street & Hwy 444	OSPA 445	TOTAL REVENUE
California	(1,592,050)	(439,243)	(20,521)	-	(2,051,814)
Idaho	6,598,883	3,944,643	(7,102)	-	10,536,423
Utah	82,388,825	128,877,629	(962,519)	(920,548)	209,383,387
Washington	7,381,807	675,933	108,196	-	8,165,936
Wyoming	12,519,837	51,438,532	1,390	-	63,959,760
TOTAL	**107,297,301**	**184,497,495**	**(880,555)**	**(920,548)**	**289,993,693**
	Ref 3.1	**Ref 3.1**	**Ref 3.1**	**Ref 3.1**	**Ref 3.1**

PacifiCorp
Oregon General Rate Case - December 2014
Revenue split between TAM and GRC Proforma Revenue

Total Revenue - 2014	TAM/ NPC	NON-TAM / NON NPC
$1,209,176,480	$364,107,266	$845,069,214
Ref # 3.1.1	Ref # 3.1.5	

The above calculation shows the split of proforma revenue between the TAM and the General Rate Case.

PacifiCorp
Oregon General Rate Case - December 2014
Present Net Power Costs In Rates
Forecast 12 Months Ending December 2014

Base Rate Schedule	MWH	Net Power Costs Collection (Schedule 201 Revenue)
4	5,379,569	$153,560,692
23	1,100,957	$30,398,376
28	1,992,851	$57,135,311
30	1,337,762	$36,664,251
33	0	$0
41	231,404	$6,421,130
47	143,852	$3,660,107
48	2,935,115	$75,205,511
15	9,286	$212,447
50	7,823	$147,131
51	19,612	$582,552
52	523	$11,891
53	8,967	$86,978
54	1,249	$20,889
Total	13,168,971	$364,107,266

Comparison to UE 245	MWH	Approved NPC
2013 Test Period	13,097,740	$362,667,557
Difference resulting from change in test period	71,231	$1,439,708
Percentage Change	0.5%	0.4%

Table 2 - Page 1 of 2
PacifiCorp
State of Oregon
General Rate Case
Historic 12 Months Ended June 2012; Forecast 12 Months Ending December 2014
Customer, kWh, and Revenue Adjustments

	CUSTOMERS			KWH								
					Type 1				Type 2		Type 3	
	305 Average Customers	Adjustment Customers	Forecast Customers	305 Booked kWh	Normalizing Adjustment kWh	Temperature Adjustments kWh	Type 1 Adjustments kWh	Total Type 1 Adjusted kWh	Blocking Adjustment kWh	Total Type 2 Adjusted kWh	Forecast Adjustment kWh	Total Type 3 Adjusted kWh
Residential												
15	2,766	-103	2,662	2,440,799	9,264		9,264	2,450,063	214	2,450,277	(145,621)	2,304,656
4	475,193	10,393	485,586	5,472,758,481	806,375	(65,041,518)	(64,235,143)	5,408,523,338	12,252	5,408,535,590	(28,966,921)	5,379,568,669
23	1,160	-1,160	0	4,684,980	121,653	(28,354)	93,299	4,778,279	(4,778,279)	0	0	0
BPA Balancing Account	0			0			0	0		0		0
SMUD Revenue Imputations	0			0			0	0		0		0
SB838 Recovery	0			0			0	0		0		0
Gain on Sale of Asset	0			0			0	0		0		0
Revenue Accounting Adjustment	0			0			0	0		0		0
Other Revenue Adj - Deferred	0			0			0	0		0		0
Other Revenue Adj - Realized	0			0			0	0		0		0
DSM	0			0			0	0		0		0
Blue Sky	0			0			0	0		0		0
Revenue Adjust Property Insur - Res	0			0			0	0		0		0
Merger Credit	0			0			0	0		0		0
Unbilled	0			1,355,000			0	1,355,000		1,355,000	(1,355,000)	0
AGA	0			0			0	0		0		0
Total Residential	**479,119**	**9,130**	**488,248**	**5,481,239,260**	**937,292**	**(65,069,871)**	**(64,132,579)**	**5,417,106,681**	**(4,765,813)**	**5,412,340,867**	**(30,467,542)**	**5,381,873,325**
Commercial												
15	4,093	-129	3,964	7,291,467	25,928		25,928	7,317,395	4,477	7,321,872	(639,626)	6,682,246
23	72,601	53	72,654	1,101,470,894	1,748,430	(5,269,208)	(3,520,778)	1,097,950,116	4,948,032	1,102,898,148	(23,952,429)	1,078,945,719
28	9,429	45	9,474	1,921,619,014	5,418,905	(4,975,379)	443,526	1,922,062,540	5,413,600	1,927,476,140	(29,416,836)	1,898,059,304
30	667	-37	630	1,024,584,048	2,204,351	1,516,851	3,721,202	1,028,305,250	91,569,219	1,119,874,469	19,530,191	1,139,404,660
47	3	0	3	24,238,000	1,789,100		1,789,100	26,027,100	0	26,027,100	(4,949,303)	21,077,797
48	106	1	107	871,460,761	413,000	4,114,839	4,527,839	875,988,600	13,051,680	889,040,280	344,347,620	1,233,387,900
54	103	2	104	1,185,971	19,258		19,258	1,205,229	0	1,205,229	44,118	1,249,347
BPA Balancing Account	0			0			0	0		0		0
SMUD Revenue Imputations	0			0			0	0		0		0
SB838 Recovery	0			0			0	0		0		0
Gain on Sale of Asset	0			0			0	0		0		0
Revenue Accounting Adjustment	0			0			0	0		0		0
Other Revenue Adj - Deferred	0			0			0	0		0		0
Other Revenue Adj - Realized	0			0			0	0		0		0
DSM	0			0			0	0		0		0
Blue Sky	0			0			0	0		0		0
evenue Adjust Property Insur - Com	0			0			0	0		0		0
Merger Credit	0			0			0	0		0		0
Unbilled	0			7,806,000			0	7,806,000		7,806,000	(7,806,000)	0
AGA	0			0			0	0		0		0
Total Commercial	**87,002**	**(66)**	**86,936**	**4,959,656,155**	**11,618,972**	**(4,612,898)**	**7,006,074**	**4,966,662,229**	**114,987,008**	**5,081,649,237**	**297,157,736**	**5,378,806,973**
Industrial												
15	143	-8	134	315,596	(138)		(138)	315,458	574	316,032	(30,880)	285,152
23	1,228	5	1,233	21,584,340	43,839		43,839	21,628,179	(3,647)	21,624,532	386,903	22,011,435
28	479	-32	447	92,157,017	72,694		72,694	92,229,711	(45,271)	92,184,440	2,290,857	94,475,297
30	152	-20	132	204,784,083	(224,582)		(224,582)	204,559,501	(7,087)	204,552,414	(6,194,868)	198,357,546
47	2	1	3	38,640,555	0		0	38,640,555	0	38,640,555	84,133,784	122,774,339
48	105	-8	97	1,798,918,212	1,763,720		1,763,720	1,800,681,932	27,271,400	1,827,953,332	(132,716,832)	1,695,236,500
BPA Balancing Account	0			0			0	0		0		0
SMUD Revenue Imputations	0			0			0	0		0		0
SB838 Recovery	0			0			0	0		0		0
Gain on Sale of Asset	0			0			0	0		0		0
Revenue Accounting Adjustment	0			0			0	0		0		0
Other Revenue Adj - Deferred	0			0			0	0		0		0
Other Revenue Adj - Realized	0			0			0	0		0		0
DSM	0			0			0	0		0		0
Blue Sky	0			0			0	0		0		0
evenue Adjust Property Insur - Com	0			0			0	0		0		0
Merger Credit	0			0			0	0		0		0
Unbilled	0			8,993,000			0	8,993,000		8,993,000	(8,993,000)	0
AGA	0			0			0	0		0		0
Total Industrial	**2,108**	**(62)**	**2,046**	**2,165,392,803**	**1,655,533**	**0**	**1,655,533**	**2,167,048,336**	**27,215,969**	**2,194,264,305**	**(61,124,036)**	**2,133,140,269**
Irrigation												
41	6,093	16	6,109	120,057,968	855,058	2,623,899	3,478,957	123,536,925	8	123,536,933	8,218,095	131,755,028
33 (Klamath)	1,993	-56	1,937	95,692,492	1,231,582	1,590,677	2,822,259	98,514,751	0	98,514,751	1,133,733	99,648,484
28	3	0	3	326,811			0	326,811	1	326,812	(10,541)	316,271
48	1	0	1	9,040,000	0		0	9,040,000	0	9,040,000	(2,549,783)	6,490,217
BPA Balancing Account	0			0			0	0		0		0
SB838 Recovery	0			0			0	0		0		0
BPA Adjustment	0			0			0	0		0		0
Demand Charge Accrual	0			0			0	0		0		0
Gain on Sale of Asset	0			0			0	0		0		0
Revenue Accounting Adjustment	0			0			0	0		0		0
Other Revenue Adj - Deferred	0			0			0	0		0		0
Other Revenue Adj - Realized	0			0			0	0		0		0
DSM	0			0			0	0		0		0
Blue Sky	0			0			0	0		0		0
Unbilled	0			2,937,000			0	2,937,000		2,937,000	(2,937,000)	0
AGA	0			0			0	0		0		0
Total Irrigation	**8,090**	**(40)**	**8,050**	**228,054,271**	**2,086,640**	**4,214,575**	**6,301,215**	**234,355,486**	**9**	**234,355,495**	**3,854,505**	**238,210,000**
Lighting												
15	9	-1	8	18,921	(13)		(13)	18,908	(1)	18,907	(4,462)	14,445
50	250	1	251	8,923,957	(21,828)		(21,828)	8,902,129	(4)	8,902,125	(1,078,788)	7,823,337
51	704	42	747	18,960,130	(91,887)		(91,887)	18,868,243	(67)	18,868,176	744,134	19,612,310
52	48	-4	44	578,199	(11,354)		(11,354)	566,845	(6)	566,839	(43,696)	523,143
53	255	11	266	9,680,883	(11,890)		(11,890)	9,668,993	(33)	9,668,960	(702,196)	8,966,764
SB838 Recovery	0			0			0	0		0		0
Gain on Sale of Asset	0			0			0	0		0		0
Revenue Accounting Adjustment	0			0			0	0		0		0
Other Revenue Adj - Deferred	0			0			0	0		0		0
Other Revenue Adj - Realized	0			0			0	0		0		0
DSM	0			0			0	0		0		0
Unbilled	0			671,000			0	671,000		671,000	(671,000)	0
AGA	0			0			0	0		0		0
Total Lighting	**1,266**	**50**	**1,316**	**38,833,090**	**(136,972)**	**0**	**(136,972)**	**38,696,118**	**(111)**	**38,696,007**	**(1,756,008)**	**36,939,999**
TOTAL COMPANY	**577,585**	**9,012**	**586,597**	**12,873,175,579**	**16,161,465**	**(65,468,194)**	**(49,306,729)**	**12,823,868,850**	**137,437,062**	**12,961,305,912**	**207,664,654**	**13,168,970,566**
				To 3.1.2	To 3.1.2	To 3.1.2			To 3.1.2		To 3.1.2	

Table 2 - Page 2 of 2
PacifiCorp
State of Oregon
General Rate Case
Historic 12 Months Ended June 2012; Forecast 12 Months Ending December 2014
Customer, kWh, and Revenue Adjustments

	REVENUES									
		Type 1					Type 2		Type 3	
	305 Booked Revenues	Remove Tariff Riders $	Actual Base Rate Revenues	Normalizing Adjustments $	Temperature Adjustment $	Total Type 1 Adjusted Revenues	Type 2 Adjustments $	Total Type 2 Adjusted Revenues	Type 3 Adjustments $	Total Forecast Revenues
Residential										
15	$392,625	$10,251	$402,875	($61,061)		$341,814	$4,220	$346,034	($46,305)	$299,729
4	$542,895,981	$23,090,439	$565,986,419	($8,052,405)	($6,010,819)	$551,923,196	$10,674,390	$562,597,586	$20,387,433	$582,985,019
23	$645,612	$18,150	$663,761	$25,457	($2,554)	$686,665	($686,665)	$0	$0	$0
BPA Balancing Account	($4,426,982)	$4,426,982	$0	$0		$0		$0		$0
SMUD Revenue Imputations	$498,272	$0	$498,272	($498,272)		$0		$0		$0
SB838 Recovery	($96,795)	$96,795	$0	$0		$0		$0		$0
Gain on Sale of Asset	$77,054	($77,054)	$0	$0		$0		$0		$0
Revenue Accounting Adjustment	($583,953)	$583,953	$0	$0		$0		$0		$0
Other Revenue Adj - Deferred	($167,935)	$167,935	$0	$0		$0		$0		$0
Other Revenue Adj - Realized	$302,280	($302,280)	$0	$0		$0		$0		$0
DSM	$8,052,979	($8,052,979)	$0	$0		$0		$0		$0
Blue Sky	$138,435	($138,435)	$0	$0		$0		$0		$0
Revenue Adjust Property Insur - Res	$1,481,660	($1,481,660)	$0	$0		$0		$0		$0
Merger Credit	($2)	$2	$0	$0		$0		$0		$0
Unbilled	$883,000	$0	$883,000	$0		$883,000		$883,000	($883,000)	$0
AGA	$14,547	$0	$14,547	$0		$14,547		$14,547		$14,547
Total Residential	**$550,106,777**	**$18,342,098**	**$568,448,874**	**($8,586,281)**	**($6,013,373)**	**$553,849,221**	**$9,991,946**	**$563,841,167**	**$19,458,128**	**$583,299,295**
Commercial										
15	$1,130,524	$6,590	$1,137,114	($184,432)		$952,683	$11,689	$964,371	($158,091)	$806,281
23	$115,080,408	$340,908	$115,421,316	$2,716,029	($453,344)	$117,684,001	$2,864,028	$120,548,029	($8,879,756)	$111,668,273
28	$156,371,615	$545,555	$156,917,171	($5,353,515)	($284,912)	$151,278,744	$4,046,192	$155,324,936	$6,443,660	$161,768,596
30	$77,488,701	$186,078	$77,674,779	($727,034)	$81,638	$77,029,383	$4,832,350	$81,861,733	$2,589,238	$84,450,971
47	$2,159,554	($2,303)	$2,157,251	$290,853		$2,448,104	$45,787	$2,493,892	($261,102)	$2,232,790
48	$54,792,716	($1,186)	$54,791,530	$3,493,370	$223,488	$58,508,388	$2,221,701	$60,730,089	$20,853,715	$81,583,804
54	$122,752	($12)	$122,740	($19,721)		$103,019	$1,829	$104,848	($5,828)	$99,020
BPA Balancing Account	$100,371	($100,371)	$0	$0		$0		$0		$0
SMUD Revenue Imputations	$438,347	$0	$438,347	($438,347)		$0		$0		$0
SB838 Recovery	($81,550)	$81,550	$0	$0		$0		$0		$0
Gain on Sale of Asset	$56,266	($56,266)	$0	$0		$0		$0		$0
Revenue Accounting Adjustment	($426,714)	$426,714	$0	$0		$0		$0		$0
Other Revenue Adj - Deferred	($141,488)	$141,488	$0	$0		$0		$0		$0
Other Revenue Adj - Realized	$254,675	($254,675)	$0	$0		$0		$0		$0
DSM	$4,428,941	($4,428,941)	$0	$0		$0		$0		$0
Blue Sky	$243,035	($243,035)	$0	$0		$0		$0		$0
Revenue Adjust Property Insur - Com	$1,121,467	($1,121,467)	$0	$0		$0		$0		$0
Merger Credit	$0	($0)	$0	$0		$0		$0		$0
Unbilled	$1,201,000	$0	$1,201,000	$0		$1,201,000		$1,201,000	($1,201,000)	$0
AGA	$2,150,404	$0	$2,150,404	$0		$2,150,404		$2,150,404		$2,150,404
Total Commercial	**$416,491,025**	**($4,479,374)**	**$412,011,651**	**($222,796)**	**($433,130)**	**$411,355,725**	**$14,023,577**	**$425,379,302**	**$19,380,836**	**$444,760,138**
Industrial										
15	$46,665	$22	$46,687	($8,161)		$38,526	$847	$39,373	($7,016)	$32,356
23	$2,293,968	$1,517	$2,295,485	$53,494		$2,348,979	$40,337	$2,389,316	($84,098)	$2,305,218
28	$8,062,111	$2,186	$8,064,298	($270,996)		$7,793,302	$185,027	$7,978,329	$762,695	$8,741,024
30	$16,588,680	$137	$16,588,816	($182,976)		$16,405,840	$403,085	$16,808,925	($8,067)	$16,800,858
47	$2,685,545	($3,671)	$2,681,873	$176,387		$2,858,260	$102,232	$2,960,492	$6,139,110	$9,099,602
48	$109,868,576	($29,432)	$109,839,144	$7,829,696		$117,668,839	$4,389,308	$122,058,147	($8,738,181)	$113,319,966
BPA Balancing Account	$342	($342)	$0	$0		$0		$0		$0
SMUD Revenue Imputations	$203,268	$0	$203,268	($203,268)		$0		$0		$0
SB838 Recovery	($54,133)	$54,133	$0	$0		$0		$0		$0
Gain on Sale of Asset	$20,006	($20,006)	$0	$0		$0		$0		$0
Revenue Accounting Adjustment	($156,501)	$156,501	$0	$0		$0		$0		$0
Other Revenue Adj - Deferred	($93,931)	$93,931	$0	$0		$0		$0		$0
Other Revenue Adj - Realized	$169,074	($169,074)	$0	$0		$0		$0		$0
DSM	$361,066	($361,066)	$0	$0		$0		$0		$0
Blue Sky	$98,232	($98,232)	$0	$0		$0		$0		$0
Revenue Adjust Property Insur - Com	$368,574	($368,574)	$0	$0		$0		$0		$0
Merger Credit	($1)	$1	$0	$0		$0		$0		$0
Unbilled	$1,153,000	$0	$1,153,000	$0		$1,153,000		$1,153,000	($1,153,000)	$0
AGA	$60,333	$0	$60,333	$0		$60,333		$60,333		$60,333
Total Industrial	**$141,674,875**	**($741,970)**	**$140,932,905**	**$7,394,175**	**$0**	**$148,327,080**	**$5,120,834**	**$153,447,915**	**($3,088,557)**	**$150,359,358**
Irrigation										
41	$11,282,542	$489,541	$11,772,083	$2,080,497	$285,027	$14,137,607	$306,164	$14,443,771	$82,199	$14,525,970
33 (Klamath)	$4,856,795	$364,445	$5,221,240	$95,843	$109,900	$5,426,984	$1,568,661	$6,995,645	$3,839,367	$10,835,012
28	$30,377	($1)	$30,376	($984)	$0	$29,393	$879	$30,272	$1,444	$31,716
48	$502,076	$40,237	$542,314	$37,154	$0	$579,468	$22,678	$602,146	($169,502)	$432,644
BPA Balancing Account	$186,665	($186,665)	$0	$0		$0		$0		$0
SB838 Recovery	($1,937)	$1,937	$0	$0		$0		$0		$0
BPA Adjustment	$58,995	($58,995)	$0	$0		$0		$0		$0
Demand Charge Accrual	($23,000)	$0	($23,000)	$23,000		$0		$0		$0
Gain on Sale of Asset	$2,032	($2,032)	$0	$0		$0		$0		$0
Revenue Accounting Adjustment	($7,619)	$7,619	$0	$0		$0		$0		$0
Other Revenue Adj - Deferred	($3,342)	$3,342	$0	$0		$0		$0		$0
Other Revenue Adj - Realized	$6,015	($6,015)	$0	$0		$0		$0		$0
DSM	$39,093	($39,093)	$0	$0		$0		$0		$0
Blue Sky	$129	($129)	$0	$0		$0		$0		$0
Unbilled	$361,000	$0	$361,000	$0		$361,000		$361,000	($361,000)	$0
AGA	$213,396	$0	$213,396	$0		$213,396		$213,396		$213,396
Total Irrigation	**$17,503,217**	**$614,192**	**$18,117,409**	**$2,235,511**	**$394,928**	**$20,747,848**	**$1,898,382**	**$22,646,230**	**$3,392,508**	**$26,038,738**
Lighting										
15	$3,078	$9	$3,086	($491)		$2,595	$35	$2,631	($777)	$1,853
50	$1,229,422	$156	$1,229,578	($216,108)		$1,013,471	$9,275	$1,022,746	($194,574)	$828,172
51	$4,146,007	($412)	$4,145,595	($740,490)		$3,405,105	$36,265	$3,441,370	($150,574)	$3,290,797
52	$91,161	$8	$91,169	($15,513)		$75,656	$828	$76,485	($11,258)	$65,226
53	$757,287	$550	$757,837	($140,144)		$617,693	$5,874	$623,568	($90,664)	$532,904
SB838 Recovery	($470)	$470	$0	$0		$0		$0		$0
Gain on Sale of Asset	$938	($938)	$0	$0		$0		$0		$0
Revenue Accounting Adjustment	$90,995	($90,995)	$0	$0		$0		$0		$0
Other Revenue Adj - Deferred	($815)	$815	$0	$0		$0		$0		$0
Other Revenue Adj - Realized	($324,533)	$324,533	$0	$0		$0		$0		$0
DSM	$73,899	($73,899)	$0	$0		$0		$0		$0
Unbilled	$121,000	$0	$121,000	$0		$121,000		$121,000	($121,000)	$0
AGA	$0	$0	$0	$0		$0		$0		$0
Total Lighting	**$6,187,968**	**$160,297**	**$6,348,265**	**($1,112,745)**	**$0**	**$5,235,520**	**$52,279**	**$5,287,799**	**($568,848)**	**$4,718,952**
TOTAL COMPANY	**$1,131,963,862**	**$13,895,242**	**$1,145,859,104**	**($292,135)**	**($6,051,575)**	**$1,139,515,394**	**$31,087,018**	**$1,170,602,413**	**$38,574,067**	**$1,209,176,480**
	To 3.1.1	To 3.1.1		To 3.1.1	To 3.1.1		To 3.1.1		To 3.1.1	

Table 3 - Page 1 of 2
PacifiCorp
State of Oregon
General Rate Case
Historic 12 Months Ended June 2012; Forecast 12 Months Ending December 2014
Revenue Adjustments

		Remove Tariff Riders																		
	305 Booked Revenues	SB838 Recovery Adjust	Revenue Accounting Adjust	Gain on Sale of Asset Adjust	Other Revenue Adj Deferred	Other Revenue Adj Realized	DSM Revenue	Blue Sky Revenue	Revenue Adjust Property Insur	Merger Credit Adjust	Sch98 BPA Adjust	Sch93 Ind. Evaluator Adjust	Sch96 Property Sales Adjust	Sch194 MEHC Sev Adjust	Sch195 Grid West Adjust	Sch203 RAC Deferral Adjust	Sch204 OSIP Adjust	Sch291 2010 Protocol Adjust	Total Remove Tariff Riders	Actual Base Rate Revenues
Residential																				
15	$392,625										$10,227	($0)	$659	($350)	($73)	($335)	($67)	$190	$10,251	$402,875
4	$542,895,981										$22,972,118	$2	$1,477,645	($800,094)	($164,182)	($708,196)	($182,670)	$495,816	$23,090,439	$565,986,419
23	$645,612										$18,135	($0)	$1,265	($679)	($141)	($685)	($148)	$402	$18,150	$663,761
BPA Balancing Account	($4,426,982)										$4,426,982								$4,426,982	$0
SMUD Revenue Imputations	$498,272																		$0	$498,272
SB838 Recovery	($96,795)	$96,795																	$96,795	$0
Gain on Sale of Asset	$77,054			($77,054)															($77,054)	$0
Revenue Accounting Adjustment	($583,953)		$583,953																$583,953	$0
Other Revenue Adj - Deferred	($167,935)				$167,935														$167,935	$0
Other Revenue Adj - Realized	$302,280					($302,280)													($302,280)	$0
DSM	$8,052,979						($8,052,979)												($8,052,979)	$0
Blue Sky	$138,435							($138,435)											($138,435)	$0
Revenue Adjust Property Insur - Res	$1,481,660								($1,481,660)										($1,481,660)	$0
Merger Credit	($2)									$2									$2	$0
Unbilled	$883,000																		$0	$883,000
AGA	$14,547																		$0	$14,547
Total Residential	$550,106,777	$96,795	$583,953	($77,054)	$167,935	($302,280)	($8,052,979)	($138,435)	($1,481,660)	$2	$27,427,462	$1	$1,479,569	($801,122)	($164,396)	($709,216)	($182,885)	$496,408	$18,342,098	$568,448,874
Commercial																				
15	$1,130,524										$6,520	($1)	$1,969	($1,045)	($219)	($1,001)	($200)	$568	$6,590	$1,137,114
23	$115,080,408										$337,535	($6)	$297,397	($159,535)	($33,043)	($161,138)	($34,823)	$94,520	$340,908	$115,421,316
28	$156,371,615										$551,250	($28)	$520,221	($278,357)	($57,802)	($291,909)	($59,602)	$161,783	$545,555	$156,917,171
30	$77,488,701										$185,393	($21)	$297,190	($158,825)	($33,020)	($157,379)	($33,562)	$86,302	$186,078	$77,674,779
47	$2,159,554										$0	($8)	$6,545	($3,640)	($727)	($5,106)	($444)	$1,078	($2,303)	$2,157,251
48	$54,792,716										$13,072	($1)	$238,831	($128,688)	($26,537)	($135,116)	($26,078)	$63,332	($1,186)	$54,791,530
54	$122,752										$0	$0	$319	($173)	($37)	($156)	($22)	$57	($12)	$122,740
BPA Balancing Account	$100,371										($100,371)								($100,371)	$0
SMUD Revenue Imputations	$438,347																		$0	$438,347
SB838 Recovery	($81,550)	$81,550																	$81,550	$0
Gain on Sale of Asset	$56,266			($56,266)															($56,266)	$0
Revenue Accounting Adjustment	($426,714)		$426,714																$426,714	$0
Other Revenue Adj - Deferred	($141,488)				$141,488														$141,488	$0
Other Revenue Adj - Realized	$254,675					($254,675)													($254,675)	$0
DSM	$4,428,941						($4,428,941)												($4,428,941)	$0
Blue Sky	$243,035							($243,035)											($243,035)	$0
Revenue Adjust Property Insur - Com	$1,121,467								($1,121,467)										($1,121,467)	$0
Merger Credit	$0									($0)									($0)	$0
Unbilled	$1,201,000																		$0	$1,201,000
AGA	$2,150,404																		$0	$2,150,404
Total Commercial	$416,491,025	$81,550	$426,714	($56,266)	$141,488	($254,675)	($4,428,941)	($243,035)	($1,121,467)	($0)	$993,400	($65)	$1,362,471	($730,265)	($151,385)	($751,804)	($154,731)	$407,639	($4,479,374)	$412,011,651
Industrial																				
15	$46,665										$19	($0)	$85	($45)	($9)	($43)	($9)	$25	$22	$46,687
23	$2,293,968										$1,451	($0)	$5,828	($3,126)	($648)	($3,158)	($682)	$1,852	$1,517	$2,295,485
28	$8,062,111										$2,459	($1)	$24,949	($13,349)	($2,772)	($13,999)	($2,858)	$7,759	$2,186	$8,064,298
30	$16,588,680										$0	($4)	$59,399	($31,745)	($6,600)	($31,455)	($6,708)	$17,249	$137	$16,588,816
47	$2,685,545										$0	($14)	$10,433	($5,804)	($1,159)	($8,139)	($708)	$1,719	($3,671)	$2,681,873
48	$109,868,576										$0	($2)	$493,008	($265,646)	($54,780)	($278,914)	($53,832)	$130,733	($29,432)	$109,839,144
BPA Balancing Account	$342										($342)								($342)	$0
SMUD Revenue Imputations	$203,268																		$0	$203,268
SB838 Recovery	($54,133)	$54,133																	$54,133	$0
Gain on Sale of Asset	$20,006			($20,006)															($20,006)	$0
Revenue Accounting Adjustment	($156,501)		$156,501																$156,501	$0
Other Revenue Adj - Deferred	($93,931)				$93,931														$93,931	$0
Other Revenue Adj - Realized	$169,074					($169,074)													($169,074)	$0
DSM	$361,066						($361,066)												($361,066)	$0
Blue Sky	$98,232							($98,232)											($98,232)	$0
Revenue Adjust Property Insur - Ind	$368,574								($368,574)										($368,574)	$0
Merger Credit	($1)									$1									$1	$0
Unbilled	$1,153,000																		$0	$1,153,000
AGA	$60,333																		$0	$60,333
Total Industrial	$141,674,875	$54,133	$156,501	($20,006)	$93,931	($169,074)	($361,066)	($98,232)	($368,574)	$1	$3,586	($21)	$593,703	($319,715)	($65,967)	($335,709)	($64,798)	$159,337	($741,970)	$140,932,905
Irrigation																				
41	$11,282,542										$502,274	($3)	$32,416	($15,908)	($3,602)	($28,848)	($2,043)	$5,255	$489,541	$11,772,083
33 (Klamath)	$4,856,795										$373,068	($6)	$25,837	($12,091)	($2,871)	($22,327)	($1,804)	$4,639	$364,445	$5,221,240
28	$30,377										$0	($0)	$88	($47)	($10)	($50)	($10)	$28	($1)	$30,376
48	$502,076										$40,385	($0)	$2,477	($1,335)	($275)	($1,402)	($271)	$657	$40,237	$542,314
BPA Balancing Account	$186,665										($186,665)								($186,665)	$0
SB838 Recovery	($1,937)	$1,937																	$1,937	$0
BPA Adjustment	$58,995										($58,995)								($58,995)	$0
Demand Charge Accrual	($23,000)																		$0	($23,000)
Gain on Sale of Asset	$2,032			($2,032)															($2,032)	$0
Revenue Accounting Adjustment	($7,619)		$7,619																$7,619	$0
Other Revenue Adj - Deferred	($3,342)				$3,342														$3,342	$0
Other Revenue Adj - Realized	$6,015					($6,015)													($6,015)	$0
DSM	$39,093						($39,093)												($39,093)	$0
Blue Sky	$129							($129)											($129)	$0
Unbilled	$361,000																		$0	$361,000
AGA	$213,396																		$0	$213,396
Total Irrigation	$17,503,217	$1,937	$7,619	($2,032)	$3,342	($6,015)	($39,093)	($129)	$0	$0	$670,067	($9)	$60,819	($29,381)	($6,758)	($52,626)	($4,128)	$10,578	$614,192	$18,117,409
Lighting																				
15	$3,078										$9	($0)	$5	($3)	($1)	($3)	($1)	$1	$9	$3,086
50	$1,229,422										$0	$0	$2,410	($1,278)	($267)	($1,073)	($244)	$608	$156	$1,229,578
51	$4,146,007										$0	($59)	$5,119	($2,705)	($568)	($3,439)	($796)	$2,036	($412)	$4,145,595
52	$91,161										$0	$0	$158	($81)	($16)	($82)	($17)	$46	$8	$91,169
53	$757,287										$0	$0	$2,614	($1,392)	($290)	($601)	($130)	$349	$550	$757,837
SB838 Recovery	($470)	$470																	$470	$0
Gain on Sale of Asset	$938			($938)															($938)	$0
Revenue Accounting Adjustment	$90,995		($90,995)																($90,995)	$0
Other Revenue Adj - Deferred	($815)				$815														$815	$0
Other Revenue Adj - Realized	($324,533)					$324,533													$324,533	$0
DSM	$73,899						($73,899)												($73,899)	$0
Unbilled	$121,000																		$0	$121,000
AGA	$0																		$0	$0
Total Lighting	$6,187,968	$470	($90,995)	($938)	$815	$324,533	($73,899)	$0	$0	$0	$9	($59)	$10,306	($5,459)	($1,142)	($5,198)	($1,188)	$3,040	$160,297	$6,348,265
TOTAL COMPANY	$1,131,963,862	$234,885	$1,083,792	($156,295)	$407,511	($407,511)	($12,955,978)	($479,832)	($2,971,700)	$2	$29,094,524	($153)	$3,506,868	($1,885,942)	($389,648)	($1,854,554)	($407,729)	$1,077,003	$13,895,242	$1,145,859,104

Table 3 - Page 2 of 2
PacifiCorp
State of Oregon
General Rate Case
Historic 12 Months Ended June 2012: Forecast 12 Months Ending December 2014
Revenue Adjustments

	Normalization Adjustments															
	SMUD Rev Imputations Adjust	Demand Charge Accrual	Sch 299 RMA Adjust	Out of Period Adjust	Subtotal Normalization Adjustments	Temperature Adjustment	Total Type 1 Adjusted Revenues	TAM Price Change ############	Klamath Price Change ##########	Blocking Adjustment	Total Type 2 Adj.	Total Type 2 Adjusted Revenues	Type 3 Price Changes	Forecast Price Change	Total Type 3 Adj.	Total Type 3 Adjusted Revenues
Residential																
15			($62,856)	$1,795	($61,061)		$341,814	$4,042	($825)	$1,003	$4,220	$346,034	($27,370)	($18,935)	($46,305)	$299,729
4			($7,774,111)	($278,294)	($8,052,405)	($6,010,819)	$551,923,196	$10,401,750	($894,555)	$1,167,195	$10,674,390	$562,597,586	$22,017,763	($1,630,330)	$20,387,433	$582,985,019
23			$10,884	$14,573	$25,457	($2,554)	$686,665	$12,708	($1,113)	($698,260)	($686,665)	$0	$0	$0	$0	$0
BPA Balancing Account					$0		$0					$0				$0
SMUD Revenue Imputations	($498,272)				($498,272)		$0					$0				$0
SB838 Recovery					$0		$0					$0				$0
Gain on Sale of Asset					$0		$0					$0				$0
Revenue Accounting Adjustment					$0		$0					$0				$0
Other Revenue Adj - Deferred					$0		$0					$0				$0
Other Revenue Adj - Realized					$0		$0					$0				$0
DSM					$0		$0					$0				$0
Blue Sky					$0		$0					$0				$0
Revenue Adjust Property Insur - Res					$0		$0					$0				$0
Merger Credit					$0		$0					$0				$0
Unbilled					$0		$883,000					$883,000		($883,000)	($883,000)	$0
AGA					$0		$14,547					$14,547				$14,547
Total Residential	**($498,272)**	**$0**	**($7,826,083)**	**($261,926)**	**($8,586,281)**	**($6,013,373)**	**$553,849,221**	**$10,418,500**	**($896,493)**	**$469,939**	**$9,991,946**	**$563,841,167**	**$21,990,393**	**($2,532,265)**	**$19,458,128**	**$583,299,295**
Commercial																
15			($187,871)	$3,439	($184,432)		$952,683	$11,266	($2,301)	$2,724	$11,689	$964,371	($80,939)	($77,152)	($158,091)	$806,281
23			$2,533,672	$182,357	$2,716,029	($453,344)	$117,684,001	$2,178,018	($190,678)	$876,688	$2,864,028	$120,548,029	($6,084,147)	($2,795,609)	($8,879,756)	$111,668,273
28			($5,800,368)	$446,853	($5,353,515)	($284,912)	$151,278,744	$3,601,692	($246,386)	$690,886	$4,046,192	$155,324,936	$8,866,374	($2,422,714)	$6,443,660	$161,768,596
30			($903,893)	$176,859	($727,034)	$81,638	$77,029,383	$1,996,054	($125,715)	$2,962,011	$4,832,350	$81,861,733	$1,327,226	$1,262,012	$2,589,238	$84,450,971
47			$97,486	$193,368	$290,853		$2,448,104	$70,196	($4,006)	($20,403)	$45,787	$2,493,892	$259,480	($520,582)	($261,102)	$2,232,790
48			$3,462,891	$30,479	$3,493,370	$223,488	$58,508,388	$1,758,054	($95,873)	$559,520	$2,221,701	$60,730,089	$426,241	$20,427,474	$20,853,715	$81,583,804
54			($21,347)	$1,627	($19,721)		$103,019	$1,334	($249)	$744	$1,829	$104,848	($9,113)	$3,285	($5,828)	$99,020
BPA Balancing Account					$0		$0					$0				$0
SMUD Revenue Imputations	($438,347)				($438,347)		$0					$0				$0
SB838 Recovery					$0		$0					$0				$0
Gain on Sale of Asset					$0		$0					$0				$0
Revenue Accounting Adjustment					$0		$0					$0				$0
Other Revenue Adj - Deferred					$0		$0					$0				$0
Other Revenue Adj - Realized					$0		$0					$0				$0
DSM					$0		$0					$0				$0
Blue Sky					$0		$0					$0				$0
Revenue Adjust Property Insur - Com					$0		$0					$0				$0
Merger Credit					$0		$0					$0				$0
Unbilled					$0		$1,201,000					$1,201,000		($1,201,000)	($1,201,000)	$0
AGA					$0		$2,150,404					$2,150,404				$2,150,404
Total Commercial	**($438,347)**	**$0**	**($819,430)**	**$1,034,981**	**($222,796)**	**($433,130)**	**$411,355,725**	**$9,616,614**	**($665,208)**	**$5,072,171**	**$14,023,577**	**$425,379,302**	**$4,705,123**	**$14,675,714**	**$19,380,836**	**$444,760,138**
Industrial																
15			($8,141)	($20)	($8,161)		$38,526	$456	($93)	$484	$847	$39,373	($3,492)	($3,524)	($7,016)	$32,356
23			$49,635	$3,859	$53,494		$2,348,979	$43,473	($3,806)	$670	$40,337	$2,389,316	($119,912)	$35,814	($84,098)	$2,305,218
28			($277,256)	$6,260	($270,996)		$7,793,302	$185,545	($12,693)	$12,175	$185,027	$7,978,329	$575,425	$187,270	$762,695	$8,741,024
30			($165,869)	($17,107)	($182,976)		$16,405,840	$425,123	($26,775)	$4,737	$403,085	$16,808,925	$578,067	($586,134)	($8,067)	$16,800,858
47			$176,387	$0	$176,387		$2,858,260	$81,956	($4,677)	$24,953	$102,232	$2,960,492	$128,155	$6,010,955	$6,139,110	$9,099,602
48			$7,711,327	$118,369	$7,829,696		$117,668,839	$3,535,700	($192,814)	$1,046,422	$4,389,308	$122,058,147	$140,295	($8,878,476)	($8,738,181)	$113,319,966
BPA Balancing Account					$0		$0					$0				$0
SMUD Revenue Imputations	($203,268)				($203,268)		$0					$0				$0
SB838 Recovery					$0		$0					$0				$0
Gain on Sale of Asset					$0		$0					$0				$0
Revenue Accounting Adjustment					$0		$0					$0				$0
Other Revenue Adj - Deferred					$0		$0					$0				$0
Other Revenue Adj - Realized					$0		$0					$0				$0
DSM					$0		$0					$0				$0
Blue Sky					$0		$0					$0				$0
Revenue Adjust Property Insur - Ind					$0		$0					$0				$0
Merger Credit					$0		$0					$0				$0
Unbilled					$0		$1,153,000					$1,153,000		($1,153,000)	($1,153,000)	$0
AGA					$0		$60,333					$60,333				$60,333
Total Industrial	**($203,268)**	**$0**	**$7,486,082**	**$111,361**	**$7,394,175**	**$0**	**$148,327,080**	**$4,272,253**	**($240,858)**	**$1,089,439**	**$5,120,834**	**$153,447,915**	**$1,298,538**	**($4,387,095)**	**($3,088,557)**	**$150,359,358**
Irrigation																
41			$1,992,073	$88,424	$2,080,497	$285,027	$14,137,607	$264,389	($22,911)	$64,686	$306,164	$14,443,771	($864,132)	$946,331	$82,199	$14,525,970
33 (Klamath)				$95,843	$95,843	$109,900	$5,426,984	$0	$1,734,820	($166,159)	$1,568,661	$6,995,645	$3,744,150	$95,217	$3,839,367	$10,835,012
28			($984)		($984)		$29,393	$700	$0	$179	$879	$30,272	$2,467	($1,023)	$1,444	$31,716
48			$37,154		$37,154		$579,468	$17,412	($1,194)	$6,460	$22,678	$602,146	($1,938)	($167,564)	($169,502)	$432,644
BPA Balancing Account					$0		$0					$0				$0
SB838 Recovery					$0		$0					$0				$0
BPA Adjustment					$0		$0					$0				$0
Demand Charge Accrual		$23,000			$23,000		$0					$0				$0
Gain on Sale of Asset					$0		$0					$0				$0
Revenue Accounting Adjustment					$0		$0					$0				$0
Other Revenue Adj - Deferred					$0		$0					$0				$0
Other Revenue Adj - Realized					$0		$0					$0				$0
DSM					$0		$0					$0				$0
Blue Sky					$0		$0					$0				$0
Unbilled					$0		$361,000					$361,000		($361,000)	($361,000)	$0
AGA					$0		$213,396					$213,396				$213,396
Total Irrigation	**$0**	**$23,000**	**$2,028,244**	**$184,267**	**$2,235,511**	**$394,928**	**$20,747,848**	**$282,501**	**$1,710,715**	**($94,834)**	**$1,898,382**	**$22,646,230**	**$2,880,547**	**$511,961**	**$3,392,508**	**$26,038,738**
Lighting																
15			($487)	($4)	($491)		$2,595	$31	($6)	$10	$35	$2,631	($212)	($565)	($777)	$1,853
50			($213,550)	($2,557)	($216,108)		$1,013,471	$11,088	($2,445)	$632	$9,275	$1,022,746	($80,364)	($114,211)	($194,574)	$828,172
51			($724,085)	($16,405)	($740,490)		$3,405,105	$37,756	($8,217)	$6,726	$36,265	$3,441,370	($275,415)	$124,841	($150,574)	$3,290,797
52			($14,166)	($1,347)	($15,513)		$75,656	$1,002	($183)	$9	$828	$76,485	($5,797)	($5,461)	($11,258)	$65,226
53			($139,404)	($740)	($140,144)		$617,693	$6,210	($1,489)	$1,153	$5,874	$623,568	($48,927)	($41,737)	($90,664)	$532,904
SB838 Recovery					$0		$0					$0				$0
Gain on Sale of Asset					$0		$0					$0				$0
Revenue Accounting Adjustment					$0		$0					$0				$0
Other Revenue Adj - Deferred					$0		$0					$0				$0
Other Revenue Adj - Realized					$0		$0					$0				$0
DSM					$0		$0					$0				$0
Unbilled					$0		$121,000					$121,000		($121,000)	($121,000)	$0
AGA					$0		$0					$0				$0
Total Lighting	**$0**	**$0**	**($1,091,692)**	**($21,053)**	**($1,112,745)**	**$0**	**$5,235,520**	**$56,087**	**($12,340)**	**$8,532**	**$52,279**	**$5,287,799**	**($410,716)**	**($158,132)**	**($568,848)**	**$4,718,952**
TOTAL COMPANY	($1,139,886)	$23,000	($222,880)	$1,047,631	($292,135)	($5,051,575)	$1,139,515,394	$24,645,955	($104,184)	$6,545,247	$31,087,018	$1,170,602,413	$30,463,885	$8,110,183	$38,574,067	$1,209,176,480

PacifiCorp
Oregon General Rate Case - December 2014
Wheeling Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Other Electric Revenue	456	1	(2,646,297)	SG	26.053%	(689,440)	3.2.2
Other Electric Revenue	456	2	3,655,593	SG	26.053%	952,392	3.2.2
Other Electric Revenue	456	3	(2,525,481)	SG	26.053%	(657,964)	3.2.2
			(1,516,184)			(395,012)	3.2.2
Adjustment to Expense:							
Wheeling Imbalance Expense	566	1	(759,938)	SG	26.053%	(197,987)	3.2.3
Adjustment Detail:							
Actual Wheeling Revenue 12 Months Ended June 2012			74,526,126				3.2.1
Total Adjustment			(1,516,184)				3.2.2
Normalized Wheeling Revenue			73,009,941				3.2.2

Description of Adjustment:

This adjustment reflects the level of wheeling revenues the Company expects in the 12 months ending December 2014 by adjusting the actual revenues for the 12 months ended June 30, 2012 for normalizing and pro forma changes. Imbalance penalty revenue and expense is removed to avoid any impact on regulated results. The final outcome of the Company's transmission rate case with FERC is not yet known, therfore, this adjustment excludes any impact associated with this rate case.

PacifiCorp
Oregon General Rate Case - December 2014
Wheeling Revenue

12 Months Ended June 2012 Actuals with Pro Forma Adjustments to December 2014

Customer	Network 301912	Pt-to-Pt 302980	Resales 302981	Unauthorized Use 302982	Deferral Fees 302983	Legacy Contracts Various	Wheeling Subject to Refund 302990	Non-Firm Wheeling 301922	ST Firm Wheeling 301926	Use of Facilities 302901	Ancillary Services Various	Penalties Various	Total
Bonneville Power Administration	-	-	-	-	-	(4,193,983)	-	-	-	-	-	-	(4,193,983)
WAPA Folsom	-	-	-	-	-	(1,000)	-	-	-	-	-	-	(1,000)
Powder River Energy Corp	-	-	-	-	-	-	-	-	-	(366)	-	-	(366)
Basin Electric Power Cooperative	(12,839)	-	-	-	-	-	-	(993)	(149)	-	(23,502)	-	(37,483)
Black Hills, Inc.	(903,466)	(1,250,550)	-	-	-	-	-	(18,943)	(218,999)	-	(76,760)	-	(2,468,717)
Bonneville Power Administration	(566,073)	(1,850,814)	-	-	-	(1,047,084)	-	(907)	(92,899)	(1,171,506)	(579,493)	(5,539)	(5,314,316)
Cargill Power Markets, LLC	-	-	-	-	-	-	-	(1,172,675)	-	-	(34,554)	-	(1,207,229)
Constellation	(23,378)	-	(779,746)	-	-	-	-	(50,220)	(1,754)	-	(274,215)	(2,144)	(1,131,457)
Coral Power/Shell	-	-	-	-	-	-	-	(298)	-	-	-	-	(298)
Deseret Generation & Transmission Cooperative	-	-	-	-	-	(2,234,721)	-	-	-	-	(1,923,662)	(47,043)	(4,205,427)
Fall River Rural Electric Cooperative	-	-	-	-	-	-	-	-	-	(151,308)	-	-	(151,308)
Foot Creek III, LLC	-	-	-	-	-	-	-	-	-	(36,182)	-	-	(36,182)
Idaho Power Company	-	(670,660)	(13,795)	-	-	-	-	(229,485)	(646,043)	(90,108)	(2,589)	-	(1,652,680)
Morgan Stanley Capital Group, Inc.	-	-	(12,672)	-	-	-	-	(1,036,238)	(311,975)	-	(34,639)	-	(1,395,524)
Pacific Gas & Electric Company	-	-	-	-	-	-	-	-	-	(18,542,930)	-	-	(18,542,930)
Powerex Corporation	(17,159)	(2,616,319)	(58,188)	-	-	-	-	(3,069,437)	(398,541)	-	(201,874)	(423)	(6,361,941)
Iberdrola Renewables Inc.	(6,703)	(750,330)	-	(13,812)	(303,750)	-	-	(961,448)	52	-	(412,254)	(21,576)	(2,469,821)
Rainbow Energy Marketing	-	-	(4,060)	-	-	-	-	(93,649)	(56,648)	-	(7,162)	-	(161,519)
Sierra Pacific Power	-	-	-	-	-	-	-	(17,288)	-	(75,184)	(538)	-	(93,010)
State of South Dakota	-	(100,044)	-	-	-	-	-	-	-	-	(3,087)	-	(103,131)
TransAlta Energy	-	-	-	-	-	-	-	(318,724)	-	-	(9,123)	-	(327,847)
Tri-State Generation and Trans.	(230,068)	-	-	-	-	(130,555)	-	(91,833)	(50,625)	-	(23,257)	(49,346)	(575,683)
UAMPS	-	-	-	-	-	(7,331,323)	-	-	-	-	(666,137)	-	(7,997,461)
Utah Municipal Power Agency	-	-	-	-	-	(2,291,629)	-	-	-	-	(190,243)	(7,281)	(2,489,154)
Warm Springs	-	-	-	-	-	-	-	-	-	(119,700)	-	-	(119,700)
Western Area Power Administration	(22,618)	-	-	-	-	-	-	-	-	-	(38,041)	-	(60,660)
Western Area Power Administration	-	-	-	-	-	(2,987,419)	-	(151,749)	(571,076)	-	(10,023)	-	(3,720,267)
NextEra Energy Resources, LLC	(139,782)	(985,981)	(376,553)	335	-	-	-	(245,064)	-	-	(281,124)	(341,241)	(2,369,409)
Southern Calif Edison Com Direct	(1,779)	-	-	(335)	-	-	-	(1,829,050)	(391,272)	(292,930)	(277,641)	(274,363)	(3,067,370)
PPL Energy Plus, LLC	-	-	-	-	-	-	-	(35,658)	(12,506)	-	(854)	-	(49,018)
US Bureau of Reclamation	(4,420)	-	-	-	-	(27,010)	-	-	-	-	(8,983)	-	(40,413)
Moon Lake Electric Association	-	-	-	-	-	(22,141)	-	-	-	-	-	-	(22,141)
Seattle City Light	-	(380,381)	-	-	-	-	-	-	-	-	(33,550)	(11,550)	(425,481)
Eugene Water & Electric Board	-	-	-	-	-	-	-	(43,017)	-	-	-	-	(43,017)
Sempra Energy Solutions LLC	(206,674)	-	-	-	-	-	-	-	-	-	(41,175)	(3,127)	(250,976)
Columbia Energy Partners	-	(248,226)	(575,634)	-	-	-	-	-	-	-	-	-	(823,860)
JPM Ventures Energy	5,610	-	-	-	-	-	-	(933,951)	-	-	(94,662)	(3,887)	(1,026,890)
Municipal Energy Agency of Nebraska	-	-	-	-	-	-	-	(753)	-	-	-	-	(753)
Raser Power Systems LLC	-	(275,121)	-	-	-	-	-	-	-	-	(65,461)	(627)	(341,209)
Nevada	-	-	-	-	-	-	-	(619)	-	-	-	-	(619)
Sacramento Municipal Utility District	-	-	-	-	(121,500)	-	-	-	-	-	-	-	(121,500)
Macquarie Energy, LLC	-	-	-	-	-	-	-	(315)	-	-	-	-	(315)
Yakima Irrigation District	-	-	-	-	(6,075)	-	-	-	-	-	-	-	(6,075)
Black Hills/Colorado Electric Utility Company, L.P.	-	-	-	-	-	-	-	(561)	(7,026)	-	-	-	(7,586)
Eagle Energy Partners	-	-	-	-	-	-	-	(18,234)	(4,077)	-	(1,180)	-	(23,492)
Enel Cove Fort, LLC	-	-	-	-	(50,625)	-	-	-	-	-	-	-	(50,625)
The Energy Authority	-	-	-	-	-	-	-	(2,245)	-	-	(160)	-	(2,405)
Alpental Energy	-	-	-	-	(6,231)	-	-	-	-	-	-	-	(6,231)
Southern Cal. PPA	-	-	-	(2,327)	-	-	-	-	-	-	-	(611)	(2,939)
Tenaska Power Services Co	-	-	-	-	-	-	-	(123,740)	(2,705)	-	(78)	-	(126,523)
Los Angeles Dept Water & Power	-	-	-	-	-	-	-	(47,299)	-	-	(3,050)	-	(50,349)
Puget Sound Energy L1 Short Term Non-Firm	-	-	-	-	-	-	-	(12)	-	-	-	-	(12)
Cowlitz County PUD	-	-	-	-	-	-	-	-	-	(118,048)	-	-	(118,048)
Reclass Unreserved Use	429,948	-	-	(429,948)	-	-	-	-	-	-	-	-	-
Accrual Reserve for Refund	-	-	-	-	-	-	1,305,240	-	-	-	575,607	-	1,880,847
Accruals and Adjustments	(70,924)	(157,084)	-	-	-	(262,946)	-	(863,069)	(380,629)	44,965	(920,938)	-	(2,610,625)
Actual Revenue Total	**(1,770,326)**	**(9,285,510)**	**(1,820,648)**	**(446,087)**	**(488,181)**	**(20,529,811)**	**1,305,240**	**(11,357,475)**	**(3,146,871)**	**(20,553,298)**	**(5,664,402)**	**(768,758)**	**(74,526,126)**

PacifiCorp
Oregon General Rate Case - December 2014
Wheeling Revenue

12 Months Ended June 2012 Actuals with Pro Forma Adjustments to December 2014

Adj Type	Customer	Network 301912	Pt-to-Pt 302980	Resales 302981	Unauthorized Use 302982	Deferral Fees 302983	Legacy Contracts Various	Wheeling Subject to Refund 302990	Non-Firm Wheeling 301922	ST Firm Wheeling 301926	Use of Facilities 302901	Ancillary Services Various	Penalties Various	Total	
Incremental Adjustment:															
1	Remove network June accrual as changes covered in adjustments and remove network revenue subject to refund reserve.	212,547	-	-	-	-	-	(175,878)	-	-	-	-	-	36,670	
1	Adjust network loads to historical rate as rates not approved, remove June accrual, and revenue subject to refund reserve.	(131,202)	-	-	-	-	-	-	-	-	-	-	-	(131,202)	
1	Remove point-to-point June accrual as changes covered in adjustments and revenue subject to refund reserve.	-	1,177,684	-	-	-	-	(800,433)	-	-	-	-	-	377,251	
1	Adjust point-to-point to historical as rates not approved plus June accrual amounts.	-	(1,153,445)	42,233	-	-	-	-	-	-	-	-	-	(1,111,212)	
1	Reverse unreserved use charges.	-	-	-	446,087	-	-	-	-	-	-	-	-	446,087	
1	Remove schedule 1 accrual as charges covered in adjustments.	-	-	-	-	-	-	-	-	-	-	125,927	-	125,927	
1	Remove schedule 1 ancillary as revenues not approved.	-	-	-	-	-	-	-	-	-	-	288,378	-	288,378	
1	Remove Schedule 2 ancillary revenue and estimated reserve as revenue not approved.	-	-	-	-	-	-	-	-	-	-	615,286	-	615,286	
1	Remove Schedule 3a ancillary revenue and estimated reserve as revenue not approved.	-	-	-	-	-	-	-	-	-	-	354,866	-	354,866	
1	Remove Schedule 3 ancillary revenue, June accrual, and estimated reserve as revenue not approved.	-	-	-	-	-	-	-	-	-	-	117,500	-	117,500	
2	Adjust Ancillary Schedule 3 to prior rates and contract amounts.	-	-	-	-	-	-	-	-	-	-	293,157	-	293,157	
1	Remove contract pt-to-pt capacity terminated: Seattle City Light (6 MW) and transfer 19 MW assignment to NextEra.	-	329,756	-	-	-	-	-	-	-	-	-	-	329,756	
1	Remove contract pt-to-pt capacity terminated: Columbia Energy (100 MW).		45,726	764,274	-	-	-	-	-	-	-	-	-	810,000	
3	Additional Deferral Fees projected	-	-	-	-	(119,319)	-	-	-	-	-	-	-	(119,319)	
2	Adjustment: Annualize Powerex contract for full year.	-	(2,733,750)	-	-	-	-	-	-	-	-	-	-	(2,733,750)	
2	Additional contract capacity: Powerex (Projected Start: 4/1/2013).	-	(1,215,000)	-	-	-	-	-	-	-	-	-	-	(1,215,000)	
3	Additional contract capacity - Yakima: 3 MW.	-	(72,900)	-	-	-	-	-	-	-	-	-	-	(72,900)	
3	Additional contract capacity - Enel Cove Fort: 25MW.	-	(607,500)	-	-	-	-	-	-	-	-	-	-	(607,500)	
1	Remove June legacy accruals as changes covered in adjustments and revenue subject to refund reserve.	-	-	-	-	-	1,657,169	(328,929)	-	-	-	-	-	1,328,240	
1	Adjust legacy loads to historical rate and peak and accrual for June.	-	-	-	-	-	(1,710,007)	-	-	-	-	-	-	(1,710,007)	
3	Project additional short-term for usage of Malin to Round Mountain: 150 MW projected July and August 2012.	-	-	-	-	-	-	-	-	(607,500)	-	-	-	(607,500)	
3	Remove Sierra Pacific d/b/a Nevada Energy as contract terminated.	-	-	-	-	-	-	-	-	-	75,200	-	-	75,200	
3	Decrease use of facilities charge for PG&E - Malin contract for lease revenue for 2014 of $14.5m.	-	-	-	-	-	-	-	-	-	3,750,000	-	-	3,750,000	
3	Estimated decrease in use of facilities charge for PG&E and SCE-transformer based on historical decline.	-	-	-	-	-	-	-	-	-	112,700	-	-	112,700	
3	Projected revenue increase: Cowlitz.	-	-	-	-	-	-	-	-	-	(5,200)	-	-	(5,200)	
1	Removal of imbalance penalties as penalties incurred are accrued and refunded to non-offending customers.	-	-	-	-	-	-	-	-	-	-	-	768,758	768,758	
	Test Period Incremental Adjustment	81,346	(4,229,429)	806,508	446,087	(119,319)	(52,838)	(1,305,240)	-	(607,500)	3,932,700	1,795,112	768,758	1,516,184	
	Accum Test Period Total	(1,688,980)	(13,514,939)	(1,014,140)	-	(607,500)	(20,582,649)	-	(11,357,475)	(3,754,371)	(16,620,598)	(3,869,290)	-	(73,009,941)	Ref. 3.2
1	Type 1 adjustments (Normalize for out of period and one-time adj's)	81,346	399,721	806,508	446,087	-	(52,838)	(1,305,240)	-	-	-	1,501,956	768,758	2,646,297	Ref. 3.2
2	Type 2 adjustments (Annualize changes that occur during the test period)	-	(3,948,750)	-	-	-	-	-	-	-	-	293,157	-	(3,655,593)	Ref. 3.2
3	Type 3 adjustments (Pro forma known and measurable changes or estimated changes)	-	(680,400)	-	-	(119,319)	-	-	-	(607,500)	3,932,700	-	-	2,525,481	Ref. 3.2
	Adjustment Total by Type	81,346	(4,229,429)	806,508	446,087	(119,319)	(52,838)	(1,305,240)	-	(607,500)	3,932,700	1,795,112	768,758	1,516,184	Ref. 3.2

PacifiCorp
Oregon General Rate Case - December 2014
Wheeling Revenue
Wheeling Imbalance Expense

	FERC 566	
Jul-11	99,775	
Aug-11	59,389	
Sep-11	87,025	
Oct-11	49,666	
Nov-11	69,255	
Dec-11	90,087	
Jan-12	45,919	
Feb-12	51,270	
Mar-12	50,280	
Apr-12	49,798	
May-12	47,572	
Jun-12	59,903	
	759,938	**Ref. 3.2**

PacifiCorp
Oregon General Rate Case - December 2014
SO2 Emission Allowances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Income:							
Remove 12 Months Ended June 2012 Allowance Sales	4118	3	1,814	SE	24.687%	448	3.3.1
Add 12 Months Ended December 2014 Amortization	4118	3	(206,119)	SE	24.687%	(50,884)	3.3.1
Adjustment to Rate Base:							
Regulatory Deferred Sales	25398	3	(121,735)	SE	24.687%	(30,052)	3.3.1
Adjustment to Taxes:							
Accumulated Deferred Income Taxes	190	3	46,200	SE	24.687%	11,405	3.3.1
Schedule M Deduction	SCHMDT	3	206,119	SE	24.687%	50,884	3.3.1
DIT Expense	41010	3	78,224	SE	24.687%	19,311	3.3.1

Description of Adjustment:

The Environmental Protection Agency ("EPA") has established guidelines that govern the volume of sulfur dioxide ("SO2") that can be emitted from power plants and granted the issuance of SO2 emission allowances to cover each ton emitted. Plants that are not in compliance with EPA guidelines may purchase emission allowances from other companies that have excess allowances. This adjustment reflects the gain on sales of SO2 allowances based on a four-year amortization period, with balances as of the 12 months ending December 2014. This is the same methodology included in the Company's last four general rate cases, Dockets UE-179, UE-210, UE-217 and UE-246.

PacifiCorp
Oregon General Rate Case - December 2014 Ending of the Period **Dec-14**
SO2 Emission Allowance Sales

Description	Date Booked	Sales To Date	Accumulated Amortization	End Unamort Balance	Current Period Amortization	Beg Unamort Balance	Unrealized Gain SCHMAT	Realized Gain SCHMDT	D.I.T. Expense	Accumulated Deferred Income Tax	Accumulated Deferred Income Tax
		Dec-14	Dec-14	Dec-14	12 Months Ended	Dec-13	12 Months Ended	12 Months Ended	12 Months Ended	Dec-13	Dec-14
Mar 2007 Sale	Mar-07	2,322,500	2,322,500	0	0	0	0	0	0	(0)	(0)
Apr 2007 Sale	Apr-07	3,727,548	3,727,548	0	0	0	0	0	0	(0)	(0)
May 2007 Sale	May-07	2,897,500	2,897,500	0	0	0	0	0	0	(0)	(0)
Oct 2007 Sale	Oct-07	2,872,500	2,872,500	0	0	0	0	0	0	(0)	(0)
Dec 2007 Sale	Dec-07	2,843,450	2,843,450	0	0	0	0	0	0	(0)	(0)
Apr 2008 Sale	Apr-08	1,192,027	1,192,027	0	0	0	0	0	0	(0)	(0)
Oct 2008 Sale	Oct-08	149,500	149,500	0	0	0	0	0	0	0	0
Nov 2008 Sale	Nov-08	1,393,500	1,393,500	0	0	0	0	0	0	0	0
Dec 2008 Sale	Dec-08	2,154,000	2,154,000	0	0	0	0	0	0	0	0
Jan 2009 Sale	Jan-09	194,500	194,500	0	0	0	0	0	0	0	0
Apr 2009 Sale	Apr-09	173,141	173,141	0	0	0	0	0	0	0	0
Jun 2009 Sale	Jun-09	1,017,500	1,017,500	0	0	0	0	0	0	(0)	(0)
Aug 2009 Sale	Aug-09	1,455,000	1,455,000	0	0	0	0	0	0	0	0
Sep 2009 Sale	Sep-09	950,750	950,750	0	0	0	0	0	0	(0)	(0)
Feb 2010 Sale	Feb-10	402,500	402,500	0	8,405	8,405	0	8,405	3,190	3,190	0
Mar 2010 Sale	Mar-10	1,647,551	1,647,551	0	68,647	68,647	0	68,647	26,052	26,052	0
Apr 2010 Sale	Apr-10	372,500	372,500	0	23,300	23,300	0	23,300	8,843	8,843	(0)
Aug 2010 Sale	Aug-10	395,000	395,000	0	57,611	57,611	0	57,611	21,864	21,864	(0)
Feb 2011 Sale	Feb-11	78,000	76,375	1,625	19,500	21,125	0	19,500	7,400	8,017	617
Mar 2011 Sale	Mar-11	41,737	40,020	1,717	10,440	12,157	0	10,440	3,962	4,614	652
Apr 2011 Sale	Apr-11	4,505	4,230	275	1,128	1,403	0	1,128	428	533	104
Jun 2011 Sale	Jun-11	40,509	36,292	4,217	10,128	14,345	0	10,128	3,844	5,444	1,600
Apr 2012 Sale	Apr-12	$\boxed{1,814}$	1,254	560	456	1,016	0	456	173	385	212
Aug 2012 Sale	Aug-12	26,000	15,718	10,282	6,504	16,786	0	6,504	2,468	6,370	3,902
Forecast Sale	Jan-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Feb-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Mar-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Apr-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	May-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Jun-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Jul-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Aug-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Sep-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Oct-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Nov-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Dec-13	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Jan-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Feb-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Mar-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Apr-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	May-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Jun-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Jul-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Aug-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Sep-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Oct-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Nov-14	0	0	0	0	0	0	0	0	0	0
Forecast Sale	Dec-14	0	0	0	0	0	0	0	0	0	0
	Totals	26,353,532	26,334,857	18,675	**206,119**	224,795	**0**	**206,119**	78,224	85,312	7,087
					Ref # 3.3		**Ref # 3.3**	**Ref # 3.3**			

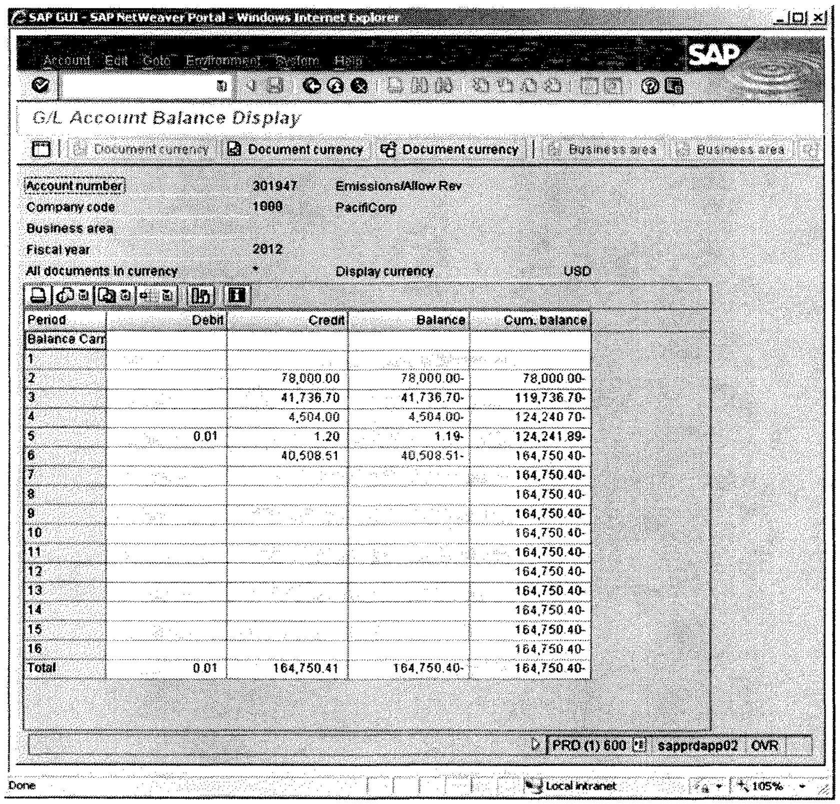
SO2 Credit Unamortized Balance	
Beginning Balance	224,795
Ending Balance	18,675
Average Balance	**121,735**
	Ref # 3.3

SO2 Sales 12 Months Ended June 2012
1,814
Ref # 3.3

	Deferred Income Tax	DIT Unamortized Balance
Ref # 3.3	**78,224**	85,312
Ref # 3.3	**0**	7,087
	78,224	**46,200**
		Ref # 3.3

PacifiCorp
Oregon General Rate Case - December 2014
SO2 Emission Allowance Sales
SAP Account 301947 - Actuals for 12 Months Ended June 2012

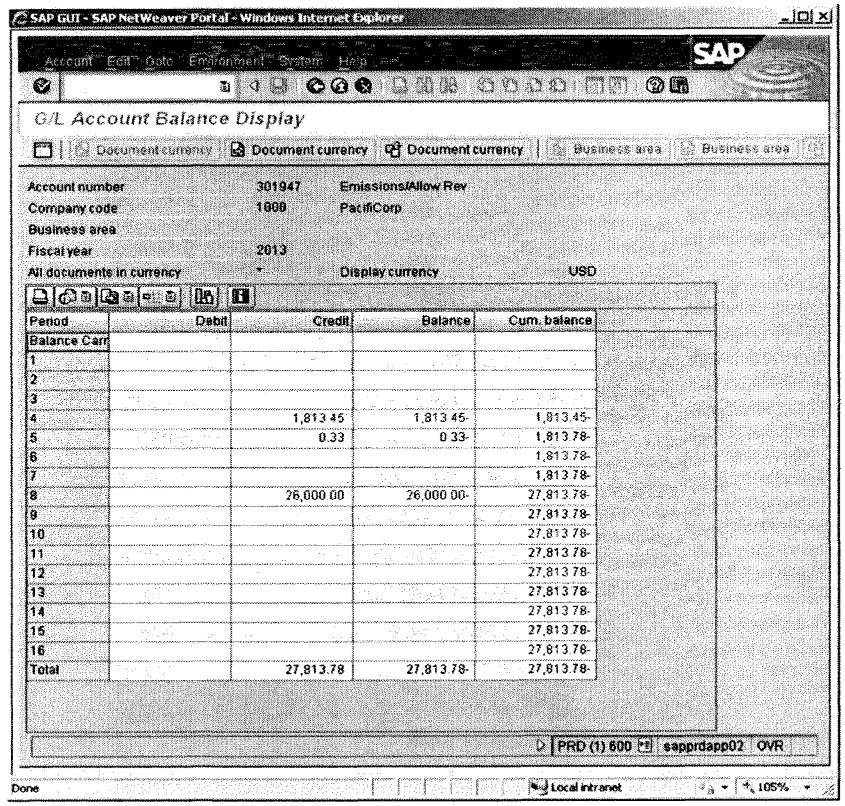
Year	Month	Amount	Accumulated Amount	
2011	7	-	-	
2011	8	-	-	
2011	9	-	-	
2011	10	-	-	
2011	11	-	-	
2011	12	-	-	
2012	1	-	-	
2012	2	-	-	
2012	3	-	-	
2012	4	(1,813)	(1,813)	
2012	5	(0)	(1,814)	
2012	6	-	**(1,814)**	**Ref # 3.3**



G/L Account Balance Display

Account number 301947 Emissions/Allow Rev
Company code 1000 PacifiCorp
Business area
Fiscal year 2012
All documents in currency * Display currency USD

Period	Debit	Credit	Balance	Cum. balance
Balance Carr				
1				
2		78,000.00	78,000.00-	78,000.00-
3		41,736.70	41,736.70-	119,736.70-
4		4,504.00	4,504.00-	124,240.70-
5	0.01	1.20	1.19-	124,241.89-
6		40,508.51	40,508.51-	164,750.40-
7				164,750.40-
8				164,750.40-
9				164,750.40-
10				164,750.40-
11				164,750.40-
12				164,750.40-
13				164,750.40-
14				164,750.40-
15				164,750.40-
16				164,750.40-
Total	0.01	164,750.41	164,750.40-	164,750.40-



G/L Account Balance Display

Account number 301947 Emissions/Allow Rev
Company code 1000 PacifiCorp
Business area
Fiscal year 2013
All documents in currency * Display currency USD

Period	Debit	Credit	Balance	Cum. balance
Balance Carr				
1				
2				
3				
4		1,813.45	1,813.45-	1,813.45-
5		0.33	0.33-	1,813.78-
6				1,813.78-
7				1,813.78-
8		26,000.00	26,000.00-	27,813.78-
9				27,813.78-
10				27,813.78-
11				27,813.78-
12				27,813.78-
13				27,813.78-
14				27,813.78-
15				27,813.78-
16				27,813.78-
Total		27,813.78	27,813.78-	27,813.78-

PacifiCorp
Oregon General Rate Case - December 2014
REC Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Remove June 2012 Booked Revenues (Including Accruals)	456	1	(79,005,374)	SG	26.053%	(20,583,271)	3.4.1
Remove June 2012 REC Deferrals	456	1	52,691,624	SG	26.053%	13,727,750	3.4.1

Description of Adjustment:

This adjustment removes all REC revenues booked during the 12 months ended June 2012. Most of Oregon's share of the renewable energy credits (RECs) are banked for compliance; however, not all RECs meet the Oregon RPS qualifications. Oregon's revenues from RPS ineligible RECs that are sold are passed backed to customers through the Oregon property sales balancing account per Commission Order No. 10-210 in Docket UP 260. This adjustment also removes REC deferrals from the 12 months ended June 2012.

PacifiCorp
Oregon General Rate Case - December 2014
REC Revenue
REC Revenue as Booked

Posting Date	Accrual	Reversal	Back Office Actual	SAP Total
SAP Acct	301944	301944	301945	
July-11	(1,024,064)	7,186,024	(7,167,568)	(1,005,608)
August-11	(1,190,400)	1,024,064	(1,025,064)	(1,191,400)
September-11	(2,261,312)	1,190,400	(1,194,080)	(2,264,992)
October-11	(8,331,080)	2,261,312	(2,261,312)	(8,331,080)
November-11	(8,061,280)	8,331,080	(8,331,080)	(8,061,280)
December-11	(8,584,280)	8,061,280	(8,074,780)	(8,597,780)
January-12	(8,481,600)	8,584,280	(8,588,232)	(8,485,552)
February-12	(7,936,120)	8,481,600	(8,478,900)	(7,933,420)
March-12	(8,484,895)	7,936,120	(8,001,435)	(8,550,210)
April-12	(8,602,746)	8,484,895	(8,614,895)	(8,732,746)
May-12	(8,872,316)	8,602,746	(8,603,502)	(8,873,072)
June-12	(6,947,565)	8,872,316	(8,902,985)	(6,978,234)
12 ME June 2012 Total	(78,777,658)	79,016,117	(79,243,833)	**(79,005,374)**
				Ref 3.4

REC Deferrals Included in Unadjusted Results:

FERC Account	4562700	
Amount 12 Months Ended June 2012	**52,691,624**	**Ref 3.4**

PacifiCorp
Oregon General Rate Case - December 2014
Ancillary Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Ancillary Contract Renewal	456	3	1,780,339	SG	26.053%	463,832	3.5.1
Ancillary Contract Termination	456	3	(59,143)	SG	26.053%	(15,408)	3.5.1
Ancillary Contract Termination	456	3	(246,670)	SG	26.053%	(64,265)	3.5.1

Description of Adjustment:

This adjusts revenue to account for the contract the Company entered into with Seattle City Light (SCL) to receive real time output from SCL's share of the Stateline wind farm and return power two months later which was renewed in December 2011. Addtionally, two ancillary service contracts are expiring during the Test Period. The ancillary revenue booked in the 12 months ended June 2012 is adjusted to reflect the Test Period revenue expected per the terms of each contract, consistent with net power costs treatment in adjustment 5.1.

PacifiCorp
Oregon General Rate Case - December 2014
Ancillary Services Revenue

Ancillary Revenue Adjustment Calculation

Revenue

FERC Acct	Acc.Text	Locatn	Factor	12 Months Ended June 2012	12 Months Ending Dec 2014	Adjustment	Ref.
4562300	Wind-based Ancl Rev	70	SG	7,800,309	9,580,647	**1,780,339**	**3.5**
4562300	Wind-based Ancl Rev	70	SG	104,935	45,792	**(59,143)**	**3.5**
4562300	Wind-based Ancl Rev	70	SG	1,115,342	868,672	**(246,670)**	**3.5**

The Company's June 2012 actual O&M expenses are the basis for the test period O&M expenses. These actual expenses are adjusted for various normalizing items including labor costs, non-labor operation and maintenance, and inflation to reflect the appropriate level of on-going costs that the Company expects to incur during the December 2014 test period. The following adjustments are included:

4.1	Miscellaneous General Expense and Revenue
4.2	Wage and Employee Benefits
4.3	Idaho Irrigation Load Control Program
4.4	Remove Non-Recurring Entries
4.5	Uncollectible Expense
4.6	DSM Revenue and Expense Removal
4.7	Insurance Expense
4.8	Generation Overhaul Expense
4.9	Incremental O&M
4.10	Naughton Unit 3 Write Off
4.11	Memberships and Subscriptions
4.12	O&M Expense Escalation
4.13	O&M Efficiency

PacifiCorp
Oregon General Rate Case - December 2014
Tab 4 Adjustment Summary

	Total Adjustments	4.1 Miscellaneous General Expense & Revenue	4.2 Wage & Employee Benefits	4.3 Idaho Irrigation Load Control Program	4.4 Remove Non-Recurring Entries	4.5 Uncollectible Expense	4.6 DSM Revenue and Expense Removal	4.7 Insurance Expense
1 Operating Revenues:								
2 General Business Revenues	-	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-	-
5 Other Operating Revenues	(10,204,815)	-	-	-	-	-	(10,204,815)	-
6 Total Operating Revenues	(10,204,815)	-	-	-	-	-	(10,204,815)	-
7								
8 Operating Expenses:								
9 Steam Production	5,193,310	-	1,521,879	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	1,077,115	-	216,208	-	-	-	-	-
12 Other Power Supply	369,279	-	554,097	(2,456,639)	2,112,939	-	-	-
13 Embedded Cost Differential (ECD)	-	-	-	-	-	-	-	-
13 Transmission	(222,688)	-	283,767	-	-	-	-	-
14 Distribution	6,074,891	-	1,572,203	-	-	-	-	-
15 Customer Accounting	1,170,262	(15,776)	943,968	-	-	173,142	-	-
16 Customer Service & Info	(23,182,913)	(78,713)	115,969	(928)	(47,055)	-	(23,160,791)	-
17 Sales	-	-	-	-	-	-	-	-
18 Administrative & General	1,498,449	(211,492)	1,297,263	-	13,692	-	-	1,449,332
19								
20 Total O&M Expenses	(8,022,295)	(305,981)	6,505,355	(2,457,567)	2,079,577	173,142	(23,160,791)	1,449,332
21								
22 Depreciation	-	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-	-
25 Income Taxes - Federal	(760,168)	52,729	(2,174,191)	821,357	(695,027)	(57,867)	4,347,239	(482,739)
26 Income Taxes - State	(103,294)	7,165	(295,437)	111,609	(94,443)	(7,863)	590,718	(65,596)
27 Income Taxes - Def Net	-	-	-	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29 Misc Revenue & Expense	148,288	148,288	-	-	-	-	-	-
30								
31 Total Operating Expenses:	(8,737,469)	(97,799)	4,035,727	(1,524,601)	1,290,107	107,412	(18,222,834)	900,996
32								
33 Operating Rev For Return:	(1,467,346)	97,799	(4,035,727)	1,524,601	(1,290,107)	(107,412)	8,018,019	(900,996)
34								
35 Rate Base:								
36 Electric Plant In Service	-	-	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-	-
44 Working Capital	(178,797)	(4,952)	81,206	(30,678)	25,959	2,161	(366,676)	18,130
45 Weatherization Loans	-	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-	-
47								
48 Total Electric Plant:	(178,797)	(4,952)	81,206	(30,678)	25,959	2,161	(366,676)	18,130
49								
50 Rate Base Deductions:								
51 Accum Prov For Deprec	-	-	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-	-
53 Accum Def Income Tax	(2,016,181)	-	-	-	-	-	(1,821,193)	(194,987)
54 Unamortized ITC	-	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-	-	-
58								
59 Total Rate Base Deductions	(2,016,181)	-	-	-	-	-	(1,821,193)	(194,987)
60								
61 Total Rate Base:	(2,194,978)	(4,952)	81,206	(30,678)	25,959	2,161	(2,187,869)	(176,858)
62								
63 Return on Rate Base	-0.038%	0.003%	-0.119%	0.045%	-0.038%	-0.003%	0.241%	-0.026%
64								
65 Return on Equity	-0.072%	0.006%	-0.228%	0.086%	-0.073%	-0.006%	0.463%	-0.050%
66								
67 TAX CALCULATION:								
68 Operating Revenue	(2,330,808)	157,693	(6,505,355)	2,457,567	(2,079,577)	(173,142)	12,955,976	(1,449,332)
69 Other Deductions								
70 Interest (AFUDC)	-	-	-	-	-	-	-	-
71 Interest	(55,605)	(125)	2,057	(777)	658	55	(55,425)	(4,480)
72 Schedule "M" Additions	-	-	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	-	-	-	-	-
74 Income Before Tax	(2,275,203)	157,818	(6,507,412)	2,458,344	(2,080,234)	(173,197)	13,011,401	(1,444,851)
75								
76 State Income Taxes	(103,294)	7,165	(295,437)	111,609	(94,443)	(7,863)	590,718	(65,596)
77 Taxable Income	(2,171,909)	150,653	(6,211,976)	2,346,735	(1,985,792)	(165,334)	12,420,683	(1,379,255)
78								
79 Federal Income Taxes + Other	(760,168)	52,729	(2,174,191)	821,357	(695,027)	(57,867)	4,347,239	(482,739)
80								
81 PRICE CHANGE	2,158,311	(163,086)	6,714,144	(2,536,443)	2,146,321	178,699	(13,597,094)	1,474,171

PacifiCorp
Oregon General Rate Case - December 2014
Tab 4 Adjustment Summary

	4.8	4.9	4.10	4.11	4.12	4.13
	Generation Overhaul Expense	Incremental O&M	Naughton Unit 3 Write Off	Memberships and Subscriptions	O&M Expense Escalation	O&M Efficiency
1 Operating Revenues:						
2 General Business Revenues	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-
7						
8 Operating Expenses:						
9 Steam Production	(1,817,388)	4,289,578	-	-	2,105,169	(905,929)
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	-	815,879	-	-	173,730	(128,702)
12 Other Power Supply	572,888	(569,725)	(691,848)	-	1,177,403	(329,838)
13 Embedded Cost Differential (ECD)	-	-	-	-	-	-
13 Transmission	-	(718,587)	-	-	381,049	(168,918)
14 Distribution	-	4,511,504	-	-	927,069	(935,885)
15 Customer Accounting	-	-	-	-	630,844	(561,916)
16 Customer Service & Info	-	-	-	-	57,638	(69,033)
17 Sales	-	-	-	-	-	-
18 Administrative & General	-	-	-	(218,798)	(59,326)	(772,222)
19						
20 Total O&M Expenses	(1,244,500)	8,328,650	(691,848)	(218,798)	5,393,577	(3,872,443)
21						
22 Depreciation	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-
25 Income Taxes - Federal	415,931	(2,783,565)	231,226	73,126	(1,802,618)	1,294,231
26 Income Taxes - State	56,518	(378,240)	31,420	9,937	(244,946)	175,865
27 Income Taxes - Def Net	-	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-
30						
31 Total Operating Expenses:	(772,050)	5,166,845	(429,202)	(135,736)	3,346,013	(2,402,347)
32						
33 Operating Rev For Return:	772,050	(5,166,845)	429,202	135,736	(3,346,013)	2,402,347
34						
35 Rate Base:						
36 Electric Plant In Service	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-
44 Working Capital	(15,535)	103,966	(8,636)	(2,731)	67,328	(48,340)
45 Weatherization Loans	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	(15,535)	103,966	(8,636)	(2,731)	67,328	(48,340)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-
53 Accum Def Income Tax	-	-	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-
58						
59 Total Rate Base Deductions	-	-	-	-	-	-
60						
61 Total Rate Base:	(15,535)	103,966	(8,636)	(2,731)	67,328	(48,340)
62						
63 Return on Rate Base	0.023%	-0.152%	0.013%	0.004%	-0.099%	0.071%
64						
65 Return on Equity	0.044%	-0.292%	0.024%	0.008%	-0.189%	0.136%
66						
67 TAX CALCULATION:						
68 Operating Revenue	1,244,500	(8,328,650)	691,848	218,798	(5,393,577)	3,872,443
69 Other Deductions						
70 Interest (AFUDC)	-	-	-	-	-	-
71 Interest	(394)	2,634	(219)	(69)	1,706	(1,225)
72 Schedule "M" Additions	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	-	-	-
74 Income Before Tax	1,244,893	(8,331,284)	692,067	218,867	(5,395,282)	3,873,668
75						
76 State Income Taxes	56,518	(378,240)	31,420	9,937	(244,946)	175,865
77 Taxable Income	1,188,375	(7,953,044)	660,647	208,930	(5,150,336)	3,697,803
78						
79 Federal Income Taxes + Other	415,931	(2,783,565)	231,226	73,126	(1,802,618)	1,294,231
80						
81 PRICE CHANGE	(1,284,442)	8,595,958	(714,053)	(225,820)	5,566,684	(3,996,729)

PacifiCorp
Oregon General Rate Case - December 2014
Miscellaneous General Expense & Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Gains on Property Sales	421	1	9,614	UT	0.000%	-	
Gains on Property Sales	421	1	410,416	SG	26.053%	106,926	
Gains on Property Sales	421	1	184,232	SO	27.384%	50,451	
Gains on Property Sales	421	1	(604,262)	NUTIL	0.000%	-	
			-			157,376	4.1.1
Loss on Property Sales	421	1	(11,782)	OR	100.000%	(11,782)	
Loss on Property Sales	421	1	1,944	WA	0.000%	-	
Loss on Property Sales	421	1	9,838	SO	27.384%	2,694	
			-			(9,088)	4.1.1
Adjustment to Expense:							
Non-utility Flights	921	1	(2,693)	SO	27.384%	(737)	
Customer Accounts	903	1	59,852	CN	30.325%	18,150	
Customer Accounts	903	1	(33,927)	OR	100.000%	(33,927)	
Advertising Expense	909	1	(230,911)	CN	30.325%	(70,024)	
Advertising Expense	909	1	(8,689)	OR	100.000%	(8,689)	
Advertising Expense	909	1	(279)	UT	0.000%	-	
Office Supplies & Exp	921	1	(50,970)	SO	27.384%	(13,958)	
Outside Services	923	1	(723,115)	SO	27.384%	(198,020)	
Regulatory Commission Expense	928	1	(2,262)	ID	0.000%	-	
Regulatory Commission Expense	928	1	667	UT	0.000%	-	
Regulatory Commission Expense	928	1	(443)	OR	100.000%	(443)	
Regulatory Commission Expense	928	1	2,039	WY	0.000%	-	
Duplicate Charges	929	1	5,095	SO	27.384%	1,395	
Memberships	930	1	67,270	UT	0.000%	-	
Memberships	930	1	990	SO	27.384%	271	
			(917,378)			(305,981)	4.1.1

Description of Adjustment:

This adjustment removes from results of operations certain miscellaneous expenses that should have been charged to non-regulated accounts in the unadjusted per book results. It also reallocates gains and losses on property sales and regulatory expenses to reflect the appropriate allocation.

PacifiCorp
Oregon General Rate Case - December 2014
Miscellaneous General Expense & Revenue

Description	FERC	Factor	Amt to Exclude
FERC 421 - (Gain)/Loss on Sale of Utility Plant			
Gains on Property Sales	421	UT	(9,614)
Gains on Property Sales	421	SG	(410,416)
Gains on Property Sales	421	SO	(184,232)
Gains on Property Sales	421	NUTIL	604,262
Loss on Property Sales	421	OR	11,782
Loss on Property Sales	421	WA	(1,944)
Loss on Property Sales	421	SO	(9,838)
			-
Non-utility Flights			
Office Supplies and Expenses	921	SO	2,693
			2,693
FERC 909 - Informational & Instructional Advertising			
Festivals	909	CN	1,624
Legislative	909	CN	5,561
Legislative	909	OR	334
Donations	909	CN	197
Donations	909	OR	200
Blue Sky	909	CN	73,155
Blue Sky	909	OR	8,005
Blue Sky	909	UT	279
Blue Sky	903	CN	(59,852)
Blue Sky	903	OR	33,927
Blue Sky	929	SO	(5,095)
Promotional	909	CN	147,394
Promotional	909	OR	150
DSM	909	CN	1,120
Sponsorships	909	CN	1,861
			208,859
FERC 921 - Office Supplies & Expenses			
Charitable Donations and Sponsorships	921	SO	10,614
Employee Expenses	921	SO	5,587
Legislative & Lobbyist	921	SO	12,830
DSM Costs	921	SO	4,301
Misc Expense	921	SO	434
SERP Banking Fees	921	SO	17,204
			50,970
FERC 923 - Outside Services			
Miscellaneous	923	SO	(53)
SERP Banking Fees	923	SO	8,504
Affiliate Services	923	SO	613,015
Blue Sky	923	SO	101,650
			723,115
FERC 928 - Regulatory Commission Expense			
2010 EMBE Project	928	ID	2,262
2010 EMBE Project	928	UT	(2,262)
Utah 2012 GRC	928	OR	443
Utah 2012 GRC	928	UT	(443)
Wyoming RBA Case	928	UT	2,039
Wyoming RBA Case	928	WY	(2,039)
			-
FERC 930 - Misc General Expense			
EDCU, UT Sports Authority Rent Contribution	930	UT	(67,270)
Sponsorships	930	SO	(990)
			(68,260)
TOTAL			**917,378**
			Ref 4.1

PacifiCorp
Oregon General Rate Case - December 2014
Wage & Employee Benefits

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Total O&M Expense Adjustment	500-935	3	22,674,474	Multiple (1)	Multiple (1)	6,505,355	4.2.2

(1) See pages 4.2.9 through 4.2.11

Description of Adjustment:

The Company has several labor groups, each with different effective contract renewal dates. The Company negotiates wage increases with each of these groups throughout the year. This adjustment recognizes increases that have occurred, or are projected to occur during the 12 month period ending December 2014. See page 4.2.1 for more information on how this adjustment was calculated.

PacifiCorp
Oregon General Rate Case - December 2014
Wage and Employee Benefit Adjustment

The actual (12 months ended June 2012), and pro forma period (12 months ending December 2014) labor expenses are summarized on page 4.2.2. The following is an explanation of the procedures used to develop the labor expenses used in this adjustment.

1. Per book results for the 12 months ended June 2012 total labor related expenses are identified on page 4.2.2, including bare labor, incentive, other labor, pensions, benefits, and payroll taxes.

2. The per book results for the 12 months ended June 2012 expenses for regular time, overtime, and premium pay were escalated prospectively by labor group to the 12 months ending December 2014 (see pages 4.2.3 & .4). Union costs were escalated using the contractual and target increases found on page 4.2.5. Non-union costs were escalated using actual increases and CPI indices.

3. Annual Incentive Plan (AIP) compensation is included using a three year average of the actual payment rate from 2010 through 2012, multiplied by pro forma wages. AIP is the second step of a two-stage compensation philosophy that provides employees with market average compensation with a portion at risk and based on achieving annual goals. Union employees do not participate in the Company's Annual Incentive Plan; instead, they receive annual increases to their wages that are reflected in the escalation described above.

4. Pro forma December 2014 pension and employee benefit expenses are based on either actuarial projections or are calculated by using actual 12 months ended June 2012 data escalated to 12 months ending December 2014. These expenses can be found on page 4.2.7.

5. Payroll tax calculations can be found on page 4.2.8.

PacifiCorp
Oregon General Rate Case - December 2014
Wage and Employee Benefit Adjustment

Account	Description	Actual 12 Months Ended June 2012	Pro Forma 12 Months Ending December 2014	Adjustment	Ref.
5001XX	Regular Ordinary Time	427,686,084	450,337,775	22,651,691	
5002XX	Overtime	57,765,409	60,824,859	3,059,450	
5003XX	Premium Pay	7,229,138	7,612,018	382,879	
	Subtotal for Escalation	**492,680,632**	**518,774,652**	**26,094,020**	4.2.3&4
5005XX	Unused Leave Accrual	2,188,821	2,304,748	115,927	4.2.6
500700	Severance/Redundancy (1)	65,488	65,488	-	
500850	Other Salary/Labor Costs	3,359,218	3,359,218	-	
50109X	Joint Owner Cutbacks	(1,125,252)	(1,184,849)	(59,597)	4.2.6
	Subtotal Bare Labor	**497,168,907**	**523,319,257**	**26,150,351**	
500410	Annual Incentive Plan	25,795,641	29,489,333	3,693,693	4.2.6
	Total Incentive	**25,795,641**	**29,489,333**	**3,693,693**	
500250	Overtime Meals	1,020,601	1,020,601	-	
500400	Bonus and Awards	479,752	479,752	-	
501325	Physical Exam	5,103	5,103	-	
502300	Education Assistance	233,067	233,067	-	
580899	Mining Salary/Benefit Credit	(261,147)	(261,147)	-	
	Total Other Labor	**1,477,377**	**1,477,377**	**-**	
	Subtotal Labor and Incentive	**524,441,924**	**554,285,968**	**29,844,043**	
50110X	Pensions (2)	35,927,602	34,997,053	(930,549)	4.2.7
501115	SERP Plan	3,411,760	-	(3,411,760)	4.2.7
50115X	Post Retirement Benefits (2)	8,362,232	2,669,863	(5,692,369)	4.2.7
501160	Post Employment Benefits	6,422,175	6,762,315	340,140	4.2.7
	Total Pensions	**54,123,769**	**44,429,231**	**(9,694,538)**	4.2.7
501102	Pension Administration	471,919	471,919	-	4.2.7
50112X	Medical (3)	58,924,131	65,294,448	6,370,317	4.2.7
501175	Dental (3)	2,887,170	4,442,491	1,555,321	4.2.7
501200	Vision (3)	368,814	546,262	177,448	4.2.7
50122X	Life	1,001,904	1,054,968	53,064	4.2.7
501250	401(k)	18,813,636	20,247,451	1,433,815	4.2.7
501251	401(k) Administration	77,570	77,570	0	4.2.7
501252	401(k) Fixed	15,823,819	16,661,901	838,083	4.2.7
501275	Accidental Death & Disability	49,868	52,509	2,641	4.2.7
501300	Long-Term Disability	3,250,530	3,422,689	172,159	4.2.7
5016XX	Worker's Compensation	1,467,328	1,545,042	77,715	4.2.7
502900	Other Salary Overhead	1,828,304	1,828,304	-	4.2.7
	Total Benefits	**104,964,991**	**115,645,554**	**10,680,563**	4.2.7
	Subtotal Pensions and Benefits	**159,088,760**	**160,074,784**	**986,025**	4.2.7
580500	Payroll Tax Expense	36,485,954	38,652,603	2,166,649	4.2.8
580700	Payroll Tax Expense-Unemployment	3,891,056	3,891,056	-	
	Total Payroll Taxes	**40,377,010**	**42,543,659**	**2,166,649**	
Total Labor		**723,907,694**	**756,904,411**	**32,996,717**	4.2.11
Non-Utility and Capitalized Labor		226,457,419	236,779,662	10,322,243	4.2.11
Total Utility Labor		**497,450,275**	**520,124,749**	**22,674,474**	4.2.11
				Ref. 4.2	

Notes:
(1) MEHC Transition severance amortization accrual effects are not included.
(2) Pension Curtailment Gain and Pension, Post Retirement Measurement Date change effects are not included.
(3) Prior to January 2012, Western Utilities dental and vision were charged to the medical account.

(Figures are in thousands)

Labor (12 months ended June 2012)

Acct	Account Desc.	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Total	
5001XX	Reg/Ordinary Time	33,875	36,694	35,802	34,064	35,820	35,915	35,623	35,411	36,288	34,995	38,600	34,600	427,686	Ref. 4.2.2
5002XX	Overtime	4,391	4,983	5,214	4,677	5,085	5,371	5,908	3,180	6,046	4,662	4,176	4,071	57,765	Ref. 4.2.2
5003XX	Premium Pay	685	743	595	559	583	845	649	403	639	551	512	465	7,229	Ref. 4.2.2
Grand Total		**38,951**	**42,419**	**41,611**	**39,300**	**41,488**	**42,131**	**42,180**	**38,994**	**42,973**	**40,208**	**43,288**	**39,136**	**492,681**	**Ref. 4.2.2**

Labor (12 months ended June 2012)

Group Code	Labor Group	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Total
2	Officer/Exempt	14,732	15,330	16,020	14,434	15,150	16,173	14,995	15,271	16,537	14,575	16,601	15,171	184,988
3	IBEW 125	2,802	3,185	3,097	2,802	3,206	2,802	3,868	2,586	2,853	2,870	2,962	2,579	35,613
4	IBEW 659	3,248	3,738	3,669	3,519	3,736	3,317	4,453	3,082	4,457	3,608	3,758	3,208	43,793
5	UWUA 197	170	238	239	175	241	163	307	149	421	184	199	161	2,648
8	UWUA 127	3,832	4,098	3,921	3,964	4,172	4,183	3,797	3,794	3,864	4,540	4,291	3,622	48,080
9	IBEW 57 WY	59	58	58	51	57	73	50	51	48	54	57	52	668
11	IBEW 57 PD	8,517	9,744	8,725	8,363	8,700	9,262	8,709	8,116	8,481	8,477	9,085	8,362	104,540
12	IBEW 57 PS	3,624	3,868	3,808	3,947	4,138	3,949	3,807	3,841	4,118	3,870	4,107	3,871	46,947
13	PCCC Non-Exempt	690	749	700	691	686	708	789	734	697	695	722	683	8,543
15	IBEW 57 CT	256	275	271	273	300	310	267	230	272	243	268	260	3,224
18	Non-Exempt	1,022	1,136	1,103	1,081	1,102	1,191	1,138	1,140	1,224	1,091	1,239	1,168	13,635
Grand Total		**38,951**	**42,419**	**41,611**	**39,300**	**41,488**	**42,131**	**42,180**	**38,994**	**42,973**	**40,208**	**43,288**	**39,136**	**492,681**

Annualization Increase

Group Code	Labor Group	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
2	Officer/Exempt							1.93%					
3	IBEW 125			1.00%					1.50%				
4	IBEW 659			1.25%								1.50%	
5	UWUA 197												2.00%
8	UWUA 127				1.50%								
9	IBEW 57 WY	1.50%											
11	IBEW 57 PD								2.00%				
12	IBEW 57 PS								2.00%				
13	PCCC Non-Exempt							2.00%					
15	IBEW 57 CT												1.75%
18	Non-Exempt							1.93%					

June 2012 Annualized Labor

Group Code	Labor Group	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Total
2	Officer/Exempt	15,016	15,626	16,329	14,712	15,442	16,485	14,995	15,271	16,537	14,575	16,601	15,171	186,761
3	IBEW 125	2,872	3,265	3,144	2,844	3,254	2,844	3,926	2,586	2,853	2,870	2,962	2,579	36,000
4	IBEW 659	3,338	3,841	3,724	3,572	3,792	3,366	4,520	3,128	4,524	3,662	3,758	3,208	44,434
5	UWUA 197	173	243	244	179	246	167	314	152	429	188	203	161	2,698
8	UWUA 127	3,889	4,160	3,980	3,964	4,172	4,183	3,797	3,794	3,864	4,540	4,291	3,622	48,258
9	IBEW 57 WY	59	58	58	51	57	73	50	51	48	54	57	52	668
11	IBEW 57 PD	8,687	9,939	8,899	8,531	8,874	9,447	8,883	8,116	8,481	8,477	9,085	8,362	105,780
12	IBEW 57 PS	3,696	3,946	3,884	4,025	4,220	4,028	3,883	3,841	4,118	3,870	4,107	3,871	47,490
13	PCCC Non-Exempt	703	764	714	705	699	722	789	734	697	695	722	683	8,628
15	IBEW 57 CT	261	280	275	278	306	316	272	234	276	247	272	260	3,276
18	Non-Exempt	1,042	1,158	1,124	1,102	1,123	1,214	1,138	1,140	1,224	1,091	1,239	1,168	13,763
Grand Total		**39,738**	**43,279**	**42,376**	**39,963**	**42,186**	**42,845**	**42,566**	**39,048**	**43,053**	**40,270**	**43,297**	**39,136**	**497,756**

PacifiCorp
Oregon General Rate Case - December 2014
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2012
Pro Forma: 12 Months Ending December 2014

Pro Forma Increases applied to escalate to December 2014

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	Officer/Exempt												
	12/26/2012	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%
	12/26/2013	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%
3	IBEW 125												
	1/26/2013	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
	1/26/2014		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
4	IBEW 659												
	4/26/2013	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
	4/26/2014					1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
5	UWUA 197												
	5/26/2013	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
	5/26/2014						2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	UWUA 127 Wyoming												
	9/26/2012	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
	9/26/2013	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
	9/26/2014										2.00%	2.00%	2.00%
9	IBEW 415 (Laramie 57)												
	6/26/2012	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
	6/26/2013	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
	6/26/2014							2.25%	2.25%	2.25%	2.25%	2.25%	2.25%
11	IBEW 57 PD												
	1/26/2013	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
	1/26/2014		2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%
12	IBEW 57 PS												
	1/26/2013	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
	1/26/2014		2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%
13	PCCC Non-Exempt												
	12/26/2012	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%
	12/26/2013	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%
15	IBEW 57 CT												
	1/26/2013	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
	1/26/2014		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
18	Non-Exempt												
	12/26/2012	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%
	12/26/2013	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%	1.72%

Pro Forma Labor December 2014

Group Code	Labor Group	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total	
2	Officer/Exempt	15,592	15,879	17,196	15,155	17,261	15,775	15,614	16,248	16,980	15,298	16,057	17,141	194,197	**Ref 4.2.6**
3	IBEW 125	4,005	2,691	2,968	2,986	3,081	2,684	2,988	3,397	3,271	2,959	3,385	2,959	37,374	
4	IBEW 659	4,588	3,175	4,592	3,717	3,872	3,305	3,439	3,957	3,837	3,680	3,907	3,468	45,536	
5	UWUA 197	320	155	438	192	207	167	180	252	254	186	256	173	2,781	
8	UWUA 127	3,950	3,948	4,021	4,723	4,464	3,768	4,046	4,328	4,141	4,207	4,428	4,439	50,464	
9	IBEW 57 WY	52	53	49	55	59	53	63	62	61	54	61	77	700	
11	IBEW 57 PD	9,105	8,548	8,932	8,928	9,568	8,807	9,149	10,467	9,372	8,984	9,346	9,949	111,156	
12	IBEW 57 PS	3,980	4,046	4,337	4,076	4,325	4,077	3,893	4,155	4,091	4,240	4,445	4,242	49,907	
13	PCCC Non-Exempt	731	794	742	733	727	751	821	763	725	723	750	710	8,971	**Ref 4.2.6**
15	IBEW 57 CT	275	242	285	255	281	269	269	289	284	287	316	326	3,378	
18	Non-Exempt	1,183	1,185	1,273	1,135	1,289	1,215	1,084	1,204	1,169	1,146	1,168	1,262	14,311	**Ref 4.2.6**
Grand Total		**43,781**	**40,715**	**44,834**	**41,956**	**45,136**	**40,870**	**41,546**	**45,123**	**44,185**	**41,763**	**44,118**	**44,748**	**518,775**	**Ref. 4.2.2**

PacifiCorp
Oregon General Rate Case - December 2014
Wage and Employee Benefit Adjustment

Labor Increases - July 2011 through December 2014

Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month. For example, an increase that occurs on December 26, 2011 is shown as effective on January 1, 2012.

12 Months Ended June 2012

Group Code	Labor Group	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	
2	Officer/Exempt							1.93%						(1)
3	IBEW 125			1.00%					1.50%					(2)
4	IBEW 659			1.25%								1.50%		(2)
5	UWUA 197												2.00%	(2)
8	UWUA 127				1.50%									(2)
9	IBEW 57 WY	1.50%												(2)
11	IBEW 57 PD								2.00%					(2)
12	IBEW 57 PS								2.00%					(2)
13	PCCC Non-Exempt							2.00%						(1)
15	IBEW 57 CT												1.75%	(2)
18	Non-Exempt							1.93%						(1)

12 Months Ending June 2013

Group Code	Labor Group	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	
2	Officer/Exempt							2.22%						(1)
3	IBEW 125								2.00%					(2)
4	IBEW 659											1.50%		(2)
5	UWUA 197												2.00%	(2)
8	UWUA 127				2.00%									(2)
9	IBEW 57 WY	1.50%												(2)
11	IBEW 57 PD								2.50%					(3)
12	IBEW 57 PS								2.50%					(3)
13	PCCC Non-Exempt							2.22%						(1)
15	IBEW 57 CT								1.25%					(2)
18	Non-Exempt							2.22%						(1)

12 Months Ending June 2014

Group Code	Labor Group	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	
2	Officer/Exempt							1.72%						(4)
3	IBEW 125								2.00%					(2)
4	IBEW 659											1.50%		(2)
5	UWUA 197												2.00%	(2)
8	UWUA 127				2.00%									(3)
9	IBEW 57 WY	2.00%												(3)
11	IBEW 57 PD								2.75%					(3)
12	IBEW 57 PS								2.75%					(3)
13	PCCC Non-Exempt							1.72%						(4)
15	IBEW 57 CT								2.00%					(3)
18	Non-Exempt							1.72%						(4)

6 Months Ending December 2014

Group Code	Labor Group	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	
2	Officer/Exempt							
3	IBEW 125							
4	IBEW 659							
5	UWUA 197							
8	UWUA 127				2.00%			(3)
9	IBEW 57 WY	2.25%						(3)
11	IBEW 57 PD							
12	IBEW 57 PS							
13	PCCC Non-Exempt							
15	IBEW 57 CT							
18	Non-Exempt							

(1) Overall actual
(2) Labor increases supported by union contracts
(3) Labor increases supported by planning targets. No contract in place for this period.
(4) Consumer Price Index (CPI)

PacifiCorp
Oregon General Rate Case - December 2014
Wage and Employee Benefit Adjustment

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay June 2012 - ACTUAL	492,680,632		4.2.2
Regular Time/Overtime/Premium Pay December 2014 - PRO FORMA	518,774,652	CAGR[1]	4.2.2
% Increase	5.30%	2.09%	

Miscellaneous Bare Labor Escalation

Description	Account	June 2012 Actual	Pro Forma Increase	Dec 2014 Pro Forma	Pro Forma Adjustment	Ref.
Unused Sick Leave Accrual	5005XX	2,188,821	5.30%	2,304,748	**115,927**	**4.2.2**
Joint Owner Cutbacks	50109X	(1,125,252)	5.30%	(1,184,849)	**(59,597)**	**4.2.2**
		1,063,569		1,119,899	56,330	

Annual Incentive Plan Escalation

Description	Account	June 2012 Actual	Dec 2014 Pro Forma	Pro Forma Adjustment	Ref.
Annual Incentive Plan Compensation	500410	25,795,641	29,489,333	**3,693,693**	**4.2.2**

Test Year Annual Incentive Plan (AIP) Calculation

	Officer/Exempt Actual Wages	PCCC Non-Exempt Actual Wages	Non-Exempt Actual Wages	Total Wages	Actual AIP	AIP as a % of Wages
Calendar Year 2010	177,805,237	8,161,210	11,363,613	197,330,060	26,606,117	13.48%
Calendar Year 2011	181,985,233	8,213,064	12,660,309	202,858,606	27,627,365	13.62%
Calendar Year 2012	184,382,162	8,436,948	13,878,069	206,697,179	28,057,782	13.57%
3-year Total	544,172,632	24,811,222	37,901,991	606,885,845	82,291,264	13.56%
Test Year	194,196,537	8,971,449	14,311,464	217,479,450	29,489,333	13.56%
	Ref 4.2.4	Ref 4.2.4	Ref 4.2.4		Ref 4.2.2	

[1]Compound Annual Growth Rate

PacifiCorp
Oregon General Rate Case - December 2014
Wage and Employee Benefit Adjustment

		A	B	C	D	D - A	
Account	Description	Actual June 2012 Net of Joint Venture	Actual June 2012 GROSS	December 2014 Projected GROSS	December 2014 Projected Net of Joint Venture	Pro Forma Adjustment	Ref
50110X	Pensions	35,927,602	36,773,350	35,820,896	34,997,053	(930,549)	4.2.2
501115	SERP Plan	3,411,760	3,411,760	-	-	(3,411,760)	4.2.2
50115X	Post Retirement Benefits	8,362,232	8,623,810	2,753,378	2,669,863	(5,692,369)	4.2.2
501160	Post Employment Benefits	6,422,175	6,614,397	6,964,718	6,762,315	340,140	4.2.2
	Subtotal	54,123,769	55,423,317	45,538,992	44,429,231	(9,694,538)	4.2.2
501102	Pension Administration	471,919	484,495	484,495	471,919	-	4.2.2
50112X	Medical (1)	58,924,131	60,814,446	67,389,126	65,294,448	6,370,317	4.2.2
501175	Dental (1)	2,887,170	2,978,971	4,583,745	4,442,491	1,555,321	4.2.2
501200	Vision (1)	368,814	380,592	563,707	546,262	177,448	4.2.2
50122X	Life	1,001,904	1,032,547	1,087,235	1,054,968	53,064	4.2.2
501250	401(k)	18,813,636	19,436,173	20,917,433	20,247,451	1,433,815	4.2.2
501251	401(k) Administration	77,570	80,018	80,018	77,570	-	4.2.2
501252	401(k) Fixed	15,823,819	16,566,605	17,444,028	16,661,901	838,083	4.2.2
501275	Accidental Death & Disability	49,868	50,412	53,082	52,509	2,641	4.2.2
501300	Long-Term Disability	3,250,530	3,347,765	3,525,074	3,422,689	172,159	4.2.2
5016XX	Worker's Compensation	1,467,328	1,507,295	1,587,126	1,545,042	77,715	4.2.2
502900	Other Salary Overhead	1,828,304	1,829,694	1,829,694	1,828,304	-	4.2.2
	Subtotal	104,964,991	108,509,014	119,544,763	115,645,554	10,680,563	4.2.2
	Grand Total	159,088,760	163,932,330	165,083,755	160,074,784	986,025	4.2.2
		Ref 4.2.2			Ref 4.2.2	Ref 4.2.2	

(1) Prior to January 2012, Western Utilities dental and vision were charged to the medical account.

PacifiCorp
Oregon General Rate Case - December 2014
Wage and Employee Benefit Adjustment
Payroll Tax Adjustment Calculation

FICA Calculated on December 2014 Pro Forma Labor		**Reference**
Pro Forma Wages Adjustment	26,150,351	4.2.2
Pro Forma Incentive Adjustment	3,693,693	4.2.2
	29,844,043	
Medicare Rate (no cap)	1.45%	
	432,739	
Social Security Rate	6.20%	
	1,850,331	
Percentage of Social Security Eligible Wages	93.71%	
	1,733,910	
Total FICA Tax	**2,166,649**	4.2.2

PacifiCorp
Oregon General Rate Case - December 2014
2010 Protocol FERC Spread

Indicator	Actual 12 Months Ended June 2012	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2014	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2014 Oregon Allocated
500SG	15,095,311	2.09%	688,065	15,783,376	26.053%	179,262	4,112,043
501SE	2,136,019	0.30%	97,363	2,233,382	24.687%	24,036	551,349
502SG	14,872,489	2.05%	677,909	15,550,398	26.053%	176,616	4,051,345
503SE	100,997	0.01%	4,604	105,600	24.687%	1,136	26,069
505SG	1,757,848	0.24%	80,125	1,837,973	26.053%	20,875	478,847
506SG	46,260,740	6.39%	2,108,629	48,369,369	26.053%	549,361	12,601,672
510SG	2,465,478	0.34%	112,380	2,577,858	26.053%	29,278	671,609
511SG	6,528,973	0.90%	297,600	6,826,572	26.053%	77,534	1,778,527
512SG	25,524,672	3.53%	1,163,450	26,688,122	26.053%	303,114	6,953,057
513SG	11,195,370	1.55%	510,300	11,705,670	26.053%	132,949	3,049,678
514SG	2,334,233	0.32%	106,398	2,440,631	26.053%	27,720	635,858
535SG-P	2,749,123	0.38%	125,309	2,874,432	26.053%	32,647	748,876
535SG-U	1,240,323	0.17%	56,536	1,296,859	26.053%	14,729	337,871
536SG-P	80,311	0.01%	3,661	83,971	26.053%	954	21,877
537SG-P	544,004	0.08%	24,796	568,801	26.053%	6,460	148,190
537SG-U	75,693	0.01%	3,450	79,144	26.053%	899	20,619
539SG-P	5,415,624	0.75%	246,852	5,662,476	26.053%	64,312	1,475,245
539SG-U	4,587,876	0.63%	209,122	4,796,998	26.053%	54,482	1,249,762
540SG-P	(271,619)	-0.04%	(12,381)	(283,999)	26.053%	(3,226)	(73,990)
542SG-P	425,242	0.06%	19,383	444,625	26.053%	5,050	115,838
542SG-U	140,103	0.02%	6,386	146,490	26.053%	1,664	38,165
543SG-P	464,560	0.06%	21,175	485,736	26.053%	5,517	126,549
543SG-U	360,261	0.05%	16,421	376,682	26.053%	4,278	98,137
544SG-P	1,136,510	0.16%	51,804	1,188,314	26.053%	13,496	309,591
544SG-U	332,730	0.05%	15,166	347,896	26.053%	3,951	90,637
545SG-P	685,052	0.09%	31,226	716,278	26.053%	8,135	186,612
545SG-U	240,738	0.03%	10,973	251,712	26.053%	2,859	65,578
548SG	5,574,212	0.77%	254,080	5,828,292	26.053%	66,196	1,518,445
549SG	3,178,810	0.44%	144,895	3,323,705	26.053%	37,749	865,925
552SG	244,091	0.03%	11,126	255,217	26.053%	2,899	66,492
553SG	2,342,149	0.32%	106,758	2,448,907	26.053%	27,814	638,014
554SG	175,242	0.02%	7,988	183,230	26.053%	2,081	47,737
556SG	966,406	0.13%	44,050	1,010,457	26.053%	11,476	263,254
557SG	34,178,668	4.72%	1,557,911	35,736,580	26.053%	405,883	9,310,452
560SG	5,350,165	0.74%	243,868	5,594,033	26.053%	63,535	1,457,414
561SG	8,293,262	1.15%	378,018	8,671,281	26.053%	98,485	2,259,129
562SG	993,859	0.14%	45,301	1,039,160	26.053%	11,802	270,732
563SG	99,072	0.01%	4,516	103,588	26.053%	1,177	26,988
566SG	172,241	0.02%	7,851	180,092	26.053%	2,045	46,919
567SG	203,509	0.03%	9,276	212,785	26.053%	2,417	55,437
568SG	1,857,981	0.26%	84,689	1,942,671	26.053%	22,064	506,124
569SG	2,091,083	0.29%	95,314	2,186,398	26.053%	24,832	569,622
570SG	6,424,850	0.89%	292,854	6,717,704	26.053%	76,297	1,750,163
571SG	(1,651,795)	-0.23%	(75,291)	(1,727,086)	26.053%	(19,616)	(449,958)
572SG	46,203	0.01%	2,106	48,309	26.053%	549	12,586
573SG	15,125	0.00%	689	15,814	26.053%	180	4,120
580CA	2,582	0.00%	118	2,699	0.000%	-	-
580IDU	(17,037)	0.00%	(777)	(17,814)	0.000%	-	-
580OR	229,708	0.03%	10,470	240,178	100.000%	10,470	240,178
580SNPD	13,997,236	1.93%	638,013	14,635,249	26.872%	171,444	3,932,726
580UT	225,932	0.03%	10,298	236,230	0.000%	-	-
580WA	53,323	0.01%	2,431	55,753	0.000%	-	-
580WYP	112,099	0.02%	5,110	117,208	0.000%	-	-
580WYU	(163)	0.00%	(7)	(171)	0.000%	-	-
581OR	(100)	0.00%	(5)	(105)	100.000%	(5)	(105)
581SNPD	12,779,783	1.77%	582,520	13,362,303	26.872%	156,533	3,590,665
582CA	33,780	0.00%	1,540	35,319	0.000%	-	-
582IDU	121,895	0.02%	5,556	127,451	0.000%	-	-
582OR	477,891	0.07%	21,783	499,674	100.000%	21,783	499,674
582SNPD	27,547	0.00%	1,256	28,802	26.872%	337	7,740
582UT	657,984	0.09%	29,992	687,976	0.000%	-	-
582WA	192,745	0.03%	8,786	201,531	0.000%	-	-
582WYP	332,240	0.05%	15,144	347,384	0.000%	-	-
583CA	355,556	0.05%	16,207	371,762	0.000%	-	-
583IDU	195,271	0.03%	8,901	204,171	0.000%	-	-
583OR	2,473,932	0.34%	112,765	2,586,698	100.000%	112,765	2,586,698
583SNPD	14,123	0.00%	644	14,767	26.872%	173	3,968
583UT	1,567,435	0.22%	71,446	1,638,880	0.000%	-	-
583WA	483,339	0.07%	22,031	505,371	0.000%	-	-
583WYP	165,253	0.02%	7,532	172,785	0.000%	-	-
583WYU	89,654	0.01%	4,087	93,741	0.000%	-	-
585SNPD	233,308	0.03%	10,635	243,943	26.872%	2,858	65,551
586CA	191,840	0.03%	8,744	200,585	0.000%	-	-
586IDU	327,596	0.05%	14,932	342,529	0.000%	-	-

PacifiCorp
Oregon General Rate Case - December 2014
2010 Protocol FERC Spread

Indicator	Actual 12 Months Ended June 2012	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2014	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2014 Oregon Allocated
586OR	2,548,171	0.35%	116,149	2,664,320	100.000%	116,149	2,664,320
586SNPD	959,973	0.13%	43,757	1,003,729	26.872%	11,758	269,718
586UT	1,189,811	0.16%	54,233	1,244,044	0.000%	-	-
586WA	451,713	0.06%	20,590	472,303	0.000%	-	-
586WYP	559,517	0.08%	25,504	585,020	0.000%	-	-
586WYU	47,796	0.01%	2,179	49,974	0.000%	-	-
587CA	510,727	0.07%	23,280	534,006	0.000%	-	-
587IDU	346,238	0.05%	15,782	362,020	0.000%	-	-
587OR	3,717,864	0.51%	169,465	3,887,330	100.000%	169,465	3,887,330
587UT	4,518,820	0.62%	205,974	4,724,794	0.000%	-	-
587WA	772,742	0.11%	35,223	807,964	0.000%	-	-
587WYP	645,102	0.09%	29,405	674,507	0.000%	-	-
587WYU	62,442	0.01%	2,846	65,288	0.000%	-	-
588CA	(20,860)	0.00%	(951)	(21,810)	0.000%	-	-
588IDU	54,833	0.01%	2,499	57,333	0.000%	-	-
588OR	(209,789)	-0.03%	(9,562)	(219,351)	100.000%	(9,562)	(219,351)
588SNPD	3,549,307	0.49%	161,782	3,711,089	26.872%	43,474	997,229
588UT	710,926	0.10%	32,405	743,331	0.000%	-	-
588WA	50,349	0.01%	2,295	52,644	0.000%	-	-
588WYP	184,643	0.03%	8,416	193,059	0.000%	-	-
588WYU	(44,244)	-0.01%	(2,017)	(46,261)	0.000%	-	-
589CA	12,986	0.00%	592	13,578	0.000%	-	-
589IDU	874	0.00%	40	913	0.000%	-	-
589OR	52,163	0.01%	2,378	54,541	100.000%	2,378	54,541
589UT	31,791	0.00%	1,449	33,240	0.000%	-	-
589WA	6,313	0.00%	288	6,601	0.000%	-	-
589WYP	3,923	0.00%	179	4,102	0.000%	-	-
589WYU	1,723	0.00%	79	1,802	0.000%	-	-
590CA	35,786	0.00%	1,631	37,417	0.000%	-	-
590IDU	21,468	0.00%	979	22,447	0.000%	-	-
590OR	245,363	0.03%	11,184	256,547	100.000%	11,184	256,547
590SNPD	3,897,180	0.54%	177,639	4,074,819	26.872%	47,734	1,094,969
590UT	280,527	0.04%	12,787	293,314	0.000%	-	-
590WA	13,322	0.00%	607	13,929	0.000%	-	-
590WYP	67,499	0.01%	3,077	70,576	0.000%	-	-
592CA	67,549	0.01%	3,079	70,628	0.000%	-	-
592IDU	478,173	0.07%	21,796	499,969	0.000%	-	-
592OR	1,274,780	0.18%	58,106	1,332,887	100.000%	58,106	1,332,887
592SNPD	1,769,397	0.24%	80,652	1,850,048	26.872%	21,672	497,138
592UT	2,653,365	0.37%	120,944	2,774,309	0.000%	-	-
592WA	284,395	0.04%	12,963	297,358	0.000%	-	-
592WYP	846,408	0.12%	38,580	884,988	0.000%	-	-
592WYU	(7,275)	0.00%	(332)	(7,607)	0.000%	-	-
593CA	1,208,143	0.17%	55,069	1,263,211	0.000%	-	-
593IDU	2,439,512	0.34%	111,196	2,550,709	0.000%	-	-
593OR	7,131,730	0.99%	325,074	7,456,804	100.000%	325,074	7,456,804
593SNPD	408,260	0.06%	18,609	426,869	26.872%	5,001	114,707
593UT	6,973,646	0.96%	317,868	7,291,515	0.000%	-	-
593WA	468,640	0.06%	21,361	490,001	0.000%	-	-
593WYP	281,420	0.04%	12,828	294,248	0.000%	-	-
593WYU	337,703	0.05%	15,393	353,096	0.000%	-	-
594CA	411,023	0.06%	18,735	429,758	0.000%	-	-
594IDU	425,705	0.06%	19,404	445,109	0.000%	-	-
594OR	3,742,575	0.52%	170,592	3,913,166	100.000%	170,592	3,913,166
594SNPD	4,096	0.00%	187	4,283	26.872%	50	1,151
594UT	6,807,703	0.94%	310,305	7,118,007	0.000%	-	-
594WA	718,219	0.10%	32,737	750,957	0.000%	-	-
594WYP	730,898	0.10%	33,315	764,214	0.000%	-	-
594WYU	127,697	0.02%	5,821	133,518	0.000%	-	-
595SNPD	664,369	0.09%	30,283	694,651	26.872%	8,137	186,664
596CA	81,574	0.01%	3,718	85,292	0.000%	-	-
596IDU	158,440	0.02%	7,222	165,662	0.000%	-	-
596OR	903,423	0.12%	41,179	944,603	100.000%	41,179	944,603
596UT	356,420	0.05%	16,246	372,666	0.000%	-	-
596WA	159,278	0.02%	7,260	166,538	0.000%	-	-
596WYP	264,541	0.04%	12,058	276,599	0.000%	-	-
596WYU	30,399	0.00%	1,386	31,785	0.000%	-	-
597CA	53,122	0.01%	2,421	55,543	0.000%	-	-
597IDU	298,797	0.04%	13,620	312,417	0.000%	-	-
597OR	969,601	0.13%	44,196	1,013,797	100.000%	44,196	1,013,797
597SNPD	992,194	0.14%	45,226	1,037,420	26.872%	12,153	278,771
597UT	1,926,699	0.27%	87,822	2,014,520	0.000%	-	-
597WA	286,462	0.04%	13,057	299,519	0.000%	-	-
597WYP	382,993	0.05%	17,457	400,450	0.000%	-	-

PacifiCorp
Oregon General Rate Case - December 2014
2010 Protocol FERC Spread

Indicator	Actual 12 Months Ended June 2012	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2014	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2014 Oregon Allocated
597WYU	97,402	0.01%	4,440	101,841	0.000%	-	-
598CA	15,564	0.00%	709	16,273	0.000%	-	-
598OR	63,503	0.01%	2,895	66,398	100.000%	2,895	66,398
598SNPD	1,160,065	0.16%	52,877	1,212,942	26.872%	14,209	325,937
598UT	5,055	0.00%	230	5,285	0.000%	-	-
598WA	21,634	0.00%	986	22,620	0.000%	-	-
598WYU	160	0.00%	7	168	0.000%	-	-
901CN	2,412,297	0.33%	109,956	2,522,252	30.325%	33,344	764,877
901OR	138	0.00%	6	144	100.000%	6	144
902CA	742,287	0.10%	33,834	776,122	0.000%	-	-
902CN	1,918,574	0.27%	87,451	2,006,025	30.325%	26,520	608,330
902IDU	1,251,086	0.17%	57,026	1,308,112	0.000%	-	-
902OR	8,060,910	1.11%	367,427	8,428,337	100.000%	367,427	8,428,337
902UT	3,462,965	0.48%	157,847	3,620,812	0.000%	-	-
902WA	677,550	0.09%	30,884	708,433	0.000%	-	-
902WYP	995,246	0.14%	45,365	1,040,611	0.000%	-	-
902WYU	155,665	0.02%	7,095	162,761	0.000%	-	-
903CA	161,363	0.02%	7,355	168,719	0.000%	-	-
903CN	32,111,145	4.44%	1,463,671	33,574,815	30.325%	443,860	10,181,616
903IDU	294,383	0.04%	13,418	307,802	0.000%	-	-
903OR	1,570,251	0.22%	71,574	1,641,825	100.000%	71,574	1,641,825
903UT	2,713,254	0.37%	123,674	2,836,928	0.000%	-	-
903WA	524,580	0.07%	23,911	548,492	0.000%	-	-
903WYP	429,513	0.06%	19,578	449,091	0.000%	-	-
903WYU	58,150	0.01%	2,651	60,801	0.000%	-	-
905CN	89,361	0.01%	4,073	93,434	30.325%	1,235	28,334
907CN	272,921	0.04%	12,440	285,361	30.325%	3,772	86,536
908CA	57,612	0.01%	2,626	60,238	0.000%	-	-
908CN	1,691,267	0.23%	77,090	1,768,357	30.325%	23,378	536,257
908IDU	485,014	0.07%	22,108	507,122	0.000%	-	-
908OR	1,776,707	0.25%	80,985	1,857,692	100.000%	80,985	1,857,692
908OTHER	14,268	0.00%	650	14,918	0.000%	-	-
908UT	2,540,737	0.35%	115,810	2,656,548	0.000%	-	-
908WA	453,333	0.06%	20,664	473,997	0.000%	-	-
908WYP	1,055,786	0.15%	48,124	1,103,910	0.000%	-	-
909CN	563,165	0.08%	25,670	588,835	30.325%	7,784	178,565
909WA	460	0.00%	21	480	0.000%	-	-
910CN	3,585	0.00%	163	3,749	30.325%	50	1,137
920CA	-	0.00%	-	-	0.000%	-	-
920OR	(2)	0.00%	(0)	(2)	100.000%	(0)	(2)
920SO	75,947,985	10.49%	3,461,815	79,409,800	27.384%	947,992	21,745,783
920UT	-	0.00%	-	-	0.000%	-	-
920WA	23	0.00%	1	24	0.000%	-	-
920WYP	-	0.00%	-	-	0.000%	-	-
921SO	(271,797)	-0.04%	(12,389)	(284,186)	27.384%	(3,393)	(77,822)
922SO	23,082,219	3.19%	1,052,120	24,134,338	27.384%	288,115	6,609,009
928CA	60,505	0.01%	2,758	63,262	0.000%	-	-
928IDU	336,302	0.05%	15,329	351,631	0.000%	-	-
928OR	766,548	0.11%	34,940	801,488	100.000%	34,940	801,488
928SO	470,734	0.07%	21,457	492,191	27.384%	5,876	134,783
928UT	1,029,154	0.14%	46,910	1,076,064	0.000%	-	-
928WA	481,704	0.07%	21,957	503,661	0.000%	-	-
928WYP	1,016,409	0.14%	46,329	1,062,738	0.000%	-	-
929SO	(695,384)	-0.10%	(31,697)	(727,081)	27.384%	(8,680)	(199,106)
930SO	27,094	0.00%	1,235	28,329	27.384%	338	7,758
935CA	(22,859)	0.00%	(1,042)	(23,901)	0.000%	-	-
935OR	(9,745)	0.00%	(444)	(10,189)	100.000%	(444)	(10,189)
935IDU	(103)	0.00%	(5)	(108)	0.000%	-	-
935SO	2,605,162	0.36%	118,747	2,723,909	27.384%	32,518	745,922
935UT	288	0.00%	13	301	0.000%	-	-
935WA	(18,160)	0.00%	(828)	(18,987)	0.000%	-	-
935WYU	(10,376)	0.00%	(473)	(10,849)	0.000%	-	-
Utility Labor	**497,450,275**	**68.72%**	**22,674,474**	**520,124,749**		**6,505,355**	**149,224,902**
						Ref 4.2	
Capital/Non Utility	226,457,419	31.28%	10,322,243	236,779,662		28.690%	28.690%
Total Labor	**723,907,694**	**100.00%**	**32,996,717**	**756,904,411**			
	Ref 4.2.2		**Ref 4.2.2**	**Ref 4.2.2**			

PacifiCorp
Oregon General Rate Case - December 2014
Idaho Irrigation Load Control Program

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Purchased Power	557	1	(6,463,491)	SG	26.053%	(1,683,933)	4.3.1
Other Purchased Power	557	1	(2,965,899)	SG	26.053%	(772,706)	4.3.1
Advertising	909	1	(3,061)	CN	30.325%	(928)	4.3.1
Other Purchased Power	557	1	9,429,390	ID	0.000%	-	4.3.1
Advertising	909	1	3,061	ID	0.000%	-	4.3.1
			(0)			(2,457,567)	

Description of Adjustment:

Payments made to Idaho irrigators as part of the Idaho Irrigation Load Control Program are system allocated in the unadjusted data. This adjustment situs assigns the payments to Idaho. Demand side management (DSM) and a portion of program administrative costs are currently situs assigned to the states in which the costs are incurred to match the benefit of reduced load reflected in allocation factors. Allocation of Class 1 DSM programs continues to be reviewed by the MSP standing committee.

PacifiCorp
Oregon General Rate Case - December 2014
Idaho Irrigation Load Control

	FERC Account	Factor	Amount	
Idaho Irrigation Load Control Incentive Payments	557	SG	**6,463,491**	**Ref. 4.3**
Irrigation Load Control Program Costs	557	SG	**2,965,899**	**Ref. 4.3**
Irrigation Load Control Program Costs	909	CN	**3,061**	**Ref. 4.3**
			9,432,450	

PacifiCorp
Oregon General Rate Case - December 2014
Remove Non-Recurring Entries

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
1) EPA and DOJ accrual	557	2	1,000,000	SG	26.053%	260,530	4.4.1
2) EEOC settlement reversal	930	2	50,000	SO	27.384%	13,692	4.4.1
3) Correction of DSM Charges	908	2	66,866	WA	0.000%	-	4.4.1
4) Jim Bridger Turbine Upgrade	557	2	3,033,000	SG	26.053%	790,188	4.4.1
5) Non-Residential Curtailment program write-off	908	2	(49,908)	UT	0.000%	-	4.4.1
	908	2	(47,055)	OR	100.000%	(47,055)	4.4.1
	908	2	(18,046)	WA	0.000%	-	4.4.1
6) Boilermaker Reserve	557	2	4,302,803	SE	24.687%	1,062,221	4.4.1

Description of Adjustment:

A variety of accounting entries were made to expense accounts during the 12 months ended June 2012 that are non-recurring in nature or relate to a prior period. These transactions are removed from results to normalize test period results. A description of each item is provided on page 4.4.1.

PacifiCorp
Oregon General Rate Case - December 2014
Remove Non-Recurring Entries

No.	Postg Date	Text	FERC Acct	Factor	Amount as Booked	Reference
1	9/29/2011	**EPA and DOJ accrual under New Review Program:** The EPA and DOJ reviewed plant upgrades and considered whether they were too large to fit under the Company's existing permits. Accordingly, in April 2009 the Company accrued a potential fee. In September 2011 it was determined this accrual was no longer necessary.	557	SG	(1,000,000)	Ref 4.4
2	8/11/2011	**Reversal of EEOC accrual:** An EEOC settlement and back pay was accrued prior to the base period. The accrual was reversed in August, 2011. This reversal of the prior period accrual needs to be removed from results.	930	SO	(50,000)	Ref 4.4
3	10/27/2011	**Correction of DSM charges:** The Company corrected DSM expenses that should have been charged to DSM Regulatory assets in October 2011. The expenses credited that relate to 2010 need to be removed as out-of-period.	908	WA	(66,866)	Ref 4.4
4	12/13/2011	**Jim Bridger Unit 2, 3 and 4 turbine upgrades:** To reverse the CWIP reserve for the potential impairment of Jim Bridger and Huntington 2 turbine upgrade projects, accrued in prior months in anticipation of a renegotiation of the contract with Mechanical Dynamics & Analysis (MD&A). Since the renegotiated MD&A contract was executed in December, this reserve was reversed.	557	SG	(3,033,000)	Ref 4.4
5	6/30/2012	**Non-residential curtailment program cost write-off:** To expense the development costs of the non-residential curtailment program.	908	UT	49,908	Ref 4.4
			908	OR	47,055	Ref 4.4
			908	WA	18,046	Ref 4.4
6	12/31/2011	**Deconsolidation Entry**: Boilermaker reserve accrual was moved to nonutility. Original accrual was made in June 2011 and removed from results. This entry also needs to be removed from results.	557	SE	(4,302,803)	Ref 4.4
				Total	**(8,337,661)**	

PacifiCorp
Oregon General Rate Case - December 2014
Uncollectible Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Uncollectible Accounts - 12 Months Ending December 2014	904	3	173,142	OR	100.000%	173,142	4.5.1

Description of Adjustment:

This adjusts the Company's per books 12 months ended June 2012 uncollectible accounts expense to the 12 months ending December 2014 pro forma test period by applying the unadjusted uncollectible rate (unadjusted uncollectible accounts expense/unadjusted general business revenues) to the pro forma level of general business revenues.

PacifiCorp
Oregon General Rate Case - December 2014
Uncollectible Accounts

	Amount	Reference	
12 Months Ended June 2012 Unadjusted Uncollectible Accounts:			
Oregon Situs Uncollectible Accounts Expense	6,762,199	A	Below
Unadjusted Oregon General Business Revenues	**1,128,512,328**	B	Pg. 2.2, General Business Revenues
Uncollectible Rate	0.599%	C	=A/B
12 Months Ending December 2014 Uncollectible Accounts:			
Normalized Oregon General Business Revenues	**1,209,176,480**	D	Pg. 3.1.1, Pro Forma Revenues
Uncollectible Rate	0.599%	C	Above
12 Months Ending December 2014 Uncollectible Accounts Expense	7,245,550	E	=D*C
Uncollectible Accounts Expense Included in Filing	6,762,199	A	Above
Escalation Percentage	4.49%	F	Page 4.12.8
Escalation Applied	310,208	F	Pg. 4.12.2, O&M Escalation
Total Expense with Escalation	7,072,408	G	=A+F
Adjustment to Expense	**173,142**		=E-G
	Ref 4.5		

Uncollectible Accounts	7,300,290	Pg 2.12, Oregon Situs from Account 904
Remove Joint Use Bad Debt	149,420	
Remove Grid West Amortization	388,671	
	6,762,199	

PacifiCorp
Oregon General Rate Case - December 2014
DSM Revenue and Expense Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Remove DSM Revenue	456	1	(1,273,811)	CA	0.000%	-	
	456	1	(3,199,350)	ID	0.000%	-	
	456	1	(10,204,815)	OR	100.000%	(10,204,815)	
	456	1	(30,158,995)	UT	0.000%	-	
	456	1	(4,270,713)	WA	0.000%	-	
	456	1	(2,419,514)	WY	0.000%	-	
			(51,527,197)			(10,204,815)	4.6.1
Adjustment to Expense:							
Remove DSM Amortization Expense	908	1	(2,208,826)	CA	0.000%	-	
	908	1	(5,750,257)	ID	0.000%	-	
	908	1	(23,160,791)	OR	100.000%	(23,160,791)	
	908	1	(47,542,835)	UT	0.000%	-	
	908	1	(8,686,670)	WA	0.000%	-	
	908	1	(3,998,687)	WY	0.000%	-	
			(91,348,067)			(23,160,791)	4.6.1
Adjustment to Tax:							
Year End ADIT Balance	283	1	(3,563,611)	SO	27.384%	(975,868)	
Year End ADIT Balance	190	1	(845,325)	OR	100.000%	(845,325)	

Description of Adjustment:

This adjustment removes July 2011 through December 2011 revenues and July 2011 through June 2012 expenses associated with the Company's Demand-side Management (DSM) programs. The January 2012 through June 2012 revenues are removed through the revenue adjustment number 3.1. DSM program costs are recovered in each state through separate tariff riders.

PacifiCorp
Oregon General Rate Case - December 2014
DSM Revenue & Expense Removal
SAP Unadjusted

Remove DSM Revenue: (July 2011 - December 2011)

FERC Account	Description	Allocation	Unadjusted Actuals	
456	DSM Revenue - CA	CA	1,273,811	
456	DSM Revenue - ID	IDU	3,199,350	
456	DSM Revenue - OR	OR	10,204,815	
456	DSM Revenue - UT	UT	30,158,995	
456	DSM Revenue - WA	WA	4,270,713	
456	DSM Revenue - WY	WY	2,419,514	
			51,527,197	**Ref. 4.6**

Remove DSM Amortization Expense: (July 2011 - June 2012)

FERC Account	Description	Allocation	Unadjusted Actuals	
908	CA DSM AMORT-SBC/ECC	CA	2,208,826	
908	IDU DSM AMORT-SBC/ECC	IDU	5,750,257	
908	OR DSM AMORT-SBC/ECC	OR	23,160,791	
908	UT DSM AMORT-SBC/ECC	UT	47,542,835	
908	WA DSM AMORT-SBC/ECC	WA	8,686,670	
908	WY DSM AMORT-SBC/ECC	WY	3,998,687	
			91,348,067	**Ref. 4.6**

PacifiCorp
Oregon General Rate Case - December 2014
Insurance Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove general liability premiums from base period	925	3	(2,004,955)	SO	27.384%	(549,042)	4.7.1
Remove provision for injuries & damages from base	925	3	(10,739,219)	SO	27.384%	(2,940,855)	4.7.1
Test period level of general liability premiums	925	3	1,618,029	SO	27.384%	443,085	4.7.2
Test period level of provision for injuries & damages	925	3	3,369,178	OR	100.000%	3,369,178	4.7.3
Remove property premiums from base period	924	3	(7,674,148)	SO	27.384%	(2,101,508)	4.7.1
Remove provision for property damages from base	924	3	(5,277,348)	OR	100.000%	(5,277,348)	4.7.1
Test period level of property insurance premiums	924	3	6,423,396	SO	27.384%	1,758,999	4.7.1
Test period level of provision for property damages	924	3	7,068,568	OR	100.000%	7,068,568	4.7.4
Remove charges related to captive insurance period from base period:							
System Allocation	924	3	(86,000)	SO	27.384%	(23,550)	4.7.1
California Allocation	924	3	(65,941)	CA	0.000%	-	4.7.1
Oregon Allocation	924	3	(117,792)	OR	100.000%	(117,792)	4.7.1
Remove entries related to the CA CEMA Reg Asset	924	1	(658,783)	SO	27.384%	(180,403)	4.7.1
Adjustment to Tax:							
ADIT - Reg Liability OR Injuries & Damages Reserve	190	3	256,699	OR	100.000%	256,699	
ADIT - Reg Liability OR Property Insurance Reserve	190	3	116,581	OR	100.000%	116,581	
ADIT - Injuries and Damages Accrual	190	3	(2,075,161)	SO	27.384%	(568,267)	

Description of Adjustment:

This adjustment uses the Commission-approved methodology from UE-217 updated for known and measurable changes for both property and liability insurance. The adjustment removes the accrual of injuries and damages and property damage from the base period and adds back the provision for property damage based a historical 10-year average and the a provision for injuries and damages based on a five-year average. Insurance premiums have been adjusted to the test period level. In addition, charges related to the captive insurance period and to the California CEMA regulatory asset have been removed from results.

PacifiCorp
Oregon General Rate Case - December 2014
Insurance Expense
Base Period Amounts to Remove

	Included in Results 12 Months Ended June 2012 Amount	Allocator	
General liability insurance premiums	1,771,168	SO	
Directors & Officers liability insurance (ends March 2012)	233,787	SO	
Provision for liability insurance to remove from base period	**2,004,955**	SO	
	Ref 4.7		
General Liability:			
Accrual for large damage claims	11,810,789	SO	
Accrual for insurance reimbursement of large damage claims	(1,071,570)	SO	
Accrual for damage claims to remove from base period	**10,739,219**	SO	
	Ref 4.7		
Commercial property insurance premiums to remove from base	**7,674,148**	SO	**Ref 4.7**
Accrual for Oregon property damages	**5,277,348**	OR	**Ref 4.7**
Charges applicable to captive period	**86,000**	SO	**Ref 4.7**
Charges applicable to captive period	**65,941**	CA	**Ref 4.7**
Charges applicable to captive period	**117,792**	OR	**Ref 4.7**
Entries related to the CEMA regulatory asset	**658,783**	CA	**Ref 4.7**

PacifiCorp
Oregon General Rate Case - December 2014
Insurance Expense
Expected Future Premium

The Company is projecting the insurance premium for Calendar Year 2014 to be at the same level as that renewed in October,2012.

	Policy Effective Date	Policy Limit	Coverage	Self-Insured Retention	Premium allocated to PacifiCorp Electric	
General Liability Insurance	10/1/12 - 10/1/13	340,000,000	All liability losses	10,000,000	**1,618,029**	**Ref 4.7**
Property Insurance	10/1/12-10/1/13	400,000,000	Property/Boiler Machinery	7,500,000	**6,423,396**	**Ref 4.7**

PacifiCorp
Oregon General Rate Case - December 2014
Insurance Expense
Provision for Injuries & Damages
5-Year Average

	Begin Bal	Accruals	Claims Paid	End Bal
2008	(6,054,192)	(8,500,333)	6,052,961	(8,501,565)
2009	(8,501,565)	(4,492,982)	5,506,675	(7,487,871)
2010	(7,487,871)	(4,815,080)	3,803,952	(8,499,000)
2011	(8,499,000)	(2,838,161)	5,869,161	(5,468,000)
2012	(5,468,000)	(40,870,138)	11,419,288	(34,918,850)
Average Accrual		12,303,339		
Oregon SO Allocation %		27.3843%		
Oregon Allocated Annual Accrual		**3,369,178**		
		Ref 4.7		

PacifiCorp
Oregon General Rate Case - December 2014
Insurance Expense
Provision for Property Damages
10-Year Average

	Actual Losses				Escalate to 2014		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses		End CPI-U Index*	% Increase	% Increase to 2014
					180.9		
Jan 2003 - Mar 2003	4,625	322,814	763,166		184.2	1.82%	131.04%
Apr 2003 - Mar 2004	17,046	4,943,627	1,181,239		187.4	1.74%	128.69%
Apr 2004 - Mar 2005	134,267	2,055,410	1,640,821		193.3	3.15%	126.49%
Apr 2005 - Mar 2006	158,670	2,639,560	938,406		199.8	3.36%	122.63%
Apr 2006 - Mar 2007	248,981	8,184,485	669,592		205.4	2.78%	118.64%
Apr 2007 - Mar 2008	1,722,233	11,252,643	1,038,168		213.5	3.98%	115.43%
Apr 2008 - Mar 2009	333,115	5,387,613	6,784,172		212.7	-0.38%	111.01%
Apr 2009 - Mar 2010	1,155,791	2,626,944	2,535,080		217.6	2.31%	111.44%
Apr 2010 - Mar 2011	546,027	5,923,626	1,905,772		223.5	2.68%	108.92%
Apr 2011 - Mar 2012	418,493	7,189,755	100,537		229.4	2.65%	106.08%
Apr 2012 - Dec 2012	327,133	5,406,075	71,553		229.6	0.09%	103.34%
2012 - 2014						3.24%	
Total	**3,774,728**	**37,413,096**	**15,550,644**				

	Actual Losses Escalated to CY 2014			
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses	Total
Jan 2003 - Mar 2003	6,061	423,009	1,000,038	
Apr 2003 - Mar 2004	21,937	6,361,977	1,520,142	
Apr 2004 - Mar 2005	169,838	2,599,950	2,075,524	
Apr 2005 - Mar 2006	194,580	3,236,948	1,150,787	
Apr 2006 - Mar 2007	295,397	9,710,284	794,421	
Apr 2007 - Mar 2008	1,988,058	12,989,477	1,198,408	
Apr 2008 - Mar 2009	369,807	5,981,053	7,531,441	
Apr 2009 - Mar 2010	1,288,040	2,927,527	2,825,152	
Apr 2010 - Mar 2011	594,743	6,452,128	2,075,804	
Apr 2011 - Mar 2012	443,926	7,626,702	106,647	
Apr 2012 - Dec 2012	338,051	5,586,500	73,941	
Total in 2014 $	5,710,438.37	63,895,554.99	20,352,304.99	
10 Year Average	571,043.84	6,389,555.50	2,035,230.50	
Oregon Allocation Factor	SG	Situs	SG	
Oregon Allocation %	26.053%	100.000%	26.053%	
Oregon Allocated 10 Year Average	**148,774**	**6,389,555**	**530,239**	**7,068,568** Ref. 7.4

PacifiCorp
Oregon General Rate Case - December 2014
Generation Overhaul Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Generation Overhaul Expense - Other	553	1	2,198,934	SG	26.053%	572,888	4.8.1
Generation Overhaul Expense - Steam	510	1	(6,949,420)	SG	26.053%	(1,810,533)	4.8.1
Generation Overhaul Expense - Cholla	510	1	(26,313)	SG	26.053%	(6,855)	4.8.1
			(4,776,799)			(1,244,500)	

Description of Adjustment:

This adjustment normalizes generation overhaul expenses in the 12 months ended June 2012 using a four-year average methodology as used in UE-246. In this adjustment overhaul expenses from July 2009 to June 2011 are restated to constant dollars to make them comparable prior to averaging. The actual overhaul costs for the 12 months ended June 2012 are subtracted from the four-year average which results in this adjustment.

PacifiCorp
Oregon General Rate Case - December 2014
Generation Overhaul Expense

FUNCTION: OTHER

Period	Overhaul Expense	Restate to Constant Dollars	Escalated Expense	
12 Months Ended June 2009	9,173,855	6.87%	9,804,191	
12 Months Ended June 2010	4,952,014	5.45%	5,221,914	
12 Months Ended June 2011	6,441,835	2.92%	6,629,888	
12 Months Ended June 2012	4,286,752		4,286,752	
4 Year Average	6,213,614		6,485,686	
12 Months Ended June 2012 Overhaul Expense - Other			4,286,752	**Ref 4.8.2**
Total 4 Year Average - Other			6,485,686	
Adjustment			**2,198,934**	**Ref 4.8**

FUNCTION: STEAM

Period	Overhaul Expense	Restate to Constant Dollars	Escalated Expense	
12 Months Ended June 2009	29,068,705	7.70%	31,306,868	
12 Months Ended June 2010	28,397,796	6.76%	30,317,522	
12 Months Ended June 2011	27,608,156	3.44%	28,558,150	
12 Months Ended June 2012	39,326,740		39,326,740	
4 Year Average	31,100,349		32,377,320	
12 Months Ended June 2012 Overhaul Expense - Steam			39,326,740	**Ref 4.8.2**
Total 4 Year Average - Steam			32,377,320	
Adjustment			**(6,949,420)**	**Ref 4.8**

Cholla

Period	Overhaul Expense	Restate to Constant Dollars	Escalated Expense	
12 Months Ended June 2009	(635,000)	7.70%	(683,892)	
12 Months Ended June 2010	542,000	6.76%	578,640	
12 Months Ended June 2011	-	3.44%	-	
12 Months Ended June 2012	-		-	
4 Year Average	(23,250)		(26,313)	
12 Months Ended June 2012 Overhaul Expense - Cholla			**-**	**Ref 4.8.2**
Total 4 Year Average - Cholla			(26,313)	
Adjustment			**(26,313)**	**Ref 4.8**

PacifiCorp
Oregon General Rate Case - December 2014
Generation Overhaul Expense

Existing Units

	12 Months Ended June 2009	12 Months Ended June 2010	12 Months Ended June 2011	12 Months Ended June 2012	
Steam					
Blundell	490,791	146,606	72,000	703,000	
BlundellIGC	-	-	-	-	
Carbon	1,692,506	(37,187)	715,000	-	
DaveJohnston	11,415,596	9,056,000	(1,116,000)	4,671,000	
Gadsby	1,105,000	3,225,000	36,000	2,328,000	
Hunter	(25,000)	8,946,180	5,052,010	7,938,700	
Huntington	769,000	967,000	6,284,000	6,436,000	
JimBridger	4,969,000	5,056,000	5,050,000	4,932,000	
Naughton	6,860,813	(4,803)	2,108,146	10,864,040	
Wyodak	-	-	5,657,000	(258,000)	
Colstrip	1,156,000	-	851,000	100,000	
Craig	235,000	948,000	2,467,000	715,000	
Hayden	400,000	95,000	432,000	897,000	
Total - Steam	29,068,705	28,397,796	27,608,156	**39,326,740**	**Ref 4.8.1**
Cholla	(635,000)	542,000	-	-	**Ref 4.8.1**
Other					
Hermiston	2,923,000	638,000	2,067,000	3,744,000	
Camas	-	500,000	6,000	-	
Currant Creek	3,964,775	2,444,976	323,915	151,610	
LakeSide	554,080	1,220,644	4,022,957	391,142	
Chehalis	1,732,000	148,395	21,964	-	
Total - Other	9,173,855	4,952,014	6,441,835	**4,286,752**	**Ref 4.8.1**
Grand Total	37,607,560	33,891,810	34,049,991	43,613,492	

PacifiCorp
Oregon General Rate Case - December 2014
Generation Overhaul Expense

Escalation Rates: OTHER*	**June09**	**June10**	**June11**	**June12**
Escalation Rate to June 2012	6.87%	5.45%	2.92%	

Escalation Rates: STEAM*	**June09**	**June10**	**June11**	**June12**
Escalation Rate to June 2012	7.70%	6.76%	3.44%	

*Rates developed using Global Insight Escalation Indicies

PacifiCorp
Oregon General Rate Case - December 2014
Incremental O&M

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Coal Fired Generation	512	3	16,464,814	SG	26.053%	4,289,578	4.9.1
Hydro - West	535	3	2,667,699	SG-P	26.053%	695,016	4.9.1
Hydro - East	535	3	463,915	SG-U	26.053%	120,864	4.9.1
Wind Generation	549	3	(2,186,790)	SG-W	26.053%	(569,725)	4.9.1
Transmission	571	3	(2,758,173)	SG	26.053%	(718,587)	4.9.2
Distribution	593	3	4,511,504	OR	100.000%	4,511,504	4.9.2
			19,162,968			8,328,650	

Description of Adjustment:

This adjustment modifies incremental O&M expense for the 12 months ended June 2012 period to the projected O&M level for the 12 months ending December 2014, after accounting for inflation escalation applied in adjustment 4.12. See also direct testimony of Company witnesses Mr. Tallman and Mr. Ralston.

PacifiCorp
Oregon General Rate Case - December 2014
Incremental O&M
Non-Labor O&M

	12 Months Ended June 2012 Actuals (A)	12 Months Ending Dec 2014 Forecast (B)	Increase to Test Period (C = B - A)	Inflation* (D)	Adjustment (E = C - D)	
Coal Fired Generation						
Carbon	4,575,903	4,816,355	240,452	192,720	47,732	
Dave Johnston	16,933,294	17,134,663	201,369	713,168	(511,800)	
Hunter	24,160,211	29,864,444	5,704,233	1,017,540	4,686,693	
Huntington	14,141,270	19,258,268	5,116,998	595,579	4,521,420	
Jim Bridger	19,943,484	24,290,240	4,346,757	839,946	3,506,810	
Naughton	13,229,987	17,573,287	4,343,300	557,199	3,786,101	
Wyodak	6,368,588	7,064,668	696,079	268,222	427,858	
	99,352,738	120,001,925	20,649,187	4,184,373	**16,464,814**	**Ref 4.9**
Hydro Generation						
East						
Reduction to Grace Flowline Maint	-	351,852	351,852	-	351,852	
West						
Lewis River Hatchery	2,491,613	2,607,020	115,407	81,895	33,512	
Lewis River Implementation	802,031	2,640,877	1,838,845	26,361	1,812,484	
North Umpqua Implementation	796,744	908,700	111,955	26,188	85,768	
					1,931,763	
System Hydro: Split East 13.2%, West 86.8%						
FERC Land Use Fee	182,725	744,863	562,138	6,006	556,132	
FERC Admin Fees	2,438,119	2,633,477	195,358	80,137	115,221	
NERC-CIPS Contract Services	102,764	68,177	(34,587)	3,378	(37,965)	
LR Recreation Services	419,271	440,609	21,338	13,781	7,557	
Other Regulatory fees	640,559	706,396	65,837	21,054	44,783	
Training	69,122	127,536	58,414	2,272	56,142	
Hydro North/LR Forest Mgmt	395,718	356,150	(39,568)	13,007	(52,574)	
Hydro Dam Safety & Surveys	417,157	571,876	154,719	13,711	141,008	
Generator Cleaning	207,000	217,755	10,755	6,804	3,952	
Hydro General WECC Generator Test	3,442	17,299	13,857	113	13,744	
					847,999	
				East Hydro Generation	351,852	
				System Hydro Generation @ 13.2% share for East	112,063	
				Total Hydro Generation Adjustment - East	**463,915**	**Ref 4.9**
				West Hydro Generation	1,931,763	
				System Hydro Generation @ 86.8% share for West	735,936	
				Total Hydro Generation Adjustment - West	**2,667,699**	**Ref 4.9**
	8,966,264	12,392,585	3,426,320	294,707	3,131,614	
Wind Generation						
Materials	1,843,172	6,400,573	4,557,401	125,960	4,431,441	
Third Party Contracts	18,393,768	12,913,922	(5,479,846)	1,257,006	(6,736,851)	
Other	4,058,061	4,107,643	49,582	277,323	(227,741)	
	24,295,001	23,422,138	**(872,863)** **Ref 4.9.3**	1,660,288	(2,533,151)	
Oil Change**						
Wind Plant Oil Changes	1,092,925	1,513,975	421,050	74,689	346,361	
	25,387,926	24,936,113	(451,813)	1,734,977	**(2,186,790)**	**Ref 4.9**
Total	133,706,928	157,330,623	23,623,695	6,214,057	17,409,637	

** Inflation is included in Adjustment 4.12*
The escalation factors used above are an average based on operations and maintenance FERC account balances at June 2012.

Steam average:	*4.212%*
Other average:	*6.834%*
Hydro average:	*3.287%*

*** The 12 Months Ending Dec 2014 forecast amount for the oil changes is based on a 3 year average.*
Reference Mr. Tallman's Confidental Exhibit xxxx

PacifiCorp
Oregon General Rate Case - December 2014
Incremental O&M
Vegetation Management

	12 Months Ended June 2012 Actuals (A)	12 Months Ending Dec 2014 Forecast (B)	Increase to Test Period (C = B - A)	Inflation* (D)	Adjustment (E = C - D)	
Distribution						
Oregon	15,099,856	20,000,594	4,900,738	389,234	**4,511,504**	**Ref 4.9**
Transmission	11,406,349	9,010,645	(2,395,704)	362,469	**(2,758,173)**	**Ref 4.9**
Vegetation Management Total	26,506,205	29,011,239	2,505,034	751,703	1,753,331	
Adjustment Total	160,213,133	186,341,862	26,128,729	6,965,760	**19,162,968**	**Ref 4.9**

** Inflation is included in Adjustment 4.12*
The distribution and transmission maintenance escalation factors are used above.

Distribution:	*2.58%*
Transmission:	*3.18%*

PacifiCorp
Oregon General Rate Case - December 2014
Incremental O&M

Wind Generation Increase Detail by Plant

	Wind Administration	Dunlap	Seven Mile I & II	High Plains & McFadden Ridge	Foote Creek	Glenrock I & III	Goodnoe Hills	Leaning Juniper	Marengo I & II	Total
Materials	4,509	699,319	598,841	639,674	1,417	623,978	653,200	(118,266)	1,454,728	4,557,401
Third Party Contracts	(79,074)	(713,939)	334,334	(597,582)	634,630	(391,338)	(164,465)	54,070	(4,556,481)	(5,479,846)
Other	47,761	311	(62,668)	(128,986)	(8,614)	4,931	(9,326)	157,194	48,978	49,582
Total	(26,804)	(14,309)	870,507	(86,894)	627,433	237,571	479,409	92,999	(3,052,774)	**(872,863)**
										Ref 4.9.1

PacifiCorp
Oregon General Rate Case - December 2014
Naughton Unit 3 Write Off

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Naughton U3 Write Off	557	1	(2,655,540)	SG	26.053%	(691,848)	4.10.1

Description of Adjustment:

This adjustment removes the Naughton 3 write-off that occurred in June 2012.

PacifiCorp
Oregon General Rate Case - December 2014
Naughton Unit 3 Write Off

Year	Period	Document Number	FERC Account	Location	Text	Factor	Amount
2012	006	139920517	5570000	000001	Clear Write-Off Asset Generation SNAU/2009/C/071	SG	628,888
2012	006	140442743	5570000	000001	Clear Write-Off Asset Gener SNAU/2009/C/071	SG	2,043,914
2012	006	140442743	5570000	000001	Clear Write-Off Asset Gener SNAU/2009/C/071	SG	(17,262)
							2,655,540
							Ref. 4.10

PacifiCorp
Oregon General Rate Case - December 2014
Memberships and Subscriptions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Total Memberships and Subscriptions in Account 930.2							
	930	1	(5,624,485)	SO	27.384%	(1,540,223)	
	930	1	(41,221)	OR	100.000%	(41,221)	
Total			(5,665,706)			(1,581,444)	4.11.1
Add Back 75% of National & Regional Memberships							
Various	930	1	1,719,173	SO	27.384%	470,783	4.11.1
OR Situs Memberships	930	1	24,203	OR	100.000%	24,203	4.11.1
Total			1,743,376			494,986	
Add Back 100% of Mandated Memberships							
WECC	930	1	3,168,466	SO	27.384%	867,661	4.11.1

Description of Adjustment:

This adjustment removes expenses in excess of Commission policy allowances as stated in the Commission order UE-94. National and regional trade organizations are recognized at 75%. Western Electricity Coordinating Council dues are included at 100% since it is a mandated membership.

Account	Factor	Description	Amount	
Remove Total Memberships and Subscriptions in Account 930.2				
930.2	SO	Included in Unadjusted Results	(5,624,485)	
930.2	OR	Included in Unadjusted Results	(41,221)	
			(5,665,706)	Ref 4.11
Allowed National and Regional Trade Memberships at 75%				
930.2	SO	ALTRUSA INTERNATIONAL INC	95	
930.2	SO	Associated Oregon Industries	28,000	
930.2	SO	Associated Taxpayers of Idaho Inc	850	
930.2	SO	Association for Computer Operations Management	600	
930.2	SO	Association of Idaho Cities	300	
930.2	SO	ASSOCIATION OF OREGON COUNTIES	500	
930.2	SO	Association of Washington Cities	1,000	
930.2	SO	ASTORIA AREA CHAMBER OF COMMERCE	465	
930.2	SO	BEAR RIVER VALLEY CHAMBER OF	350	
930.2	SO	BRIGHAM CITY AREA CHAMBER	296	
930.2	SO	BROWNSVILLE CHAMBER OF COMMERCE	90	
930.2	SO	CALIFORNIA ASSOC FOR LOCAL	785	
930.2	SO	CANNON BEACH CHAMBER OF COMMERCE	290	
930.2	SO	CENTRAL LIONS CLUB	36	
930.2	SO	CFA INSTITUTE	350	
930.2	SO	CHAMBER OF COMMERCE - CITY OF ROGUE	59	
930.2	SO	CITY CLUB OF IDAHO FALLS	50	
930.2	SO	Columbia Corridor Assn	3,000	
930.2	SO	Consortium for Energy Efficiency	17,516	
930.2	SO	CRESCENT CITY - DEL NORTE COUNTY	495	
930.2	SO	DATA ADMINISTRATION MGMT ASSOC	1,400	
930.2	SO	DAYTON CHAMBER OF COMMERCE, DAYTON WA	-	
930.2	SO	DOUGLAS ROTARY CLUB	130	
930.2	SO	DRAPER AREA CHAMBER OF COMMERCE	860	
930.2	SO	EAGLE POINT CHAMBER OF COMMERCE	50	
930.2	SO	Edison Electric Institute	658,741	
930.2	SO	Electric Power Research Institute	347,419	
930.2	SO	FOUR COUNTY ECO DEVELOPMENT CORP	12,500	
930.2	SO	GRANGER CHAMBER OF COMMERCE	225	
930.2	SO	GRANTS PASS TOWNE CENTER	150	
930.2	SO	GREATER GATEWAY BOOSTERS	100	
930.2	SO	GREATER PRESTON BUSINESS ASSOC	200	
930.2	SO	GREATER WAPATO AREA CHAMBER	250	
930.2	SO	Idaho Association of Counties	350	
930.2	SO	IESNA	500	
930.2	SO	INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS	311	
930.2	SO	Intermountain Electrical Assoc	9,000	
930.2	SO	KLAMATH COUNTY CHAMBER OF COMMERCE	715	
930.2	SO	KLAMATH FOREST PROTECTION ASSOC	39	
930.2	SO	LEAGUE OF OREGON CITIES	1,000	
930.2	SO	LINCOLN CITY CHAMBER OF COMMERCE	790	
930.2	SO	MID-WILLAMETTE VALLEY COORDINATING	52	
930.2	SO	Montana Tax Foundation Inc	1,050	
930.2	SO	MT SHASTA CHAMBER OF COMMERCE	165	
930.2	SO	NATIONAL ARBOR DAY FOUNDATION	-	
930.2	SO	National Automated Clearing House	4,500	
930.2	SO	NATIONAL COAL TRANSPORTATION ASSOC	1,250	
930.2	SO	National Electric Energy Testing Research and Application Center	71,250	
930.2	SO	NATIONAL EXCHANGE CLUB	41	
930.2	SO	National Joint Utilities	9,000	
930.2	SO	North American Electric Reliability Council	670,097	
930.2	SO	North American Transmission Forum	38,628	
930.2	SO	NORTH SANTIAM CHAMBER OF COMMERCE	1,015	
930.2	SO	Northern Tier Transmission Group	109,142	
930.2	SO	Northwest Energy Efficiency Council	2,000	
930.2	SO	Oregon Business Associations	12,250	
930.2	SO	Oregon Business Council	31,183	
930.2	SO	Oregon Rural Electric Cooperative	750	
930.2	SO	OREGON SOLAR ENERGY INDSTRS ASSOC	2,000	
930.2	SO	OREGON SPORTS AUTHORITY	5,000	
930.2	SO	OSWILG	90	
930.2	SO	Pacific NW Utilities Conference	70,075	
930.2	SO	PARK CITY CHAMBER BUREAU	229	
930.2	SO	PHILOMATH AREA CHAMBER OF COMMERCE	125	
930.2	SO	POMEROY CHAMBER OF COMMERCE	150	
930.2	SO	Portland Business Alliance	49,400	
930.2	SO	POWELL VALLEY CHAMBER OF	750	
930.2	SO	Project Management Institute	144	
930.2	SO	Project Management Professional	60	
930.2	SO	ROBERT SNIPPEN	40	
930.2	SO	Rocky Mountain Electrical League	18,000	
930.2	SO	ROTARY CLUB OF CASPER	409	
930.2	SO	ROTARY CLUB OF CEDAR CITY	528	
930.2	SO	ROTARY CLUB OF GRANTS PASS	200	
930.2	SO	ROTARY CLUB OF GREATER MEDFORD	530	
930.2	SO	ROTARY CLUB OF SUTHERLIN	220	
930.2	SO	SALINA CHAMBER OF COMMERCE	50	
930.2	SO	SE WASHINGTON ECONOMIC	1,500	
930.2	SO	Society for Human Resource Management	180	
930.2	SO	SOUTH COAST DEVELOPMENT	7,500	
930.2	SO	SOUTH JORDAN CHAMBER	300	
930.2	SO	Southern Oregon Timber Industries	260	
930.2	SO	The Information Systems Audit and Control Association	200	
930.2	SO	THE ROTARY CLUB OF POWELL	500	
930.2	SO	UTAH ALLIANCE FOR ECONOMIC	1,000	
930.2	SO	Utah Community Forest Council	(500)	
930.2	SO	Utah Foundation	6,650	
930.2	SO	UTAH HISPANIC CHAMBER OF COMMERCE	2,500	
930.2	SO	Utah Manufacturers Association	6,000	
930.2	SO	Utah Taxpayers Association	14,000	
930.2	SO	Utah Water Users' Assn	500	
930.2	SO	VERNAL AREA CHAMBER OF COMMERCE	490	
930.2	SO	Walla Walla Area Utilities Coord	100	
930.2	SO	WALLA WALLA SUNRISE ROTARY	(364)	
930.2	SO	WALLA WALLA SUNRISE ROTARY CLUB	500	
930.2	SO	WASHINGTON COUNTY	1,200	
930.2	SO	Washington Pulp & Paper Foundation	2,160	
930.2	SO	Washington Research Council	2,000	
930.2	SO	Western Energy Institute	42,977	
930.2	SO	Western Lampac	2,000	
930.2	SO	WORLDATWORK	245	
930.2	SO	Wyoming Assoc of Municipalities	325	
930.2	SO	WYOMING INFRASTRUCTURE AUTHORITY WINTER BOARD MEETING	350	
930.2	SO	Wyoming Taxpayers Association	9,427	
		Total of Memberships Above	2,292,230	
		75% of Memberships Above	1,719,173	Ref 4.11
930.2	OR	Albany Chamber	26	
930.2	OR	CITY OF INDEPENDENCE	525	
930.2	OR	CLATSOP ECONOMIC DEVELOPMENT	5,000	
930.2	OR	COTTAGE GROVE COMMUNITY DEVELOPMENT CORPORATION	2,500	
930.2	OR	East Linn Utilities Coordinating	125	
930.2	OR	GRANTS PASS JOSEPHINE COUNTY	1,250	
930.2	OR	Lane Utilities Coordinating Council	100	
930.2	OR	Linn-Benton Utilities	175	
930.2	OR	M&H ECONOMIC CONSULTANTS	1,200	
930.2	OR	Medford Rough Rotary	100	
930.2	OR	NONPROFIT ASSOCIATION OF OREGON	2,500	
930.2	OR	OUS SOUTHERN OREGON UNIVERSITY, ASHLAND OR	500	
930.2	OR	Portland Executives Assn	1,200	
930.2	OR	Rough River U Club	70	
930.2	OR	SOUTHERN OREGON REGIONAL ECONOMIC DEVELOPMENT INC	6,500	
930.2	OR	STATE OF OREGON	10,000	
930.2	OR	UMPQUA COMMUNITY COLLEGE, ROSEBURG OR	500	
			32,271	
		75% of OR Situs Memberships	24,203	Ref 4.11
Mandated Membership Fees at 100%				
930.2	SO	Western Electricity Coordinating Council	3,168,466	Ref 4.11
		Total Memberships and Subscriptions Allowed	4,911,842	

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	128,931	SG	26.053%	33,590	
Steam Operations	500	3	96,389	SG	26.053%	25,112	
Steam Operations	501	3	652,584	SE	24.687%	161,102	
Steam Operations	501	3	152,005	SE	24.687%	37,525	
Steam Operations	502	3	660,770	SG	26.053%	172,151	
Steam Operations	502	3	415,804	SG	26.053%	108,329	
Steam Operations	503	3	(4,713)	SE	24.687%	(1,163)	
Steam Operations	505	3	62,689	SG	26.053%	16,332	
Steam Operations	505	3	47,328	SG	26.053%	12,330	
Steam Operations	506	3	477,058	SG	26.053%	124,288	
Steam Operations	506	3	85,136	SG	26.053%	22,180	
Steam Operations	507	3	15,568	SG	26.053%	4,056	
Steam Maintenance	510	3	(199,885)	SG	26.053%	(52,076)	
Steam Maintenance	510	3	78,080	SG	26.053%	20,342	
Steam Maintenance	511	3	645,503	SG	26.053%	168,173	
Steam Maintenance	511	3	33,362	SG	26.053%	8,692	
Steam Maintenance	512	3	3,119,486	SG	26.053%	812,720	
Steam Maintenance	512	3	211,127	SG	26.053%	55,005	
Steam Maintenance	513	3	1,038,196	SG	26.053%	270,481	
Steam Maintenance	513	3	23,705	SG	26.053%	6,176	
Steam Maintenance	514	3	291,185	SG	26.053%	75,862	
Steam Maintenance	514	3	91,971	SG	26.053%	23,961	
Hydro Operations	535	3	69,968	SG-P	26.053%	18,229	
Hydro Operations	535	3	(63,792)	SG-U	26.053%	(16,620)	
Hydro Operations	536	3	4,336	SG-P	26.053%	1,130	
Hydro Operations	537	3	91,592	SG-P	26.053%	23,862	
Hydro Operations	537	3	6,922	SG-U	26.053%	1,803	
Hydro Operations	539	3	280,674	SG-P	26.053%	73,124	
Hydro Operations	539	3	72,437	SG-U	26.053%	18,872	
Hydro Operations	540	3	3,234	SG-P	26.053%	843	
Hydro Operations	540	3	1,024	SG-U	26.053%	267	
Hydro Maintenance	541	3	16	SG-P	26.053%	4	
Hydro Maintenance	542	3	20,397	SG-P	26.053%	5,314	
Hydro Maintenance	542	3	2,681	SG-U	26.053%	698	
Hydro Maintenance	543	3	50,677	SG-P	26.053%	13,203	
Hydro Maintenance	543	3	8,481	SG-U	26.053%	2,209	
Hydro Maintenance	544	3	35,696	SG-P	26.053%	9,300	
Hydro Maintenance	544	3	5,843	SG-U	26.053%	1,522	
Hydro Maintenance	545	3	54,434	SG-P	26.053%	14,182	
Hydro Maintenance	545	3	22,211	SG-U	26.053%	5,787	
Other Operations	546	3	35,286	SG	26.053%	9,193	
Other Operations	548	3	871,425	SG	26.053%	227,032	
Other Operations	548	3	33,847	SG	26.053%	8,818	
Other Operations	549	3	823,621	SG	26.053%	214,578	
Other Operations	550	3	315,537	SG	26.053%	82,207	

Description of Adjustment:

Consistent with the Company's two previous rate cases, UE-217 and UE-246, this adjustment calculates the non-labor O&M escalation from June 2012 to December 2014 for accounts 500 to 935, excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2012 actual data was separated into labor and non-labor components and costs that should not be included in June 2012 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Maintenance	552	3	48,902	SG	26.053%	12,740	
Other Maintenance	552	3	1,646	SG	26.053%	429	
Other Maintenance	553	3	559,050	SG	26.053%	145,649	
Other Maintenance	553	3	34,393	SG	26.053%	8,960	
Other Maintenance	554	3	161,485	SG	26.053%	42,072	
Other Maintenance	554	3	6,999	SG	26.053%	1,824	
Other Operations	556	3	59,509	SG	26.053%	15,504	
Other Operations	557	3	687,737	Situs	100.000%	(4,003)	
Other Operations	557	3	1,506,968	SG	26.053%	392,610	
Other Operations	557	3	(8,247)	SE	24.687%	(2,036)	
Other Operations	557	3	83,492	SGCT	26.141%	21,825	
Transmission Operations	560	3	(28,894)	SG	26.053%	(7,528)	
Transmission Operations	561	3	53,956	SG	26.053%	14,057	
Transmission Operations	562	3	106,851	SG	26.053%	27,838	
Transmission Operations	563	3	15,715	SG	26.053%	4,094	
Transmission Operations	566	3	129,183	SG	26.053%	33,656	
Transmission Operations	567	3	130,777	SG	26.053%	34,071	
Transmission Maintenance	568	3	11,145	SG	26.053%	2,904	
Transmission Maintenance	569	3	76,712	SG	26.053%	19,986	
Transmission Maintenance	570	3	126,931	SG	26.053%	33,069	
Transmission Maintenance	571	3	784,831	SG	26.053%	204,472	
Transmission Maintenance	572	3	1,568	SG	26.053%	408	
Transmission Maintenance	573	3	53,818	SG	26.053%	14,021	
Distribution Operations	580	3	8,965	Situs	100.000%	899	
Distribution Operations	580	3	(18,766)	SNPD	26.872%	(5,043)	
Distribution Operations	581	3	5	Situs	100.000%	5	
Distribution Operations	581	3	20,817	SNPD	26.872%	5,594	
Distribution Operations	582	3	113,626	Situs	100.000%	32,693	
Distribution Operations	582	3	459	SNPD	26.872%	123	
Distribution Operations	583	3	54,650	Situs	100.000%	23,085	
Distribution Operations	583	3	194	SNPD	26.872%	52	
Distribution Operations	584	3	7	Situs	100.000%	-	
Distribution Operations	584	3	54	SNPD	26.872%	15	
Distribution Operations	585	3	(665)	SNPD	26.872%	(179)	
Distribution Operations	586	3	63,892	Situs	100.000%	31,037	
Distribution Operations	586	3	14,316	SNPD	26.872%	3,847	
Distribution Operations	587	3	124,431	Situs	100.000%	40,611	
Distribution Operations	588	3	42,498	Situs	100.000%	15,243	
Distribution Operations	588	3	(3,790)	SNPD	26.872%	(1,018)	
Distribution Operations	589	3	144,869	Situs	100.000%	85,087	
Distribution Operations	589	3	2,531	SNPD	26.872%	680	
Distribution Maintenance	590	3	4,215	Situs	100.000%	1,533	
Distribution Maintenance	590	3	(10,484)	SNPD	26.872%	(2,817)	
Distribution Maintenance	591	3	53,474	Situs	100.000%	23,776	
Distribution Maintenance	591	3	3,736	SNPD	26.872%	1,004	
Distribution Maintenance	592	3	126,616	Situs	100.000%	46,124	
Distribution Maintenance	592	3	(1,592)	SNPD	26.872%	(428)	
Distribution Maintenance	593	3	1,767,817	Situs	100.000%	552,465	

Description of Adjustment:

Consistent with the Company's two previous rate cases, UE-217 and UE-246, this adjustment calculates the non-labor O&M escalation from June 2012 to December 2014 for accounts 500 to 935, excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2012 actual data was separated into labor and non-labor components and costs that should not be included in June 2012 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

PacifiCorp
Oregon General Rate Case - December 2014
(cont. 2) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution Maintenance	593	3	22,680	SNPD	26.872%	6,094	
Distribution Maintenance	594	3	210,407	Situs	100.000%	51,984	
Distribution Maintenance	594	3	59	SNPD	26.872%	16	
Distribution Maintenance	595	3	5,301	SNPD	26.872%	1,424	
Distribution Maintenance	596	3	51,025	Situs	100.000%	7,267	
Distribution Maintenance	597	3	24,941	Situs	100.000%	5,741	
Distribution Maintenance	597	3	4,841	SNPD	26.872%	1,301	
Distribution Maintenance	598	3	64,701	Situs	100.000%	10,785	
Distribution Maintenance	598	3	(44,405)	SNPD	26.872%	(11,932)	
Customer Accounts Operations	901	3	(6)	Situs	100.000%	1	
Customer Accounts Operations	901	3	22,000	CN	30.325%	6,671	
Customer Accounts Operations	902	3	138,713	Situs	100.000%	65,293	
Customer Accounts Operations	902	3	19,166	CN	30.325%	5,812	
Customer Accounts Operations	903	3	112,022	Situs	100.000%	31,717	
Customer Accounts Operations	903	3	679,141	CN	30.325%	205,950	
Customer Accounts Operations	904	3	658,238	Situs	100.000%	310,208	
Customer Accounts Operations	904	3	12,100	CN	30.325%	3,669	
Customer Accounts Operations	905	3	275	Situs	100.000%	275	
Customer Accounts Operations	905	3	4,108	CN	30.325%	1,246	
Customer Service Operations	907	3	1,021	CN	30.325%	310	
Customer Service Operations	908	3	52,909	Situs	100.000%	1,930	
Customer Service Operations	908	3	(4,546)	CN	30.325%	(1,379)	
Customer Service Operations	908	3	165,762	OTHER	0.000%	-	
Customer Service Operations	909	3	59,879	Situs	100.000%	24,092	
Customer Service Operations	909	3	103,150	CN	30.325%	31,281	
Customer Service Operations	910	3	4,634	CN	30.325%	1,405	
A&G Operations	920	3	(356,104)	Situs	100.000%	(60,145)	
A&G Operations	920	3	(158,434)	SO	27.384%	(43,386)	
A&G Operations	921	3	3,626	CN	30.325%	1,100	
A&G Operations	921	3	12,782	Situs	100.000%	3,041	
A&G Operations	921	3	461,507	SO	27.384%	126,380	
A&G Operations	922	3	(3,528,263)	SO	27.384%	(966,189)	
A&G Operations	923	3	16,994	Situs	100.000%	7,103	
A&G Operations	923	3	350,794	SO	27.384%	96,062	
A&G Operations	928	3	802,723	Situs	100.000%	226,972	
A&G Operations	928	3	213,653	SG	26.053%	55,663	
A&G Operations	928	3	120,039	SO	27.384%	32,872	
A&G Operations	929	3	(503,420)	SO	27.384%	(137,858)	
A&G Operations	930	3	9,187	Situs	100.000%	1,202	
A&G Operations	930	3	71	SG	26.053%	19	
A&G Operations	930	3	524,719	SO	27.384%	143,690	
A&G Operations	931	3	142,158	Situs	100.000%	135,203	
A&G Operations	931	3	686,942	SO	27.384%	188,114	
A&G Operations	935	3	9,525	Situs	100.000%	3,546	
A&G Operations	935	3	493	CN	30.325%	150	
A&G Operations	935	3	464,265	SO	27.384%	127,136	
Total			19,626,600			5,393,577	4.12.6

Description of Adjustment:

Consistent with the Company's two previous rate cases, UE-217 and UE-246, this adjustment calculates the non-labor O&M escalation from June 2012 to December 2014 for accounts 500 to 935, excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2012 actual data was separated into labor and non-labor components and costs that should not be included in June 2012 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

PacifiCorp
Oregon General Rate Case - December 2014
O&M Expense Escalation
12 Months Ending December 2014

Function	Allocation Code	Jun 2012 Unadjusted O&M	3.2 Wheeling Revenue	4.1 Miscellaneous General Expense	4.2 Remove Unadjusted Labor	4.3 Idaho Irrigation Load Control Program	4.4 Remove Non-Recurring Entries	4.6 DSM Revenue and Expense Removal	4.7 Insurance Expense	4.8 Generation Overhaul Expense	4.10 Naughton Unit 3 Write Off	4.11 Memberships and Subscriptions	5.1 Net Power Cost Study	5.4 BPA Residential Exchange	8.9 Regulatory Asset Amortization	8.11 Misc Asset Sales and Removals
Steam Operation																
	NPCSE	646,945,843	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCSSECH	53,938,291	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCID	178,300	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCWYP	480,935	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SE	16,121,513	-	-	(2,237,016)	-	-	-	-	-	-	-	-	-	-	-
	SG	106,811,369	-	-	(77,986,394)	-	-	-	-	-	-	-	-	-	-	-
	SSECH	3,257,603	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SSGCH	13,815,600	-	-	6	-	-	-	-	-	-	-	-	-	-	-
	Steam Operation Total	841,549,452	-	-	(80,223,404)	-	-	-	-	-	-	-	-	-	-	-
Steam Maintenance																
	SG	181,237,666	-	-	(48,172,475)	-	-	-	-	(6,949,420)	-	-	-	-	-	-
	SSGCH	11,194,808	-	-	123,750	-	-	-	-	(26,313)	-	-	-	-	-	-
	Steam Maintenance Total	192,432,475	-	-	(48,048,726)	-	-	-	-	(6,975,733)	-	-	-	-	-	-
Hydro Operations																
	SG-P	23,305,940	-	-	(8,517,444)	-	-	-	-	-	-	-	-	-	-	(77,947)
	SG-U	6,479,087	-	-	(5,903,892)	-	-	-	-	-	-	-	-	-	-	(32,582)
	Hydro Operations Total	29,785,027	-	-	(14,421,337)	-	-	-	-	-	-	-	-	-	-	(110,528)
Hydro Maintenance																
	SG-P	6,672,086	-	-	(2,711,364)	-	-	-	-	-	-	-	-	-	-	-
	SG-U	2,037,251	-	-	(1,073,833)	-	-	-	-	-	-	-	-	-	-	-
	Hydro Maintenance Total	8,709,337	-	-	(3,785,197)	-	-	-	-	-	-	-	-	-	-	-
Purchased Power																
	ID	(3,223,363)	-	-	-	-	-	-	-	-	-	-	-	3,223,363	-	-
	NPCSE	(16,365,455)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCSG	501,391,831	-	-	-	-	-	-	-	-	-	-	1,226,403	-	-	-
	OR	(29,094,524)	-	-	-	-	-	-	-	-	-	-	-	29,094,524	-	-
	SG	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WA	(7,379,869)	-	-	-	-	-	-	-	-	-	-	-	7,379,869	-	-
	Purchase Power Total	445,328,620	-	-	-	-	-	-	-	-	-	-	1,226,403	39,697,756	-	-
Other Operations																
	ID	(32,973)	-	-	-	9,429,390	-	-	-	-	-	-	-	-	-	-
	NPCSE	385,597,558	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCSSECT	9,132,801	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	OR	(53,813)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SE	(4,413,675)	-	-	-	-	4,302,803	-	-	-	-	-	-	-	-	-
	SG	100,433,763	-	-	(43,626,940)	(9,429,390)	4,033,000	-	-	-	(2,655,540)	-	-	-	(38,381)	-
	SG-W	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SGCT	1,122,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SSGCT	726,180	-	-	(271,157)	-	-	-	-	-	-	-	-	-	-	-
	WA	(97,006)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other Operations Total	492,415,260	-	-	(43,898,097)	0	8,335,803	-	-	-	(2,655,540)	-	-	-	(38,381)	-
Other Maintenance																
	SG	19,591,084	-	-	(2,566,236)	-	-	-	-	2,198,934	-	-	-	-	-	-
	SG-W	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SSGCT	1,270,522	-	-	(195,246)	-	-	-	-	-	-	-	-	-	-	-
	Other Maintenance Total	20,861,606	-	-	(2,761,482)	-	-	-	-	2,198,934	-	-	-	-	-	-
Transmission Operations																
	NPCSE	9,480,873	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NPCSG	131,761,383	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SG	22,104,145	(759,938)	-	(15,112,108)	-	-	-	-	-	-	-	-	-	-	-
	Transmission Operations Total	163,346,401	(759,938)	-	(15,112,108)	-	-	-	-	-	-	-	-	-	-	-
Transmission Maintenance																
	SG	41,982,788	-	-	(8,783,448)	-	-	-	-	-	-	-	-	-	-	-
	Transmission Maintenance Total	41,982,788	-	-	(8,783,448)	-	-	-	-	-	-	-	-	-	-	-
Distribution Operations																
	CA	1,510,168	-	-	(1,086,610)	-	-	-	-	-	-	-	-	-	-	-
	ID	1,479,361	-	-	(1,029,669)	-	-	-	-	-	-	-	-	-	-	-
	OR	13,695,372	-	-	(9,289,840)	-	-	-	-	-	-	-	-	-	-	-
	SNPD	31,853,178	-	-	(31,561,277)	-	-	-	-	-	-	-	-	-	-	-
	UT	12,397,066	-	-	(8,902,699)	-	-	-	-	-	-	-	-	-	-	-
	WA	2,654,497	-	-	(2,010,525)	-	-	-	-	-	-	-	-	-	-	-
	WYP	3,058,651	-	-	(2,002,613)	-	-	-	-	-	-	-	-	-	-	-
	WYU	337,573	-	-	(157,371)	-	-	-	-	-	-	-	-	-	-	-
	Distribution Operations Total	66,985,865	-	-	(56,040,603)	-	-	-	-	-	-	-	-	-	-	-

PacifiCorp
Oregon General Rate Case - December 2014
O&M Expense Escalation
12 Months Ending December 2014

Function	Allocation Code	Jun 2012 Unadjusted O&M	3.2 Wheeling Revenue	4.1 Miscellaneous General Expense	4.2 Remove Unadjusted Labor	4.3 Idaho Irrigation Load Control Program	4.4 Remove Non-Recurring Entries	4.6 DSM Revenue and Expense Removal	4.7 Insurance Expense	4.8 Generation Overhaul Expense	4.10 Naughton Unit 3 Write Off	4.11 Memberships and Subscriptions	5.1 Net Power Cost Study	5.4 BPA Residential Exchange	8.9 Regulatory Asset Amortization	8.11 Misc Asset Sales and Removals
Distribution Maintenance																
	CA	7,269,544	-	-	(1,872,759)	-	-	-	-	-	-	-	-	-	-	-
	ID	8,179,947	-	-	(3,822,096)	-	-	-	-	-	-	-	-	-	-	-
	OR	41,474,033	-	-	(14,330,975)	-	-	-	-	-	-	-	-	-	-	-
	SNPD	8,124,946	-	-	(8,895,560)	-	-	-	-	-	-	-	-	-	-	-
	UT	55,679,031	-	-	(19,003,415)	-	-	-	-	-	-	-	-	-	-	-
	WA	6,537,560	-	-	(1,951,950)	-	-	-	-	-	-	-	-	-	-	-
	WYP	12,464,637	-	-	(2,573,919)	-	-	-	-	-	-	-	-	-	-	-
	WYU	1,886,056	-	-	(585,925)	-	-	-	-	-	-	-	-	-	-	-
Distribution Maintenance Total		141,615,756	-	-	(53,036,600)	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts Operations																
	CA	1,683,758	-	-	(903,651)	-	-	-	-	-	-	-	-	-	-	-
	CN	52,881,472	-	59,852	(36,531,376)	-	-	-	-	-	-	-	-	-	-	-
	ID	2,685,504	-	-	(1,545,469)	-	-	-	-	-	-	-	-	-	-	-
	OR	19,133,124	-	(33,927)	(9,631,298)	-	-	-	-	-	-	-	-	-	(388,671)	-
	UT	11,617,689	-	-	(6,176,219)	-	-	-	-	-	-	-	-	-	-	-
	WA	3,672,706	-	-	(1,202,130)	-	-	-	-	-	-	-	-	-	-	-
	WYP	2,684,530	-	-	(1,424,759)	-	-	-	-	-	-	-	-	-	-	-
	WYU	301,075	-	-	(213,815)	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts Operations Total		94,659,859	-	25,925	(57,628,718)	-	-	-	-	-	-	-	-	-	(388,671)	-
Customer Service Operations																
	CA	2,743,211	-	-	(57,612)	-	-	(2,208,826)	-	-	-	-	-	-	-	-
	CN	5,336,618	-	(230,911)	(2,530,938)	(3,061)	-	-	-	-	-	-	-	-	-	-
	ID	6,652,054	-	-	(485,014)	3,061	-	(5,750,257)	-	-	-	-	-	-	-	-
	OR	25,635,107	-	(8,689)	(1,776,707)	-	(47,055)	(23,160,791)	-	-	-	-	-	-	-	-
	OTHER	4,103,072	-	-	(14,268)	-	-	-	-	-	-	-	-	-	-	-
	UT	50,846,417	-	(279)	(2,540,737)	-	(49,908)	(47,542,835)	-	-	-	-	-	-	-	-
	WA	9,195,046	-	-	(453,793)	-	48,821	(8,686,670)	-	-	-	-	-	-	-	-
	WYP	5,482,042	-	-	(1,055,786)	-	-	(3,998,687)	-	-	-	-	-	-	-	-
	WYU	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service Operations Total		109,993,566	-	(239,879)	(8,914,856)	-	(48,142)	(91,348,067)	-	-	-	-	-	-	-	-
A&G Operations & Maintenance																
	920	70,829,304	-	-	(75,948,007)	-	-	-	-	-	-	-	-	-	(1,909,702)	-
	921	9,153,141	-	(53,663)	271,797	-	-	-	-	-	-	-	-	-	-	-
	922	(25,112,617)	-	-	(23,082,219)	-	-	-	-	-	-	-	-	-	-	-
	923	7,202,679	-	(723,115)	-	-	-	-	-	-	-	-	-	-	-	-
	924	16,776,778	-	-	-	-	-	-	(658,783)	-	-	-	-	-	-	-
	925	15,065,328	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	926	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	928	23,855,311	-	-	(4,161,355)	-	-	-	-	-	-	-	-	-	-	-
	929	(6,339,512)	-	5,095	695,384	-	-	-	-	-	-	-	-	-	-	-
	930	11,492,021	-	68,260	(27,094)	-	50,000	-	-	-	-	(753,865)	-	-	-	-
	931	6,735,013	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	935	22,890,959	-	-	(2,544,207)	-	-	-	-	-	-	-	-	-	-	-
A&G Operations & Maintenance Total		152,548,405	-	(703,424)	(104,795,700)	-	50,000	-	(658,783)	-	-	(753,865)	-	-	(1,909,702)	-
Grand Total		2,802,214,417	(759,938)	(917,378)	(497,450,275)	0	8,337,661	(91,348,067)	(658,783)	(4,776,799)	(2,655,540)	(753,865)	1,226,403	39,697,756	(2,336,754)	(110,528)

PacifiCorp
Oregon General Rate Case - December 2014
O&M Expense Escalation
12 Months Ending December 2014

Function	Allocation Code	8.12 - Remove Rolling Hills	O&M Before Escalation	Escalation Percentages	4.12 O&M Escalation	O&M After Escalation
Steam Operation						
	NPCSE	-	646,945,843	0.00%	-	646,945,843
	NPCSSECH	-	53,938,291	0.00%	-	53,938,291
	NPCID	-	178,300	0.00%	-	178,300
	NPCWYP	-	480,935	0.00%	-	480,935
	SE	-	13,884,497	4.67%	647,872	14,532,368
	SG	-	28,824,974	4.67%	1,345,017	30,169,991
	SSECH	-	3,257,603	4.67%	152,005	3,409,608
	SSGCH	-	13,815,606	4.67%	644,657	14,460,263
Steam Operation Total		-	761,326,048		2,789,550	764,115,598
Steam Maintenance						
	SG	-	126,115,771	3.88%	4,894,484	131,010,255
	SSGCH	-	11,292,245	3.88%	438,246	11,730,491
Steam Maintenance Total		-	137,408,015		5,332,730	142,740,746
Hydro Operations						
	SG-P	-	14,710,549	3.06%	449,804	15,160,353
	SG-U	-	542,613	3.06%	16,591	559,205
Hydro Operations Total		-	15,253,162		466,396	15,719,558
Hydro Maintenance						
	SG-P	-	3,960,722	4.07%	161,220	4,121,942
	SG-U	-	963,418	4.07%	39,216	1,002,634
Hydro Maintenance Total		-	4,924,139		200,436	5,124,575
Purchased Power						
	ID	-	-	0.00%	-	0
	NPCSE	-	(16,365,455)	0.00%	-	(16,365,455)
	NPCSG	-	502,618,233	0.00%	-	502,618,233
	OR	-	-	0.00%	-	0
	SG	-	-	0.00%	-	0
	WA	-	0	0.00%	-	0
Purchase Power Total		-	486,252,778		-	486,252,778
Other Operations						
	ID	-	9,396,416	7.44%	698,955	10,095,372
	NPCSE	-	385,597,558	0.00%	-	385,597,558
	NPCSSECT	-	9,132,801	0.00%	-	9,132,801
	OR	-	(53,813)	7.44%	(4,003)	(57,816)
	SE	-	(110,872)	7.44%	(8,247)	(119,119)
	SG	(153,882)	48,562,631	7.44%	3,612,346	52,174,977
	SG-W	-	-	7.44%	-	-
	SGCT	-	1,122,425	7.44%	83,492	1,205,917
	SSGCT	-	455,023	7.44%	33,847	488,870
	WA	-	(97,006)	7.44%	(7,216)	(104,222)
Other Operations Total		(153,882)	454,005,164		4,409,175	458,414,338
Other Maintenance						
	SG	-	19,223,783	4.00%	769,436	19,993,219
	SG-W	-	-	4.00%	-	0
	SSGCT	-	1,075,276	4.00%	43,038	1,118,314
Other Maintenance Total		-	20,299,059		812,474	21,111,533
Transmission Operations						
	NPCSE	-	9,480,873	0.00%	-	9,480,873
	NPCSG	-	131,761,383	0.00%	-	131,761,383
	SG	-	6,232,099	6.54%	407,589	6,639,688
Transmission Operations Total		-	147,474,356		407,589	147,881,945
Transmission Maintenance						
	SG	-	33,199,340	3.18%	1,055,003	34,254,343
Transmission Maintenance Total		-	33,199,340		1,055,003	34,254,343
Distribution Operations						
	CA	-	423,558	5.19%	21,984	445,541
	ID	-	449,692	5.19%	23,340	473,033
	OR	-	4,405,531	5.19%	228,661	4,634,192
	SNPD	-	291,901	5.19%	15,151	307,052
	UT	-	3,494,367	5.19%	181,369	3,675,736
	WA	-	643,972	5.19%	33,424	677,396
	WYP	-	1,056,038	5.19%	54,812	1,110,850
	WYU	-	180,203	5.19%	9,353	189,556
Distribution Operations Total		-	10,945,262		568,093	11,513,355

PacifiCorp
Oregon General Rate Case - December 2014
O&M Expense Escalation
12 Months Ending December 2014

Function	Allocation Code	8.12 - Remove Rolling Hills	O&M Before Escalation	Escalation Percentages	4.12 O&M Escalation	O&M After Escalation
Distribution Maintenance						
	CA	-	5,396,785	2.58%	139,115	5,535,899
	ID	-	4,357,851	2.58%	112,334	4,470,185
	OR	-	27,143,058	2.58%	699,675	27,842,733
	SNPD	-	(770,614)	2.58%	(19,864)	(790,479)
	UT	-	36,675,616	2.58%	945,399	37,621,015
	WA	-	4,585,610	2.58%	118,205	4,703,815
	WYP	-	9,890,718	2.58%	254,956	10,145,674
	WYU	-	1,300,131	2.58%	33,514	1,333,645
Distribution Maintenance Total		-	88,579,156		2,283,332	90,862,488
Customer Accounts Operations						
	CA	-	780,107	4.49%	35,013	815,120
	CN	-	16,409,948	4.49%	736,514	17,146,462
	ID	-	1,140,035	4.49%	51,167	1,191,202
	OR	-	9,079,228	4.49%	407,495	9,486,723
	UT	-	5,441,470	4.49%	244,225	5,685,695
	WA	-	2,470,576	4.49%	110,885	2,581,460
	WYP	-	1,259,771	4.49%	56,541	1,316,312
	WYU	-	87,259	4.49%	3,916	91,176
Customer Accounts Operations Total		-	36,668,395		1,645,756	38,314,151
Customer Service Operations						
	CA	-	476,772	4.05%	19,329	496,101
	CN	-	2,571,708	4.05%	104,258	2,675,966
	ID	-	419,844	4.05%	17,021	436,865
	OR	-	641,865	4.05%	26,022	667,887
	OTHER	-	4,088,804	4.05%	165,762	4,254,567
	UT	-	712,657	4.05%	28,891	741,548
	WA	-	103,404	4.05%	4,192	107,596
	WYP	-	427,569	4.05%	17,334	444,903
	WYU	-	-	4.05%	-	0
Customer Service Operations Total		-	9,442,622		382,809	9,825,431
A&G Operations & Maintenance						
	920	-	(7,028,404)	7.32%	(514,538)	(7,542,942)
	921	-	9,371,275	5.10%	477,914	9,849,189
	922	-	(48,194,835)	7.32%	(3,528,263)	(51,723,099)
	923	-	6,479,564	5.68%	367,788	6,847,352
	924	-	16,117,995	0.00%	-	16,117,995
	925	-	15,065,328	0.00%	-	15,065,328
	926	-	-	8.51%	-	0
	928	-	19,693,955	5.77%	1,136,415	20,830,370
	929	(1,237,510)	(6,876,543)	7.32%	(503,420)	(7,379,963)
	930	-	10,829,322	4.93%	533,977	11,363,300
	931	-	6,735,013	12.31%	829,099	7,564,113
	935	-	20,346,752	2.33%	474,283	20,821,035
A&G Operations & Maintenance Total		(1,237,510)	42,539,422		(726,743)	41,812,678
Grand Total		(1,391,392)	2,248,316,918		**19,626,600**	2,267,943,518
					Ref 4.12.2	

PacifiCorp
Oregon General Rate Case - December 2014
O&M Efficiency

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	(2,116,023)	SG	26.053%	(551,288)	
Fuel Related - Non-NPC	501	3	(60,697)	SE	24.687%	(14,984)	
Steam Maintenance	512	3	(1,303,717)	SG	26.053%	(339,658)	
Hydro Operations	535	3	(231,106)	SG-P	26.053%	(60,210)	
Hydro Operations	535	3	(160,192)	SG-U	26.053%	(41,735)	
Hydro Maintenance	545	3	(73,568)	SG-P	26.053%	(19,167)	
Hydro Maintenance	545	3	(29,137)	SG-U	26.053%	(7,591)	
Other Operations	548	3	(237,498)	SG	26.053%	(61,875)	
Other Maintenance	553	3	(74,928)	SG	26.053%	(19,521)	
Other Expenses	557	3	(953,600)	SG	26.053%	(248,441)	
Transmission Operations	560	3	(410,040)	SG	26.053%	(106,828)	
Transmission Maintenance	571	3	(238,323)	SG	26.053%	(62,090)	
Distribution Operations	580	3	(664,203)	Situs	100.000%	(252,063)	
Distribution Operations	580	3	(856,360)	SNPD	26.872%	(230,118)	
Distribution Maintenance	593	3	(1,197,689)	Situs	100.000%	(388,846)	
Distribution Maintenance	593	3	(241,365)	SNPD	26.872%	(64,859)	
Customer Accounts	903	3	(991,214)	CN	30.325%	(300,587)	
Customer Accounts	903	3	(572,439)	Situs	100.000%	(261,328)	
Customer Services	908	3	(68,673)	CN	30.325%	(20,825)	
Customer Services	908	3	(387)	OTHER	0.000%	-	
Customer Services	908	3	(172,829)	Situs	100.000%	(48,208)	
Administrative & General	920	3	(100,139)	Situs	100.000%	(20,799)	
Administrative & General	920	3	(2,674,275)	SO	27.384%	(732,330)	
Administrative & General	935	3	1,654	Situs	100.000%	264	
Administrative & General	935	3	(70,686)	SO	27.384%	(19,357)	
			(13,497,435)			(3,872,443)	4.13.1

Description of Adjustment:

The Company has implemented efficiency initiatives which have not been fully captured in the WEBA adjustment number 4.2. This adjustment reflects known and measureable changes to salary and wages for the rate effective period reducing the Company's normalized O&M. Benefits levels in adjustment number 4.2 already reflect the impact of the efficiency initiatives.

PacifiCorp
Oregon General Rate Case - December 2014
O&M Efficiency

Account	Description	Actual 12 Months Ended June 2012	Pro Forma 12 Months Ending December 2014	Adjustment	Ref.
5001XX	Regular Ordinary Time	427,686,084	450,337,775	22,651,691	
5002XX	Overtime	57,765,409	60,824,859	3,059,450	
5003XX	Premium Pay	7,229,138	7,612,018	382,879	
	Subtotal for Escalation	**492,680,632**	**518,774,652**	**26,094,020**	4.2.3&4
5005XX	Unused Leave Accrual	2,188,821	2,304,748	115,927	4.2.6
500700	Severance/Redundancy (1)	65,488	65,488	-	
500850	Other Salary/Labor Costs	3,359,218	3,359,218	-	
50109X	Joint Owner Cutbacks	(1,125,252)	(1,184,849)	(59,597)	4.2.6
	Subtotal Bare Labor	**497,168,907**	**523,319,257**	**26,150,351**	
500410	Annual Incentive Plan	25,795,641	29,489,333	3,693,693	4.2.6
	Total Incentive	**25,795,641**	**29,489,333**	**3,693,693**	
500250	Overtime Meals	1,020,601	1,020,601	-	
500400	Bonus and Awards	479,752	479,752	-	
501325	Physical Exam	5,103	5,103	-	
502300	Education Assistance	233,067	233,067	-	
580899	Mining Salary/Benefit Credit	(261,147)	(261,147)	-	
	Total Other Labor	**1,477,377**	**1,477,377**	**-**	
	Subtotal Labor and Incentive	**524,441,924**	**554,285,968**	**29,844,043**	
580500	Payroll Tax Expense	36,485,954	38,652,603	2,166,649	
580700	Payroll Tax Expense-Unemployment	3,891,056	3,891,056	-	
	Total Payroll Taxes	**40,377,010**	**42,543,659**	**2,166,649**	
	Total Labor	**564,818,934**	**596,829,627**	**32,010,692**	
Non-Utility and Capitalized Labor		176,690,259	186,704,048	10,013,789	
Total Utility Labor		**388,128,675**	**410,125,579**	**21,996,904**	
	Average FTEs 12 Months Ended June 2012	**5,636.5**	**5,636.5**		
	Average Cost per FTE	**100,207**	**105,887**		
	Projected FTEs		**5,451.0**		
	O&M Efficiency Adjustment Labor		**(19,641,958)**		
	Non-Utility and Capitalized Labor		6,144,522	31.28%	
	O&M Efficiency Adjustment - Total Company		**(13,497,435)**		
	O&M Efficiency Adjustment - OR Allocated		**(3,872,443)**		

Net Power Cost Adjustment Index

The following adjustments were used to develop pro forma net power costs for the test period. The Company's booked power costs for the 12 months ended June 2012 provide the starting point for establishing the adjustment amounts for the December 2014 test period.

5.1 Net Power Cost
5.2 James River Royalty Offset
5.3 Little Mountain
5.4 BPA Residential Exchange
5.5 Black Cap Solar LLC Project

PacifiCorp
Oregon General Rate Case - December 2014
Tab 5 Adjustment Summary

		Total Adjustments	5.1 Net Power Cost	5.2 James River Royalty Offset	5.3 Little Mountain	5.4 BPA Residential Exchange	5.5 Black Cap Solar LLC Project
1	Operating Revenues:						
2	General Business Revenues	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-
4	Special Sales	37,150,351	37,150,351	-	-	-	-
5	Other Operating Revenues	135,638	-	1,121,010	(985,372)	-	-
6	Total Operating Revenues	37,285,989	37,150,351	1,121,010	(985,372)	-	-
7							
8	Operating Expenses:						
9	Steam Production	31,191,424	31,191,424	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-
12	Other Power Supply	49,279,783	20,541,378	-	(740,413)	29,094,524	384,295
13	Embedded Cost Differential (ECD)	-	-	-	-	-	-
13	Transmission	657,728	657,728	-	-	-	-
14	Distribution	-	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-
18	Administrative & General	-	-	-	-	-	-
19							
20	Total O&M Expenses	81,128,935	52,390,529	-	(740,413)	29,094,524	384,295
21							
22	Depreciation	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-	-
25	Income Taxes - Federal	(14,659,982)	(5,099,832)	374,468	(81,701)	(9,723,845)	(129,072)
26	Income Taxes - State	(1,992,048)	(692,982)	50,884	(11,102)	(1,321,309)	(17,539)
27	Income Taxes - Def Net	-	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-
30							
31	Total Operating Expenses:	64,476,904	46,597,715	425,352	(833,216)	18,049,369	237,684
32							
33	Operating Rev For Return:	(27,190,915)	(9,447,364)	695,658	(152,156)	(18,049,369)	(237,684)
34							
35	Rate Base:						
36	Electric Plant In Service	75,000	-	-	-	-	75,000
37	Plant Held for Future Use	-	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-
44	Working Capital	1,297,390	937,629	8,559	(16,766)	363,186	4,783
45	Weatherization Loans	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-
47							
48	Total Electric Plant:	1,372,390	937,629	8,559	(16,766)	363,186	79,783
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-
53	Accum Def Income Tax	-	-	-	-	-	-
54	Unamortized ITC	-	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-	-
58							
59	Total Rate Base Deductions	-	-	-	-	-	-
60							
61	Total Rate Base:	1,372,390	937,629	8,559	(16,766)	363,186	79,783
62							
63	Return on Rate Base	-0.803%	-0.280%	0.020%	-0.004%	-0.532%	-0.007%
64							
65	Return on Equity	-1.541%	-0.538%	0.039%	-0.009%	-1.020%	-0.014%
66							
67	TAX CALCULATION:						
68	Operating Revenue	(43,842,946)	(15,240,178)	1,121,010	(244,959)	(29,094,524)	(384,295)
69	Other Deductions						
70	Interest (AFUDC)	-	-	-	-	-	-
71	Interest	34,766	23,753	217	(425)	9,200	2,021
72	Schedule "M" Additions	-	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-	-
74	Income Before Tax	(43,877,712)	(15,263,931)	1,120,793	(244,535)	(29,103,724)	(386,316)
75							
76	State Income Taxes	(1,992,048)	(692,982)	50,884	(11,102)	(1,321,309)	(17,539)
77	Taxable Income	(41,885,664)	(14,570,948)	1,069,909	(233,433)	(27,782,415)	(368,777)
78							
79	Federal Income Taxes + Other	(14,659,982)	(5,099,832)	374,468	(81,701)	(9,723,845)	(129,072)
80							
81	PRICE CHANGE	45,341,832	15,812,417	(1,154,481)	250,617	30,028,312	404,967

PacifiCorp
Oregon General Rate Case - December 2014
Net Power Cost

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447NPC	3	27,098,027	SG	26.053%	7,059,849	5.1.1
Existing Firm UPL	447NPC	3	30,332,094	SG	26.053%	7,902,421	5.1.1
Post-Merger Firm	447NPC	3	85,166,933	SG	26.053%	22,188,542	5.1.1
Non-Firm	447NPC	3	(1,870)	SE	24.687%	(462)	5.1.1
Total Sales for Resale			142,595,185			37,150,351	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	3	2,845,214	SG	26.053%	741,264	5.1.1
Existing Firm Demand UPL	555NPC	3	52,544,159	SG	26.053%	13,689,330	5.1.1
Existing Firm Energy	555NPC	3	25,882,481	SE	24.687%	6,389,539	5.1.1
Post-merger Firm	555NPC	3	29,818,764	SG	26.053%	7,768,683	5.1.1
Secondary Purchases	555NPC	3	16,365,455	SE	24.687%	4,040,096	5.1.1
Seasonal Contracts	555NPC	3	-	SG	26.053%	-	5.1.1
Other Generation	555NPC	3	3,354,157	SG	26.053%	873,859	5.1.1
Total Purchased Power Adjustments:			130,810,230			33,502,771	
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	3	27,925,313	SG	26.053%	7,275,382	5.1.1
Existing Firm UPL	565NPC	3	-	SG	26.053%	-	5.1.1
Post-merger Firm	565NPC	3	(21,254,532)	SG	26.053%	(5,537,444)	5.1.1
Non-Firm	565NPC	3	(4,375,673)	SE	24.687%	(1,080,211)	5.1.1
Total Wheeling Expense Adjustments:			2,295,108			657,728	
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	3	(178,300)	ID	0.000%	-	5.1.1
Fuel - Overburden Amortization - Wyoming	501NPC	3	(480,935)	WYP	0.000%	-	5.1.1
Fuel Consumed - Coal	501NPC	3	129,885,241	SE	24.687%	32,064,422	5.1.1
Fuel Consumed - Gas	501NPC	3	(8,703,911)	SE	24.687%	(2,148,711)	5.1.1
Steam from Other Sources	503NPC	3	(600,797)	SE	24.687%	(148,317)	5.1.1
Natural Gas Consumed	547NPC	3	(51,238,526)	SE	24.687%	(12,649,118)	5.1.1
Simple Cycle Combustion Turbines	547NPC	3	(1,998,681)	SE	24.687%	(493,409)	5.1.1
Cholla / APS Exchange	501NPC	3	5,768,402	SE	24.687%	1,424,030	5.1.1
Total Fuel Expense Adjustments:			72,452,493			18,048,897	
Total Power Cost Adjustment			62,962,646			15,059,044	
Oregon Solar Project	555NPC	3	(138,381)	OR	100.000%	(138,381)	5.1.5
Remove Power Cost Deferrals	555NPC	1	1,226,403	SG	26.053%	319,515	5.1.1

Description of Adjustment:

The net power cost adjustment normalizes power costs by adjusting sales for resale, purchased power, wheeling and fuel in a manner consistent with the contractual terms of sales and purchase agreements, and normal hydro and temperature conditions for the 12 month period ending December 2014.The GRID study for this adjustment is based on forecasted loads for the period. As described in the testimony of Gary W. Tawwater, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC as part of the general rate case.

PacifiCorp
Oregon General Rate Case - December 2014
Net Power Cost Adjustment

Description	Account	(1) Total Account (B Tabs)	(2) Remove Non-NPC/ NPC Mechanism Accruals	(3) Unadjusted NPC (1) + (2)	(4) Type 1 Adjustments	(5) Type 1 Normalized NPC (3) + (4)	(6) Type 3 Pro Forma NPC	(7) Type 3 Adjustment (6) - (5)	2010 Protocol Factor
Sales for Resale (Account 447)									
Existing Firm Sales PPL	447.12			-		-	27,098,027	27,098,027	SG
Existing Firm Sales UPL	447.122			-		-	30,332,094	30,332,094	SG
Post-merger Firm Sales	447.13, 447.14, 447.2, 447.61, 447.62	329,539,169		329,539,169		329,539,169	414,706,102	85,166,933	SG
Non-firm Sales	447.5	1,870		1,870		1,870	-	(1,870)	SE
Transmission Services	447.9	136,043	(136,043)	-		-		-	S
On-system Wholesale Sales	447.1	9,938,260	(9,938,260)	-		-		-	S
Total Revenue Adjustments		339,615,342	(10,074,303)	329,541,039	-	329,541,039	472,136,224	142,595,185	
Purchased Power (Account 555)									
Existing Firm Demand PPL	555.66			-		-	2,845,214	2,845,214	SG
Existing Firm Demand UPL	555.68			-		-	52,544,159	52,544,159	SG
Existing Firm Energy	555.65, 555.69			-		-	25,882,481	25,882,481	SE
Post-merger Firm	555, 555.55,555.61,555.62, 555.63, 555.64, 555.67, 555.8	501,391,831		501,391,831		501,391,831	532,436,997	31,045,167	SG
Secondary Purchases	555.7, 555.25	(16,365,455)		(16,365,455)		(16,365,455)	-	16,365,455	SE
Purchased Power Deferrals/Amortization - CA	555.6			-		-		-	CA
Purchased Power Deferrals/Amortization - OR	555.6			-		-		-	OR
Purchased Power Deferrals/Amortization - WA	555.6			-		-		-	WA
Purchased Power Deferrals/Amortization - UT	555.6			-		-		-	UT
Purchased Power Deferrals/Amortization - ID	555.6			-		-		-	ID
Purchased Power Deferrals/Amortization - WY	555.6			-		-		-	WY
Seasonal Contracts				-			-	-	
Wind Integration Charge						-	3,354,157	3,354,157	SG
BPA Regional Adjustments	555.11, 555.12, 555.133	(39,697,756)	39,697,756	-		-	-	-	S
Post-merger Firm Type 1				-	1,226,403	1,226,403	-	(1,226,403)	SG
Total Purchased Power Adjustment		445,328,620	39,697,756	485,026,376	1,226,403	486,252,778	617,063,008	130,810,230	
Wheeling (Account 565)									
Existing Firm PPL	565.26			-		-	27,925,313	27,925,313	SG
Existing Firm UPL	565.27	-		-		-	-	-	SG
Post-merger Firm	565.0, 565.46, 565.1	131,761,383		131,761,383		131,761,383	110,506,851	(21,254,532)	SG
Non-firm	565.25	9,480,873		9,480,873		9,480,873	5,105,200	(4,375,673)	SE
Total Wheeling Expense Adjustment		141,242,257	-	141,242,257	-	141,242,257	143,537,364	2,295,108	
Fuel Expense (Accounts 501, 503 and 547)									
Fuel - Overburden Amortization - Idaho	501.12	178,300		178,300		178,300	-	(178,300)	IDU
Fuel - Overburden Amortization - Wyoming	501.12	480,935		480,935		480,935	-	(480,935)	WYP
Fuel Consumed - Coal	501.1	630,849,764		630,849,764		630,849,764	760,735,004	129,885,241	SE
Fuel Consumed - Gas	501.35	12,120,405		12,120,405		12,120,405	3,416,494	(8,703,911)	SE
Steam From Other Sources	503	3,975,674		3,975,674		3,975,674	3,374,877	(600,797)	SE
Natural Gas Consumed	547	385,597,558		385,597,558		385,597,558	334,359,033	(51,238,526)	SE
Simple Cycle Combustion Turbines	547	9,132,801		9,132,801		9,132,801	7,134,120	(1,998,681)	SE
Cholla/APS Exchange	501.1,501.2,501.45	53,938,291	-	53,938,291		53,938,291	59,706,693	5,768,402	SE
Miscellaneous Fuel Costs	501,501.2,501.3, 501.4, 501.45, 501.5,501.51	19,382,513	(19,382,513)	-		-	-	-	SE
Total Fuel Expense		1,115,656,241	(19,382,513)	1,096,273,728	-	1,096,273,728	1,168,726,221	72,452,493	
Net Power Cost		**1,362,611,775**	**30,389,546**	**1,393,001,321**	**1,226,403**	**1,394,227,724**	**1,457,190,370**	**62,962,646**	
					Ref 5.1		**Ref 5.1.3**	**Ref 5.1**	

NPC Mechanism Accruals (included in column 2)	-	**Oregon Solar Project Ref 5.1.5**	**(138,381)**	**(138,381)**	OR
Unadjusted NPC	**1,393,001,321**		**Ref. 5.1**	**Ref. 5.1**
	Ref. 2.2 line 66			
		Total NPC	**1,457,051,989**	**62,824,265**

PacifiCorp
Oregon General Rate Case - December 2014
Net Power Cost Adjustment

Study Results
MERGED PEAK/ENERGY SPLIT
($)

Period Ending
Dec-14

	Merged 01/14-12/14	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	27,098,027	27,098,027			
Post Merger	414,706,102				414,706,102
Utah Pre Merger	30,332,094	30,332,094			
NonFirm Sub Total	-			-	
TOTAL SPECIAL SALES	472,136,224	57,430,121	-	-	414,706,102
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	-	-			
Pacific Capacity	-	-	-		
Mid Columbia	889,939	266,982	622,957		
Misc/Pacific	270,000	55,988	214,012		
Q.F. Contracts/PPL	70,760,260	2,522,245	12,288,744		55,949,271
Small Purchases west	-		-		
Pacific Sub Total	71,920,198	2,845,214	13,125,713	-	55,949,271
Gemstate	3,173,700		3,173,700		
GSLM	-		-		
QF Contracts/UPL	95,354,851	22,212,064	9,519,456		63,623,331
IPP Layoff	30,332,094	30,332,094	-		
Small Purchases east	63,612		63,612		
UP&L to PP&L	-	-	-		
Utah Sub Total	128,924,257	52,544,159	12,756,768	-	63,623,331
APS Supplemental p27875	888,931				888,931
Blanding Purchase p379174	30,485				30,485
Combine Hills Wind p160595	4,721,025				4,721,025
Deseret Purchase p194277	35,090,562				35,090,562
Georgia-Pacific Camas	8,005,931				8,005,931
Hermiston Purchase p99563	88,429,951				88,429,951
Hurricane Purchase p393045	124,675				124,675
MagCorp Reserves p510378	5,922,770				5,922,770
Nucor p346856	5,763,000				5,763,000
P4 Production p137215/p145258	19,999,999				19,999,999
Rock River Wind p100371	4,940,853				4,940,853
Three Buttes Wind p460457	20,598,497				20,598,497
Top of the World Wind p522807	40,244,943				40,244,943
Tri-State Purchase p27057	10,491,879				10,491,879
Wolverine Creek Wind p244520	10,148,500				10,148,500
PSCo Exchange p340325	5,400,000				5,400,000
Seasonal Purchased Power					
Constellation 2013-2016	6,315,320				6,315,320
Short Term Firm Purchases	145,747,073				145,747,073
New Firm Sub Total	412,864,395	-	-	-	412,864,395
Integration Charge	3,354,157				3,354,157
Non Firm Sub Total	-			-	
TOTAL PURCHASED PW & NET INT.	617,063,008	55,389,373	25,882,481	-	535,791,154

PacifiCorp
Oregon General Rate Case - December 2014
Net Power Cost Adjustment

Study Results
MERGED PEAK/ENERGY SPLIT
($)

Period Ending
Dec-14

	Merged 01/14-12/14	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Fa	27,925,313	27,925,313			
Utah Firm Wheeling and Use of Facil	-	-			
Post Merger	110,506,851				110,506,851
Nonfirm Wheeling	5,105,200			5,105,200	
TOTAL WHEELING & U. OF F. EXPEN:	143,537,364	27,925,313	-	5,105,200	110,506,851
THERMAL FUEL BURN EXPENSE					
Carbon	24,712,536			24,712,536	
Cholla	59,706,693			59,706,693	
Colstrip	16,127,928			16,127,928	
Craig	23,795,784			23,795,784	
Chehalis	63,620,084			63,620,084	
Currant Creek	66,449,751			66,449,751	
Dave Johnston	61,875,551			61,875,551	
Gadsby	3,416,494			3,416,494	
Gadsby CT	7,134,120			7,134,120	
Hayden	14,478,468			14,478,468	
Hermiston	50,151,617			50,151,617	
Hunter	168,151,457			168,151,457	
Huntington	120,144,086			120,144,086	
Jim Bridger	198,733,091			198,733,091	
Lake Side	93,805,616			93,805,616	
Lake Side 2	60,331,964			60,331,964	
Little Mountain	-			-	
Naughton - Gas	-			-	
Naughton	107,924,454			107,924,454	
Wyodak	24,791,650			24,791,650	
TOTAL FUEL BURN EXPENSE	1,165,351,344	-	-	1,165,351,344	-
OTHER GENERATION EXPENSE					
Blundell	3,374,877			3,374,877	
TOTAL OTHER GEN. EXPENSE	3,374,877	-	-	3,374,877	-
NET POWER COST	1,457,190,370	25,884,564	25,882,481	1,173,831,421	231,591,903

PacifiCorp
Oregon General Rate Case - December 2014
Net Power Cost Adjustment
Amounts removed from accounts for consistency with GRID

Non-Net Power Costs		
Sales for Resale (Account 447)		
Transmission Services - revenues received not included in GRID	136,043	
On System Wholesale sales - these are not included in GRID	9,938,260	
	10,074,303	**Ref 5.1.1**
Purchased Power (Account 555)		
BPA regional adjustments - these are credits that are passed to customers in the northwest and are not included in GRID	(39,697,756)	**Ref 5.1.1**
Fuel Expense (Accounts 501, 503 and 547)		
Cholla:		
Cholla fuel handling	3,071,589	
Cholla start-up diesel	186,014	
Other non GRID Cholla		
	3,257,603	
Other Plants:		
Fuel handling	5,875,361	
Start up gas	424,754	
Diesel	8,514,047	
Residual disposal	1,044,766	
Other non GRID	265,982	
	16,124,910	
	19,382,513	**Ref 5.1.1**
Net Power Cost Deferrals	(78,976,378)	**Ref 5.1**
	(109,365,924)	**Ref 5.1.1**

PacifiCorp
Oregon General Rate Case - December 2014
Net Power Cost Adjustment
Oregon Solar Project

	12 Months Ending Dec 2014 Total	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Total Energy Impact	**(138,381)**	(4,908)	(8,471)	(8,512)	(11,834)	(11,350)	(11,664)	(19,261)	(19,950)	(18,123)	(11,324)	(7,044)	(5,940)
	Ref 5.1												

PacifiCorp
Oregon General Rate Case - December 2014
James River Royalty Offset

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Other Electric Revenue	456	3	4,302,805	SG	26.053%	1,121,010	Below

Adjustment Detail:

	12 Months Ending December 2014	
James River Offset		
Capital Recovery	3,695,061	
Major Maintenance Allowance	607,744	
Total Offset	4,302,805	Above

Description of Adjustment:

On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the 20 year operational term of the agreement as an offset to royalties paid to James River based on contract provisions. The contract costs of energy for the Camas unit are included in the Company's net power costs as purchased power expense, but GRID does not include an offsetting revenue credit for the capital and maintenance cost recovery. This pro forma adjustment adds the royalty offset to FERC account 456, other electric revenue, for the 12 month period ending December 2014, the same period used in determining pro forma net power costs in this filing.

PacifiCorp
Oregon General Rate Case - December 2014
Little Mountain

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Other Electric Revenue	456	3	(3,782,183)	SG	26.053%	(985,372)	5.3.1
Adjustment to Expense:							
Generation Expense	548	3	(2,841,948)	SG	26.053%	(740,413)	5.3.1

Description of Adjustment:

The Company has provided both electricity and steam from the Little Mountain plant to the Great Salt Lake Minerals Company (GSL) since 1968. On August 1, 2011 the electrical generator at the Little Mountain plant experienced a catastrophic electrical fault. In August 2011, the Company installed a mobile packaged boiler in order to provide enough steam for Great Salt Lake Minerals to maintain its operations. In December 2011 a new sales agreement was signed between PacifiCorp and GSL for PacifiCorp to continue to provide steam supply service to GSL. The Company currently plans to operate the steam boilers through January 2013 and will then initiate tear-down. This adjustment removes the steam revenue and related O&M expense after February 2013.

PacifiCorp
Oregon General Rate Case - December 2014
Little Mountain

Remove Little Mountain Revenue

Description	FERC Acct	Factor	12 Months Ended June 2012	12 Months Ending Dec 2014	Adjustment	Ref.
Steam Revenue	456	SG	3,782,183	-	**(3,782,183)**	**Ref 5.3**

Remove Little Mountain O&M Expense

Labor Expense

Description	FERC Acct	Factor	Labor Expense	Labor Escalation*	Escalated Labor O&M 12 Months Ended June 2012	Total Labor 12 Months Ending Dec 2014	Adjustment
Generation Expense	548	SG	890,113	4.56%	930,685	-	(930,685)
				Below			

Non-Labor Expense

Description	FERC Acct	Factor	Non-Labor Expense	Non-Labor Escalation	Escalated Non-Labor O&M 12 Months Ended June 2012	Total Non-Labor 12 Months Ending Dec 2014	Adjustment
Generation Expense	548	SG	1,778,936	7.44%	1,911,263	-	(1,911,263)
				Ref 4.12.8			
						Total O&M Adjustment	**(2,841,948)**
							Ref 5.3

*These costs are escalated in the Wage and Employee Benefit adjustment, so the amount of this adjustment is increased based on the overall escalation to completely remove these expenses including escalation from results of operations.

June 2012 Total Utility Labor =	497,450,275	Page 4.2.2
December 2014 Escalated Utility Labor =	520,124,749	Page 4.2.2
Escalation Factor	4.56%	Above

PacifiCorp
Oregon General Rate Case - December 2014
BPA Residential Exchange

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Purchased Power Expense	555	1	29,094,524	OR	100.000%	29,094,524	5.4.1
Purchased Power Expense	555	1	7,379,869	WA	0.000%	-	
Purchased Power Expense	555	1	3,223,363	ID	0.000%	-	
			39,697,756			29,094,524	

Description of Adjustment:

The Company receives a monthly purchase power credit from Bonneville Power Administration (BPA). This credit is treated as a 100% pass-through to eligible customers. Both a revenue credit and a purchase power expense credit is posted to unadjusted results which must be removed for normalized results. This adjustment reverses the BPA purchase power expense credit recorded. The Revenue Normalizing adjustment No. 3.1 removes the revenue credit passed onto customers.

PacifiCorp
Oregon General Rate Case - December 2014
BPA Residential Exchange
Account 505201
Oregon

Six Months Ended December 2011 Expense	(17,351,347)
Six Months Ended June 2012 Expense	(11,743,177)
	(29,094,524)
	Ref 5.4

Account number	505201	Reg Bill Intchg Rec/	
Company code	1000	PacifiCorp	
Business area			
Fiscal year	2012		
All documents in currency	*	Display currency	USD

Period	Debit	Credit	Balance	Cum. balance
Balance Carr				
1	3,131,327.45	5,376,089.50	2,244,762.05-	2,244,762.05-
2	2,244,762.05	3,711,516.73	1,466,754.68-	3,711,516.73-
3	1,466,754.68	3,064,451.58	1,597,696.90-	5,309,213.63-
4	1,597,696.90	3,165,368.26	1,567,671.36-	6,876,884.99-
5	1,567,671.36	3,108,085.38	1,540,414.02-	8,417,299.01-
6	1,540,414.02	2,832,535.53	1,292,121.51-	9,709,420.52-
7	1,292,121.51	2,419,576.88	1,127,455.37-	10,836,875.89-
8	1,127,455.37	2,968,763.94	1,841,308.57-	12,678,184.46-
9	1,841,308.57	10,586,233.98	8,744,925.41-	21,423,109.87-
10	8,744,925.41	10,223,842.72	1,478,917.31-	22,902,027.18-
11	1,478,917.31	3,216,400.25	1,737,482.94-	24,639,510.12-
12	1,737,482.94	4,158,740.11	2,421,257.17-	27,060,767.29-
13				27,060,767.29-
14				27,060,767.29-
15				27,060,767.29-
16				27,060,767.29-
Total	27,770,837.57	54,831,604.86	27,060,767.29-	27,060,767.29-

Account number	505201	Reg Bill Intchg Rec/	
Company code	1000	PacifiCorp	
Business area			
Fiscal year	2013		
All documents in currency	*	Display currency	USD

Period	Debit	Credit	Balance	Cum. balance
Balance Carr				
1	2,421,257.17	5,024,354.54	2,603,097.37-	2,603,097.37-
2	2,603,097.37	4,716,614.99	2,113,517.62-	4,716,614.99-
3	2,113,517.62	4,122,820.57	2,009,302.95-	6,725,917.94-
4	2,009,302.95	3,849,477.90	1,840,174.95-	8,566,092.89-
5	1,840,174.95	3,491,742.82	1,651,567.87-	10,217,660.76-
6	1,651,567.87	3,177,083.98	1,525,516.11-	11,743,176.87-
7	1,525,516.11	3,099,749.05	1,574,232.94-	13,317,409.81-
8	1,574,232.94		1,574,232.94	11,743,176.87-
9				11,743,176.87-
10				11,743,176.87-
11				11,743,176.87-
12				11,743,176.87-
13				11,743,176.87-
14				11,743,176.87-
15				11,743,176.87-
16				11,743,176.87-
Total	15,738,666.98	27,481,843.85	11,743,176.87-	11,743,176.87-

PacifiCorp
Oregon General Rate Case - December 2014
Black Cap Solar LLC Project

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Lease and O&M Expense	550	3	384,295	OR	100.000%	384,295	5.5.1
Adjustment to Rate Base:							
Land	340	3	75,000	OR	100.000%	75,000	5.5.1

Description of Adjustment:

This adjustment accounts for the test period costs related to the Black Cap Solar LLC project, which became operational in October 2012. This adjustment adds the O&M expense, the lease payment expense, and the land balance associated with the project to the Test Period. The net power cost benefit associated with this project is included in the NPC Adjustment (page 5.1) and the TAM.

Because this project is being procured to satisfy the Company's obligation under Oregon Statute ORS 757.370, it's classified as a state specific initiative under the 2010 Protocol allocation methodology. As such, the costs and benefits associated with this project are situs assigned to Oregon customers. Please reference confidential exhibit PAC/1103 for additional detail.

PacifiCorp
Oregon General Rate Case - December 2014
Black Cap Solar LLC Project

	O&M
Jan-14	14,583
Feb-14	-
Mar-14	-
Apr-14	10,688
May-14	-
Jun-14	-
Jul-14	10,688
Aug-14	-
Sep-14	-
Oct-14	10,955
Nov-14	-
Dec-14	-
	46,912
	Year Ending Dec14
	Ref. 5.5

Lease Payment	
In-Service Date	Oct-12
Monthly Amount	28,115

	Lease Payment
Jan-14	28,115
Feb-14	28,115
Mar-14	28,115
Apr-14	28,115
May-14	28,115
Jun-14	28,115
Jul-14	28,115
Aug-14	28,115
Sep-14	28,115
Oct-14	28,115
Nov-14	28,115
Dec-14	28,115
	337,383
	Year Ending Dec14
	Ref. 5.5

Land Cost	
In-Service Date	Oct-12
Amount	**75,000**
	Ref. 5.5

Depreciation and Amortization Adjustment Index

The following adjustments were used to arrive at the normalized levels of depreciation and amortization expense along with the associated reserve balances reflected in the test period.

6.1 – 6.1.1	Depreciation and Amortization Expense – Adjustment to Test Period
6.1.2 – 6.1.3	Depreciation and Amortization Expense – Adjustment to Depreciation Study
6.2	Depreciation and Amortization Reserve

PacifiCorp
Oregon General Rate Case - December 2014
Tab 6 Adjustment Summary

		Total Adjustments	6.1 - 6.1.1 Depreciation / Amortization Expense - Adjustment to Test Period	6.1.2 - 6.1.3 Depreciation / Amortization Expense - Adjustment to Depreciation Study Rates	6.2 Depreciation / Amortization Reserve
1	Operating Revenues:				
2	General Business Revenues	-	-	-	-
3	Interdepartmental	-	-	-	-
4	Special Sales	-	-	-	-
5	Other Operating Revenues	-	-	-	-
6	Total Operating Revenues	-	-	-	-
7					
8	Operating Expenses:				
9	Steam Production	(73,384)	-	(73,384)	-
10	Nuclear Production	-	-	-	-
11	Hydro Production	(15,541)	-	(15,541)	-
12	Other Power Supply	(12,522)	-	(12,522)	-
13	Embedded Cost Differential (ECD)	-	-	-	-
13	Transmission	(6,413)	-	(6,413)	-
14	Distribution	(35,547)	-	(35,547)	-
15	Customer Accounting	(21,361)	-	(21,361)	-
16	Customer Service & Info	(2,621)	-	(2,621)	-
17	Sales	-	-	-	-
18	Administrative & General	(29,318)	-	(29,318)	-
19					
20	Total O&M Expenses	(196,707)	-	(196,707)	-
21					
22	Depreciation	46,509,009	19,076,009	27,432,999	-
23	Amortization	644,345	644,345	-	-
24	Taxes Other Than Income	-	-	-	-
25	Income Taxes - Federal	(13,555,340)	(6,587,493)	(9,098,124)	2,130,277
26	Income Taxes - State	(1,841,946)	(895,131)	(1,236,284)	289,469
27	Income Taxes - Def Net	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-
30					
31	Total Operating Expenses:	31,559,361	12,237,730	16,901,884	2,419,747
32					
33	Operating Rev For Return:	(31,559,361)	(12,237,730)	(16,901,884)	(2,419,747)
34					
35	Rate Base:				
36	Electric Plant In Service	-	-	-	-
37	Plant Held for Future Use	-	-	-	-
38	Misc Deferred Debits	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-
40	Nuclear Fuel	-	-	-	-
41	Prepayments	-	-	-	-
42	Fuel Stock	-	-	-	-
43	Material & Supplies	-	-	-	-
44	Working Capital	(313,779)	(150,564)	(211,905)	48,690
45	Weatherization Loans	-	-	-	-
46	Misc Rate Base	-	-	-	-
47					
48	Total Electric Plant:	(313,779)	(150,564)	(211,905)	48,690
49					
50	Rate Base Deductions:				
51	Accum Prov For Deprec	(243,039,682)	-	-	(243,039,682)
52	Accum Prov For Amort	(8,698,357)	-	-	(8,698,357)
53	Accum Def Income Tax	-	-	-	-
54	Unamortized ITC	-	-	-	-
55	Customer Adv For Const	-	-	-	-
56	Customer Service Deposits	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-
58					
59	Total Rate Base Deductions	(251,738,039)	-	-	(251,738,039)
60					
61	Total Rate Base:	(252,051,818)	(150,564)	(211,905)	(251,689,349)
62					
63	Return on Rate Base	-0.380%	-0.359%	-0.497%	0.476%
64					
65	Return on Equity	-0.729%	-0.690%	-0.953%	0.914%
66					
67	TAX CALCULATION:				
68	Operating Revenue	(46,956,647)	(19,720,354)	(27,236,293)	-
69	Other Deductions				
70	Interest (AFUDC)	-	-	-	-
71	Interest	(6,385,158)	(3,814)	(5,368)	(6,375,976)
72	Schedule "M" Additions	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-
74	Income Before Tax	(40,571,489)	(19,716,540)	(27,230,925)	6,375,976
75					
76	State Income Taxes	(1,841,946)	(895,131)	(1,236,284)	289,469
77	Taxable Income	(38,729,543)	(18,821,409)	(25,994,641)	6,086,507
78					
79	Federal Income Taxes + Other	(13,555,340)	(6,587,493)	(9,098,124)	2,130,277
80					
81	PRICE CHANGE	20,371,790	20,309,165	28,049,074	(27,986,448)

PacifiCorp
Oregon General Rate Case - December 2014
Depreciation / Amortization Expense - Adjustment to Test Period

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	403SP	3	8,406,004	SG	26.053%	2,190,016	
Steam Depreciation Expense	403SP	3	5,203,603	SG	26.053%	1,355,695	
Steam Depreciation Expense	403SP	3	35,687,385	SG	26.053%	9,297,635	
Steam Depreciation Expense	403SP	3	4,300,168	SG	26.053%	1,120,323	
Hydro Depreciation Expense	403HP	3	(8,904)	SG	26.053%	(2,320)	
Hydro Depreciation Expense	403HP	3	(59,779)	SG	26.053%	(15,574)	
Hydro Depreciation Expense	403HP	3	3,687,326	SG-P	26.053%	960,659	
Hydro Depreciation Expense	403HP	3	(677,076)	SG-U	26.053%	(176,399)	
Other Depreciation Expense	403OP	3	(50,299)	SG	26.053%	(13,104)	
Other Depreciation Expense	403OP	3	94,147	SG	26.053%	24,528	
Other Depreciation Expense	403OP	3	(7,905,579)	SG-W	26.053%	(2,059,641)	
Other Depreciation Expense	403OP	3	(6,642)	SG	26.053%	(1,731)	
Transmission Depreciation Expense	403TP	3	(216,455)	SG	26.053%	(56,393)	
Transmission Depreciation Expense	403TP	3	(169,641)	SG	26.053%	(44,197)	
Transmission Depreciation Expense	403TP	3	14,716,221	SG	26.053%	3,834,017	
Distribution Depreciation Expense	403360	3	80,238	Situs	100.000%	23,782	
Distribution Depreciation Expense	403361	3	116,573	Situs	100.000%	34,551	
Distribution Depreciation Expense	403362	3	1,183,181	Situs	100.000%	350,683	
Distribution Depreciation Expense	403364	3	1,360,169	Situs	100.000%	403,140	
Distribution Depreciation Expense	403365	3	914,581	Situs	100.000%	271,072	
Distribution Depreciation Expense	403366	3	431,155	Situs	100.000%	127,790	
Distribution Depreciation Expense	403367	3	1,014,749	Situs	100.000%	300,761	
Distribution Depreciation Expense	403368	3	1,557,288	Situs	100.000%	461,564	
Distribution Depreciation Expense	403369	3	838,488	Situs	100.000%	248,519	
Distribution Depreciation Expense	403370	3	239,607	Situs	100.000%	71,017	
Distribution Depreciation Expense	403371	3	11,999	Situs	100.000%	3,556	
Distribution Depreciation Expense	403373	3	83,682	Situs	100.000%	24,802	
General Depreciation Expense	403GP	3	67,280	CA	0.000%	-	
General Depreciation Expense	403GP	3	294,537	OR	100.000%	294,537	
General Depreciation Expense	403GP	3	48,104	WA	0.000%	-	
General Depreciation Expense	403GP	3	270,588	WYP	0.000%	-	
General Depreciation Expense	403GP	3	446,132	UT	0.000%	-	
General Depreciation Expense	403GP	3	58,502	ID	0.000%	-	
General Depreciation Expense	403GP	3	(789)	WYU	0.000%	-	
General Depreciation Expense	403GP	3	(105,532)	SG	26.053%	(27,494)	
General Depreciation Expense	403GP	3	(147,739)	SG	26.053%	(38,491)	
General Depreciation Expense	403GP	3	1,024,075	SG	26.053%	266,802	
General Depreciation Expense	403GP	3	(439,045)	SO	27.384%	(120,229)	
General Depreciation Expense	403GP	3	17,289	SG	26.053%	4,504	
General Depreciation Expense	403GP	3	(65)	SG	26.053%	(17)	
General Depreciation Expense	403GP	3	(127,653)	CN	30.325%	(38,711)	
General Depreciation Expense	403GP	3	1,431	SE	24.687%	353	
Total Depreciation Expense			72,239,303			19,076,009	6.1.4

Description of Adjustment:

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.5. The annualized 2013 depreciation and amortization expense for the test period is calculated by applying the current composite depreciation and amortization rates to the December 2013 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2014
(cont.) Depreciation / Amortization Expense - Adjustment to Test Period

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Amortization	404IP	3	-	CA	0.000%	-	
Intangible Amortization	404IP	3	403,628	CN	30.325%	122,401	
Intangible Amortization	404IP	3	(657)	SG	26.053%	(171)	
Intangible Amortization	404IP	3	-	SG	26.053%	-	
Intangible Amortization	404IP	3	636	ID	0.000%	-	
Intangible Amortization	404IP	3	(2,049)	OR	100.000%	(2,049)	
Intangible Amortization	404IP	3	280,155	SE	24.687%	69,161	
Intangible Amortization	404IP	3	(3,295,906)	SG	26.053%	(858,682)	
Intangible Amortization	404IP	3	(65,404)	SG-P	26.053%	(17,040)	
Intangible Amortization	404IP	3	(6,172)	SG-U	26.053%	(1,608)	
Intangible Amortization	404IP	3	(156,748)	SG	26.053%	(40,838)	
Intangible Amortization	404IP	3	5,714,834	SO	27.384%	1,564,965	
Intangible Amortization	404IP	3	388	UT	0.000%	-	
Intangible Amortization	404IP	3	(184)	WA	0.000%	-	
Intangible Amortization	404IP	3	(437)	WYP	0.000%	-	
Intangible Amortization	404IP	3	-	WYU	0.000%	-	
Hydro Amortization	404HP	3	-	SG	26.053%	-	
Hydro Amortization	404HP	3	78,613	SG-P	26.053%	20,481	
Hydro Amortization	404HP	3	(1,885)	SG-U	26.053%	(491)	
Other Amortization	404OP	3	-	SG	26.053%	-	
General Amortization	404GP	3	(133,441)	CA	0.000%	-	
General Amortization	404GP	3	0	CN	30.325%	0	
General Amortization	404GP	3	(214,208)	OR	100.000%	(214,208)	
General Amortization	404GP	3	8,852	SO	27.384%	2,424	
General Amortization	404GP	3	18	UT	0.000%	-	
General Amortization	404GP	3	(110,646)	WA	0.000%	-	
General Amortization	404GP	3	(173,210)	WYP	0.000%	-	
General Amortization	404GP	3	16	WYU	0.000%	-	
Total Amorization			2,326,192			644,345	6.1.5

Description of Adjustment:

This adjustment reflects the incremental amortization expense that is calculated on the plant additions included in this filing in adjustment 8.5. The annualized 2013 depreciation and amortization expense for the test period is calculated by applying the current composite depreciation and amortization rates to the December 2013 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2014
Depreciation / Amortization Expense - Adjustment to Depreciation Study Rates

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	403SP	3	18,645,763	SG	26.053%	4,857,781	
Steam Depreciation Expense	403SP	3	14,173,754	SG	26.053%	3,692,688	
Steam Depreciation Expense	403SP	3	85,298,577	SG	26.053%	22,222,840	
Steam Depreciation Expense	403SP	3	12,445,646	SG	26.053%	3,242,464	
Hydro Depreciation Expense	403HP	3	1,368,430	SG	26.053%	356,517	
Hydro Depreciation Expense	403HP	3	437,109	SG	26.053%	113,880	
Hydro Depreciation Expense	403HP	3	3,769,570	SG-P	26.053%	982,086	
Hydro Depreciation Expense	403HP	3	2,111,791	SG-U	26.053%	550,185	
Other Depreciation Expense	403OP	3	(36,770)	SG	26.053%	(9,580)	
Other Depreciation Expense	403OP	3	6,958,847	SG	26.053%	1,812,988	
Other Depreciation Expense	403OP	3	(13,264,459)	SG-W	26.053%	(3,455,790)	
Other Depreciation Expense	403OP	3	523,803	SG	26.053%	136,466	
Transmission Depreciation Expense	403TP	3	(677,429)	SG	26.053%	(176,490)	
Transmission Depreciation Expense	403TP	3	(795,724)	SG	26.053%	(207,310)	
Transmission Depreciation Expense	403TP	3	(3,329,783)	SG	26.053%	(867,508)	
Distribution Depreciation Expense	403360	3	(104,858)	Situs	100.000%	(59,660)	
Distribution Depreciation Expense	403361	3	(152,341)	Situs	100.000%	(86,676)	
Distribution Depreciation Expense	403362	3	(1,546,209)	Situs	100.000%	(879,735)	
Distribution Depreciation Expense	403364	3	(1,777,502)	Situs	100.000%	(1,011,332)	
Distribution Depreciation Expense	403365	3	(1,195,196)	Situs	100.000%	(680,022)	
Distribution Depreciation Expense	403366	3	(563,443)	Situs	100.000%	(320,578)	
Distribution Depreciation Expense	403367	3	(1,326,099)	Situs	100.000%	(754,500)	
Distribution Depreciation Expense	403368	3	(2,035,101)	Situs	100.000%	(1,157,896)	
Distribution Depreciation Expense	403369	3	(1,095,756)	Situs	100.000%	(623,444)	
Distribution Depreciation Expense	403370	3	(313,125)	Situs	100.000%	(178,156)	
Distribution Depreciation Expense	403371	3	(15,680)	Situs	100.000%	(8,922)	
Distribution Depreciation Expense	403373	3	(109,358)	Situs	100.000%	(62,220)	
General Depreciation Expense	403GP	3	(8,229)	CA	0.000%	-	
General Depreciation Expense	403GP	3	45,671	OR	100.000%	45,671	
General Depreciation Expense	403GP	3	(247,316)	WA	0.000%	-	
General Depreciation Expense	403GP	3	(278,271)	WYP	0.000%	-	
General Depreciation Expense	403GP	3	32,856	UT	0.000%	-	
General Depreciation Expense	403GP	3	8,048	ID	0.000%	-	
General Depreciation Expense	403GP	3	(52,852)	WYU	0.000%	-	
General Depreciation Expense	403GP	3	(1,875)	SG	26.053%	(489)	
General Depreciation Expense	403GP	3	(202)	SG	26.053%	(53)	
General Depreciation Expense	403GP	3	(107,088)	SG	26.053%	(27,900)	
General Depreciation Expense	403GP	3	(48,575)	SO	27.384%	(13,302)	
General Depreciation Expense	403GP	3	7,073	SG	26.053%	1,843	
General Depreciation Expense	403GP	3	2	SG	26.053%	0	
General Depreciation Expense	403GP	3	(2,950)	CN	30.325%	(895)	
General Depreciation Expense	403GP	3	190	SE	24.687%	47	
Total Depreciation Expense			116,740,939			27,432,999	6.1.4

Description of Adjustment:

This adjustment reflects the incremental depreciation expense for the proposed depreciation study rates. The depreciation expense is calculated by applying the proposed composite depreciation rates to the December 2013 projected plant balances. The Company's application to implement revised depreciation rates was filed January 31, 2013, under Docket No. UM-1647. This adjustment is subject to change depending on the outcome of that docket.

PacifiCorp
Oregon General Rate Case - December 2014
(cont.) Depreciation / Amortization Expense - Adjustment to Depreciation Study Rates

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	(80,336)	SG	26.053%	(20,930)	
Fuel Related - Non-NPC	501	3	(2,304)	SE	24.687%	(569)	
Steam Maintenance	512	3	(49,496)	SG	26.053%	(12,895)	
Hydro Operations	535	3	(8,774)	SG-P	26.053%	(2,286)	
Hydro Operations	535	3	(6,082)	SG-U	26.053%	(1,584)	
Hydro Maintenance	545	3	(2,793)	SG-P	26.053%	(728)	
Hydro Maintenance	545	3	(1,106)	SG-U	26.053%	(288)	
Other Operations	548	3	(9,017)	SG	26.053%	(2,349)	
Other Maintenance	553	3	(2,845)	SG	26.053%	(741)	
Other Expenses	557	3	(36,204)	SG	26.053%	(9,432)	
Transmission Operations	560	3	(15,567)	SG	26.053%	(4,056)	
Transmission Maintenance	571	3	(9,048)	SG	26.053%	(2,357)	
Distribution Operations	580	3	(25,217)	Situs	100.000%	(9,570)	
Distribution Operations	580	3	(32,512)	SNPD	26.872%	(8,737)	
Distribution Maintenance	593	3	(45,471)	Situs	100.000%	(14,763)	
Distribution Maintenance	593	3	(9,164)	SNPD	26.872%	(2,462)	
Customer Accounts	903	3	(37,632)	CN	30.325%	(11,412)	
Customer Accounts	903	3	(21,733)	Situs	100.000%	(9,921)	
Customer Services	908	3	(2,607)	CN	30.325%	(791)	
Customer Services	908	3	(15)	OTHER	0.000%	-	
Customer Services	908	3	(6,562)	Situs	100.000%	(1,830)	
Administrative & General	920	3	(3,802)	Situs	100.000%	(790)	
Administrative & General	920	3	(101,530)	SO	27.384%	(27,803)	
Administrative & General	935	3	63	Situs	100.000%	10	
Administrative & General	935	3	(2,684)	SO	27.384%	(735)	
			(512,436)			(147,019)	6.1.16
Customer Accounts	903	3	(92)	CN	30.325%	(28)	
Fuel Related - Non-NPC	501	3	(47,927)	SE	24.687%	(11,832)	
Steam Maintenance	512	3	(104,242)	SG	26.053%	(27,158)	
Hydro Operations	535	3	(27,347)	SG-P	26.053%	(7,125)	
Hydro Operations	535	3	(13,548)	SG-U	26.053%	(3,530)	
Distribution Operations	580	3	(59)	SNPD	26.872%	(16)	
Distribution Operations	580	3	(4)	WA	0.000%	-	
			(193,219)			(49,688)	
Total Vehicle Depreciation			(705,655)			(196,707)	6.1.16

Description of Adjustment:

This adjustment reflects the incremental depreciation expense for the proposed depreciation study rates for vehicles. The Company's application to implement revised depreciation rates was filed January 31, 2013, under Docket No. UM-1647. This adjustment is subject to change depending on the outcome of that docket.

PacifiCorp
Oregon General Rate Case - December 2014
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 Months Ended June 2012 Expense	Annualized Existing Rates Dec 2013 Expense	Adjustment to Test Period	Proposed Annualized Rates Dec 2013 Expense	Adjustment to Proposed Depreciation Study Rates
DEPRECIATION EXPENSE							
Steam Production Plant:							
Pre-merger Pacific	403SP	SG	20,827,113	29,233,117	8,406,004	47,878,880	18,645,763
Pre-merger Utah	403SP	SG	22,806,424	28,010,026	5,203,603	42,183,780	14,173,754
Post-merger	403SP	SG	81,336,929	117,024,313	35,687,385	202,322,890	85,298,577
Post-merger	403SP	SG	7,904,603	12,204,771	4,300,168	24,650,417	12,445,646
Total Steam Plant			132,875,068	186,472,228	53,597,160	317,035,968	130,563,740
Hydro Production Plant:							
Pre-merger Pacific	403HP	SG	2,905,579	2,896,674	(8,904)	4,265,105	1,368,430
Pre-merger Utah	403HP	SG	984,010	924,231	(59,779)	1,361,340	437,109
Post-merger	403HP	SG-P	6,022,129	9,709,454	3,687,326	13,479,024	3,769,570
Post-merger	403HP	SG-U	3,944,617	3,267,541	(677,076)	5,379,332	2,111,791
Total Hydro Plant			13,856,334	16,797,901	2,941,566	24,484,800	7,686,900
Other Production Plant:							
Pre-merger Utah	403OP	SG	87,069	36,770	(50,299)	-	(36,770)
Post-merger	403OP	SG	32,137,349	32,231,496	94,147	39,190,342	6,958,847
Post-merger Wind	403OP	SG-W	80,878,925	72,973,347	(7,905,579)	59,708,888	(13,264,459)
Post-merger	403OP	SG	2,646,606	2,639,964	(6,642)	3,163,767	523,803
Total Other Production Plant			115,749,949	107,881,576	(7,868,374)	102,062,997	(5,818,579)
Transmission Plant:							
Pre-merger Pacific	403TP	SG	10,907,803	10,691,348	(216,455)	10,013,919	(677,429)
Pre-merger Utah	403TP	SG	12,462,921	12,293,280	(169,641)	11,497,556	(795,724)
Post-merger	403TP	SG	62,098,401	76,814,622	14,716,221	73,484,839	(3,329,783)
Total Transmission Plant			85,469,125	99,799,250	14,330,125	94,996,315	(4,802,935)
Distribution Plant:							
California	403364	CA	6,493,869	6,769,461	275,593	6,207,976	(561,485)
Oregon	403364	OR	49,849,943	52,171,182	2,321,239	46,348,040	(5,823,142)
Washington	403364	WA	12,638,754	12,945,871	307,118	11,634,596	(1,311,275)
Eastern Wyoming	403364	WYP	14,097,938	15,187,865	1,089,926	14,974,192	(213,672)
Utah	403364	UT	59,875,564	63,216,464	3,340,900	61,832,541	(1,383,923)
Idaho	403364	ID	7,269,660	7,692,947	423,286	6,760,893	(932,053)
Western Wyoming	403364	WYU	2,830,061	2,903,709	73,648	2,894,593	(9,117)
Total Distribution Plant			153,055,790	160,887,500	7,831,710	150,652,831	(10,234,668)
General Plant:							
California	403GP	CA	265,923	333,203	67,280	324,974	(8,229)
Oregon	403GP	OR	4,075,918	4,370,455	294,537	4,416,126	45,671
Washington	403GP	WA	1,444,828	1,492,932	48,104	1,245,616	(247,316)
Eastern Wyoming	403GP	WYP	2,166,072	2,436,660	270,588	2,158,389	(278,271)
Utah	403GP	UT	4,059,209	4,505,341	446,132	4,538,197	32,856
Idaho	403GP	ID	786,205	844,707	58,502	852,756	8,048
Western Wyoming	403GP	WYU	373,292	372,503	(789)	319,651	(52,852)
Pre-merger Pacific	403GP	SG	137,096	31,565	(105,532)	29,689	(1,875)
Pre-merger Utah	403GP	SG	178,000	30,261	(147,739)	30,059	(202)
Post-merger	403GP	SG	6,436,678	7,460,753	1,024,075	7,353,665	(107,088)
General Office	403GP	SO	14,944,608	14,505,563	(439,045)	14,456,988	(48,575)
General Office	403GP	SG	137,187	154,475	17,289	161,548	7,073
General Office	403GP	SG	6,010	5,945	(65)	5,947	2
Customer Service	403GP	CN	1,748,089	1,620,436	(127,653)	1,617,486	(2,950)
Fuel Related	403GP	SE	15,835	17,267	1,431	17,457	190
Total General Plant			36,774,950	38,182,066	1,407,116	37,528,548	(653,518)
Total Depreciation Expense			537,781,217	610,020,520	**72,239,303**	726,761,459	**116,740,939**
					Ref 6.1		**Ref 6.1.2**

PacifiCorp
Oregon General Rate Case - December 2014
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 Months Ended June 2012 Expense	Annualized Existing Rates Dec 2013 Expense	Adjustment to Test Period	Proposed Annualized Rates Dec 2013 Expense	Adjustment to Proposed Depreciation Study Rates
AMORTIZATION EXPENSE							
Intangible Plant:							
California	404IP	CA	-	-	-	-	-
Customer Service	404IP	CN	6,015,598	6,419,226	403,628	6,419,226	-
Pre-merger Utah	404IP	SG	16,758	16,101	(657)	16,101	-
Pre-merger Pacific	404IP	SG	-	-	-	-	-
Idaho	404IP	ID	20,530	21,166	636	21,166	-
Oregon	404IP	OR	13,810	11,762	(2,049)	11,762	-
Fuel Related	404IP	SE	55,997	336,152	280,155	336,152	-
Post-merger	404IP	SG	10,083,201	6,787,294	(3,295,906)	6,787,294	-
Hydro Relicensing	404IP	SG-P	2,615,116	2,549,712	(65,404)	2,549,712	-
Hydro Relicensing	404IP	SG-U	307,800	301,628	(6,172)	301,628	-
Post-merger	404IP	SG	156,748	-	(156,748)	-	-
General Office	404IP	SO	15,468,250	21,183,084	5,714,834	21,183,084	-
Utah	404IP	UT	12,784	13,172	388	13,172	-
Washington	404IP	WA	184	-	(184)	-	-
Eastern Wyoming	404IP	WYP	143,548	143,111	(437)	143,111	-
Western Wyoming	404IP	WYU	-	-	-	-	-
Total Intangible Plant			34,910,324	37,782,406	2,872,082	37,782,406	-
Hydro Production Plant:							
Pre-merger Pacific	404HP	SG	-	-	-	-	-
Post-merger	404HP	SG-P	232,997	311,610	78,613	311,610	-
Post-merger	404HP	SG-U	46,417	44,532	(1,885)	44,532	-
Total Hydro Plant			279,414	356,143	76,729	356,143	-
Other Production Plant:							
Post-merger	404OP	SG	-	-	-	-	-
Total Other Plant			-	-	-	-	-
General Plant:							
California	404GP	CA	143,131	9,690	(133,441)	9,690	-
General Office	404GP	CN	273,367	273,367	0	273,367	-
Oregon	404GP	OR	445,579	231,371	(214,208)	231,371	-
General Office	404GP	SO	1,270,053	1,278,904	8,852	1,278,904	-
Utah	404GP	UT	796	814	18	814	-
Washington	404GP	WA	203,429	92,783	(110,646)	92,783	-
Eastern Wyoming	404GP	WYP	539,636	366,425	(173,210)	366,425	-
Western Wyoming	404GP	WYU	4,803	4,819	16	4,819	-
Total General Plant			2,880,793	2,258,174	(622,619)	2,258,174	-
Total Amortization			38,070,531	40,396,723	**2,326,192**	40,396,723	-
					Ref 6.1.1		**Ref 6.1.2**
Total Depreciation and Amortization			575,851,748	650,417,243	74,565,495	767,158,182	116,740,939
				Ref. 6.1.15		**Ref. 6.1.15**	

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - Dec 2013 Depreciation & Amortization Expense

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Jun 2012	Depreciation Expense Jun 2012	Adjustments	Adjusted EPIS Balance Jul 2012	Depreciation Expense Jul 2012	Adjustments	Adjusted EPIS Balance Aug 2012	Depreciation Expense Aug 2012	Adjustments	Adjusted EPIS Balance Sep 2012	Depreciation Expense Sep 2012	Adjustments
DEPRECIATION EXPENSE															
Steam Production Plant:															
Pre-merger Pacific	SG	2.835%	4.644%	1,074,887,888	2,539,717	(2,436,494)	1,072,451,394	2,536,839	(2,436,494)	1,070,014,899	2,531,082	(2,436,494)	1,067,578,405	2,525,325	(2,436,494)
Pre-merger Utah	SG	2.496%	3.759%	1,161,645,259	2,416,280	(2,193,078)	1,159,452,181	2,413,999	(2,193,078)	1,157,259,102	2,409,437	(2,193,078)	1,155,066,024	2,404,875	(2,193,078)
Post-merger	SG	3.022%	5.226%	3,734,646,567	9,406,596	1,402,324	3,736,048,891	9,408,362	1,317,999	3,737,366,890	9,411,788	(501,343)	3,736,865,546	9,412,816	2,483,367
Geothermal - Blundell	SG	3.022%	5.226%	26,513,666	66,781	-	26,513,666	66,781	-	26,513,666	66,781	-	26,513,666	66,781	183,641
Pollution Control Equipment	SG	3.022%	5.226%	-	-	2,548,968	2,548,968	3,210	6,482,066	9,031,034	14,583	2,170,066	11,201,100	25,480	(415,950)
Pollution Control Equipment	SG	2.312%	4.670%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	2.312%	4.670%	526,334,475	1,014,170	(1,150,401)	525,184,074	1,013,062	(1,314,992)	523,869,082	1,010,687	(1,199,977)	522,669,106	1,008,264	(1,312,921)
Total Steam Plant				6,524,027,855	15,443,543	(1,828,682)	6,522,199,174	15,442,252	1,855,500	6,524,054,674	15,444,357	(4,160,827)	6,519,893,846	15,443,541	(3,691,436)
Hydro Production Plant:															
Pre-merger Pacific	SG	1.568%	2.309%	189,186,513	247,231	(248,338)	188,938,175	247,069	(248,338)	188,689,836	246,744	(248,338)	188,441,498	246,420	(248,338)
Pre-merger Utah	SG	2.218%	3.266%	42,928,509	79,333	(69,546)	42,858,963	79,268	(69,546)	42,789,417	79,140	(69,546)	42,719,871	79,011	(69,546)
Post-merger	SG-P	1.912%	2.654%	305,332,251	486,514	733,703	306,065,954	487,098	351,051	306,417,005	487,962	20,018,837	326,435,842	504,191	76,293,176
Post-merger	SG-U	2.722%	4.481%	101,214,696	229,555	(55,903)	101,158,793	229,491	(55,903)	101,102,890	229,364	(55,903)	101,046,987	229,238	(55,903)
Total Hydro Plant				638,661,969	1,042,632	359,916	639,021,885	1,042,926	(22,736)	638,999,148	1,043,211	19,645,050	658,644,198	1,058,860	75,919,389
Other Production Plant:															
Pre-merger Utah	SG	9.784%	0.000%	574,052	4,680	(11,013)	563,039	4,635	(11,013)	552,026	4,546	(11,013)	541,013	4,456	(11,013)
Post-merger	SG	2.569%	3.124%	1,231,397,065	2,636,218	(675,703)	1,230,721,362	2,635,494	(488,293)	1,230,233,069	2,634,249	(675,703)	1,229,557,366	2,633,003	(675,703)
Post-merger Wind	SG-W	4.042%	3.307%	1,801,194,000	6,066,626	508,478	1,801,702,478	6,067,482	301,277	1,802,003,755	6,068,846	426,317	1,802,430,072	6,070,071	(75,101)
Post-merger	SG	3.321%	3.980%	80,383,054	222,450	87,535	80,470,589	222,571	(59,645)	80,410,944	222,610	(59,645)	80,351,299	222,445	(19,645)
Total Other Plant				3,113,548,171	8,929,974	(90,703)	3,113,457,468	8,930,183	(257,674)	3,113,199,794	8,930,250	(320,044)	3,112,879,750	8,929,974	(781,462)
Transmission Plant:															
Pre-merger Pacific	SG	1.944%	1.821%	558,326,015	904,384	(460,913)	557,865,102	904,011	(460,913)	557,404,189	903,264	(460,913)	556,943,276	902,518	(460,913)
Pre-merger Utah	SG	1.897%	1.774%	654,414,764	1,034,610	(357,371)	654,057,392	1,034,327	(357,371)	653,700,021	1,033,762	(357,371)	653,342,650	1,033,197	(357,371)
Post-merger	SG	1.883%	1.802%	3,370,415,062	5,290,094	6,585,608	3,377,000,671	5,295,263	12,844,934	3,389,845,605	5,310,511	8,509,033	3,398,354,637	5,327,270	16,613,246
Total Transmission Plant				4,583,155,841	7,229,089	5,767,324	4,588,923,165	7,233,601	12,026,650	4,600,949,815	7,247,538	7,690,748	4,608,640,563	7,262,985	15,794,962
Distribution Plant:															
California	CA	2.891%	2.651%	227,450,794	547,987	184,440	227,635,233	548,209	223,829	227,859,063	548,701	253,731	228,112,793	549,276	126,678
Oregon	OR	2.842%	2.525%	1,778,810,385	4,212,822	2,763,143	1,781,573,528	4,216,094	3,066,340	1,784,639,867	4,222,997	1,709,075	1,786,348,942	4,228,652	2,698,398
Washington	WA	3.117%	2.801%	409,946,001	1,064,781	(68,672)	409,877,329	1,064,692	788,526	410,665,854	1,065,627	942,138	411,607,993	1,067,874	454,499
Eastern Wyoming	WYP	2.832%	2.792%	505,318,315	1,192,651	1,669,426	506,987,741	1,194,622	1,852,040	508,839,781	1,198,777	1,538,585	510,378,366	1,202,779	3,032,784
Utah	UT	2.480%	2.426%	2,479,578,827	5,124,502	3,573,499	2,483,152,326	5,128,194	8,404,929	2,491,557,255	5,140,572	1,599,150	2,493,156,404	5,150,910	2,638,367
Idaho	ID	2.574%	2.262%	287,738,808	617,225	457,792	288,196,600	617,716	536,101	288,732,701	618,782	333,957	289,066,658	619,715	934,549
Western Wyoming	WYU	2.983%	2.974%	98,752,285	245,517	(79,123)	98,673,162	245,418	(79,123)	98,594,039	245,222	(79,123)	98,514,916	245,025	(79,123)
Total Distribution Plant				5,787,595,414	13,005,484	8,500,504	5,796,095,918	13,014,944	14,792,642	5,810,888,560	13,040,677	6,297,513	5,817,186,073	13,064,230	9,806,151
General Plant:															
California	CA	2.058%	2.007%	14,227,219	24,401	15,024	14,242,244	24,414	5,370	14,247,613	24,431	425,433	14,673,046	24,801	22,495
Oregon	OR	2.441%	2.467%	164,460,377	334,606	780,988	165,241,365	335,401	377,694	165,619,059	336,579	1,582,496	167,201,555	338,573	24,471
Washington	WA	3.390%	2.828%	44,234,833	124,951	(160,127)	44,074,706	124,725	(98,941)	43,975,765	124,359	(109,029)	43,866,736	124,065	56,641
Eastern Wyoming	WYP	3.706%	3.283%	60,039,262	185,444	754,480	60,793,742	186,609	430,331	61,224,074	188,439	892,681	62,116,755	190,482	938,384
Utah	UT	2.214%	2.231%	187,259,398	345,565	470,211	187,729,608	345,999	(114,691)	187,614,917	346,327	3,928,274	191,543,191	349,846	(512,120)
Idaho	ID	2.259%	2.281%	35,266,574	66,401	209,495	35,476,069	66,598	(21,354)	35,454,715	66,775	(28,255)	35,426,460	66,729	112,135
Western Wyoming	WYU	2.801%	2.403%	14,140,196	33,003	(46,675)	14,093,521	32,948	(46,675)	14,046,845	32,839	(46,675)	14,000,170	32,730	(46,675)
Pre-merger Pacific	SG	2.985%	2.808%	3,387,174	8,427	(129,438)	3,257,736	8,266	(129,438)	3,128,297	7,944	(129,438)	2,998,859	7,622	(129,438)
Pre-merger Utah	SG	2.074%	2.060%	6,246,028	10,794	(265,935)	5,980,093	10,564	(265,935)	5,714,158	10,105	(265,935)	5,448,223	9,645	(265,935)
Post-merger	SG	3.387%	3.338%	205,329,563	579,539	1,301,157	206,630,719	581,375	1,287,984	207,918,703	585,029	(319,865)	207,598,838	586,395	39,250
General Office	SO	6.447%	6.426%	235,102,241	1,263,123	(1,048,745)	234,053,496	1,260,306	(1,012,564)	233,040,932	1,254,769	(824,357)	232,216,575	1,249,834	(150,585)
General Office	SG	2.963%	3.098%	4,149,017	10,243	(33,669)	4,115,348	10,202	(33,669)	4,081,679	10,118	(33,669)	4,048,009	10,035	(33,669)
General Office	SG	3.287%	3.288%	204,151	559	(1,294)	202,857	557	(1,294)	201,563	554	(1,294)	200,269	550	(1,294)
Customer Service	CN	8.230%	8.215%	21,753,359	149,198	(114,712)	21,638,647	148,805	(114,712)	21,523,935	148,018	(114,712)	21,409,224	147,231	(114,712)
Fuel Related	SE	2.653%	2.682%	774,707	1,712	(6,875)	767,832	1,705	(6,875)	760,956	1,690	(6,875)	754,081	1,674	(6,875)
Total General Plant				996,574,100	3,137,967	1,723,883	998,297,983	3,138,474	255,229	998,553,212	3,137,977	4,948,779	1,003,501,991	3,140,214	(67,928)
Mining Plant:															
Coal Mine	SE	3.569%	7.689%	292,563,015	870,120	(566,568)	291,996,447	869,278	1,485,269	293,481,716	870,644	(739,402)	292,742,314	871,753	796,189
Total Mining Plant				292,563,015	870,120	(566,568)	291,996,447	869,278	1,485,269	293,481,716	870,644	(739,402)	292,742,314	871,753	796,189
Subtotal				21,936,126,366	49,658,810	13,865,674	21,949,992,040	49,671,659	30,134,879	21,980,126,919	49,714,654	33,361,816	22,013,488,735	49,771,557	97,775,865

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - Dec 2013 Depreciation & Amortization Expense

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Jun 2012	Depreciation Expense Jun 2012	Adjustments	Adjusted EPIS Balance Jul 2012	Depreciation Expense Jul 2012	Adjustments	Adjusted EPIS Balance Aug 2012	Depreciation Expense Aug 2012	Adjustments	Adjusted EPIS Balance Sep 2012	Depreciation Expense Sep 2012	Adjustments
AMORTIZATION EXPENSE															
Intangible Plant:															
California	CA	0.000%	0.000%	353,808	-	-	353,808	-	-	353,808	-	-	353,808	-	-
Customer Service	CN	5.242%	5.242%	122,787,241	536,334	(17,785)	122,769,456	536,295	(17,785)	122,751,670	536,217	(17,785)	122,733,885	536,140	(17,785)
Pre-merger Utah	SG	2.788%	2.788%	600,993	1,397	(1,310)	599,683	1,395	(1,310)	598,373	1,392	(1,310)	597,063	1,389	(1,310)
Pre-merger Pacific	SG	0.000%	0.000%	-	-	(53,158)	(53,158)	-	(53,158)	(106,315)	-	(53,158)	(159,473)	-	(53,158)
Idaho	ID	1.478%	1.478%	1,431,992	1,764	-	1,431,992	1,764	-	1,431,992	1,764	-	1,431,992	1,764	-
Oregon	OR	0.295%	0.295%	3,994,986	981	(115)	3,994,872	981	(115)	3,994,757	981	(115)	3,994,642	981	(115)
Fuel Related	SE	9.457%	9.457%	3,666,461	28,896	(6,226)	3,660,235	28,871	(6,226)	3,654,008	28,822	(6,226)	3,647,782	28,773	(6,226)
Post-merger	SG	4.709%	4.709%	149,004,785	584,680	255,799	149,260,584	585,182	(641,937)	148,618,647	584,425	(685,272)	147,933,375	581,821	(685,272)
Hydro Relicensing	SG-P	2.628%	2.628%	99,510,474	217,912	(137,905)	99,372,569	217,761	(137,905)	99,234,663	217,459	(137,905)	99,096,758	217,157	(137,905)
Hydro Relicensing	SG-U	3.338%	3.338%	9,189,363	25,564	(8,563)	9,180,800	25,553	(8,563)	9,172,237	25,529	(8,563)	9,163,674	25,505	(8,563)
General Office	SO	5.350%	5.350%	383,331,947	1,708,911	(6,971)	383,324,976	1,708,895	(219,611)	383,105,365	1,708,390	(47,660)	383,057,705	1,707,794	1,688,739
Utah	UT	0.439%	0.439%	3,004,061	1,098	(82)	3,003,979	1,098	(82)	3,003,897	1,098	(82)	3,003,815	1,098	(82)
Washington	WA	0.000%	0.000%	1,465,232	-	(14)	1,465,218	-	(14)	1,465,203	-	(14)	1,465,189	-	(14)
Eastern Wyoming	WYP	9.592%	9.592%	1,507,442	12,049	(856)	1,506,586	12,046	(856)	1,505,730	12,039	(856)	1,504,874	12,032	(856)
Western Wyoming	WYU	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant				779,848,787	3,119,585	22,813	779,871,600	3,119,840	(1,087,563)	778,784,037	3,118,115	(958,947)	777,825,089	3,114,453	777,451
Hydro Production Plant:															
Pre-merger Pacific	SG	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.457%	2.457%	12,680,977	25,968	-	12,680,977	25,968	-	12,680,977	25,968	-	12,680,977	25,968	-
Post-merger	SG-U	6.237%	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-
Total Hydro Plant				13,395,003	29,679	-	13,395,003	29,679	-	13,395,003	29,679	-	13,395,003	29,679	-
Other Production Plant:															
Post-merger	SG	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-	-	-	-
General Plant:															
California	CA	2.753%	2.753%	352,021	807	-	352,021	807	-	352,021	807	-	352,021	807	-
General Office	CN	8.038%	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-
Oregon	OR	4.836%	4.836%	4,784,256	19,281	-	4,784,256	19,281	-	4,784,256	19,281	-	4,784,256	19,281	-
General Office	SO	7.897%	7.897%	16,195,557	106,575	-	16,195,557	106,575	-	16,195,557	106,575	-	16,195,557	106,575	-
Utah	UT	3.596%	3.596%	22,625	68	-	22,625	68	-	22,625	68	-	22,625	68	-
Washington	WA	3.204%	3.204%	2,895,621	7,732	-	2,895,621	7,732	-	2,895,621	7,732	-	2,895,621	7,732	-
Eastern Wyoming	WYP	7.791%	7.791%	4,703,443	30,535	-	4,703,443	30,535	-	4,703,443	30,535	-	4,703,443	30,535	-
Western Wyoming	WYU	8.640%	8.640%	55,782	402	-	55,782	402	-	55,782	402	-	55,782	402	-
Total General Plant				32,410,179	188,181	-	32,410,179	188,181.16	-	32,410,179	188,181.16	-	32,410,179	188,181.16	-
Subtotal				825,653,969	3,337,445	22,813	825,676,782	3,337,700	(1,087,563)	824,589,219	3,335,975	(958,947)	823,630,271	3,332,313	777,451
Total				22,761,780,335	52,996,255	13,888,487	22,775,668,822	53,009,359	29,047,316	22,804,716,138	53,050,629	32,402,869	22,837,119,007	53,103,870	98,553,316

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - Dec 2013 Depreciation & Amortization Expense

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Oct 2012	Depreciation Expense Oct 2012	Adjustments	Adjusted EPIS Balance Nov 2012	Depreciation Expense Nov 2012	Adjustments	Adjusted EPIS Balance Dec 2012	Depreciation Expense Dec 2012	Adjustments	Adjusted EPIS Balance Jan 2013	Depreciation Expense Jan 2013	Adjustments
DEPRECIATION EXPENSE															
Steam Production Plant:															
Pre-merger Pacific	SG	2.835%	4.644%	1,065,141,910	2,519,568	(2,436,494)	1,062,705,416	2,513,811	(2,436,494)	1,060,268,922	2,508,054	(2,436,494)	1,057,832,427	2,502,297	(2,436,494)
Pre-merger Utah	SG	2.496%	3.759%	1,152,872,946	2,400,314	(2,193,078)	1,150,679,867	2,395,752	(2,193,078)	1,148,486,789	2,391,190	(2,193,078)	1,146,293,710	2,386,629	(2,193,078)
Post-merger	SG	3.022%	5.226%	3,739,348,913	9,415,312	1,224,754	3,740,573,667	9,419,982	13,901,269	3,754,474,936	9,439,031	(1,818,457)	3,752,656,479	9,454,248	(1,818,457)
Geothermal - Blundell	SG	3.022%	5.226%	26,697,307	67,012	224,152	26,921,459	67,526	44,622	26,966,081	67,864	-	26,966,081	67,920	-
Pollution Control Equipment	SG	3.022%	5.226%	10,785,150	27,689	48,578	10,833,728	27,226	7,024,818	17,858,546	36,134	43,833	17,902,379	45,036	3,984,079
Pollution Control Equipment	SG	2.312%	4.670%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	2.312%	4.670%	521,356,185	1,005,843	(502,527)	520,853,658	1,004,094	2,588,952	523,442,611	1,006,104	(1,216,387)	522,226,224	1,007,426	(1,218,451)
Total Steam Plant				6,516,202,411	15,435,737	(3,634,615)	6,512,567,795	15,428,391	18,930,088	6,531,497,883	15,448,378	(7,620,583)	6,523,877,300	15,463,557	(3,682,401)
Hydro Production Plant:															
Pre-merger Pacific	SG	1.568%	2.309%	188,193,160	246,095	(248,338)	187,944,821	245,771	(248,338)	187,696,483	245,446	(248,338)	187,448,144	245,122	(248,338)
Pre-merger Utah	SG	2.218%	3.266%	42,650,325	78,883	(69,546)	42,580,779	78,754	(69,546)	42,511,233	78,626	(69,546)	42,441,687	78,497	(69,546)
Post-merger	SG-P	1.912%	2.654%	402,729,018	580,922	22,390,493	425,119,511	659,543	15,029,667	440,149,178	689,355	130,614	440,279,792	701,434	3,951,863
Post-merger	SG-U	2.722%	4.481%	100,991,084	229,111	19,269,119	120,260,203	250,899	189,299	120,449,502	272,964	(55,903)	120,393,599	273,116	(55,903)
Total Hydro Plant				734,563,587	1,135,011	41,341,727	775,905,315	1,234,967	14,901,082	790,806,396	1,286,392	(243,174)	790,563,223	1,298,168	3,578,076
Other Production Plant:															
Pre-merger Utah	SG	9.784%	0.000%	530,000	4,366	(11,013)	518,987	4,276	(11,013)	507,974	4,187	(11,013)	496,961	4,097	(11,013)
Post-merger	SG	2.569%	3.124%	1,228,881,663	2,631,556	19,473,632	1,248,355,294	2,651,678	2,662,610	1,251,017,904	2,675,373	(675,703)	1,250,342,202	2,677,499	348,095
Post-merger Wind	SG-W	4.042%	3.307%	1,802,354,971	6,070,663	(75,101)	1,802,279,870	6,070,410	1,585,855	1,803,865,725	6,072,954	(73,003)	1,803,792,722	6,075,502	(73,003)
Post-merger	SG	3.321%	3.980%	80,331,654	222,335	(59,645)	80,272,009	222,225	(59,645)	80,212,364	222,060	(59,645)	80,152,719	221,895	(59,645)
Total Other Plant				3,112,098,288	8,928,920	19,327,873	3,131,426,160	8,948,589	4,177,807	3,135,603,967	8,974,573	(819,364)	3,134,784,603	8,978,993	204,434
Transmission Plant:															
Pre-merger Pacific	SG	1.944%	1.821%	556,482,364	901,771	(460,913)	556,021,451	901,025	(460,913)	555,560,538	900,278	(460,913)	555,099,625	899,531	(460,913)
Pre-merger Utah	SG	1.897%	1.774%	652,985,278	1,032,632	(357,371)	652,627,907	1,032,067	(357,371)	652,270,536	1,031,502	(357,371)	651,913,164	1,030,937	(357,371)
Post-merger	SG	1.883%	1.802%	3,414,967,883	5,346,985	6,077,103	3,421,044,987	5,364,792	85,339,411	3,506,384,398	5,436,535	19,417,719	3,525,802,117	5,518,746	4,442,250
Total Transmission Plant				4,624,435,525	7,281,389	5,258,819	4,629,694,345	7,297,884	84,521,127	4,714,215,471	7,368,315	18,599,435	4,732,814,906	7,449,215	3,623,966
Distribution Plant:															
California	CA	2.891%	2.651%	228,239,472	549,734	272,511	228,511,983	550,215	336,703	228,848,686	550,949	414,734	229,263,420	551,854	423,803
Oregon	OR	2.842%	2.525%	1,789,047,340	4,233,871	2,980,609	1,792,027,949	4,240,596	3,658,769	1,795,686,718	4,248,458	2,246,896	1,797,933,613	4,255,451	2,461,678
Washington	WA	3.117%	2.801%	412,062,491	1,069,688	105,885	412,168,376	1,070,416	201,250	412,369,626	1,070,815	195,767	412,565,393	1,071,330	218,703
Eastern Wyoming	WYP	2.832%	2.792%	513,411,150	1,208,173	1,470,010	514,881,159	1,213,487	1,560,030	516,441,190	1,217,063	1,324,821	517,766,011	1,220,467	1,512,797
Utah	UT	2.480%	2.426%	2,495,794,771	5,155,289	3,789,606	2,499,584,377	5,161,931	4,444,325	2,504,028,702	5,170,439	2,457,812	2,506,486,514	5,177,572	3,632,794
Idaho	ID	2.574%	2.262%	290,001,206	621,075	340,722	290,341,928	622,443	311,575	290,653,503	623,143	568,627	291,222,130	624,087	617,155
Western Wyoming	WYU	2.983%	2.974%	98,435,793	244,828	(79,123)	98,356,670	244,631	(79,123)	98,277,547	244,435	(79,123)	98,198,424	244,238	(79,123)
Total Distribution Plant				5,826,992,224	13,082,659	8,880,219	5,835,872,443	13,103,719	10,433,529	5,846,305,972	13,125,301	7,129,534	5,853,435,506	13,144,999	8,787,807
General Plant:															
California	CA	2.058%	2.007%	14,695,541	25,185	(27,796)	14,667,745	25,180	362,472	15,030,217	25,467	119,075	15,149,292	25,880	26,657
Oregon	OR	2.441%	2.467%	167,226,026	340,208	1,705,595	168,931,621	341,968	3,302,263	172,233,884	347,062	(357,648)	171,876,236	350,058	(355,505)
Washington	WA	3.390%	2.828%	43,923,377	123,991	120,051	44,043,429	124,241	194,249	44,237,677	124,684	(79,096)	44,158,581	124,847	119,528
Eastern Wyoming	WYP	3.706%	3.283%	63,055,139	193,310	449,920	63,505,059	195,454	721,464	64,226,523	197,263	238,261	64,464,784	198,745	(32,835)
Utah	UT	2.214%	2.231%	191,031,071	352,998	1,060,529	192,091,600	353,504	2,442,075	194,533,675	356,736	(111,554)	194,422,121	358,886	208,281
Idaho	ID	2.259%	2.281%	35,538,596	66,808	(31,723)	35,506,873	66,883	1,044,230	36,551,103	67,836	263,619	36,814,721	69,068	8,921
Western Wyoming	WYU	2.801%	2.403%	13,953,495	32,621	(46,675)	13,906,820	32,513	(46,675)	13,860,145	32,404	(46,675)	13,813,470	32,295	(46,675)
Pre-merger Pacific	SG	2.985%	2.808%	2,869,421	7,300	(129,438)	2,739,982	6,978	(129,438)	2,610,544	6,656	(129,438)	2,481,106	6,334	(129,438)
Pre-merger Utah	SG	2.074%	2.060%	5,182,288	9,186	(265,935)	4,916,353	8,726	(265,935)	4,650,418	8,266	(265,935)	4,384,483	7,807	(265,935)
Post-merger	SG	3.387%	3.338%	207,638,088	585,999	452,456	208,090,544	586,693	8,959,263	217,049,807	599,976	(154,291)	216,895,517	612,402	(136,945)
General Office	SO	6.447%	6.426%	232,065,989	1,247,215	106,570	232,172,559	1,247,097	505,820	232,678,380	1,248,742	(101,971)	232,576,409	1,249,827	(1,127,397)
General Office	SG	2.963%	3.098%	4,014,340	9,952	(33,669)	3,980,670	9,869	351,311	4,331,982	10,261	(33,669)	4,298,312	10,653	(33,669)
General Office	SG	3.287%	3.288%	198,974	547	(1,294)	197,680	543	(1,294)	196,386	540	(1,294)	195,092	536	(1,294)
Customer Service	CN	8.230%	8.215%	21,294,512	146,444	(114,712)	21,179,800	145,658	(114,712)	21,065,088	144,871	(114,712)	20,950,376	144,084	(114,712)
Fuel Related	SE	2.653%	2.682%	747,206	1,659	(6,875)	740,330	1,644	(6,875)	733,455	1,629	(6,875)	726,579	1,614	(6,875)
Total General Plant				1,003,434,063	3,143,424	3,237,002	1,006,671,065	3,146,951	17,318,218	1,023,989,283	3,172,394	(782,204)	1,023,207,079	3,193,036	(1,887,895)
Mining Plant:															
Coal Mine	SE	3.569%	7.689%	293,538,502	871,837	(265,160)	293,273,343	872,627	(679,223)	292,594,119	871,223	3,572,839	296,166,958	875,526	(399,161)
Total Mining Plant				293,538,502	871,837	(265,160)	293,273,343	872,627	(679,223)	292,594,119	871,223	3,572,839	296,166,958	875,526	(399,161)
Subtotal				22,111,264,600	49,878,977	74,145,866	22,185,410,466	50,033,128	149,602,627	22,335,013,093	50,246,576	19,836,482	22,354,849,575	50,403,493	10,224,824

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - Dec 2013 Depreciation & Amortization Expense

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Oct 2012	Depreciation Expense Oct 2012	Adjustments	Adjusted EPIS Balance Nov 2012	Depreciation Expense Nov 2012	Adjustments	Adjusted EPIS Balance Dec 2012	Depreciation Expense Dec 2012	Adjustments	Adjusted EPIS Balance Jan 2013	Depreciation Expense Jan 2013	Adjustments
AMORTIZATION EXPENSE															
Intangible Plant:															
California	CA	0.000%	0.000%	353,808	-	-	353,808	-	-	353,808	-	-	353,808	-	-
Customer Service	CN	5.242%	5.242%	122,716,099	536,062	(17,785)	122,698,314	535,984	(17,785)	122,680,528	535,907	(17,785)	122,662,743	535,829	(17,785)
Pre-merger Utah	SG	2.788%	2.788%	595,754	1,386	(1,310)	594,444	1,383	(1,310)	593,134	1,380	(1,310)	591,824	1,377	(1,310)
Pre-merger Pacific	SG	0.000%	0.000%	(212,630)	-	(53,158)	(265,788)	-	(53,158)	(318,945)	-	(53,158)	(372,103)	-	(53,158)
Idaho	ID	1.478%	1.478%	1,431,992	1,764	-	1,431,992	1,764	-	1,431,992	1,764	-	1,431,992	1,764	-
Oregon	OR	0.295%	0.295%	3,994,528	981	(115)	3,994,413	981	(115)	3,994,298	980	(115)	3,994,183	980	(115)
Fuel Related	SE	9.457%	9.457%	3,641,555	28,724	(6,226)	3,635,329	28,675	(6,226)	3,629,102	28,626	(6,226)	3,622,876	28,577	(6,226)
Post-merger	SG	4.709%	4.709%	147,248,103	579,132	(685,272)	146,562,830	576,443	5,804,616	152,367,447	586,487	(685,272)	151,682,175	596,531	(685,272)
Hydro Relicensing	SG-P	2.628%	2.628%	98,958,852	216,855	(137,905)	98,820,947	216,553	(137,905)	98,683,041	216,251	(137,905)	98,545,136	215,949	(137,905)
Hydro Relicensing	SG-U	3.338%	3.338%	9,155,111	25,481	(8,563)	9,146,548	25,457	(8,563)	9,137,985	25,433	(8,563)	9,129,422	25,410	(8,563)
General Office	SO	5.350%	5.350%	384,746,443	1,711,452	746,049	385,492,493	1,716,879	1,086,753	386,579,246	1,720,965	591,481	387,170,727	1,724,706	(283,575)
Utah	UT	0.439%	0.439%	3,003,733	1,098	(82)	3,003,650	1,098	(82)	3,003,568	1,098	(82)	3,003,486	1,098	(82)
Washington	WA	0.000%	0.000%	1,465,175	-	(14)	1,465,161	-	(14)	1,465,147	-	(14)	1,465,133	-	(14)
Eastern Wyoming	WYP	9.592%	9.592%	1,504,018	12,025	(856)	1,503,161	12,018	(856)	1,502,305	12,011	(856)	1,501,449	12,005	(856)
Western Wyoming	WYU	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant				778,602,540	3,114,960	(165,238)	778,437,302	3,117,235	6,665,355	785,102,657	3,130,902	(319,806)	784,782,851	3,144,224	(1,194,863)
Hydro Production Plant:															
Pre-merger Pacific	SG	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.457%	2.457%	12,680,977	25,968	-	12,680,977	25,968	-	12,680,977	25,968	-	12,680,977	25,968	-
Post-merger	SG-U	6.237%	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-
Total Hydro Plant				13,395,003	29,679	-	13,395,003	29,679	-	13,395,003	29,679	-	13,395,003	29,679	-
Other Production Plant:															
Post-merger	SG	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-	-	-	-
General Plant:															
California	CA	2.753%	2.753%	352,021	807	-	352,021	807	-	352,021	807	-	352,021	807	-
General Office	CN	8.038%	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-
Oregon	OR	4.836%	4.836%	4,784,256	19,281	-	4,784,256	19,281	-	4,784,256	19,281	-	4,784,256	19,281	-
General Office	SO	7.897%	7.897%	16,195,557	106,575	-	16,195,557	106,575	-	16,195,557	106,575	-	16,195,557	106,575	-
Utah	UT	3.596%	3.596%	22,625	68	-	22,625	68	-	22,625	68	-	22,625	68	-
Washington	WA	3.204%	3.204%	2,895,621	7,732	-	2,895,621	7,732	-	2,895,621	7,732	-	2,895,621	7,732	-
Eastern Wyoming	WYP	7.791%	7.791%	4,703,443	30,535	-	4,703,443	30,535	-	4,703,443	30,535	-	4,703,443	30,535	-
Western Wyoming	WYU	8.640%	8.640%	55,782	402	-	55,782	402	-	55,782	402	-	55,782	402	-
Total General Plant				32,410,179	188,181.16	-	32,410,179	188,181.16	-	32,410,179	188,181.16	-	32,410,179	188,181.16	-
Subtotal				824,407,723	3,332,819	(165,238)	824,242,485	3,335,095	6,665,355	830,907,839	3,348,762	(319,806)	830,588,033	3,362,084	(1,194,863)
Total				22,935,672,323	53,211,796	73,980,628	23,009,652,950	53,368,223	156,267,981	23,165,920,932	53,595,337	19,516,676	23,185,437,608	53,765,577	9,029,961

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - Dec 2013 Depreciation & Amortization Expense

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Feb 2013	Depreciation Expense Feb 2013	Adjustments	Adjusted EPIS Balance Mar 2013	Depreciation Expense Mar 2013	Adjustments	Adjusted EPIS Balance Apr 2013	Depreciation Expense Apr 2013	Adjustments	Adjusted EPIS Balance May 2013	Depreciation Expense May 2013	Adjustments
DEPRECIATION EXPENSE															
Steam Production Plant:															
Pre-merger Pacific	SG	2.835%	4.644%	1,055,395,933	2,496,540	(2,436,494)	1,052,959,438	2,490,783	(2,436,494)	1,050,522,944	2,485,027	(2,436,494)	1,048,086,449	2,479,270	(2,436,494)
Pre-merger Utah	SG	2.496%	3.759%	1,144,100,632	2,382,067	(2,193,078)	1,141,907,553	2,377,505	(2,193,078)	1,139,714,475	2,372,943	(2,193,078)	1,137,521,397	2,368,382	(2,193,078)
Post-merger	SG	3.022%	5.226%	3,750,838,022	9,449,668	(255,315)	3,750,582,708	9,447,056	5,696,899	3,756,279,607	9,453,909	39,199,072	3,795,478,679	9,510,450	7,360,554
Geothermal - Blundell	SG	3.022%	5.226%	26,966,081	67,920	-	26,966,081	67,920	-	26,966,081	67,920	-	26,966,081	67,920	-
Pollution Control Equipment	SG	3.022%	5.226%	21,886,458	50,109	38,833	21,925,291	55,175	38,833	21,964,124	55,273	16,804	21,980,928	55,343	16,804
Pollution Control Equipment	SG	2.312%	4.670%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	2.312%	4.670%	521,007,773	1,005,080	(1,218,451)	519,789,322	1,002,733	(1,023,179)	518,766,143	1,000,573	3,616,666	522,382,809	1,003,071	(1,293,159)
Total Steam Plant				6,520,194,899	15,451,385	(6,064,506)	6,514,130,393	15,441,173	82,980	6,514,213,374	15,435,645	38,202,969	6,552,416,343	15,484,436	1,454,626
Hydro Production Plant:															
Pre-merger Pacific	SG	1.568%	2.309%	187,199,806	244,797	(248,338)	186,951,468	244,473	(248,338)	186,703,129	244,148	(248,338)	186,454,791	243,824	(248,338)
Pre-merger Utah	SG	2.218%	3.266%	42,372,141	78,369	(69,546)	42,302,595	78,240	(69,546)	42,233,049	78,112	(69,546)	42,163,503	77,983	(69,546)
Post-merger	SG-P	1.912%	2.654%	444,231,655	704,686	(4,503)	444,227,152	707,831	969,918	445,197,070	708,600	15,485,397	460,682,467	721,710	150,080
Post-merger	SG-U	2.722%	4.481%	120,337,696	272,989	(55,903)	120,281,793	272,862	(55,903)	120,225,890	272,735	(55,903)	120,169,987	272,608	(55,903)
Total Hydro Plant				794,141,298	1,300,841	(378,291)	793,763,008	1,303,406	596,131	794,359,138	1,303,595	15,111,609	809,470,748	1,316,125	(223,707)
Other Production Plant:															
Pre-merger Utah	SG	9.784%	0.000%	485,948	4,007	(11,013)	474,935	3,917	(11,013)	463,922	3,827	(11,013)	452,909	3,738	(11,013)
Post-merger	SG	2.569%	3.124%	1,250,690,297	2,677,149	(675,703)	1,250,014,594	2,676,798	5,797,837	1,255,812,430	2,682,281	(498,943)	1,255,313,487	2,687,953	(379,662)
Post-merger Wind	SG-W	4.042%	3.307%	1,803,719,719	6,075,256	(73,003)	1,803,646,715	6,075,010	(73,003)	1,803,573,712	6,074,764	(73,003)	1,803,500,709	6,074,518	(75,914)
Post-merger	SG	3.321%	3.980%	80,093,074	221,730	(59,645)	80,033,429	221,565	(59,645)	79,973,784	221,400	(59,645)	79,914,139	221,235	(59,645)
Total Other Plant				3,134,989,037	8,978,142	(819,364)	3,134,169,673	8,977,290	5,654,176	3,139,823,849	8,982,272	(642,604)	3,139,181,244	8,987,444	(526,234)
Transmission Plant:															
Pre-merger Pacific	SG	1.944%	1.821%	554,638,713	898,785	(460,913)	554,177,800	898,038	(460,913)	553,716,887	897,292	(460,913)	553,255,974	896,545	(460,913)
Pre-merger Utah	SG	1.897%	1.774%	651,555,793	1,030,372	(357,371)	651,198,422	1,029,807	(357,371)	650,841,050	1,029,242	(357,371)	650,483,679	1,028,677	(357,371)
Post-merger	SG	1.883%	1.802%	3,530,244,367	5,537,471	4,729,165	3,534,973,531	5,544,669	5,514,636	3,540,488,167	5,552,708	390,111,853	3,930,600,020	5,863,189	34,920,138
Total Transmission Plant				4,736,438,872	7,466,628	3,910,881	4,740,349,753	7,472,514	4,696,352	4,745,046,104	7,479,242	389,293,569	5,134,339,673	7,788,412	34,101,854
Distribution Plant:															
California	CA	2.891%	2.651%	229,687,223	552,864	497,664	230,184,888	553,974	405,952	230,590,840	555,063	424,312	231,015,151	556,063	442,410
Oregon	OR	2.842%	2.525%	1,800,395,291	4,261,027	2,719,950	1,803,115,241	4,267,163	2,935,834	1,806,051,075	4,273,860	2,950,165	1,809,001,240	4,280,830	2,560,721
Washington	WA	3.117%	2.801%	412,784,096	1,071,869	346,556	413,130,652	1,072,603	272,954	413,403,606	1,073,407	281,037	413,684,643	1,074,127	298,553
Eastern Wyoming	WYP	2.832%	2.792%	519,278,808	1,223,816	1,517,938	520,796,745	1,227,392	1,468,381	522,265,126	1,230,916	1,482,324	523,747,450	1,234,399	1,578,123
Utah	UT	2.480%	2.426%	2,510,119,308	5,183,865	2,331,476	2,512,450,784	5,190,028	2,536,434	2,514,987,217	5,195,059	9,911,732	2,524,898,949	5,207,922	3,113,750
Idaho	ID	2.574%	2.262%	291,839,285	625,359	669,693	292,508,978	626,739	717,229	293,226,207	628,226	683,224	293,909,431	629,728	791,035
Western Wyoming	WYU	2.983%	2.974%	98,119,301	244,041	(79,123)	98,040,178	243,845	(79,123)	97,961,056	243,648	(79,123)	97,881,933	243,451	(79,123)
Total Distribution Plant				5,862,223,312	13,162,841	8,004,154	5,870,227,466	13,181,744	8,257,661	5,878,485,127	13,200,180	15,653,670	5,894,138,797	13,226,520	8,705,468
General Plant:															
California	CA	2.058%	2.007%	15,175,950	26,005	114,043	15,289,992	26,126	41,317	15,331,309	26,259	36,853	15,368,162	26,326	72,439
Oregon	OR	2.441%	2.467%	171,520,731	349,332	645,410	172,166,140	349,627	67,814	172,233,954	350,353	(349,762)	171,884,192	350,066	1,363,201
Washington	WA	3.390%	2.828%	44,278,109	124,904	48,337	44,326,446	125,141	(76,053)	44,250,393	125,102	(76,781)	44,173,612	124,886	(73,806)
Eastern Wyoming	WYP	3.706%	3.283%	64,431,950	199,062	415,034	64,846,983	199,653	(39,486)	64,807,498	200,233	(35,636)	64,771,861	200,117	159,704
Utah	UT	2.214%	2.231%	194,630,402	358,976	1,043,657	195,674,059	360,131	(148,789)	195,525,270	360,956	(137,121)	195,388,149	360,693	965,230
Idaho	ID	2.259%	2.281%	36,823,642	69,324	166,880	36,990,523	69,490	2,365	36,992,888	69,649	6,002	36,998,890	69,657	7,174
Western Wyoming	WYU	2.801%	2.403%	13,766,795	32,186	(46,675)	13,720,120	32,077	(46,675)	13,673,444	31,968	(46,675)	13,626,769	31,859	(46,675)
Pre-merger Pacific	SG	2.985%	2.808%	2,351,667	6,012	(129,438)	2,222,229	5,690	(129,438)	2,092,791	5,368	(129,438)	1,963,352	5,046	(129,438)
Pre-merger Utah	SG	2.074%	2.060%	4,118,548	7,347	(265,935)	3,852,613	6,888	(265,935)	3,586,678	6,428	(265,935)	3,320,743	5,969	(265,935)
Post-merger	SG	3.387%	3.338%	216,758,571	611,991	(139,241)	216,619,331	611,601	(133,848)	216,485,483	611,215	310,578	216,796,061	611,465	301,480
General Office	SO	6.447%	6.426%	231,449,012	1,246,524	(901,406)	230,547,606	1,241,074	(818,111)	229,729,495	1,236,455	(953,198)	228,776,296	1,231,697	(874,406)
General Office	SG	2.963%	3.098%	4,264,643	10,570	(33,669)	4,230,973	10,487	931,123	5,162,096	11,595	(33,669)	5,128,427	12,703	(33,669)
General Office	SG	3.287%	3.288%	193,798	533	(1,294)	192,504	529	(1,294)	191,210	526	(1,294)	189,915	522	(1,294)
Customer Service	CN	8.230%	8.215%	20,835,664	143,297	(114,712)	20,720,952	142,511	(114,712)	20,606,240	141,724	(114,712)	20,491,528	140,937	(114,712)
Fuel Related	SE	2.653%	2.682%	719,704	1,598	(6,875)	712,828	1,583	(6,875)	705,953	1,568	(6,875)	699,077	1,553	(6,875)
Total General Plant				1,021,319,184	3,187,663	794,115	1,022,113,299	3,182,607	(738,598)	1,021,374,701	3,179,399	(1,797,666)	1,019,577,035	3,173,494	1,322,416
Mining Plant:															
Coal Mine	SE	3.569%	7.689%	295,767,796	880,245	(590,161)	295,177,635	878,774	4,003,839	299,181,473	883,850	(664,161)	298,517,312	888,817	12,839
Total Mining Plant				295,767,796	880,245	(590,161)	295,177,635	878,774	4,003,839	299,181,473	883,850	(664,161)	298,517,312	888,817	12,839
Subtotal				22,365,074,398	50,427,744	4,856,828	22,369,931,226	50,437,508	22,552,540	22,392,483,766	50,464,184	455,157,385	22,847,641,152	50,865,247	44,847,260

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - Dec 2013 Depreciation & Amortization Expense

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Feb 2013	Depreciation Expense Feb 2013	Adjustments	Adjusted EPIS Balance Mar 2013	Depreciation Expense Mar 2013	Adjustments	Adjusted EPIS Balance Apr 2013	Depreciation Expense Apr 2013	Adjustments	Adjusted EPIS Balance May 2013	Depreciation Expense May 2013	Adjustments
AMORTIZATION EXPENSE															
Intangible Plant:															
California	CA	0.000%	0.000%	353,808	-	-	353,808	-	-	353,808	-	-	353,808	-	-
Customer Service	CN	5.242%	5.242%	122,644,957	535,751	(17,785)	122,627,172	535,674	(17,785)	122,609,386	535,596	(17,785)	122,591,601	535,518	(17,785)
Pre-merger Utah	SG	2.788%	2.788%	590,514	1,374	(1,310)	589,204	1,371	(1,310)	587,894	1,368	(1,310)	586,584	1,365	(1,310)
Pre-merger Pacific	SG	0.000%	0.000%	(425,260)	-	(53,158)	(478,418)	-	(53,158)	(531,576)	-	(53,158)	(584,733)	-	(53,158)
Idaho	ID	1.478%	1.478%	1,431,992	1,764	-	1,431,992	1,764	-	1,431,992	1,764	-	1,431,992	1,764	-
Oregon	OR	0.295%	0.295%	3,994,069	980	(115)	3,993,954	980	(115)	3,993,839	980	(115)	3,993,725	980	(115)
Fuel Related	SE	9.457%	9.457%	3,616,650	28,528	(6,226)	3,610,423	28,479	(6,226)	3,604,197	28,430	(6,226)	3,597,970	28,381	(6,226)
Post-merger	SG	4.709%	4.709%	150,996,902	593,842	(685,272)	150,311,630	591,153	(685,272)	149,626,358	588,464	(685,272)	148,941,085	585,775	(685,272)
Hydro Relicensing	SG-P	2.628%	2.628%	98,407,230	215,647	(137,905)	98,269,325	215,345	(137,905)	98,131,419	215,043	(137,905)	97,993,514	214,741	(137,905)
Hydro Relicensing	SG-U	3.338%	3.338%	9,120,859	25,386	(8,563)	9,112,296	25,362	(8,563)	9,103,733	25,338	(8,563)	9,095,170	25,314	(8,563)
General Office	SO	5.350%	5.350%	386,887,152	1,725,392	(90,542)	386,796,609	1,724,558	(19,643)	386,776,966	1,724,312	(134,921)	386,642,045	1,723,968	(67,402)
Utah	UT	0.439%	0.439%	3,003,404	1,098	(82)	3,003,322	1,098	(82)	3,003,240	1,098	(82)	3,003,157	1,098	(82)
Washington	WA	0.000%	0.000%	1,465,119	-	(14)	1,465,104	-	(14)	1,465,090	-	(14)	1,465,076	-	(14)
Eastern Wyoming	WYP	9.592%	9.592%	1,500,593	11,998	(856)	1,499,736	11,991	(856)	1,498,880	11,984	(856)	1,498,024	11,977	(856)
Western Wyoming	WYU	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant				783,587,988	3,141,759	(1,001,830)	782,586,158	3,137,774	(930,931)	781,655,227	3,134,377	(1,046,209)	780,609,019	3,130,881	(978,689)
Hydro Production Plant:															
Pre-merger Pacific	SG	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.457%	2.457%	12,680,977	25,968	-	12,680,977	25,968	-	12,680,977	25,968	-	12,680,977	25,968	-
Post-merger	SG-U	6.237%	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-
Total Hydro Plant				13,395,003	29,679	-	13,395,003	29,679	-	13,395,003	29,679	-	13,395,003	29,679	-
Other Production Plant:															
Post-merger	SG	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-	-	-	-
General Plant:															
California	CA	2.753%	2.753%	352,021	807	-	352,021	807	-	352,021	807	-	352,021	807	-
General Office	CN	8.038%	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-
Oregon	OR	4.836%	4.836%	4,784,256	19,281	-	4,784,256	19,281	-	4,784,256	19,281	-	4,784,256	19,281	-
General Office	SO	7.897%	7.897%	16,195,557	106,575	-	16,195,557	106,575	-	16,195,557	106,575	-	16,195,557	106,575	-
Utah	UT	3.596%	3.596%	22,625	68	-	22,625	68	-	22,625	68	-	22,625	68	-
Washington	WA	3.204%	3.204%	2,895,621	7,732	-	2,895,621	7,732	-	2,895,621	7,732	-	2,895,621	7,732	-
Eastern Wyoming	WYP	7.791%	7.791%	4,703,443	30,535	-	4,703,443	30,535	-	4,703,443	30,535	-	4,703,443	30,535	-
Western Wyoming	WYU	8.640%	8.640%	55,782	402	-	55,782	402	-	55,782	402	-	55,782	402	-
Total General Plant				32,410,179	188,181.16	-	32,410,179	188,181.16	-	32,410,179	188,181.16	-	32,410,179	188,181.16	-
Subtotal				829,393,170	3,359,619	(1,001,830)	828,391,340	3,355,633	(930,931)	827,460,409	3,352,236	(1,046,209)	826,414,201	3,348,740	(978,689)
Total				23,194,467,568	53,787,363	3,854,998	23,198,322,566	53,793,142	21,621,609	23,219,944,176	53,816,420	454,111,177	23,674,055,352	54,213,988	43,868,571

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - Dec 2013 Depreciation & Amortization Expense

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Jun 2013	Depreciation Expense Jun 2013	Adjustments	Adjusted EPIS Balance Jul 2013	Depreciation Expense Jul 2013	Adjustments	Adjusted EPIS Balance Aug 2013	Depreciation Expense Aug 2013	Adjustments	Adjusted EPIS Balance Sep 2013	Depreciation Expense Sep 2013	Adjustments
DEPRECIATION EXPENSE															
Steam Production Plant:															
Pre-merger Pacific	SG	2.835%	4.644%	1,045,649,955	2,473,513	(2,436,494)	1,043,213,460	2,467,756	(2,436,494)	1,040,776,966	2,461,999	(2,436,494)	1,038,340,472	2,456,242	(2,436,494)
Pre-merger Utah	SG	2.496%	3.759%	1,135,328,318	2,363,820	(2,193,078)	1,133,135,240	2,359,258	(2,193,078)	1,130,942,161	2,354,697	(2,193,078)	1,128,749,083	2,350,135	(2,193,078)
Post-merger	SG	3.022%	5.226%	3,802,839,233	9,569,085	(1,832,997)	3,801,006,237	9,576,047	(481,820)	3,800,524,417	9,573,131	(901,284)	3,799,623,133	9,571,390	(631,850)
Geothermal - Blundell	SG	3.022%	5.226%	26,966,081	67,920	-	26,966,081	67,920	-	26,966,081	67,920	-	26,966,081	67,920	-
Pollution Control Equipment	SG	3.022%	5.226%	21,997,732	55,385	16,804	22,014,536	55,428	1,902,180	23,916,716	57,844	4,637,507	28,554,223	66,080	16,804
Pollution Control Equipment	SG	2.312%	4.670%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	2.312%	4.670%	521,089,649	1,005,310	(1,318,451)	519,771,198	1,002,794	(398,277)	519,372,921	1,001,140	(783,128)	518,589,793	1,000,002	(1,245,128)
Total Steam Plant				6,553,870,968	15,535,034	(7,764,217)	6,546,106,752	15,529,203	(3,607,490)	6,542,499,261	15,516,732	(1,676,477)	6,540,822,784	15,511,769	(6,489,747)
Hydro Production Plant:															
Pre-merger Pacific	SG	1.568%	2.309%	186,206,452	243,499	(248,338)	185,958,114	243,174	(248,338)	185,709,776	242,850	(248,338)	185,461,437	242,525	(248,338)
Pre-merger Utah	SG	2.218%	3.266%	42,093,957	77,855	(69,546)	42,024,411	77,726	(69,546)	41,954,865	77,598	(69,546)	41,885,319	77,469	(69,546)
Post-merger	SG-P	1.912%	2.654%	460,832,547	734,167	27,440,825	488,273,372	756,148	(213,082)	488,060,290	777,840	937,862	488,998,152	778,418	11,191,732
Post-merger	SG-U	2.722%	4.481%	120,114,084	272,482	(55,903)	120,058,181	272,355	(55,903)	120,002,278	272,228	(55,903)	119,946,375	272,101	(55,903)
Total Hydro Plant				809,247,040	1,328,002	27,067,037	836,314,078	1,349,404	(586,869)	835,727,208	1,370,516	564,075	836,291,283	1,370,514	10,817,945
Other Production Plant:															
Pre-merger Utah	SG	9.784%	0.000%	441,895	3,648	(11,013)	430,882	3,558	(11,013)	419,869	3,468	(11,013)	408,856	3,378	(11,013)
Post-merger	SG	2.569%	3.124%	1,254,933,825	2,687,012	(675,703)	1,254,258,122	2,685,883	200,393	1,254,458,515	2,685,374	(529,687)	1,253,928,828	2,685,022	(412,031)
Post-merger Wind	SG-W	4.042%	3.307%	1,803,424,795	6,074,267	(75,914)	1,803,348,881	6,074,012	(75,914)	1,803,272,967	6,073,756	(75,914)	1,803,197,053	6,073,500	(75,914)
Post-merger	SG	3.321%	3.980%	79,854,495	221,070	(59,645)	79,794,850	220,905	(59,645)	79,735,205	220,740	(59,645)	79,675,560	220,575	(59,645)
Total Other Plant				3,138,655,010	8,985,997	(822,275)	3,137,832,735	8,984,357	53,821	3,137,886,556	8,983,338	(676,259)	3,137,210,297	8,982,475	(558,603)
Transmission Plant:															
Pre-merger Pacific	SG	1.944%	1.821%	552,795,062	895,799	(460,913)	552,334,149	895,052	(460,913)	551,873,236	894,305	(460,913)	551,412,323	893,559	(460,913)
Pre-merger Utah	SG	1.897%	1.774%	650,126,308	1,028,112	(357,371)	649,768,936	1,027,547	(357,371)	649,411,565	1,026,982	(357,371)	649,054,194	1,026,417	(357,371)
Post-merger	SG	1.883%	1.802%	3,965,520,158	6,196,747	7,192,044	3,972,712,201	6,229,796	7,300,763	3,980,012,964	6,241,170	15,232,998	3,995,245,962	6,258,854	21,114,043
Total Transmission Plant				5,168,441,527	8,120,658	6,373,759	5,174,815,286	8,152,396	6,482,478	5,181,297,765	8,162,458	14,414,714	5,195,712,478	8,178,830	20,295,759
Distribution Plant:															
California	CA	2.891%	2.651%	231,457,561	557,107	427,860	231,885,421	558,155	515,066	232,400,487	559,291	427,080	232,827,567	560,426	415,486
Oregon	OR	2.842%	2.525%	1,811,561,961	4,287,356	6,811,389	1,818,373,350	4,298,454	2,731,689	1,821,105,038	4,309,755	2,421,095	1,823,526,133	4,315,857	7,199,985
Washington	WA	3.117%	2.801%	413,983,196	1,074,879	258,806	414,242,001	1,075,603	340,261	414,582,262	1,076,381	245,077	414,827,339	1,077,141	212,260
Eastern Wyoming	WYP	2.832%	2.792%	525,325,573	1,238,010	1,690,980	527,016,553	1,241,868	2,015,763	529,032,316	1,246,242	1,595,403	530,627,719	1,250,504	2,966,129
Utah	UT	2.480%	2.426%	2,528,012,699	5,221,382	3,455,588	2,531,468,287	5,228,170	4,063,376	2,535,531,663	5,235,940	4,001,557	2,539,533,220	5,244,273	2,600,799
Idaho	ID	2.574%	2.262%	294,700,466	631,310	735,135	295,435,602	632,947	844,555	296,280,157	634,641	731,689	297,011,845	636,331	600,333
Western Wyoming	WYU	2.983%	2.974%	97,802,810	243,254	(79,123)	97,723,687	243,058	(79,123)	97,644,564	242,861	(79,123)	97,565,441	242,664	(79,123)
Total Distribution Plant				5,902,844,265	13,253,298	13,300,636	5,916,144,901	13,278,255	10,431,587	5,926,576,487	13,305,111	9,342,778	5,935,919,266	13,327,197	13,915,869
General Plant:															
California	CA	2.058%	2.007%	15,440,601	26,420	29,609	15,470,210	26,507	43,721	15,513,932	26,570	34,151	15,548,083	26,637	616,450
Oregon	OR	2.441%	2.467%	173,247,393	351,097	(373,708)	172,873,685	352,104	(345,419)	172,528,266	351,372	151,359	172,679,625	351,175	4,231,396
Washington	WA	3.390%	2.828%	44,099,806	124,674	(77,939)	44,021,867	124,459	(75,831)	43,946,036	124,242	(79,237)	43,866,799	124,023	337,924
Eastern Wyoming	WYP	3.706%	3.283%	64,931,565	200,308	(6,495)	64,925,070	200,545	(3,500)	64,921,570	200,529	3,813	64,925,383	200,530	844,134
Utah	UT	2.214%	2.231%	196,353,378	361,457	(38,831)	196,314,548	362,311	(25,285)	196,289,263	362,252	243,100	196,532,363	362,453	6,875,587
Idaho	ID	2.259%	2.281%	37,006,063	69,669	33,782	37,039,846	69,708	36,443	37,076,289	69,774	22,503	37,098,792	69,830	234,001
Western Wyoming	WYU	2.801%	2.403%	13,580,094	31,750	(46,675)	13,533,419	31,641	(46,675)	13,486,744	31,532	(46,675)	13,440,069	31,423	(46,675)
Pre-merger Pacific	SG	2.985%	2.808%	1,833,914	4,724	(129,438)	1,704,475	4,402	(129,438)	1,575,037	4,080	(129,438)	1,445,599	3,757	(129,438)
Pre-merger Utah	SG	2.074%	2.060%	3,054,808	5,509	(265,935)	2,788,873	5,049	(265,935)	2,522,938	4,590	(265,935)	2,257,003	4,130	(265,935)
Post-merger	SG	3.387%	3.338%	217,097,540	612,329	(397,350)	216,700,190	612,193	(237,132)	216,463,058	611,298	(415,686)	216,047,372	610,377	1,180,563
General Office	SO	6.447%	6.426%	227,901,890	1,226,787	(650,010)	227,251,881	1,222,692	(650,972)	226,600,909	1,219,197	(905,145)	225,695,764	1,215,017	(527,463)
General Office	SG	2.963%	3.098%	5,094,757	12,620	(33,669)	5,061,088	12,536	(33,669)	5,027,419	12,453	(33,669)	4,993,749	12,370	(33,669)
General Office	SG	3.287%	3.288%	188,621	518	(1,294)	187,327	515	(1,294)	186,033	511	(1,294)	184,739	508	(1,294)
Customer Service	CN	8.230%	8.215%	20,376,817	140,150	(114,712)	20,262,105	139,364	(114,712)	20,147,393	138,577	(114,712)	20,032,681	137,790	(114,712)
Fuel Related	SE	2.653%	2.682%	692,202	1,538	(6,875)	685,326	1,522	(6,875)	678,451	1,507	(6,875)	671,575	1,492	(6,875)
Total General Plant				1,020,899,451	3,169,549	(2,079,541)	1,018,819,910	3,165,550	(1,856,574)	1,016,963,336	3,158,486	(1,543,741)	1,015,419,596	3,151,512	13,193,992
Mining Plant:															
Coal Mine	SE	3.569%	7.689%	298,530,150	887,848	344,839	298,874,989	888,380	848,839	299,723,827	890,155	(39,161)	299,684,666	891,359	805,839
Total Mining Plant				298,530,150	887,848	344,839	298,874,989	888,380	848,839	299,723,827	890,155	(39,161)	299,684,666	891,359	805,839
Subtotal				22,892,488,412	51,280,388	36,420,239	22,928,908,651	51,347,544	11,765,791	22,940,674,442	51,386,796	20,385,928	22,961,060,370	51,413,657	51,981,052

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - Dec 2013 Depreciation & Amortization Expense

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Jun 2013	Depreciation Expense Jun 2013	Adjustments	Adjusted EPIS Balance Jul 2013	Depreciation Expense Jul 2013	Adjustments	Adjusted EPIS Balance Aug 2013	Depreciation Expense Aug 2013	Adjustments	Adjusted EPIS Balance Sep 2013	Depreciation Expense Sep 2013	Adjustments
AMORTIZATION EXPENSE															
Intangible Plant:															
California	CA	0.000%	0.000%	353,808	-	-	353,808	-	-	353,808	-	-	353,808	-	-
Customer Service	CN	5.242%	5.242%	122,573,815	535,440	(17,785)	122,556,030	535,363	(17,785)	122,538,244	535,285	(17,785)	122,520,459	535,207	(17,785)
Pre-merger Utah	SG	2.788%	2.788%	585,275	1,362	(1,310)	583,965	1,358	(1,310)	582,655	1,355	(1,310)	581,345	1,352	(1,310)
Pre-merger Pacific	SG	0.000%	0.000%	(637,891)	-	(53,158)	(691,048)	-	(53,158)	(744,206)	-	(53,158)	(797,363)	-	(53,158)
Idaho	ID	1.478%	1.478%	1,431,992	1,764	-	1,431,992	1,764	-	1,431,992	1,764	-	1,431,992	1,764	-
Oregon	OR	0.295%	0.295%	3,993,610	980	(115)	3,993,495	980	(115)	3,993,380	980	(115)	3,993,266	980	(115)
Fuel Related	SE	9.457%	9.457%	3,591,744	28,332	(6,226)	3,585,517	28,283	(6,226)	3,579,291	28,233	(6,226)	3,573,064	28,184	(6,226)
Post-merger	SG	4.709%	4.709%	148,255,813	583,086	(685,272)	147,570,541	580,397	(685,272)	146,885,268	577,708	(685,272)	146,199,996	575,019	(685,272)
Hydro Relicensing	SG-P	2.628%	2.628%	97,855,608	214,439	(137,905)	97,717,703	214,137	(137,905)	97,579,797	213,835	(137,905)	97,441,892	213,533	(137,905)
Hydro Relicensing	SG-U	3.338%	3.338%	9,086,607	25,291	(8,563)	9,078,044	25,267	(8,563)	9,069,481	25,243	(8,563)	9,060,918	25,219	(8,563)
General Office	SO	5.350%	5.350%	386,574,643	1,723,517	123,807	386,698,450	1,723,643	123,086	386,821,536	1,724,193	3,615,425	390,436,962	1,732,526	823,562
Utah	UT	0.439%	0.439%	3,003,075	1,098	(82)	3,002,993	1,098	(82)	3,002,911	1,098	(82)	3,002,829	1,098	(82)
Washington	WA	0.000%	0.000%	1,465,062	-	(14)	1,465,048	-	(14)	1,465,034	-	(14)	1,465,019	-	(14)
Eastern Wyoming	WYP	9.592%	9.592%	1,497,168	11,970	(856)	1,496,312	11,964	(856)	1,495,455	11,957	(856)	1,494,599	11,950	(856)
Western Wyoming	WYU	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant				779,630,330	3,127,278	(787,480)	778,842,849	3,124,253	(788,201)	778,054,648	3,121,651	2,704,138	780,758,786	3,126,833	(87,726)
Hydro Production Plant:															
Pre-merger Pacific	SG	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.457%	2.457%	12,680,977	25,968	-	12,680,977	25,968	-	12,680,977	25,968	-	12,680,977	25,968	-
Post-merger	SG-U	6.237%	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-	714,026	3,711	-
Total Hydro Plant				13,395,003	29,679	-	13,395,003	29,679	-	13,395,003	29,679	-	13,395,003	29,679	-
Other Production Plant:															
Post-merger	SG	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-	-	-	-
General Plant:															
California	CA	2.753%	2.753%	352,021	807	-	352,021	807	-	352,021	807	-	352,021	807	-
General Office	CN	8.038%	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	-
Oregon	OR	4.836%	4.836%	4,784,256	19,281	-	4,784,256	19,281	-	4,784,256	19,281	-	4,784,256	19,281	-
General Office	SO	7.897%	7.897%	16,195,557	106,575	-	16,195,557	106,575	-	16,195,557	106,575	-	16,195,557	106,575	-
Utah	UT	3.596%	3.596%	22,625	68	-	22,625	68	-	22,625	68	-	22,625	68	-
Washington	WA	3.204%	3.204%	2,895,621	7,732	-	2,895,621	7,732	-	2,895,621	7,732	-	2,895,621	7,732	-
Eastern Wyoming	WYP	7.791%	7.791%	4,703,443	30,535	-	4,703,443	30,535	-	4,703,443	30,535	-	4,703,443	30,535	-
Western Wyoming	WYU	8.640%	8.640%	55,782	402	-	55,782	402	-	55,782	402	-	55,782	402	-
Total General Plant				32,410,179	188,181.16	-	32,410,179	188,181.16	-	32,410,179	188,181.16	-	32,410,179	188,181.16	-
Subtotal				825,435,512	3,345,138	(787,480)	824,648,032	3,342,112	(788,201)	823,859,830	3,339,511	2,704,138	826,563,968	3,344,693	(87,726)
Total				23,717,923,924	54,625,526	35,632,758	23,753,556,682	54,689,657	10,977,590	23,764,534,272	54,726,307	23,090,066	23,787,624,338	54,758,350	51,893,327

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - Dec 2013 Depreciation & Amortization Expense

Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Oct 2013	Depreciation Expense Oct 2013	Adjustments	Adjusted EPIS Balance Nov 2013	Depreciation Expense Nov 2013	Adjustments	Adjusted EPIS Balance Dec 2013	Depreciation Expense Dec 2013	Annualized Existing Rates Depreciation Expense	Proposed Rate
DEPRECIATION EXPENSE													
Steam Production Plant:													
Pre-merger Pacific	SG	2.835%	4.644%	1,035,903,977	2,450,485	(2,436,494)	1,033,467,483	2,444,728	(2,436,494)	1,031,030,988	2,438,972	29,233,117	47,878,880
Pre-merger Utah	SG	2.496%	3.759%	1,126,556,005	2,345,573	(2,193,078)	1,124,362,926	2,341,011	(2,193,078)	1,122,169,848	2,336,450	28,010,026	42,183,780
Post-merger	SG	3.022%	5.226%	3,798,991,283	9,569,459	597,429	3,799,588,712	9,569,415	15,441,410	3,815,030,122	9,589,614	115,308,729	199,356,822
Geothermal - Blundell	SG	3.022%	5.226%	26,966,081	67,920	-	26,966,081	67,920	-	26,966,081	67,920	815,046	1,409,130
Pollution Control Equipment	SG	3.022%	5.226%	28,571,027	71,942	16,804	28,587,831	71,984	1,206,819	29,794,650	73,525	900,539	1,556,938
Pollution Control Equipment	SG	2.312%	4.670%	-	-	-	-	-	1,910,426	1,910,426	1,841	44,173	89,219
Post-merger	SG	2.312%	4.670%	517,344,665	998,048	1,488,848	518,833,513	998,283	7,092,500	525,926,012	1,006,550	12,160,598	24,561,198
Total Steam Plant				6,534,333,037	15,503,427	(2,526,492)	6,531,806,545	15,493,342	21,021,582	6,552,828,127	15,514,871.69	186,472,228	317,035,968
Hydro Production Plant:													
Pre-merger Pacific	SG	1.568%	2.309%	185,213,099	242,201	(248,338)	184,964,760	241,876	(248,338)	184,716,422	241,552	2,896,674	4,265,105
Pre-merger Utah	SG	2.218%	3.266%	41,815,773	77,341	(69,546)	41,746,227	77,212	(69,546)	41,676,681	77,084	924,231	1,361,340
Post-merger	SG-P	1.912%	2.654%	500,189,884	788,081	2,712,821	502,902,706	799,159	4,895,706	507,798,411	805,221	9,709,454	13,479,024
Post-merger	SG-U	2.722%	4.481%	119,890,472	271,975	57,782	119,948,254	271,977	111,489	120,059,744	272,169	3,267,541	5,379,332
Total Hydro Plant				847,109,228	1,379,597	2,452,719	849,561,947	1,390,224	4,689,311	854,251,258	1,396,025	16,797,901	24,484,800
Other Production Plant:													
Pre-merger Utah	SG	9.784%	0.000%	397,843	3,289	(11,013)	386,830	3,199	(11,013)	375,817	3,109	36,770	-
Post-merger	SG	2.569%	3.124%	1,253,516,796	2,684,013	1,272,033	1,254,788,829	2,684,934	(157,739)	1,254,631,090	2,686,127	32,231,496	39,190,342
Post-merger Wind	SG-W	4.042%	3.307%	1,803,121,139	6,073,245	(75,914)	1,803,045,225	6,072,989	2,449,809	1,805,495,034	6,076,987	72,973,347	59,708,888
Post-merger	SG	3.321%	3.980%	79,615,915	220,410	(59,645)	79,556,270	220,245	(59,645)	79,496,625	220,080	2,639,964	3,163,767
Total Other Plant				3,136,651,693	8,980,956	1,125,461	3,137,777,154	8,981,366	2,221,412	3,139,998,567	8,986,301.97	107,881,576	102,062,997
Transmission Plant:													
Pre-merger Pacific	SG	1.944%	1.821%	550,951,411	892,812	(460,913)	550,490,498	892,066	(460,913)	550,029,585	891,319	10,691,348	10,013,919
Pre-merger Utah	SG	1.897%	1.774%	648,696,822	1,025,852	(357,371)	648,339,451	1,025,287	(357,371)	647,982,079	1,024,722	12,293,280	11,497,556
Post-merger	SG	1.883%	1.802%	4,016,360,004	6,287,379	27,383,114	4,043,743,118	6,325,439	34,589,254	4,078,332,373	6,374,073	76,814,622	73,484,839
Total Transmission Plant				5,216,008,237	8,206,043	26,564,830	5,242,573,067	8,242,792	33,770,970	5,276,344,037	8,290,114.89	99,799,250	94,996,315
Distribution Plant:													
California	CA	2.891%	2.651%	233,243,053	561,441	395,445	233,638,498	562,418	509,439	234,147,937	563,508	6,769,461	6,207,976
Oregon	OR	2.842%	2.525%	1,830,726,118	4,327,250	1,941,802	1,832,667,920	4,338,075	3,050,193	1,835,718,113	4,343,987	52,171,182	46,348,040
Washington	WA	3.117%	2.801%	415,039,599	1,077,735	92,340	415,131,940	1,078,131	220,172	415,352,112	1,078,537	12,945,871	11,634,596
Eastern Wyoming	WYP	2.832%	2.792%	533,593,848	1,255,887	1,293,767	534,887,615	1,260,914	1,361,967	536,249,582	1,264,048	15,187,865	14,974,192
Utah	UT	2.480%	2.426%	2,542,134,019	5,251,096	2,774,090	2,544,908,109	5,256,650	4,123,579	2,549,031,689	5,263,778	63,216,464	61,832,541
Idaho	ID	2.574%	2.262%	297,612,178	637,760	574,226	298,186,404	639,020	672,784	298,859,188	640,357	7,692,947	6,760,893
Western Wyoming	WYU	2.983%	2.974%	97,486,318	242,468	(79,123)	97,407,195	242,271	(79,123)	97,328,072	242,074	2,903,709	2,894,593
Total Distribution Plant				5,949,835,134	13,353,637	6,992,548	5,956,827,682	13,377,479	9,859,011	5,966,686,693	13,396,288.52	160,887,500	150,652,831
General Plant:													
California	CA	2.058%	2.007%	16,164,533	27,195	13,431	16,177,964	27,735	11,767	16,189,731	27,757	333,203	324,974
Oregon	OR	2.441%	2.467%	176,911,021	355,633	(350,971)	176,560,050	359,581	2,448,147	179,008,197	361,714	4,370,455	4,416,126
Washington	WA	3.390%	2.828%	44,204,724	124,388	(80,221)	44,124,503	124,752	(80,751)	44,043,752	124,525	1,492,932	1,245,616
Eastern Wyoming	WYP	3.706%	3.283%	65,769,517	201,839	(15,808)	65,753,709	203,119	(12,724)	65,740,985	203,075	2,436,660	2,158,389
Utah	UT	2.214%	2.231%	203,407,950	369,022	(2,573)	203,405,377	375,363	45,624	203,451,000	375,403	4,505,341	4,538,197
Idaho	ID	2.259%	2.281%	37,332,793	70,071	25,299	37,358,091	70,315	28,314	37,386,406	70,366	844,707	852,756
Western Wyoming	WYU	2.801%	2.403%	13,393,394	31,314	(46,675)	13,346,719	31,205	(46,675)	13,300,043	31,096	372,503	319,651
Pre-merger Pacific	SG	2.985%	2.808%	1,316,160	3,435	(129,438)	1,186,722	3,113	(129,438)	1,057,284	2,791	31,565	29,689
Pre-merger Utah	SG	2.074%	2.060%	1,991,068	3,671	(265,935)	1,725,133	3,211	(265,935)	1,459,198	2,752	30,261	30,059
Post-merger	SG	3.387%	3.338%	217,227,935	611,456	(154,979)	217,072,956	612,903	3,204,559	220,277,515	617,207	7,460,753	7,353,665
General Office	SO	6.447%	6.426%	225,168,301	1,211,169	(187,593)	224,980,708	1,209,248	9,866	224,990,574	1,208,770	14,505,563	14,456,988
General Office	SG	2.963%	3.098%	4,960,080	12,287	(33,669)	4,926,410	12,204	287,833	5,214,243	12,518	154,475	161,548
General Office	SG	3.287%	3.288%	183,445	504	(1,294)	182,151	501	(1,294)	180,857	497	5,945	5,947
Customer Service	CN	8.230%	8.215%	19,917,969	137,003	(114,712)	19,803,257	136,216	(114,712)	19,688,545	135,430	1,620,436	1,617,486
Fuel Related	SE	2.653%	2.682%	664,700	1,477	(6,875)	657,824	1,462	(6,875)	650,949	1,447	17,267	17,457
Total General Plant				1,028,613,588	3,160,465	(1,352,015)	1,027,261,573	3,170,929	5,377,705	1,032,639,278	3,175,347.05	38,182,066	37,528,548
Mining Plant:													
Coal Mine	SE	3.569%	7.689%	300,490,504	892,499	624,839	301,115,343	894,627	(79,161)	301,036,182	895,438	10,743,846	23,147,345
Total Mining Plant				300,490,504	892,499	624,839	301,115,343	894,627	(79,161)	301,036,182	895,438.20	10,743,846	23,147,345
Subtotal				23,013,041,422	51,476,626	33,881,890	23,046,923,312	51,550,759	76,860,830	23,123,784,141	51,654,387	620,764,366	749,908,804

PacifiCorp
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Description	Factor	Existing Rate	Proposed Rate	Adjusted EPIS Balance Oct 2013	Depreciation Expense Oct 2013	Adjustments	Adjusted EPIS Balance Nov 2013	Depreciation Expense Nov 2013	Adjustments	Adjusted EPIS Balance Dec 2013	Depreciation Expense Dec 2013	Annualized Existing Rates Depreciation Expense	Proposed Rate
AMORTIZATION EXPENSE													
Intangible Plant:													
California	CA	0.000%	0.000%	353,808	-	-	353,808	-	-	353,808	-	-	-
Customer Service	CN	5.242%	5.242%	122,502,673	535,130	(17,785)	122,484,888	535,052	(17,785)	122,467,102	534,974	6,419,226	6,419,226
Pre-merger Utah	SG	2.788%	2.788%	580,035	1,349	(1,310)	578,725	1,346	(1,310)	577,415	1,343	16,101	16,101
Pre-merger Pacific	SG	0.000%	0.000%	(850,521)	-	(53,158)	(903,679)	-	(53,158)	(956,836)	-	-	-
Idaho	ID	1.478%	1.478%	1,431,992	1,764	-	1,431,992	1,764	-	1,431,992	1,764	21,166	21,166
Oregon	OR	0.295%	0.295%	3,993,151	980	(115)	3,993,036	980	(115)	3,992,922	980	11,762	11,762
Fuel Related	SE	9.457%	9.457%	3,566,838	28,135	(6,226)	3,560,611	28,086	(6,226)	3,554,385	28,037	336,152	336,152
Post-merger	SG	4.709%	4.709%	145,514,724	572,330	(685,272)	144,829,451	569,641	(685,272)	144,144,179	566,952	6,787,294	6,787,294
Hydro Relicensing	SG-P	2.628%	2.628%	97,303,986	213,231	(137,905)	97,166,081	212,929	(137,905)	97,028,175	212,627	2,549,712	2,549,712
Hydro Relicensing	SG-U	3.338%	3.338%	9,052,355	25,195	(8,563)	9,043,792	25,171	(8,563)	9,035,229	25,148	301,628	301,628
General Office	SO	5.350%	5.350%	391,260,523	1,742,421	518,415	391,778,938	1,745,412	4,192,268	395,971,206	1,755,912	21,183,084	21,183,084
Utah	UT	0.439%	0.439%	3,002,747	1,098	(82)	3,002,664	1,098	(82)	3,002,582	1,098	13,172	13,172
Washington	WA	0.000%	0.000%	1,465,005	-	(14)	1,464,991	-	(14)	1,464,977	-	-	-
Eastern Wyoming	WYP	9.592%	9.592%	1,493,743	11,943	(856)	1,492,887	11,936	(856)	1,492,030	11,929	143,111	143,111
Western Wyoming	WYU	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant				780,671,060	3,133,576	(392,873)	780,278,188	3,133,416	3,280,980	783,559,168	3,140,765	37,782,406	37,782,406
Hydro Production Plant:													
Pre-merger Pacific	SG	0.000%	0.000%	-	-	-	-	-	-	-	-		-
Post-merger	SG-P	2.457%	2.457%	12,680,977	25,968	-	12,680,977	25,968	-	12,680,977	25,968	311,610	311,610
Post-merger	SG-U	6.237%	6.237%	714,026	3,711	-	714,026	3,711	-	714,026	3,711	44,532	44,532
Total Hydro Plant				13,395,003	29,679	-	13,395,003	29,679	-	13,395,003	29,679	356,143	356,143
Other Production Plant:													
Post-merger	SG	0.000%	0.000%	-	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-	-
General Plant:													
California	CA	2.753%	2.753%	352,021	807	-	352,021	807	-	352,021	807	9,690	9,690
General Office	CN	8.038%	8.038%	3,400,873	22,781	-	3,400,873	22,781	-	3,400,873	22,781	273,367	273,367
Oregon	OR	4.836%	4.836%	4,784,256	19,281	-	4,784,256	19,281	-	4,784,256	19,281	231,371	231,371
General Office	SO	7.897%	7.897%	16,195,557	106,575	-	16,195,557	106,575	-	16,195,557	106,575	1,278,904	1,278,904
Utah	UT	3.596%	3.596%	22,625	68	-	22,625	68	-	22,625	68	814	814
Washington	WA	3.204%	3.204%	2,895,621	7,732	-	2,895,621	7,732	-	2,895,621	7,732	92,783	92,783
Eastern Wyoming	WYP	7.791%	7.791%	4,703,443	30,535	-	4,703,443	30,535	-	4,703,443	30,535	366,425	366,425
Western Wyoming	WYU	8.640%	8.640%	55,782	402	-	55,782	402	-	55,782	402	4,819	4,819
Total General Plant				32,410,179	188,181.16	-	32,410,179	188,181.16	-	32,410,179	188,181.16	2,258,174	2,258,174
Subtotal				826,476,242	3,351,436	(392,873)	826,083,370	3,351,276	3,280,980	829,364,350	3,358,625	40,396,723	40,396,723
Total				23,839,517,664	54,828,062	33,489,017	23,873,006,682	54,902,035	80,141,810	23,953,148,492	55,013,012	661,161,089	790,305,527
												Ref. 6.1.5	Ref. 6.1.5
											Total Not Including Mining	650,417,243	767,158,182

PacifiCorp
Oregon General Rate Case - December 2014
Vehicle Depreciation Expense - Adjustment to Proposed Depreciation Rates

Factor	EPIS	Annual Depreciation Existing Rates		Annual Depreciation Proposed Rates		Difference	
CA	6,612,263	431,223		326,058		(105,165)	
DGP	964,224	54,884		51,498		(3,386)	
DGU	2,353,334	134,732		127,233		(7,499)	
IDU	13,366,008	692,473		772,801		80,328	
OR	58,178,054	3,569,643		3,493,527		(76,115)	
SE	493,394	29,128		28,915		(213)	
SG	52,006,312	3,039,329		2,819,026		(220,303)	
SO	9,298,778	512,025		490,967		(21,058)	
SSGCH	1,343,821	47,786		27,145		(20,641)	
SSGCT	44,655	2,287		2,258		(29)	
UT	76,401,426	4,990,756		4,713,080		(277,676)	
WA	13,250,420	936,663		732,280		(204,383)	
WYP	20,296,957	1,277,680		1,210,453		(67,227)	
WYU	4,918,632	298,692		283,125		(15,567)	
Grand Total	**259,528,280**	**16,017,302**		**15,078,368**		**(938,934)**	
			WEBA Allocation		79.42%	(745,715)	
			Direct Allocation		20.58%	(193,219)	Ref 6.1.3
						(938,934)	
			WEBA Allocation		79.42%	(745,715)	
			Capital/Non Utility			(233,279)	
						(512,436)	Ref 6.1.3

PacifiCorp
Oregon General Rate Case - December 2014
Depreciation / Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Depreciation Reserve	108SP	3	(19,156,658)	SG	26.053%	(4,990,884)	
Steam Depreciation Reserve	108SP	3	(17,123,936)	SG	26.053%	(4,461,299)	
Steam Depreciation Reserve	108SP	3	(377,687,048)	SG	26.053%	(98,398,813)	
Steam Depreciation Reserve	108SP	3	(25,513,285)	SG	26.053%	(6,646,976)	
Hydro Depreciation Reserve	108HP	3	(1,272,558)	SG	26.053%	(331,540)	
Hydro Depreciation Reserve	108HP	3	(583,194)	SG	26.053%	(151,940)	
Hydro Depreciation Reserve	108HP	3	(10,390,987)	SG-P	26.053%	(2,707,164)	
Hydro Depreciation Reserve	108HP	3	(5,814,145)	SG-U	26.053%	(1,514,759)	
Other Depreciation Reserve	108OP	3	171,769	SG	26.053%	44,751	
Other Depreciation Reserve	108OP	3	(42,889,042)	SG	26.053%	(11,173,883)	
Other Depreciation Reserve	108OP	3	(94,762,861)	SG-W	26.053%	(24,688,570)	
Other Depreciation Reserve	108OP	3	(3,424,404)	SG	26.053%	(892,160)	
Transmission Depreciation Reserve	108TP	3	(7,130,357)	SG	26.053%	(1,857,672)	
Transmission Depreciation Reserve	108TP	3	(11,262,361)	SG	26.053%	(2,934,183)	
Transmission Depreciation Reserve	108TP	3	(82,034,013)	SG	26.053%	(21,372,323)	
Distribution Depreciation Reserve	108360	3	(1,559,856)	Situs	100.000%	(597,415)	
Distribution Depreciation Reserve	108361	3	(2,266,214)	Situs	100.000%	(867,946)	
Distribution Depreciation Reserve	108362	3	(23,001,345)	Situs	100.000%	(8,809,372)	
Distribution Depreciation Reserve	108364	3	(26,442,045)	Situs	100.000%	(10,127,139)	
Distribution Depreciation Reserve	108365	3	(17,779,694)	Situs	100.000%	(6,809,512)	
Distribution Depreciation Reserve	108366	3	(8,381,759)	Situs	100.000%	(3,210,162)	
Distribution Depreciation Reserve	108367	3	(19,726,987)	Situs	100.000%	(7,555,314)	
Distribution Depreciation Reserve	108368	3	(30,274,085)	Situs	100.000%	(11,594,787)	
Distribution Depreciation Reserve	108369	3	(16,300,428)	Situs	100.000%	(6,242,963)	
Distribution Depreciation Reserve	108370	3	(4,658,029)	Situs	100.000%	(1,783,996)	
Distribution Depreciation Reserve	108371	3	(233,261)	Situs	100.000%	(89,338)	
Distribution Depreciation Reserve	108373	3	(1,626,800)	Situs	100.000%	(623,054)	
General Depreciation Reserve	108GP	3	(275,813)	CA	0.000%	-	
General Depreciation Reserve	108GP	3	(922,086)	OR	100.000%	(922,086)	
General Depreciation Reserve	108GP	3	(905,087)	WA	0.000%	-	
General Depreciation Reserve	108GP	3	(1,347,999)	WYP	0.000%	-	
General Depreciation Reserve	108GP	3	(3,520,809)	UT	0.000%	-	
General Depreciation Reserve	108GP	3	75,473	ID	0.000%	-	
General Depreciation Reserve	108GP	3	(112,276)	WYU	0.000%	-	
General Depreciation Reserve	108GP	3	2,169,824	SG	26.053%	565,304	
General Depreciation Reserve	108GP	3	4,491,328	SG	26.053%	1,170,126	
General Depreciation Reserve	108GP	3	(7,474,383)	SG	26.053%	(1,947,301)	
General Depreciation Reserve	108GP	3	6,609,526	SO	27.384%	1,809,969	
General Depreciation Reserve	108GP	3	264,747	SG	26.053%	68,975	
General Depreciation Reserve	108GP	3	10,091	SG	26.053%	2,629	
General Depreciation Reserve	108GP	3	(433,699)	CN	30.325%	(131,520)	
General Depreciation Reserve	108GP	3	52,493	SE	24.687%	12,959	
Mining Depreciation Reserve	108MP	3	(13,287,801)	SE	24.687%	(3,280,324)	
Total Depreciation Reserve			(865,730,053)			(243,039,682)	6.2.2

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2013 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2012 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2012 to December 31, 2013. An incremental amount has been added to the December 31, 2013 balance to reflect the annualized 2013 depreciation & amortization expense being added in through adjustment 6.1.

PacifiCorp
Oregon General Rate Case - December 2014
(cont.) Depreciation / Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Amortization Reserve	111IP	3	-	CA	0.000%	-	
Intangible Amortization Reserve	111IP	3	(9,315,692)	CN	30.325%	(2,824,998)	
Intangible Amortization Reserve	111IP	3	(31,749)	ID	0.000%	-	
Intangible Amortization Reserve	111IP	3	(847)	SG	26.053%	(221)	
Intangible Amortization Reserve	111IP	3	(15,580)	OR	100.000%	(15,580)	
Intangible Amortization Reserve	111IP	3	(396,568)	SE	24.687%	(97,900)	
Intangible Amortization Reserve	111IP	3	2,054,118	SG	26.053%	535,159	
Intangible Amortization Reserve	111IP	3	(1,369,448)	SG-P	26.053%	(356,782)	
Intangible Amortization Reserve	111IP	3	(300,452)	SG-U	26.053%	(78,277)	
Intangible Amortization Reserve	111IP	3	(18,160,550)	SO	27.384%	(4,973,131)	
Intangible Amortization Reserve	111IP	3	956,836	SG	26.053%	249,285	
Intangible Amortization Reserve	111IP	3	(18,282)	UT	0.000%	-	
Intangible Amortization Reserve	111IP	3	255	WA	0.000%	-	
Intangible Amortization Reserve	111IP	3	(199,870)	WYP	0.000%	-	
Intangible Amortization Reserve	111IP	3	-	WYU	0.000%	-	
Intangible Amortization Reserve	111IP	3	-	SG	26.053%	-	
Hydro Amortization Reserve	111HP	3	-	SG	26.053%	-	
Hydro Amortization Reserve	111HP	3	(467,415)	SG-P	26.053%	(121,776)	
Hydro Amortization Reserve	111HP	3	(66,799)	SG-U	26.053%	(17,403)	
Other Amortizaton Reserve	111OP	3	-	SG	26.053%	-	
General Amortization Reserve	111GP	3	(14,535)	CA	0.000%	-	
General Amortization Reserve	111GP	3	(410,051)	CN	30.325%	(124,348)	
General Amortization Reserve	111GP	3	-	SG	26.053%	-	
General Amortization Reserve	111GP	3	(347,056)	OR	100.000%	(347,056)	
General Amortization Reserve	111GP	3	(1,918,356)	SO	27.384%	(525,328)	
General Amortization Reserve	111GP	3	(1,220)	UT	0.000%	-	
General Amortization Reserve	111GP	3	(139,175)	WA	0.000%	-	
General Amortization Reserve	111GP	3	(549,638)	WYP	0.000%	-	
General Amortization Reserve	111GP	3	(7,229)	WYU	0.000%	-	
Total Amorization Reserve			(30,719,303)			(8,698,357)	6.2.3

Description of Adjustment:

This adjustment steps forward the amortization reserve to a December 2013 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2012 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2012 to December 31, 2013. An incremental amount has been added to the December 31, 2013 balance to reflect the annualized 2013 depreciation & amortization expense being added in through adjustments 6.1.

PacifiCorp
Oregon General Rate Case - December 2014
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 Months Ended Jun 2012 Reserve	CY 2013 Adjusted Reserve	Adjustment to Test Period
DEPRECIATION RESERVE					
Steam Production Plant:					
Pre-merger Pacific	108SP	SG	(755,843,347)	(775,000,005)	(19,156,658)
Pre-merger Utah	108SP	SG	(773,471,879)	(790,595,815)	(17,123,936)
Post-merger	108SP	SG	(650,025,095)	(1,027,712,143)	(377,687,048)
Post-merger	108SP	SG	(172,395,851)	(197,909,136)	(25,513,285)
Total Steam Plant			(2,351,736,172)	(2,791,217,099)	(439,480,927)
Hydro Production Plant:					
Pre-merger Pacific	108HP	SG	(128,940,690)	(130,213,248)	(1,272,558)
Pre-merger Utah	108HP	SG	(29,281,162)	(29,864,357)	(583,194)
Post-merger	108HP	SG-P	(46,432,078)	(56,823,065)	(10,390,987)
Post-merger	108HP	SG-U	(21,132,737)	(26,946,882)	(5,814,145)
Total Hydro Plant			(225,786,667)	(243,847,551)	(18,060,884)
Other Production Plant:					
Pre-merger Utah	108OP	SG	(1,000,886)	(829,117)	171,769
Post-merger	108OP	SG	(212,142,171)	(255,031,212)	(42,889,042)
Post-merger - Wind	108OP	SG-W	(276,277,623)	(371,040,484)	(94,762,861)
Post-merger	108OP	SG	(22,545,768)	(25,970,172)	(3,424,404)
Total Other Plant			(511,966,448)	(652,870,986)	(140,904,538)
Transmission Plant:					
Pre-merger Pacific	108TP	SG	(369,658,339)	(376,788,696)	(7,130,357)
Pre-merger Utah	108TP	SG	(398,638,323)	(409,900,684)	(11,262,361)
Post-merger	108TP	SG	(483,090,560)	(565,124,573)	(82,034,013)
Total Transmission Plant			(1,251,387,221)	(1,351,813,952)	(100,426,731)
Distribution Plant:					
California	108364	CA	(104,213,338)	(112,254,001)	(8,040,663)
Oregon	108364	OR	(810,551,730)	(868,862,729)	(58,310,998)
Washington	108364	WA	(183,336,291)	(194,468,611)	(11,132,320)
Eastern Wyoming	108364	WYP	(191,839,909)	(206,535,489)	(14,695,580)
Utah	108364	UT	(764,685,831)	(814,685,513)	(49,999,681)
Idaho	108364	ID	(121,279,852)	(128,411,173)	(7,131,321)
Western Wyoming	108364	WYU	(40,473,126)	(43,413,065)	(2,939,939)
Total Distribution Plant			(2,216,380,077)	(2,368,630,579)	(152,250,503)
General Plant:					
California	108GP	CA	(4,601,895)	(4,877,708)	(275,813)
Oregon	108GP	OR	(50,557,550)	(51,479,635)	(922,086)
Washington	108GP	WA	(18,607,057)	(19,512,143)	(905,087)
Eastern Wyoming	108GP	WYP	(18,862,700)	(20,210,699)	(1,347,999)
Utah	108GP	UT	(58,517,030)	(62,037,839)	(3,520,809)
Idaho	108GP	ID	(10,996,252)	(10,920,779)	75,473
Western Wyoming	108GP	WYU	(4,651,419)	(4,763,695)	(112,276)
Pre-merger Pacific	108GP	SG	(2,426,930)	(257,106)	2,169,824
Pre-merger Utah	108GP	SG	(3,676,496)	814,832	4,491,328
Post-merger	108GP	SG	(58,957,181)	(66,431,564)	(7,474,383)
General Office	108GP	SO	(78,928,937)	(72,319,411)	6,609,526
General Office	108GP	SG	(2,102,292)	(1,837,545)	264,747
General Office	108GP	SG	(51,569)	(41,478)	10,091
Customer Service	108GP	CN	(8,786,738)	(9,220,436)	(433,699)
Fuel Related	108GP	SE	(310,133)	(257,640)	52,493
Total General Plant			(322,034,176)	(323,352,846)	(1,318,669)
Mining Plant:					
Coal Mine	108MP	SE	(161,499,586)	(174,787,386)	(13,287,801)
Total Mining Plant			(161,499,586)	(174,787,386)	(13,287,801)
Total Depreciation Reserve			(7,040,790,346)	(7,906,520,400)	**(865,730,053)**
					Ref 6.2

PacifiCorp
Oregon General Rate Case - December 2014
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 Months Ended Jun 2012 Reserve	CY 2013 Adjusted Reserve	Adjustment to Test Period
AMORTIZATION RESERVE					
Intangible Plant:					
California	111IP	CA	-	-	-
Customer Service	111IP	CN	(103,869,877)	(113,185,569)	(9,315,692)
Idaho	111IP	ID	(785,488)	(817,237)	(31,749)
Pre-merger Utah	111IP	SG	(374,534)	(375,381)	(847)
Oregon	111IP	OR	(61,511)	(77,091)	(15,580)
Fuel Related	111IP	SE	(1,794,223)	(2,190,791)	(396,568)
Post-merger	111IP	SG	(52,567,449)	(50,513,331)	2,054,118
Hydro Relicensing	111IP	SG-P	(17,989,791)	(19,359,239)	(1,369,448)
Hydro Relicensing	111IP	SG-U	(3,831,411)	(4,131,863)	(300,452)
General Office	111IP	SO	(280,901,816)	(299,062,366)	(18,160,550)
Pre-merger Pacific	111IP	SG	-	956,836	956,836
Utah	111IP	UT	(42,863)	(61,144)	(18,282)
Washington	111IP	WA	-	255	255
Eastern Wyoming	111IP	WYP	(373,670)	(573,541)	(199,870)
Western Wyoming	111IP	WYU	-	-	-
General Office	111IP	SG	(327,836)	(327,836)	-
Total Intangible Plant			(462,920,468)	(489,718,297)	(26,797,829)
Hydro Production Plant:					
Pre-merger Pacific	111HP	SG	-	-	-
Post-merger	111HP	SG-P	(473,877)	(941,292)	(467,415)
Post-merger	111HP	SG-U	(506,676)	(573,475)	(66,799)
Total Hydro Plant			(980,553)	(1,514,767)	(534,214)
Other Production Plant:					
Post-merger	111OP	SG	-	-	-
Total Other Plant			-	-	-
General Plant:					
California	111GP	CA	(300,596)	(315,131)	(14,535)
General Office	111GP	CN	(3,134,593)	(3,544,644)	(410,051)
General Office	111GP	SG	-	-	-
Oregon	111GP	OR	(3,943,245)	(4,290,302)	(347,056)
General Office	111GP	SO	(12,094,200)	(14,012,557)	(1,918,356)
Utah	111GP	UT	(12,916)	(14,137)	(1,220)
Washington	111GP	WA	(1,704,011)	(1,843,186)	(139,175)
Eastern Wyoming	111GP	WYP	(4,104,030)	(4,653,668)	(549,638)
Western Wyoming	111GP	WYU	(41,123)	(48,352)	(7,229)
Total General Plant			(25,334,715)	(28,721,975)	(3,387,261)
Total Amortization Reserve			(489,235,736)	(519,955,039)	**(30,719,303)**
					Ref 6.2.1
Total Depreciation & Amortization Reserve			(7,530,026,082)	(8,426,475,439)	(896,449,357)
				Ref. 6.2.9	

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - December 2013 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jun 2012	Adjustments	Adjusted Reserve Balance Jul 2012	Adjustments	Adjusted Reserve Balance Aug 2012	Adjustments	Adjusted Reserve Balance Sep 2012	Adjustments	Adjusted Reserve Balance Oct 2012	Adjustments	Adjusted Reserve Balance Nov 2012	Adjustments	Adjusted Reserve Balance Dec 2012	Adjustments
DEPRECIATION RESERVE															
Steam Production Plant:															
Pre-merger Pacific	SG	(755,843,347)	(100,344)	(755,943,691)	(94,587)	(756,038,279)	(88,830)	(756,127,109)	(83,073)	(756,210,183)	(77,317)	(756,287,499)	(71,560)	(756,359,059)	(65,803)
Pre-merger Utah	SG	(773,471,879)	(220,920)	(773,692,799)	(216,359)	(773,909,158)	(211,797)	(774,120,955)	(207,235)	(774,328,190)	(202,674)	(774,530,864)	(198,112)	(774,728,976)	(193,550)
Post-merger	SG	(801,350,857)	(7,463,601)	(808,814,458)	(7,535,406)	(816,349,863)	(6,164,427)	(822,514,291)	(7,242,454)	(829,756,745)	(6,878,439)	(836,635,184)	(6,118,163)	(842,753,347)	(7,671,835)
Geothermal - Blundell	SG	(3,487,790)	(66,781)	(3,554,571)	(66,781)	(3,621,352)	(66,781)	(3,688,133)	(67,012)	(3,755,146)	(67,526)	(3,822,671)	(67,864)	(3,890,536)	(67,920)
Pollution Control Equipment	SG	-	(3,210)	(3,210)	(14,583)	(17,794)	(25,480)	(43,273)	(27,689)	(70,962)	(27,226)	(98,188)	(36,134)	(134,322)	(45,036)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(191,028,048)	310,126	(190,717,922)	312,501	(190,405,421)	314,924	(190,090,497)	317,345	(189,773,151)	319,094	(189,454,057)	317,084	(189,136,973)	315,762
Total Steam Plant		(2,525,181,921)	(7,544,731)	(2,532,726,652)	(7,615,215)	(2,540,341,866)	(6,242,391)	(2,546,584,258)	(7,310,119)	(2,553,894,377)	(6,934,086)	(2,560,828,463)	(6,174,749)	(2,567,003,212)	(7,728,383)
Hydro Production Plant:															
Pre-merger Pacific	SG	(128,940,690)	1,270	(128,939,421)	1,594	(128,937,826)	1,919	(128,935,908)	2,243	(128,933,665)	2,568	(128,931,097)	2,892	(128,928,205)	3,217
Pre-merger Utah	SG	(29,281,162)	(9,722)	(29,290,885)	(9,594)	(29,300,478)	(9,465)	(29,309,944)	(9,337)	(29,319,281)	(9,208)	(29,328,489)	(9,080)	(29,337,569)	(8,951)
Post-merger	SG-P	(46,432,078)	1,369,887	(45,062,190)	555,538	(44,506,653)	1,398,574	(43,108,079)	(436,185)	(43,544,264)	(1,240,810)	(44,785,074)	(474,172)	(45,259,246)	(736,250)
Post-merger	SG-U	(21,132,737)	(286,134)	(21,418,871)	(286,007)	(21,704,878)	(285,880)	(21,990,759)	164,430	(21,826,329)	(194,996)	(22,021,324)	(217,061)	(22,238,386)	(217,213)
Total Hydro Plant		(225,786,667)	1,075,301	(224,711,366)	261,531	(224,449,836)	1,105,147	(223,344,689)	(278,849)	(223,623,538)	(1,442,446)	(225,065,984)	(697,421)	(225,763,405)	(959,197)
Other Production Plant:															
Pre-merger Utah	SG	(1,000,886)	6,378	(994,508)	6,467	(988,041)	6,557	(981,484)	6,647	(974,837)	6,737	(968,100)	6,827	(961,274)	6,916
Post-merger	SG	(212,142,171)	(1,959,792)	(214,101,962)	(1,958,546)	(216,060,508)	(1,957,300)	(218,017,807)	(1,955,853)	(219,973,660)	(1,975,975)	(221,949,635)	(1,999,670)	(223,949,305)	(2,001,797)
Post-merger Wind	SG-W	(276,277,623)	(5,991,568)	(282,269,191)	(5,992,932)	(288,262,123)	(5,994,157)	(294,256,280)	(5,994,749)	(300,251,029)	(5,994,496)	(306,245,525)	(5,997,040)	(312,242,565)	(5,999,588)
Post-merger	SG	(22,545,768)	(162,926)	(22,708,694)	(162,965)	(22,871,659)	(162,800)	(23,034,459)	(162,690)	(23,197,149)	(162,580)	(23,359,729)	(162,415)	(23,522,145)	(162,250)
Total Other Plant		(511,966,448)	(8,107,908)	(520,074,356)	(8,107,975)	(528,182,331)	(8,107,699)	(536,290,030)	(8,106,645)	(544,396,675)	(8,126,314)	(552,522,989)	(8,152,298)	(560,675,288)	(8,156,718)
Transmission Plant:															
Pre-merger Pacific	SG	(369,658,339)	(443,098)	(370,101,437)	(442,352)	(370,543,789)	(441,605)	(370,985,394)	(440,859)	(371,426,252)	(440,112)	(371,866,364)	(439,365)	(372,305,729)	(438,619)
Pre-merger Utah	SG	(398,638,323)	(676,956)	(399,315,279)	(676,391)	(399,991,670)	(675,826)	(400,667,496)	(675,261)	(401,342,757)	(674,696)	(402,017,453)	(674,131)	(402,691,584)	(673,566)
Post-merger	SG	(483,090,560)	(3,987,919)	(487,078,479)	(4,003,168)	(491,081,647)	(4,019,926)	(495,101,573)	(4,039,642)	(499,141,215)	(4,057,449)	(503,198,664)	(4,129,191)	(507,327,855)	(4,211,403)
Total Transmission Plant		(1,251,387,221)	(5,107,974)	(1,256,495,194)	(5,121,911)	(1,261,617,105)	(5,137,357)	(1,266,754,463)	(5,155,761)	(1,271,910,224)	(5,172,257)	(1,277,082,481)	(5,242,687)	(1,282,325,168)	(5,323,588)
Distribution Plant:															
California	CA	(104,213,338)	(466,853)	(104,680,191)	(467,345)	(105,147,537)	(467,921)	(105,615,457)	(468,379)	(106,083,836)	(468,860)	(106,552,696)	(469,594)	(107,022,289)	(470,499)
Oregon	OR	(810,551,730)	(3,470,110)	(814,021,840)	(3,477,013)	(817,498,853)	(3,482,668)	(820,981,521)	(3,487,887)	(824,469,408)	(3,494,612)	(827,964,020)	(3,502,474)	(831,466,495)	(3,509,468)
Washington	WA	(183,336,291)	(680,726)	(184,017,017)	(681,661)	(184,698,677)	(683,908)	(185,382,586)	(685,722)	(186,068,308)	(686,450)	(186,754,757)	(686,849)	(187,441,606)	(687,364)
Eastern Wyoming	WYP	(191,839,909)	(777,204)	(192,617,113)	(781,360)	(193,398,473)	(785,361)	(194,183,834)	(790,756)	(194,974,590)	(796,070)	(195,770,659)	(799,645)	(196,570,305)	(803,050)
Utah	UT	(764,685,831)	(2,753,739)	(767,439,570)	(2,766,117)	(770,205,687)	(2,776,454)	(772,982,142)	(2,780,833)	(775,762,975)	(2,787,476)	(778,550,451)	(2,795,984)	(781,346,435)	(2,803,116)
Idaho	ID	(121,279,852)	(431,469)	(121,711,321)	(432,535)	(122,143,856)	(433,468)	(122,577,323)	(434,828)	(123,012,152)	(436,196)	(123,448,348)	(436,896)	(123,885,244)	(437,840)
Western Wyoming	WYU	(40,473,126)	(166,295)	(40,639,421)	(166,099)	(40,805,520)	(165,902)	(40,971,422)	(165,705)	(41,137,127)	(165,509)	(41,302,636)	(165,312)	(41,467,947)	(165,115)
Total Distribution Plant		(2,216,380,077)	(8,746,397)	(2,225,126,473)	(8,772,129)	(2,233,898,602)	(8,795,682)	(2,242,694,285)	(8,814,111)	(2,251,508,396)	(8,835,171)	(2,260,343,567)	(8,856,753)	(2,269,200,320)	(8,876,452)
General Plant:															
California	CA	(4,601,895)	(13,378)	(4,615,273)	(13,396)	(4,628,669)	(13,765)	(4,642,434)	(14,149)	(4,656,584)	(14,145)	(4,670,729)	(14,432)	(4,685,160)	(14,845)
Oregon	OR	(50,557,550)	(27,965)	(50,585,515)	(29,144)	(50,614,659)	(31,138)	(50,645,797)	(32,773)	(50,678,570)	(34,533)	(50,713,103)	(39,627)	(50,752,731)	(42,623)
Washington	WA	(18,607,057)	(64,358)	(18,671,415)	(63,992)	(18,735,408)	(63,699)	(18,799,106)	(63,625)	(18,862,731)	(63,874)	(18,926,605)	(64,318)	(18,990,923)	(64,481)
Eastern Wyoming	WYP	(18,862,700)	(77,612)	(18,940,312)	(79,442)	(19,019,754)	(81,485)	(19,101,239)	(84,313)	(19,185,552)	(86,457)	(19,272,009)	(88,266)	(19,360,275)	(89,748)
Utah	UT	(58,517,030)	(172,510)	(58,689,540)	(172,838)	(58,862,379)	(176,357)	(59,038,736)	(179,509)	(59,218,245)	(180,015)	(59,398,261)	(183,247)	(59,581,508)	(185,397)
Idaho	ID	(10,996,252)	7,283	(10,988,969)	7,106	(10,981,863)	7,152	(10,974,711)	7,073	(10,967,637)	6,998	(10,960,640)	6,045	(10,954,595)	4,813
Western Wyoming	WYU	(4,651,419)	(10,535)	(4,661,954)	(10,427)	(4,672,381)	(10,318)	(4,682,698)	(10,209)	(4,692,907)	(10,100)	(4,703,007)	(9,991)	(4,712,997)	(9,882)
Pre-merger Pacific	SG	(2,426,930)	116,416	(2,310,513)	116,738	(2,193,775)	117,060	(2,076,715)	117,382	(1,959,332)	117,704	(1,841,628)	118,026	(1,723,602)	118,348
Pre-merger Utah	SG	(3,676,496)	243,762	(3,432,734)	244,222	(3,188,512)	244,681	(2,943,831)	245,141	(2,698,689)	245,601	(2,453,089)	246,060	(2,207,029)	246,520
Post-merger	SG	(58,957,181)	(392,223)	(59,349,404)	(395,876)	(59,745,280)	(397,243)	(60,142,523)	(396,847)	(60,539,369)	(397,541)	(60,936,910)	(410,823)	(61,347,733)	(423,249)
General Office	SO	(78,928,937)	327,165	(78,601,772)	332,702	(78,269,070)	337,637	(77,931,433)	340,256	(77,591,177)	340,374	(77,250,803)	338,729	(76,912,074)	337,644
General Office	SG	(2,102,292)	16,839	(2,085,452)	16,922	(2,068,530)	17,005	(2,051,525)	17,089	(2,034,436)	17,172	(2,017,265)	16,780	(2,000,485)	16,387
General Office	SG	(51,569)	516	(51,053)	520	(50,533)	523	(50,009)	527	(49,482)	531	(48,952)	534	(48,418)	538
Customer Service	CN	(8,786,738)	(34,093)	(8,820,831)	(33,306)	(8,854,137)	(32,519)	(8,886,656)	(31,733)	(8,918,389)	(30,946)	(8,949,334)	(30,159)	(8,979,493)	(29,372)
Fuel Related	SE	(310,133)	2,737	(307,396)	2,752	(304,644)	2,767	(301,877)	2,782	(299,094)	2,798	(296,297)	2,813	(293,484)	2,828
Total General Plant		(322,034,176)	(77,957)	(322,112,133)	(77,460)	(322,189,593)	(79,697)	(322,269,290)	(82,907)	(322,352,196)	(86,434)	(322,438,630)	(111,876)	(322,550,506)	(132,518)
Mining Plant:															
Coal Mine	SE	(161,499,586)	(31,116)	(161,530,702)	(32,482)	(161,563,184)	(33,592)	(161,596,776)	(33,676)	(161,630,452)	(34,466)	(161,664,917)	(33,061)	(161,697,979)	(37,364)
Total Mining Plant		(161,499,586)	(31,116)	(161,530,702)	(32,482)	(161,563,184)	(33,592)	(161,596,776)	(33,676)	(161,630,452)	(34,466)	(161,664,917)	(33,061)	(161,697,979)	(37,364)
Subtotal		(7,214,236,095)	(28,540,782)	(7,242,776,877)	(29,465,641)	(7,272,242,518)	(27,291,272)	(7,299,533,790)	(29,782,067)	(7,329,315,857)	(30,631,174)	(7,359,947,032)	(29,268,847)	(7,389,215,879)	(31,214,220)

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - December 2013 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jun 2012	Adjustments	Adjusted Reserve Balance Jul 2012	Adjustments	Adjusted Reserve Balance Aug 2012	Adjustments	Adjusted Reserve Balance Sep 2012	Adjustments	Adjusted Reserve Balance Oct 2012	Adjustments	Adjusted Reserve Balance Nov 2012	Adjustments	Adjusted Reserve Balance Dec 2012	Adjustments
AMORTIZATION RESERVE															
Intangible Plant:															
California	CA	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service	CN	(103,869,877)	(518,510)	(104,388,387)	(518,432)	(104,906,818)	(518,354)	(105,425,173)	(518,276)	(105,943,449)	(518,199)	(106,461,648)	(518,121)	(106,979,769)	(518,043)
Idaho	ID	(785,488)	(1,764)	(787,252)	(1,764)	(789,016)	(1,764)	(790,780)	(1,764)	(792,543)	(1,764)	(794,307)	(1,764)	(796,071)	(1,764)
Pre-merger Utah	SG	(374,534)	(85)	(374,619)	(82)	(374,701)	(79)	(374,780)	(76)	(374,856)	(73)	(374,929)	(70)	(374,999)	(67)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(61,511)	(866)	(62,377)	(866)	(63,243)	(866)	(64,108)	(866)	(64,974)	(866)	(65,840)	(866)	(66,706)	(866)
Fuel Related	SE	(1,794,223)	(22,645)	(1,816,868)	(22,596)	(1,839,464)	(22,547)	(1,862,011)	(22,498)	(1,884,509)	(22,449)	(1,906,957)	(22,400)	(1,929,357)	(22,351)
Post-merger	SG	(52,567,449)	100,090	(52,467,359)	100,848	(52,366,511)	103,452	(52,263,060)	106,140	(52,156,919)	108,829	(52,048,090)	98,786	(51,949,304)	88,742
Hydro Relicensing	SG-P	(17,989,791)	(79,855)	(18,069,646)	(79,553)	(18,149,199)	(79,251)	(18,228,451)	(78,949)	(18,307,400)	(78,647)	(18,386,047)	(78,345)	(18,464,393)	(78,043)
Hydro Relicensing	SG-U	(3,831,411)	(16,990)	(3,848,400)	(16,966)	(3,865,366)	(16,942)	(3,882,308)	(16,918)	(3,899,226)	(16,894)	(3,916,120)	(16,870)	(3,932,991)	(16,847)
General Office	SO	(280,901,816)	(970,178)	(281,871,994)	(969,673)	(282,841,667)	(969,077)	(283,810,744)	(972,735)	(284,783,479)	(978,162)	(285,761,641)	(982,248)	(286,743,889)	(985,988)
Pre-merger Pacific	SG	-	53,158	53,158	53,158	106,315	53,158	159,473	53,158	212,630	53,158	265,788	53,158	318,945	53,158
Utah	UT	(42,863)	(1,016)	(43,879)	(1,016)	(44,895)	(1,016)	(45,911)	(1,016)	(46,927)	(1,016)	(47,942)	(1,016)	(48,958)	(1,016)
Washington	WA	-	14	14	14	28	14	42	14	57	14	71	14	85	14
Eastern Wyoming	WYP	(373,670)	(11,189)	(384,860)	(11,183)	(396,042)	(11,176)	(407,218)	(11,169)	(418,387)	(11,162)	(429,549)	(11,155)	(440,704)	(11,148)
Western Wyoming	WYU		-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	-
Total Intangible Plant		(462,920,468)	(1,469,836)	(464,390,304)	(1,468,111)	(465,858,415)	(1,464,448)	(467,322,863)	(1,464,955)	(468,787,818)	(1,467,231)	(470,255,049)	(1,480,897)	(471,735,946)	(1,494,220)
Hydro Production Plant:															
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(473,877)	(25,968)	(499,845)	(25,968)	(525,812)	(25,968)	(551,780)	(25,968)	(577,747)	(25,968)	(603,715)	(25,968)	(629,682)	(25,968)
Post-merger	SG-U	(506,676)	(3,711)	(510,387)	(3,711)	(514,098)	(3,711)	(517,809)	(3,711)	(521,520)	(3,711)	(525,231)	(3,711)	(528,942)	(3,711)
Total Hydro Plant		(980,553)	(29,679)	(1,010,232)	(29,679)	(1,039,910)	(29,679)	(1,069,589)	(29,679)	(1,099,267)	(29,679)	(1,128,946)	(29,679)	(1,158,625)	(29,679)
Other Production Plant:															
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant:															
California	CA	(300,596)	(807)	(301,403)	(807)	(302,211)	(807)	(303,018)	(807)	(303,826)	(807)	(304,633)	(807)	(305,441)	(807)
General Office	CN	(3,134,593)	(22,781)	(3,157,374)	(22,781)	(3,180,154)	(22,781)	(3,202,935)	(22,781)	(3,225,716)	(22,781)	(3,248,496)	(22,781)	(3,271,277)	(22,781)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(3,943,245)	(19,281)	(3,962,526)	(19,281)	(3,981,807)	(19,281)	(4,001,088)	(19,281)	(4,020,369)	(19,281)	(4,039,650)	(19,281)	(4,058,931)	(19,281)
General Office	SO	(12,094,200)	(106,575)	(12,200,776)	(106,575)	(12,307,351)	(106,575)	(12,413,927)	(106,575)	(12,520,502)	(106,575)	(12,627,077)	(106,575)	(12,733,653)	(106,575)
Utah	UT	(12,916)	(68)	(12,984)	(68)	(13,052)	(68)	(13,120)	(68)	(13,187)	(68)	(13,255)	(68)	(13,323)	(68)
Washington	WA	(1,704,011)	(7,732)	(1,711,743)	(7,732)	(1,719,475)	(7,732)	(1,727,207)	(7,732)	(1,734,939)	(7,732)	(1,742,671)	(7,732)	(1,750,403)	(7,732)
Eastern Wyoming	WYP	(4,104,030)	(30,535)	(4,134,565)	(30,535)	(4,165,101)	(30,535)	(4,195,636)	(30,535)	(4,226,172)	(30,535)	(4,256,707)	(30,535)	(4,287,243)	(30,535)
Western Wyoming	WYU	(41,123)	(402)	(41,525)	(402)	(41,926)	(402)	(42,328)	(402)	(42,729)	(402)	(43,131)	(402)	(43,533)	(402)
Total General Plant		(25,334,715)	(188,181)	(25,522,896)	(188,181)	(25,711,077)	(188,181)	(25,899,258)	(188,181)	(26,087,439)	(188,181)	(26,275,620)	(188,181)	(26,463,802)	(188,181)
Subtotal		(489,235,736)	(1,687,695)	(490,923,432)	(1,685,970)	(492,609,402)	(1,682,308)	(494,291,710)	(1,682,815)	(495,974,525)	(1,685,090)	(497,659,615)	(1,698,757)	(499,358,372)	(1,712,079)
Total		(7,703,471,831)	(30,228,477)	(7,733,700,309)	(31,151,611)	(7,764,851,920)	(28,973,580)	(7,793,825,500)	(31,464,882)	(7,825,290,382)	(32,316,265)	(7,857,606,647)	(30,967,604)	(7,888,574,251)	(32,926,299)

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - December 2013 Depreciation & Amortization Reser

Description	Factor	Adjusted Reserve Balance Jan 2013	Adjustments	Adjusted Reserve Balance Feb 2013	Adjustments	Adjusted Reserve Balance Mar 2013	Adjustments	Adjusted Reserve Balance Apr 2013	Adjustments	Adjusted Reserve Balance May 2013	Adjustments	Adjusted Reserve Balance Jun 2013	Adjustments	Adjusted Reserve Balance Jul 2013	Adjustments
DEPRECIATION RESERVE															
Steam Production Plant:															
Pre-merger Pacific	SG	(756,424,862)	(60,046)	(756,484,908)	(54,289)	(756,539,197)	(48,532)	(756,587,729)	(42,775)	(756,630,504)	(37,018)	(756,667,522)	(31,261)	(756,698,784)	(25,505)
Pre-merger Utah	SG	(774,922,526)	(188,988)	(775,111,514)	(184,427)	(775,295,941)	(179,865)	(775,475,806)	(175,303)	(775,651,109)	(170,742)	(775,821,851)	(166,180)	(775,988,031)	(161,618)
Post-merger	SG	(850,425,182)	(7,667,255)	(858,092,437)	(7,664,643)	(865,757,081)	(7,671,496)	(873,428,577)	(7,728,037)	(881,156,614)	(7,786,673)	(888,943,287)	(7,793,634)	(896,736,921)	(7,790,719)
Geothermal - Blundell	SG	(3,958,456)	(67,920)	(4,026,377)	(67,920)	(4,094,297)	(67,920)	(4,162,218)	(67,920)	(4,230,138)	(67,920)	(4,298,059)	(67,920)	(4,365,979)	(67,920)
Pollution Control Equipment	SG	(179,359)	(50,109)	(229,467)	(55,175)	(284,643)	(55,273)	(339,916)	(55,343)	(395,259)	(55,385)	(450,644)	(55,428)	(506,072)	(57,844)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(188,821,211)	318,108	(188,503,104)	320,455	(188,182,648)	322,615	(187,860,033)	320,116	(187,539,917)	317,878	(187,222,039)	320,394	(186,901,645)	322,048
Total Steam Plant		(2,574,731,596)	(7,716,211)	(2,582,447,807)	(7,705,999)	(2,590,153,806)	(7,700,472)	(2,597,854,278)	(7,749,263)	(2,605,603,541)	(7,799,861)	(2,613,403,402)	(7,794,030)	(2,621,197,431)	(7,781,559)
Hydro Production Plant:															
Pre-merger Pacific	SG	(128,924,988)	3,541	(128,921,447)	3,866	(128,917,581)	4,190	(128,913,390)	4,515	(128,908,876)	4,839	(128,904,036)	5,164	(128,898,872)	5,488
Pre-merger Utah	SG	(29,346,520)	(8,823)	(29,355,342)	(8,694)	(29,364,037)	(8,566)	(29,372,602)	(8,437)	(29,381,039)	(8,309)	(29,389,348)	(8,180)	(29,397,528)	(8,052)
Post-merger	SG-P	(45,995,496)	(661,502)	(46,656,998)	857,353	(45,799,645)	(565,416)	(46,365,061)	(728,526)	(47,093,588)	(528,983)	(47,622,571)	(802,964)	(48,425,535)	(734,657)
Post-merger	SG-U	(22,455,598)	(217,086)	(22,672,684)	(216,959)	(22,889,643)	(216,832)	(23,106,476)	(216,706)	(23,323,181)	(216,579)	(23,539,760)	(216,452)	(23,756,212)	(216,325)
Total Hydro Plant		(226,722,602)	(883,870)	(227,606,471)	635,565	(226,970,906)	(786,624)	(227,757,530)	(949,154)	(228,706,684)	(749,031)	(229,455,715)	(1,022,433)	(230,478,147)	(953,545)
Other Production Plant:															
Pre-merger Utah	SG	(954,357)	7,006	(947,351)	7,096	(940,255)	7,186	(933,069)	7,275	(925,794)	7,365	(918,429)	7,455	(910,974)	7,545
Post-merger	SG	(225,951,101)	(2,001,446)	(227,952,547)	(2,001,095)	(229,953,642)	(2,006,578)	(231,960,220)	(2,012,250)	(233,972,471)	(2,011,310)	(235,983,780)	(2,010,180)	(237,993,960)	(2,009,671)
Post-merger Wind	SG-W	(318,242,152)	(5,999,342)	(324,241,494)	(5,999,096)	(330,240,590)	(5,998,850)	(336,239,440)	(5,998,604)	(342,238,044)	(5,998,353)	(348,236,397)	(5,998,098)	(354,234,494)	(5,997,842)
Post-merger	SG	(23,684,395)	(162,085)	(23,846,480)	(161,920)	(24,008,400)	(161,755)	(24,170,155)	(161,590)	(24,331,745)	(161,425)	(24,493,170)	(161,260)	(24,654,430)	(161,095)
Total Other Plant		(568,832,006)	(8,155,867)	(576,987,872)	(8,155,015)	(585,142,887)	(8,159,997)	(593,302,885)	(8,165,169)	(601,468,053)	(8,163,722)	(609,631,776)	(8,162,082)	(617,793,858)	(8,161,063)
Transmission Plant:															
Pre-merger Pacific	SG	(372,744,348)	(437,872)	(373,182,220)	(437,126)	(373,619,346)	(436,379)	(374,055,725)	(435,632)	(374,491,357)	(434,886)	(374,926,243)	(434,139)	(375,360,382)	(433,393)
Pre-merger Utah	SG	(403,365,150)	(673,001)	(404,038,151)	(672,436)	(404,710,587)	(671,871)	(405,382,458)	(671,306)	(406,053,764)	(670,741)	(406,724,505)	(670,176)	(407,394,681)	(669,611)
Post-merger	SG	(511,539,258)	(4,230,128)	(515,769,385)	(4,237,325)	(520,006,711)	(4,245,364)	(524,252,075)	(4,555,846)	(528,807,921)	(4,889,404)	(533,697,325)	(4,922,453)	(538,619,777)	(4,933,827)
Total Transmission Plant		(1,287,648,756)	(5,341,001)	(1,292,989,757)	(5,346,887)	(1,298,336,643)	(5,353,614)	(1,303,690,258)	(5,662,784)	(1,309,353,042)	(5,995,031)	(1,315,348,073)	(6,026,768)	(1,321,374,841)	(6,036,830)
Distribution Plant:															
California	CA	(107,492,788)	(471,509)	(107,964,297)	(472,619)	(108,436,916)	(473,707)	(108,910,623)	(474,708)	(109,385,331)	(475,752)	(109,861,082)	(476,800)	(110,337,882)	(477,936)
Oregon	OR	(834,975,962)	(3,515,043)	(838,491,005)	(3,521,179)	(842,012,185)	(3,527,877)	(845,540,061)	(3,534,847)	(849,074,908)	(3,541,372)	(852,616,280)	(3,552,471)	(856,168,751)	(3,563,771)
Washington	WA	(188,128,970)	(687,903)	(188,816,873)	(688,637)	(189,505,510)	(689,441)	(190,194,951)	(690,161)	(190,885,112)	(690,913)	(191,576,025)	(691,637)	(192,267,662)	(692,415)
Eastern Wyoming	WYP	(197,373,354)	(806,398)	(198,179,753)	(809,975)	(198,989,728)	(813,499)	(199,803,227)	(816,981)	(200,620,208)	(820,593)	(201,440,801)	(824,451)	(202,265,252)	(828,825)
Utah	UT	(784,149,551)	(2,809,410)	(786,958,961)	(2,815,573)	(789,774,534)	(2,820,603)	(792,595,137)	(2,833,467)	(795,428,604)	(2,846,926)	(798,275,530)	(2,853,715)	(801,129,245)	(2,861,484)
Idaho	ID	(124,323,084)	(439,112)	(124,762,195)	(440,492)	(125,202,687)	(441,979)	(125,644,667)	(443,481)	(126,088,148)	(445,063)	(126,533,211)	(446,700)	(126,979,910)	(448,394)
Western Wyoming	WYU	(41,633,063)	(164,918)	(41,797,981)	(164,722)	(41,962,703)	(164,525)	(42,127,228)	(164,328)	(42,291,556)	(164,132)	(42,455,687)	(163,935)	(42,619,622)	(163,738)
Total Distribution Plant		(2,278,076,772)	(8,894,293)	(2,286,971,065)	(8,913,196)	(2,295,884,261)	(8,931,632)	(2,304,815,893)	(8,957,972)	(2,313,773,866)	(8,984,751)	(2,322,758,616)	(9,009,707)	(2,331,768,324)	(9,036,564)
General Plant:															
California	CA	(4,700,005)	(14,970)	(4,714,975)	(15,090)	(4,730,065)	(15,224)	(4,745,289)	(15,291)	(4,760,580)	(15,384)	(4,775,964)	(15,472)	(4,791,436)	(15,535)
Oregon	OR	(50,795,354)	(41,897)	(50,837,251)	(42,192)	(50,879,443)	(42,918)	(50,922,361)	(42,631)	(50,964,992)	(43,662)	(51,008,654)	(44,669)	(51,053,323)	(43,937)
Washington	WA	(19,055,404)	(64,538)	(19,119,942)	(64,775)	(19,184,717)	(64,736)	(19,249,453)	(64,520)	(19,313,973)	(64,307)	(19,378,280)	(64,093)	(19,442,373)	(63,876)
Eastern Wyoming	WYP	(19,450,023)	(90,065)	(19,540,088)	(90,656)	(19,630,744)	(91,236)	(19,721,980)	(91,120)	(19,813,099)	(91,311)	(19,904,410)	(91,548)	(19,995,958)	(91,532)
Utah	UT	(59,766,905)	(185,487)	(59,952,392)	(186,642)	(60,139,034)	(187,468)	(60,326,501)	(187,204)	(60,513,705)	(187,968)	(60,701,673)	(188,823)	(60,890,496)	(188,763)
Idaho	ID	(10,949,782)	4,557	(10,945,225)	4,391	(10,940,834)	4,232	(10,936,602)	4,224	(10,932,378)	4,212	(10,928,167)	4,173	(10,923,994)	4,107
Western Wyoming	WYU	(4,722,879)	(9,773)	(4,732,652)	(9,664)	(4,742,316)	(9,555)	(4,751,871)	(9,446)	(4,761,317)	(9,337)	(4,770,655)	(9,228)	(4,779,883)	(9,119)
Pre-merger Pacific	SG	(1,605,253)	118,670	(1,486,583)	118,992	(1,367,590)	119,314	(1,248,276)	119,637	(1,128,639)	119,959	(1,008,681)	120,281	(888,400)	120,603
Pre-merger Utah	SG	(1,960,509)	246,979	(1,713,529)	247,439	(1,466,091)	247,899	(1,218,192)	248,358	(969,834)	248,818	(721,016)	249,277	(471,739)	249,737
Post-merger	SG	(61,770,981)	(422,838)	(62,193,819)	(422,448)	(62,616,267)	(422,063)	(63,038,330)	(422,312)	(63,460,641)	(423,176)	(63,883,817)	(423,040)	(64,306,858)	(422,145)
General Office	SO	(76,574,430)	340,947	(76,233,484)	346,397	(75,887,087)	351,016	(75,536,071)	355,774	(75,180,297)	360,684	(74,819,614)	364,779	(74,454,835)	368,274
General Office	SG	(1,984,097)	16,471	(1,967,627)	16,554	(1,951,073)	15,446	(1,935,627)	14,338	(1,921,289)	14,421	(1,906,868)	14,504	(1,892,364)	14,587
General Office	SG	(47,880)	541	(47,339)	545	(46,794)	548	(46,246)	552	(45,694)	555	(45,139)	559	(44,580)	562
Customer Service	CN	(9,008,866)	(28,585)	(9,037,451)	(27,799)	(9,065,250)	(27,012)	(9,092,262)	(26,225)	(9,118,487)	(25,438)	(9,143,925)	(24,652)	(9,168,577)	(23,865)
Fuel Related	SE	(290,656)	2,843	(287,813)	2,858	(284,954)	2,874	(282,081)	2,889	(279,192)	2,904	(276,288)	2,919	(273,369)	2,934
Total General Plant		(322,683,025)	(127,145)	(322,810,170)	(122,090)	(322,932,260)	(118,882)	(323,051,141)	(112,977)	(323,164,118)	(109,032)	(323,273,150)	(105,032)	(323,378,182)	(97,968)
Mining Plant:															
Coal Mine	SE	(161,735,343)	(42,084)	(161,777,427)	(40,613)	(161,818,039)	(45,689)	(161,863,728)	(50,655)	(161,914,383)	(49,687)	(161,964,070)	(50,219)	(162,014,289)	(51,994)
Total Mining Plant		(161,735,343)	(42,084)	(161,777,427)	(40,613)	(161,818,039)	(45,689)	(161,863,728)	(50,655)	(161,914,383)	(49,687)	(161,964,070)	(50,219)	(162,014,289)	(51,994)
Subtotal		(7,420,430,098)	(31,160,470)	(7,451,590,569)	(29,648,235)	(7,481,238,804)	(31,096,910)	(7,512,335,714)	(31,647,974)	(7,543,983,688)	(31,851,114)	(7,575,834,802)	(32,170,271)	(7,608,005,073)	(32,119,522)

PacifiCorp
Oregon General Rate Case - December 2014
Jun 2012 - December 2013 Depreciation & Amortization Reser

Description	Factor	Adjusted Reserve Balance Jan 2013	Adjustments	Adjusted Reserve Balance Feb 2013	Adjustments	Adjusted Reserve Balance Mar 2013	Adjustments	Adjusted Reserve Balance Apr 2013	Adjustments	Adjusted Reserve Balance May 2013	Adjustments	Adjusted Reserve Balance Jun 2013	Adjustments	Adjusted Reserve Balance Jul 2013	Adjustments
AMORTIZATION RESERVE															
Intangible Plant:															
California	CA	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service	CN	(107,497,812)	(517,966)	(108,015,778)	(517,888)	(108,533,666)	(517,810)	(109,051,476)	(517,733)	(109,569,209)	(517,655)	(110,086,864)	(517,577)	(110,604,441)	(517,500)
Idaho	ID	(797,835)	(1,764)	(799,599)	(1,764)	(801,362)	(1,764)	(803,126)	(1,764)	(804,890)	(1,764)	(806,654)	(1,764)	(808,418)	(1,764)
Pre-merger Utah	SG	(375,066)	(64)	(375,130)	(61)	(375,190)	(58)	(375,248)	(55)	(375,303)	(52)	(375,354)	(49)	(375,403)	(46)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(67,572)	(866)	(68,437)	(866)	(69,303)	(866)	(70,169)	(866)	(71,034)	(866)	(71,900)	(866)	(72,765)	(866)
Fuel Related	SE	(1,951,707)	(22,301)	(1,974,009)	(22,252)	(1,996,261)	(22,203)	(2,018,464)	(22,154)	(2,040,619)	(22,105)	(2,062,724)	(22,056)	(2,084,780)	(22,007)
Post-merger	SG	(51,860,563)	91,431	(51,769,132)	94,119	(51,675,013)	96,808	(51,578,204)	99,497	(51,478,707)	102,186	(51,376,521)	104,875	(51,271,645)	107,564
Hydro Relicensing	SG-P	(18,542,436)	(77,741)	(18,620,177)	(77,439)	(18,697,617)	(77,137)	(18,774,754)	(76,835)	(18,851,590)	(76,533)	(18,928,123)	(76,231)	(19,004,355)	(75,929)
Hydro Relicensing	SG-U	(3,949,837)	(16,823)	(3,966,660)	(16,799)	(3,983,459)	(16,775)	(4,000,234)	(16,751)	(4,016,986)	(16,728)	(4,033,713)	(16,704)	(4,050,417)	(16,680)
General Office	SO	(287,729,877)	(986,675)	(288,716,552)	(985,841)	(289,702,393)	(985,595)	(290,687,988)	(985,251)	(291,673,239)	(984,800)	(292,658,039)	(984,925)	(293,642,964)	(985,476)
Pre-merger Pacific	SG	372,103	53,158	425,260	53,158	478,418	53,158	531,576	53,158	584,733	53,158	637,891	53,158	691,048	53,158
Utah	UT	(49,974)	(1,016)	(50,990)	(1,016)	(52,006)	(1,016)	(53,022)	(1,016)	(54,037)	(1,016)	(55,053)	(1,016)	(56,069)	(1,016)
Washington	WA	99	14	113	14	127	14	142	14	156	14	170	14	184	14
Eastern Wyoming	WYP	(451,853)	(11,142)	(462,994)	(11,135)	(474,129)	(11,128)	(485,257)	(11,121)	(496,378)	(11,114)	(507,492)	(11,107)	(518,599)	(11,100)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	-
Total Intangible Plant		(473,230,166)	(1,491,755)	(474,721,920)	(1,487,769)	(476,209,690)	(1,484,372)	(477,694,062)	(1,480,876)	(479,174,938)	(1,477,274)	(480,652,211)	(1,474,248)	(482,126,459)	(1,471,647)
Hydro Production Plant:															
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(655,650)	(25,968)	(681,617)	(25,968)	(707,585)	(25,968)	(733,552)	(25,968)	(759,520)	(25,968)	(785,487)	(25,968)	(811,455)	(25,968)
Post-merger	SG-U	(532,654)	(3,711)	(536,365)	(3,711)	(540,076)	(3,711)	(543,787)	(3,711)	(547,498)	(3,711)	(551,209)	(3,711)	(554,920)	(3,711)
Total Hydro Plant		(1,188,303)	(29,679)	(1,217,982)	(29,679)	(1,247,660)	(29,679)	(1,277,339)	(29,679)	(1,307,017)	(29,679)	(1,336,696)	(29,679)	(1,366,374)	(29,679)
Other Production Plant:															
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant:															
California	CA	(306,248)	(807)	(307,056)	(807)	(307,863)	(807)	(308,671)	(807)	(309,478)	(807)	(310,286)	(807)	(311,093)	(807)
General Office	CN	(3,294,057)	(22,781)	(3,316,838)	(22,781)	(3,339,618)	(22,781)	(3,362,399)	(22,781)	(3,385,180)	(22,781)	(3,407,960)	(22,781)	(3,430,741)	(22,781)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(4,078,212)	(19,281)	(4,097,492)	(19,281)	(4,116,773)	(19,281)	(4,136,054)	(19,281)	(4,155,335)	(19,281)	(4,174,616)	(19,281)	(4,193,897)	(19,281)
General Office	SO	(12,840,228)	(106,575)	(12,946,803)	(106,575)	(13,053,379)	(106,575)	(13,159,954)	(106,575)	(13,266,529)	(106,575)	(13,373,105)	(106,575)	(13,479,680)	(106,575)
Utah	UT	(13,391)	(68)	(13,459)	(68)	(13,526)	(68)	(13,594)	(68)	(13,662)	(68)	(13,730)	(68)	(13,798)	(68)
Washington	WA	(1,758,135)	(7,732)	(1,765,867)	(7,732)	(1,773,599)	(7,732)	(1,781,331)	(7,732)	(1,789,062)	(7,732)	(1,796,794)	(7,732)	(1,804,526)	(7,732)
Eastern Wyoming	WYP	(4,317,778)	(30,535)	(4,348,313)	(30,535)	(4,378,849)	(30,535)	(4,409,384)	(30,535)	(4,439,920)	(30,535)	(4,470,455)	(30,535)	(4,500,991)	(30,535)
Western Wyoming	WYU	(43,934)	(402)	(44,336)	(402)	(44,737)	(402)	(45,139)	(402)	(45,541)	(402)	(45,942)	(402)	(46,344)	(402)
Total General Plant		(26,651,983)	(188,181)	(26,840,164)	(188,181)	(27,028,345)	(188,181)	(27,216,526)	(188,181)	(27,404,707)	(188,181)	(27,592,888)	(188,181)	(27,781,070)	(188,181)
Subtotal		(501,070,452)	(1,709,614)	(502,780,066)	(1,705,629)	(504,485,695)	(1,702,232)	(506,187,927)	(1,698,736)	(507,886,662)	(1,695,133)	(509,581,796)	(1,692,108)	(511,273,903)	(1,689,506)
Total		(7,921,500,550)	(32,870,085)	(7,954,370,635)	(31,353,864)	(7,985,724,498)	(32,799,142)	(8,018,523,640)	(33,346,710)	(8,051,870,350)	(33,546,248)	(8,085,416,598)	(33,862,378)	(8,119,278,976)	(33,809,029)

PacifiCorp
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Description	Factor	Adjusted Reserve Balance Aug 2013	Adjustments	Adjusted Reserve Balance Sep 2013	Adjustments	Adjusted Reserve Balance Oct 2013	Adjustments	Adjusted Reserve Balance Nov 2013	Adjustments	Adjusted Reserve Balance Dec 2013	CY 2013 YE Balance	Incremental Reserve For Annualized Depreciation	CY 2013 Adjusted Reserve Year End Balance
DEPRECIATION RESERVE													
Steam Production Plant:													
Pre-merger Pacific	SG	(756,724,288)	(19,748)	(756,744,036)	(13,991)	(756,758,027)	(8,234)	(756,766,261)	(2,477)	(756,768,738)	(756,768,738)	(18,231,267)	(775,000,005)
Pre-merger Utah	SG	(776,149,649)	(157,056)	(776,306,705)	(152,495)	(776,459,200)	(147,933)	(776,607,133)	(143,371)	(776,750,504)	(776,750,504)	(13,845,311)	(790,595,815)
Post-merger	SG	(904,527,640)	(7,788,977)	(912,316,616)	(7,787,046)	(920,103,663)	(7,787,003)	(927,890,665)	(7,807,202)	(935,697,867)	(935,697,867)	(85,023,350)	(1,020,721,217)
Geothermal - Blundell	SG	(4,433,900)	(67,920)	(4,501,820)	(67,920)	(4,569,741)	(67,920)	(4,637,661)	(67,920)	(4,705,581)	(4,705,581)	(594,084)	(5,299,665)
Pollution Control Equipment	SG	(563,916)	(66,080)	(629,996)	(71,942)	(701,938)	(71,984)	(773,922)	(73,525)	(847,447)	(847,447)	(843,814)	(1,691,261)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	(1,841)	(1,841)	(1,841)	(87,378)	(89,219)
Post-merger	SG	(186,579,598)	323,186	(186,256,412)	325,140	(185,931,271)	324,905	(185,606,366)	316,638	(185,289,728)	(185,289,728)	(12,530,189)	(197,819,917)
Total Steam Plant		(2,628,978,990)	(7,776,596)	(2,636,755,586)	(7,768,254)	(2,644,523,840)	(7,758,169)	(2,652,282,009)	(7,779,698)	(2,660,061,707)	(2,660,061,707)	(131,155,392)	(2,791,217,099)
Hydro Production Plant:													
Pre-merger Pacific	SG	(128,893,384)	5,813	(128,887,571)	6,138	(128,881,433)	6,462	(128,874,971)	6,787	(128,868,184)	(128,868,184)	(1,345,064)	(130,213,248)
Pre-merger Utah	SG	(29,405,580)	(7,923)	(29,413,503)	(7,795)	(29,421,297)	(7,666)	(29,428,963)	(7,537)	(29,436,501)	(29,436,501)	(427,856)	(29,864,357)
Post-merger	SG-P	(49,160,192)	(793,234)	(49,953,426)	(840,898)	(50,794,323)	(805,975)	(51,600,299)	(727,037)	(52,327,336)	(52,327,336)	(4,495,729)	(56,823,065)
Post-merger	SG-U	(23,972,537)	(216,198)	(24,188,735)	(216,072)	(24,404,807)	(216,074)	(24,620,881)	(216,266)	(24,837,146)	(24,837,146)	(2,109,735)	(26,946,882)
Total Hydro Plant		(231,431,692)	(1,011,543)	(232,443,235)	(1,058,626)	(233,501,861)	(1,023,253)	(234,525,114)	(944,054)	(235,469,167)	(235,469,167)	(8,378,384)	(243,847,551)
Other Production Plant:													
Pre-merger Utah	SG	(903,429)	7,635	(895,794)	7,724	(888,070)	7,814	(880,255)	7,904	(872,351)	(872,351)	43,235	(829,117)
Post-merger	SG	(240,003,631)	(2,009,319)	(242,012,950)	(2,008,311)	(244,021,260)	(2,009,231)	(246,030,491)	(2,010,424)	(248,040,915)	(248,040,915)	(6,990,297)	(255,031,212)
Post-merger Wind	SG-W	(360,232,336)	(5,997,586)	(366,229,923)	(5,997,331)	(372,227,253)	(5,997,075)	(378,224,328)	(6,001,073)	(384,225,400)	(384,225,400)	13,184,916	(371,040,484)
Post-merger	SG	(24,815,525)	(160,930)	(24,976,455)	(160,765)	(25,137,220)	(160,600)	(25,297,819)	(160,435)	(25,458,254)	(25,458,254)	(511,918)	(25,970,172)
Total Other Plant		(625,954,921)	(8,160,200)	(634,115,121)	(8,158,681)	(642,273,802)	(8,159,091)	(650,432,894)	(8,164,027)	(658,596,921)	(658,596,921)	5,725,935	(652,870,986)
Transmission Plant:													
Pre-merger Pacific	SG	(375,793,775)	(432,646)	(376,226,421)	(431,899)	(376,658,320)	(431,153)	(377,089,473)	(430,406)	(377,519,879)	(377,519,879)	731,183	(376,788,696)
Pre-merger Utah	SG	(408,064,292)	(669,046)	(408,733,339)	(668,481)	(409,401,820)	(667,916)	(410,069,736)	(667,351)	(410,737,087)	(410,737,087)	836,403	(409,900,684)
Post-merger	SG	(543,553,604)	(4,951,511)	(548,505,115)	(4,980,035)	(553,485,150)	(5,018,095)	(558,503,245)	(5,066,730)	(563,569,975)	(563,569,975)	(1,554,598)	(565,124,573)
Total Transmission Plant		(1,327,411,671)	(6,053,203)	(1,333,464,874)	(6,080,416)	(1,339,545,290)	(6,117,164)	(1,345,662,454)	(6,164,487)	(1,351,826,941)	(1,351,826,941)	12,989	(1,351,813,952)
Distribution Plant:													
California	CA	(110,815,818)	(479,071)	(111,294,889)	(480,086)	(111,774,975)	(481,063)	(112,256,038)	(482,153)	(112,738,190)	(112,738,190)	484,190	(112,254,001)
Oregon	OR	(859,732,522)	(3,569,873)	(863,302,395)	(3,581,266)	(866,883,661)	(3,592,091)	(870,475,752)	(3,598,003)	(874,073,755)	(874,073,755)	5,211,026	(868,862,729)
Washington	WA	(192,960,077)	(693,175)	(193,653,253)	(693,769)	(194,347,022)	(694,165)	(195,041,187)	(694,571)	(195,735,758)	(195,735,758)	1,267,147	(194,468,611)
Eastern Wyoming	WYP	(203,094,077)	(833,087)	(203,927,163)	(838,470)	(204,765,633)	(843,497)	(205,609,130)	(846,631)	(206,455,760)	(206,455,760)	(79,728)	(206,535,489)
Utah	UT	(803,990,729)	(2,869,818)	(806,860,547)	(2,876,641)	(809,737,188)	(2,882,195)	(812,619,382)	(2,889,322)	(815,508,705)	(815,508,705)	823,192	(814,685,513)
Idaho	ID	(127,428,304)	(450,084)	(127,878,388)	(451,513)	(128,329,901)	(452,773)	(128,782,674)	(454,110)	(129,236,784)	(129,236,784)	825,612	(128,411,173)
Western Wyoming	WYU	(42,783,360)	(163,541)	(42,946,902)	(163,345)	(43,110,246)	(163,148)	(43,273,394)	(162,951)	(43,436,346)	(43,436,346)	23,280	(43,413,065)
Total Distribution Plant		(2,340,804,887)	(9,058,650)	(2,349,863,537)	(9,085,089)	(2,358,948,626)	(9,108,931)	(2,368,057,557)	(9,127,741)	(2,377,185,298)	(2,377,185,298)	8,554,719	(2,368,630,579)
General Plant:													
California	CA	(4,806,971)	(15,602)	(4,822,572)	(16,160)	(4,838,732)	(16,700)	(4,855,432)	(16,721)	(4,872,153)	(4,872,153)	(5,555)	(4,877,708)
Oregon	OR	(51,097,260)	(43,740)	(51,140,999)	(48,198)	(51,189,197)	(52,146)	(51,241,343)	(54,279)	(51,295,622)	(51,295,622)	(184,013)	(51,479,635)
Washington	WA	(19,506,249)	(63,657)	(19,569,905)	(64,022)	(19,633,928)	(64,386)	(19,698,314)	(64,159)	(19,762,472)	(19,762,472)	250,329	(19,512,143)
Eastern Wyoming	WYP	(20,087,491)	(91,533)	(20,179,024)	(92,842)	(20,271,866)	(94,122)	(20,365,988)	(94,078)	(20,460,065)	(20,460,065)	249,366	(20,210,699)
Utah	UT	(61,079,259)	(188,964)	(61,268,223)	(195,533)	(61,463,756)	(201,874)	(61,665,631)	(201,914)	(61,867,545)	(61,867,545)	(170,294)	(62,037,839)
Idaho	ID	(10,919,887)	4,051	(10,915,835)	3,810	(10,912,025)	3,566	(10,908,459)	3,515	(10,904,944)	(10,904,944)	(15,835)	(10,920,779)
Western Wyoming	WYU	(4,789,002)	(9,010)	(4,798,012)	(8,901)	(4,806,914)	(8,792)	(4,815,706)	(8,684)	(4,824,390)	(4,824,390)	60,695	(4,763,695)
Pre-merger Pacific	SG	(767,798)	120,925	(646,873)	121,247	(525,626)	121,569	(404,058)	121,891	(282,167)	(282,167)	25,061	(257,106)
Pre-merger Utah	SG	(222,002)	250,196	28,194	250,656	278,850	251,116	529,966	251,575	781,541	781,541	33,291	814,832
Post-merger	SG	(64,729,003)	(421,224)	(65,150,226)	(422,303)	(65,572,529)	(423,750)	(65,996,280)	(428,054)	(66,424,334)	(66,424,334)	(7,230)	(66,431,564)
General Office	SO	(74,086,561)	372,454	(73,714,107)	376,302	(73,337,805)	378,223	(72,959,582)	378,701	(72,580,881)	(72,580,881)	261,471	(72,319,411)
General Office	SG	(1,877,776)	14,671	(1,863,106)	14,754	(1,848,352)	14,837	(1,833,515)	14,523	(1,818,992)	(1,818,992)	(18,552)	(1,837,545)
General Office	SG	(44,017)	566	(43,451)	570	(42,882)	573	(42,309)	577	(41,732)	(41,732)	254	(41,478)
Customer Service	CN	(9,192,442)	(23,078)	(9,215,520)	(22,291)	(9,237,811)	(21,505)	(9,259,316)	(20,718)	(9,280,034)	(9,280,034)	59,597	(9,220,436)
Fuel Related	SE	(270,434)	2,950	(267,485)	2,965	(264,520)	2,980	(261,540)	2,995	(258,545)	(258,545)	904	(257,640)
Total General Plant		(323,476,151)	(90,995)	(323,567,146)	(99,948)	(323,667,094)	(110,412)	(323,777,506)	(114,830)	(323,892,335)	(323,892,335)	539,490	(323,352,846)
Mining Plant:													
Coal Mine	SE	(162,066,282)	(53,198)	(162,119,480)	(54,338)	(162,173,818)	(56,465)	(162,230,283)	(57,277)	(162,287,560)	(162,287,560)	(12,499,826)	(174,787,386)
Total Mining Plant		(162,066,282)	(53,198)	(162,119,480)	(54,338)	(162,173,818)	(56,465)	(162,230,283)	(57,277)	(162,287,560)	(162,287,560)	(12,499,826)	(174,787,386)
Subtotal		(7,640,124,595)	(32,204,383)	(7,672,328,978)	(32,305,352)	(7,704,634,330)	(32,333,486)	(7,736,967,816)	(32,352,113)	(7,769,319,929)	(7,769,319,929)	(137,200,470)	(7,906,520,400)

PacifiCorp
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Description	Factor	Adjusted Reserve Balance Aug 2013	Adjustments	Adjusted Reserve Balance Sep 2013	Adjustments	Adjusted Reserve Balance Oct 2013	Adjustments	Adjusted Reserve Balance Nov 2013	Adjustments	Adjusted Reserve Balance Dec 2013	CY 2013 YE Balance	Incremental Reserve For Annualized Depreciation	CY 2013 Adjusted Reserve Year End Balance
AMORTIZATION RESERVE													
Intangible Plant:													
California	CA	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service	CN	(111,121,941)	(517,422)	(111,639,363)	(517,344)	(112,156,707)	(517,267)	(112,673,973)	(517,189)	(113,191,162)	(113,191,162)	5,593	(113,185,569)
Idaho	ID	(810,181)	(1,764)	(811,945)	(1,764)	(813,709)	(1,764)	(815,473)	(1,764)	(817,237)	(817,237)	-	(817,237)
Pre-merger Utah	SG	(375,449)	(43)	(375,491)	(39)	(375,531)	(36)	(375,567)	(33)	(375,600)	(375,600)	219	(375,381)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(73,631)	(866)	(74,496)	(865)	(75,362)	(865)	(76,227)	(865)	(77,093)	(77,093)	2	(77,091)
Fuel Related	SE	(2,106,787)	(21,958)	(2,128,745)	(21,909)	(2,150,654)	(21,860)	(2,172,514)	(21,811)	(2,194,324)	(2,194,324)	3,533	(2,190,791)
Post-merger	SG	(51,164,081)	110,253	(51,053,828)	112,942	(50,940,886)	115,631	(50,825,255)	118,320	(50,706,935)	(50,706,935)	193,604	(50,513,331)
Hydro Relicensing	SG-P	(19,080,284)	(75,627)	(19,155,911)	(75,325)	(19,231,237)	(75,023)	(19,306,260)	(74,721)	(19,380,982)	(19,380,982)	21,743	(19,359,239)
Hydro Relicensing	SG-U	(4,067,097)	(16,656)	(4,083,753)	(16,632)	(4,100,385)	(16,608)	(4,116,994)	(16,585)	(4,133,578)	(4,133,578)	1,715	(4,131,863)
General Office	SO	(294,628,440)	(993,809)	(295,622,249)	(1,003,704)	(296,625,952)	(1,006,695)	(297,632,647)	(1,017,195)	(298,649,842)	(298,649,842)	(412,524)	(299,062,366)
Pre-merger Pacific	SG	744,206	53,158	797,363	53,158	850,521	53,158	903,679	53,158	956,836	956,836	-	956,836
Utah	UT	(57,084)	(1,016)	(58,100)	(1,016)	(59,115)	(1,016)	(60,131)	(1,016)	(61,146)	(61,146)	2	(61,144)
Washington	WA	198	14	212	14	227	14	241	14	255	255	-	255
Eastern Wyoming	WYP	(529,700)	(11,094)	(540,793)	(11,087)	(551,880)	(11,080)	(562,960)	(11,073)	(574,033)	(574,033)	493	(573,541)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	-	(327,836)	(327,836)	-	(327,836)
Total Intangible Plant		(483,598,106)	(1,476,829)	(485,074,935)	(1,483,572)	(486,558,506)	(1,483,412)	(488,041,918)	(1,490,760)	(489,532,678)	(489,532,678)	(185,619)	(489,718,297)
Hydro Production Plant:													
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(837,422)	(25,968)	(863,390)	(25,968)	(889,357)	(25,968)	(915,325)	(25,968)	(941,292)	(941,292)	-	(941,292)
Post-merger	SG-U	(558,631)	(3,711)	(562,342)	(3,711)	(566,053)	(3,711)	(569,764)	(3,711)	(573,475)	(573,475)	-	(573,475)
Total Hydro Plant		(1,396,053)	(29,679)	(1,425,731)	(29,679)	(1,455,410)	(29,679)	(1,485,088)	(29,679)	(1,514,767)	(1,514,767)	-	(1,514,767)
Other Production Plant:													
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-	-
General Plant:													
California	CA	(311,901)	(807)	(312,708)	(807)	(313,516)	(807)	(314,323)	(807)	(315,131)	(315,131)	-	(315,131)
General Office	CN	(3,453,521)	(22,781)	(3,476,302)	(22,781)	(3,499,083)	(22,781)	(3,521,863)	(22,781)	(3,544,644)	(3,544,644)	-	(3,544,644)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(4,213,178)	(19,281)	(4,232,459)	(19,281)	(4,251,740)	(19,281)	(4,271,021)	(19,281)	(4,290,302)	(4,290,302)	-	(4,290,302)
General Office	SO	(13,586,255)	(106,575)	(13,692,831)	(106,575)	(13,799,406)	(106,575)	(13,905,982)	(106,575)	(14,012,557)	(14,012,557)	-	(14,012,557)
Utah	UT	(13,865)	(68)	(13,933)	(68)	(14,001)	(68)	(14,069)	(68)	(14,137)	(14,137)	-	(14,137)
Washington	WA	(1,812,258)	(7,732)	(1,819,990)	(7,732)	(1,827,722)	(7,732)	(1,835,454)	(7,732)	(1,843,186)	(1,843,186)	-	(1,843,186)
Eastern Wyoming	WYP	(4,531,526)	(30,535)	(4,562,062)	(30,535)	(4,592,597)	(30,535)	(4,623,133)	(30,535)	(4,653,668)	(4,653,668)	-	(4,653,668)
Western Wyoming	WYU	(46,746)	(402)	(47,147)	(402)	(47,549)	(402)	(47,950)	(402)	(48,352)	(48,352)	-	(48,352)
Total General Plant		(27,969,251)	(188,181)	(28,157,432)	(188,181)	(28,345,613)	(188,181)	(28,533,794)	(188,181)	(28,721,975)	(28,721,975)	-	(28,721,975)
Subtotal		(512,963,410)	(1,694,688)	(514,658,098)	(1,701,431)	(516,359,529)	(1,701,271)	(518,060,801)	(1,708,620)	(519,769,421)	(519,769,421)	(185,619)	(519,955,039)
Total		(8,153,088,005)	(33,899,072)	(8,186,987,076)	(34,006,783)	(8,220,993,860)	(34,034,757)	(8,255,028,617)	(34,060,733)	(8,289,089,350)	(8,289,089,350)	(137,386,089)	(8,426,475,439)

Ref. 6.2.3

PacifiCorp
Oregon General Rate Case - December 2014
Depreciation Reserve

Removal Projects Included in the Filing

Steam Projects:	Factor	Amount (July12-Dec13)
Carbon Plant Closure Project	SG	839,851
U3-4 Engr Analysis and Demo Obsolete Equ	SG	2,447,855
NAU U1 Flue Gas Desulfurization Sys	SG	1,387,794
FGD Pond 1 Closure-Ash Haul/Fill	SG	994,599
Total		5,670,099

PacifiCorp
Oregon General Rate Case - December 2014
Oregon Coal-Fired Steam Plant Depreciation

Depreciation Reserve Adjustment

	Total Company	Factor	Factor %	Oregon Allocated
Adjustment to June 2012 Reserve:				
Steam Plant Accumulated Depreciation*	(154,813,552)	SG	26.053%	(40,333,577)
Steam Plant Accumulated Depreciation*	(18,632,197)	SG	26.053%	(4,854,247)
	(173,445,749)			(45,187,824)

*This represents 4 and 1/2 years (January 2008 - June 2012) of the increase at the current approved rate.

Depreciation Reserve Adjustment By Plant

Plant	Factor	Adjustment to Reserve
CHOLLA	SG	(18,632,197)
NAUGHTON	SG	(683,348)
HUNTINGTON	SG	(16,173,523)
HUNTER	SG	(39,678,404)
CRAIG	SG	(6,464,147)
HAYDEN	SG	(3,077,757)
COLSTRIP	SG	(6,930,820)
DAVE JOHNSTON	SG	(16,489,261)
JIM BRIDGER	SG	(48,520,098)
WYODAK	SG	(16,796,194)
		(173,445,749)

This is the increase in the depreciation reserve June 2012 starting balance in adjustment 6.2. This reflects the increase from January 2008 to June 2012 to reflect the different depreciation rates Oregon is using for the coal-fired generating plants. This was approved in the Depreciation Study, in Docket UM-1329 Order 08-427, with rates effective January 1, 2008.

PacifiCorp
Oregon General Rate Case - December 2014
Hydro Decommissioning
Spending, Accruals, and Balances - West Side, East Side, and Total Resources

West Side	Spend	Accruals	Balance
July-11	510,133	(185,352)	(15,795,341)
August-11	1,297,299	(185,352)	(14,683,394)
September-11	4,262,792	(185,352)	(10,605,954)
October-11	2,233,011	(185,352)	(8,558,296)
November-11	380,161	(185,352)	(8,363,487)
December-11	1,034,853	(185,352)	(7,513,986)
January-12	629,272	(185,352)	(7,070,066)
February-12	508,069	(185,352)	(6,747,349)
March-12	1,145,320	(185,352)	(5,787,381)
April-12	2,124,670	(185,352)	(3,848,064)
May-12	890,732	(185,352)	(3,142,684)
June-12	2,909,337	(185,352)	(418,699)
July-12	1,829,256	(185,352)	1,225,205
August-12	1,015,770	(185,352)	2,055,623
September-12	1,875,035	(185,352)	3,745,306
October-12	567,191	(635,536)	3,676,961
November-12	(496,451)	(297,898)	2,882,612
December-12	300,000	(297,898)	2,884,714
January-13	50,000	(297,898)	2,636,816
February-13	128,000	(297,898)	2,466,918
March-13	1,650,000	(297,898)	3,819,020
April-13	228,000	(297,898)	3,749,122
May-13	78,000	(297,898)	3,529,224
June-13	290,000	(297,898)	3,521,326
July-13	38,000	(297,898)	3,261,428
August-13	128,000	(297,898)	3,091,530
September-13	70,000	(297,898)	2,863,632
October-13	32,000	(297,898)	2,597,734
November-13	78,000	(297,898)	2,377,836
December-13	163,000	(297,898)	2,242,938
January-14	26,000	(139,388)	2,129,550
February-14	26,000	(139,388)	2,016,162
March-14	36,000	(139,388)	1,912,774
April-14	26,000	(139,388)	1,799,386
May-14	26,000	(139,388)	1,685,998
June-14	176,000	(139,388)	1,722,610
July-14	36,000	(139,388)	1,619,222
August-14	26,000	(139,388)	1,505,834
September-14	26,000	(139,388)	1,392,446
October-14	31,000	(139,388)	1,284,058
November-14	75,000	(139,388)	1,219,670
December-14	165,000	(139,388)	1,245,282

East Side	Spend	Accruals	Balance
July-11	-	(112,546)	964,071
August-11	-	(112,546)	851,525
September-11	-	(112,546)	738,979
October-11	-	(112,546)	626,434
November-11	-	(112,562)	513,872
December-11	-	(112,546)	401,326
January-12	-	(112,546)	288,780
February-12	-	(112,546)	176,234
March-12	-	(112,546)	63,688
April-12	-	(112,546)	(48,858)
May-12	-	(112,546)	(161,404)
June-12	-	(112,546)	(273,950)
July-12	-	(112,546)	(386,497)
August-12	-	(112,546)	(499,043)
September-12	-	(112,546)	(611,589)
October-12	-	337,638	(273,952)
November-12	-	-	(273,952)
December-12	-	-	(273,952)
January-13	-	-	(273,952)
February-13	-	-	(273,952)
March-13	-	-	(273,952)
April-13	-	-	(273,952)
May-13	-	-	(273,952)
June-13	-	-	(273,952)
July-13	-	-	(273,952)
August-13	-	-	(273,952)
September-13	-	-	(273,952)
October-13	-	-	(273,952)
November-13	-	-	(273,952)
December-13	-	-	(273,952)
January-14	-	(8,163)	(282,115)
February-14	-	(8,163)	(290,278)
March-14	-	(8,163)	(298,441)
April-14	-	(8,163)	(306,604)
May-14	-	(8,163)	(314,767)
June-14	-	(8,163)	(322,930)
July-14	-	(8,163)	(331,093)
August-14	-	(8,163)	(339,256)
September-14	-	(8,163)	(347,419)
October-14	-	(8,163)	(355,582)
November-14	-	(8,163)	(363,745)
December-14	-	(8,163)	(371,908)

Total Resources	Spend	Accruals	Balance
July-11	510,133	(297,898)	(14,831,269)
August-11	1,297,299	(297,898)	(13,831,869)
September-11	4,262,792	(297,898)	(9,866,975)
October-11	2,233,011	(297,898)	(7,931,862)
November-11	380,161	(297,914)	(7,849,615)
December-11	1,034,853	(297,898)	(7,112,661)
January-12	629,272	(297,898)	(6,781,287)
February-12	508,069	(297,898)	(6,571,116)
March-12	1,145,320	(297,898)	(5,723,694)
April-12	2,124,670	(297,898)	(3,896,922)
May-12	890,732	(297,898)	(3,304,088)
June-12	2,909,337	(297,898)	(692,650)
July-12	1,829,256	(297,898)	838,708
August-12	1,015,770	(297,898)	1,556,580
September-12	1,875,035	(297,898)	3,133,716
October-12	567,191	(297,898)	3,403,009
November-12	(496,451)	(297,898)	2,608,661
December-12	300,000	(297,898)	2,610,763
January-13	50,000	(297,898)	2,362,865
February-13	128,000	(297,898)	2,192,967
March-13	1,650,000	(297,898)	3,545,069
April-13	228,000	(297,898)	3,475,171
May-13	78,000	(297,898)	3,255,273
June-13	290,000	(297,898)	3,247,375
July-13	38,000	(297,898)	2,987,477
August-13	128,000	(297,898)	2,817,579
September-13	70,000	(297,898)	2,589,681
October-13	32,000	(297,898)	2,323,783
November-13	78,000	(297,898)	2,103,885
December-13	163,000	(297,898)	1,968,987
January-14	26,000	(147,551)	1,847,436
February-14	26,000	(147,551)	1,725,885
March-14	36,000	(147,551)	1,614,334
April-14	26,000	(147,551)	1,492,783
May-14	26,000	(147,551)	1,371,232
June-14	176,000	(147,551)	1,399,681
July-14	36,000	(147,551)	1,288,130
August-14	26,000	(147,551)	1,166,579
September-14	26,000	(147,551)	1,045,028
October-14	31,000	(147,551)	928,477
November-14	75,000	(147,551)	855,926
December-14	165,000	(147,551)	873,375

The following adjustments were used to arrive at the normalized levels of tax expenses. The Company's 12 months ended June 2012 accrued tax data provided the basis for known and measurable adjustments to the December 2014 test period.

7.1 Interest True-Up
7.2 Property Tax Expense
7.3 Renewable Energy Tax Credit
7.4 AFUDC Equity
7.5 Medicare Deferred Accounting
7.6 Pro Forma Schedule M's
7.7 Pro Forma Deferred Income Tax Expense
7.8 Pro Forma ADIT Balances
7.9 Wyoming Wind Generation Tax
7.10 Franchise and Resource Supplier Taxes

The tax impacts of the following adjustments are included within the adjustment itself:

- SO2 Emission Allowances, page 3.3
- DSM Expense and Revenue, page 4.6
- Insurance Expense, Page 4.7
- Powerdale Hydro Removal, page 8.8
- Regulatory Asset Amortization, page 8.9
- Remove Rolling Hills, page 8.12

The tax impacts of the following adjustments are included within adjustments 7.6 through 7.8:

- Little Mountain, page 5.3
- Pro Forma Plant Additions 8.6
- Pro Forma Plant Retirements 8.7
- Klamath Hydroelectric Settlement Agreement, page 8.11
- Misc. Asset Sales and Removals, page 8.12

PacifiCorp
Oregon General Rate Case - December 2014
Tab 7 Adjustment Summary

	Total Adjustments	7.2 Property Tax Expense	7.3 Renewable Energy Tax Credit	7.4 AFUDC Equity	7.5 Medicare Tax Deferral	7.6 Pro Forma Schedule M's	7.7 Pro Forma Deferred Income Tax Expense
1 Operating Revenues:							
2 General Business Revenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	-	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-	-	-
13 Embedded Cost Differential (ECD)	-	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	894,328	-	-	-	894,328	-	-
19							
20 Total O&M Expenses	894,328	-	-	-	894,328	-	-
21							
22 Depreciation	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-
24 Taxes Other Than Income	5,479,921	3,463,124	-	-	-	-	-
25 Income Taxes - Federal	41,946,976	(1,157,430)	1,240,053	819,409	(298,898)	41,055,735	-
26 Income Taxes - State	5,468,944	(157,276)	(56,780)	111,344	(40,615)	5,573,122	-
27 Income Taxes - Def Net	(48,414,852)	-	-	-	-	-	(48,414,852)
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	5,375,316	2,148,418	1,183,272	930,753	554,814	46,628,858	(48,414,852)
32							
33 Operating Rev For Return:	(5,375,316)	(2,148,418)	(1,183,272)	(930,753)	(554,814)	(46,628,858)	48,414,852
34							
35 Rate Base:							
36 Electric Plant In Service	-	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-
44 Working Capital	1,082,354	43,230	23,810	18,728	11,164	938,256	-
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	1,082,354	43,230	23,810	18,728	11,164	938,256	-
49							
50 Rate Base Deductions:							
51 Accum Prov For Deprec	-	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	(115,102,825)	-	-	-	-	-	-
54 Unamortized ITC	1,403,824	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-	-
58							
59 Total Rate Base Deductions	(113,699,001)	-	-	-	-	-	-
60							
61 Total Rate Base:	(112,616,646)	43,230	23,810	18,728	11,164	938,256	-
62							
63 Return on Rate Base	0.097%	-0.068%	-0.038%	-0.030%	-0.018%	-1.482%	1.537%
64							
65 Return on Equity	0.187%	-0.131%	-0.072%	-0.057%	-0.034%	-2.845%	2.950%
66							
67 TAX CALCULATION:							
68 Operating Revenue	(6,374,249)	(3,463,124)	-	-	(894,328)	-	-
69 Other Deductions							
70 Interest (AFUDC)	(2,452,986)	-	-	(2,452,986)	-	-	-
71 Interest	(2,852,886)	1,095	603	474	283	23,769	-
72 Schedule "M" Additions	37,567,685	-	-	-	-	37,567,685	-
73 Schedule "M" Deductions	(85,212,080)	-	-	-	-	(85,212,080)	-
74 Income Before Tax	121,711,389	(3,464,219)	(603)	2,452,512	(894,611)	122,755,997	-
75							
76 State Income Taxes	5,468,944	(157,276)	(56,780)	111,344	(40,615)	5,573,122	-
77 Taxable Income	116,242,445	(3,306,944)	56,177	2,341,168	(853,995)	117,182,875	-
78							
79 Federal Income Taxes + Other	41,946,976	(1,157,430)	1,240,053	819,409	(298,898)	41,055,735	-
80							
81 PRICE CHANGE	(5,391,799)	3,574,273	1,968,582	1,548,471	923,031	77,575,337	(80,422,771)

PacifiCorp
Oregon General Rate Case - December 2014
Tab 7 Adjustment Summary

	7.8	7.9	7.10
	Pro Forma ADIT Balances	Wyoming Wind Generation Tax	Franchise and Resource Supplier Taxes
1 Operating Revenues:			
2 General Business Revenues	-	-	-
3 Interdepartmental	-	-	-
4 Special Sales	-	-	-
5 Other Operating Revenues	-	-	-
6 Total Operating Revenues	-	-	-
7			
8 Operating Expenses:			
9 Steam Production	-	-	-
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	-
12 Other Power Supply	-	-	-
13 Embedded Cost Differential (ECD)	-	-	-
13 Transmission	-	-	-
14 Distribution	-	-	-
15 Customer Accounting	-	-	-
16 Customer Service & Info	-	-	-
17 Sales	-	-	-
18 Administrative & General	-	-	-
19			
20 Total O&M Expenses	-	-	-
21			
22 Depreciation	-	-	-
23 Amortization	-	-	-
24 Taxes Other Than Income	-	272,786	1,744,011
25 Income Taxes - Federal	962,153	(91,169)	(582,876)
26 Income Taxes - State	130,741	(12,388)	(79,203)
27 Income Taxes - Def Net	-	-	-
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	-
30			
31 Total Operating Expenses:	1,092,893	169,228	1,081,932
32			
33 Operating Rev For Return:	(1,092,893)	(169,228)	(1,081,932)
34			
35 Rate Base:			
36 Electric Plant In Service	-	-	-
37 Plant Held for Future Use	-	-	-
38 Misc Deferred Debits	-	-	-
39 Elec Plant Acq Adj	-	-	-
40 Nuclear Fuel	-	-	-
41 Prepayments	-	-	-
42 Fuel Stock	-	-	-
43 Material & Supplies	-	-	-
44 Working Capital	21,991	3,405	21,770
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	21,991	3,405	21,770
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	-	-
52 Accum Prov For Amort	-	-	-
53 Accum Def Income Tax	(115,102,825)	-	-
54 Unamortized ITC	1,403,824	-	-
55 Customer Adv For Const	-	-	-
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	-	-	-
58			
59 Total Rate Base Deductions	(113,699,001)	-	-
60			
61 Total Rate Base:	(113,677,010)	3,405	21,770
62			
63 Return on Rate Base	0.237%	-0.006%	-0.036%
64			
65 Return on Equity	0.455%	-0.011%	-0.068%
66			
67 TAX CALCULATION:			
68 Operating Revenue	-	(272,786)	(1,744,011)
69 Other Deductions			
70 Interest (AFUDC)	-	-	-
71 Interest	(2,879,748)	86	552
72 Schedule "M" Additions	-	-	-
73 Schedule "M" Deductions	-	-	-
74 Income Before Tax	2,879,748	(272,872)	(1,744,563)
75			
76 State Income Taxes	130,741	(12,388)	(79,203)
77 Taxable Income	2,749,007	(260,483)	(1,665,359)
78			
79 Federal Income Taxes + Other	962,153	(91,169)	(582,876)
80			
81 PRICE CHANGE	(12,640,248)	281,541	1,799,985

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Interest	427	3	(426,179)	OR	100.000%	(426,179)	Below

	Total Company		
Interest June 2012	327,928,239	86,165,786	2.18
Interest Dec 2014	326,446,716	85,739,606	Below
Adjustment:	(1,481,523)	(426,179)	

Rate Base	12,960,774,777	3,384,540,086	2.2
Other & Non-Utility	74,408,200	-	
Adjusted Rate Base	12,886,366,576	3,384,540,086	2.2
Weighted Cost of Debt	2.533%	2.533%	2.1
	326,446,716	85,739,606	2.18

Description of Adjustment:

This adjustment synchronizes interest expense with the jurisdictional allocated rate base. This is calculated by multiplying net rate base by the Company's weighted cost of debt. A separate column is not shown for adjustment 7.1 on page 7.0.2 as the interest true-up component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

PacifiCorp
Oregon General Rate Case - December 2014
Property Tax Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	12,646,405	GPS	27.384%	3,463,124	7.2.1

Description of Adjustment:

This adjustment normalizes the difference between actual accrued property tax expense and forecasted property tax expense resulting from estimated capital additions. For additional information on the Company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/1103.

PacifiCorp
Oregon General Rate Case - December 2014
Estimated Property Tax Expense for December 2014
Property Tax Adjustment Summary

FERC Account	G/L Account	Co. Code	Total	Ref
408.15	579000	1000	115,040,595	
Total Accrued Property Tax - 12 Months Ended June 2012			115,040,595	
Forecasted Property Tax Exp. for the 12 Months Ending Dec 2014			127,687,000	Conf. Ex. PAC/1003
Less Accrued Property Tax - 12 Months Ended June 30, 2012			(115,040,595)	
Incremental Adjustment to Property Taxes			**12,646,405**	**7.2**

PacifiCorp
Oregon General Rate Case - December 2014
Renewable Energy Tax Credit

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
FED Renewable Energy Tax Credit	40910	3	(65,873,189)	SG	26.053%	(17,161,943)	7.3.1
OR BETC Credit	40911	3	(384,905)	SG	26.053%	(100,279)	7.3.1
Total			(66,258,094)			(17,262,222)	
Remove from Base Period:							
FED Renewable Energy Tax Credit	40910	1	70,557,450	SG	26.053%	18,382,334	
UT Renewable Energy Tax Credit	40911	1	167,068	SG	26.053%	43,526	
			4,684,261				

Description of Adjustment:

The Company is entitled to recognize federal and state income tax credits as a result of placing renewable generating plants in service. The federal tax credit is based on the kilowatt hours ("kWh") generated by the plants, and the credit can be taken for the first ten years of generation from qualifying property. This adjustment reflects this credit based on the qualifying production as modeled in GRID for the test period NPC study.

The Utah State production tax credit expired in December 2011 and is not reflected in the test period in this proceeding. The Oregon Business Energy Tax Credit ("BETC") is based on investment in qualifying plant, and the credit is utilized over a three- to five-year period on qualifying property.

PacifiCorp
Oregon General Rate Case - December 2014
Renewable Energy Tax Credit Calculation

Description	FED Amount										UT Expired 12/1/2011
Hydro											
JC Boyle	9,008,583										
Factor (inflated tax per unit)	0.0115										
	103,599										
	Ref #7.3										
Wind/Geothermal											
Total KWh Production	2,859,547,404										-
Factor (inflated tax per unit)	0.023										0.0035
	65,769,590										-
	Ref #7.3										**Ref #7.3**
					OR BETC						
	OR										12 Month Ending
BETC			2006	2007	2008	2009	2010	2010	2010	2011	6/30/2013
	Leaning Juniper	Pcorp Lighting	Transit Passes	Transit Passes	Transit Passes	Transit Passes	01-03 Transit	Transit Passes	LCT Lighting	Lemolo Hydro	Amortization
Investment	10,000,000	24,366	266,368	275,107	338,071	349,969	199,700	367,356	39,048	3,546,000	
35% Credit	3,500,000	8,528	93,229	96,287	118,325	122,489	69,895	128,575	13,667	1,773,000	
Amortization											
12/31/2006	1,000,000	2,437	26,637								
12/31/2007	1,000,000	2,437	26,637	27,511							
6/30/2008	250,000	609	6,659	13,755							
12/31/2008	250,000	609	6,659	13,755	33,807						
6/30/2009	250,000	609	6,659	6,878	16,904						
12/31/2009	250,000	609	6,659	6,878	16,903	34,997					
6/30/2010	250,000	609	6,659	6,878	8,452	17,498	9,985	18,368			
12/31/2010	250,000	609	6,660	6,878	8,452	17,498	9,985	18,368	3,905		
6/30/2011				6,877	8,452	8,749	9,985	18,368	1,953	177,300	
12/31/2011	0	0	0	6,877	8,452	8,749	9,985	18,368	1,953	177,300	
3/31/2012					4,226	4,374	2,496	4,592	488	88,650	
6/30/2012					4,226	4,374	2,496	4,592	488	88,650	
12/31/2012					8,452	8,749	4,993	9,184	977	177,300	
3/31/2013						4,374	2,496	4,592	488	88,650	
6/30/2013						4,375	2,496	4,592	488	88,650	
12/31/2013						8,749	4,993	9,184	976	177,300	
12/31/2014							9,985	18,368	1,952	354,600	**384,905**
12/31/2015										354,600	**Ref #7.3**
12/31/2016											
Total Utilized	3,500,000	8,528	93,229	96,287	118,325	122,486	69,895	128,576	13,667	1,773,000	

*Transit passes generated in Aug of each year.

PacifiCorp
Oregon General Rate Case - December 2014
AFUDC Equity

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
AFUDC - Equity	419	3	(9,284,690)	SNP	26.420%	(2,452,986)	7.4.1

Description of Adjustment:

This adjustment reflects the appropriate level of AFUDC – Equity into regulated results to align the tax Schedule M with regulatory income. Per the Commission Order No. 10-022, AFUDC-Equity in this case is included using flow-through tax treatment.

PacifiCorp
Oregon General Rate Case - December 2014
AFUDC Equity for 12 Months Ending December 2013

Period	Description	Source	Equity
12 Months Ended June 2012	FERC Account 419	Per SAP A/C 382XXX	(54,338,671)
12 Months Ended December 2013	AFUDC-Equity SCHMDT	Per PowerTax	(63,623,361)
	Total		(63,623,361)
Adjustment to Account 419		**Ref 7.4**	**(9,284,690)**

PacifiCorp
Oregon General Rate Case - December 2014
Medicare Tax Deferral

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Medicare Deferral Amortization	930	3	894,328	OR	100.000%	894,328	7.5.1

Description of Adjustment:

As established in Oregon Docket No. UM-1479 and UE-217 this adjustment recognizes the amortization of the Medicare Deferral regulatory asset for the 12 months ending December 2014.

PacifiCorp
Oregon General Rate Case - December 2014
Medicare Deferred Accounting

Description		**Oregon**
Net Tax Benefits of Non-Deductible Post-Retirement Benefits	**A**	9,665,845
Gross-Up Factor for Income Taxes = (1/(1-.37951))	**B**	1.6116
Total Company Regulatory Asset for Non-Deducible Post-Retirement Benefits	**C**	**15,577,761**
2010 Protocol Allocation Factor: SO	**D**	28.7053%
Jurisdictionally Allocated Regulatory Asset for Non-Deductible Post-Retirment Benefits	**E**	**4,471,643**

Net Income Impact = **A * D**	2,774,610

Period	**Oregon**
Three Months Ended December 31, 2010	0
Calendar Year Ended December 31, 2011	0
Calendar Year Ended December 31, 2012	0
Calendar Year Ending December 31, 2013	894,329
Calendar Year Ending December 31, 2014	894,328
Calendar Year Ending December 31, 2015	894,328
Calendar Year Ending December 31, 2016	894,328
Calendar Year Ending December 31, 2017	894,328
Total Amortization: Regulatory Assets	**4,471,641**

Period	**Oregon**
Three Months Ended December 31, 2010	0
Calendar Year Ended December 31, 2011	0
Calendar Year Ended December 31, 2012	0
Calendar Year Ending December 31, 2013	554,922
Calendar Year Ending December 31, 2014	554,922
Calendar Year Ending December 31, 2015	554,922
Calendar Year Ending December 31, 2016	554,922
Calendar Year Ending December 31, 2017	554,922
Net Income Impact: Regulatory Assets	**2,774,610**

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Schedule M's

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment Permanent	SCHMAP	3	7,137	OTHER	0.000%	-	
	SCHMAP	3	71,461	SCHMDEXP	27.101%	19,367	
	SCHMAP	3	(64,060)	SE	24.687%	(15,814)	
	SCHMAP	3	(6,848,996)	SO	27.384%	(1,875,547)	
			(6,834,458)			(1,871,994)	
	SCHMDP	3	100,147	SCHMDEXP	27.101%	27,141	
	SCHMDP	3	19,015	SE	24.687%	4,694	
	SCHMDP	3	(1,634)	SNP	26.420%	(432)	
	SCHMDP	3	(11,495,969)	SO	27.384%	(3,148,086)	
			(11,378,441)			(3,116,682)	
Schedule M Adjustment Temporary	SCHMAT	3	(4,402,986)	BADDEBT	47.407%	(2,087,337)	
	SCHMAT	3	(179,193)	CA	0.000%	-	
	SCHMAT	3	5,368,804	CIAC	26.872%	1,442,684	
	SCHMAT	3	(4,582,312)	GPS	27.384%	(1,254,832)	
	SCHMAT	3	(183,104)	ID	0.000%	-	
	SCHMAT	3	(7,491,514)	OR	100.000%	(7,491,514)	
	SCHMAT	3	(37,579,357)	OTHER	0.000%	-	
	SCHMAT	3	204,246,930	SCHMDEXP	27.101%	55,353,499	
	SCHMAT	3	(26,031,778)	SE	24.687%	(6,426,395)	
	SCHMAT	3	1,993,526	SG	26.053%	519,373	
	SCHMAT	3	15,344,895	SNP	26.420%	4,054,073	
	SCHMAT	3	(9,557,365)	SNPD	26.872%	(2,568,217)	
	SCHMAT	3	(7,662,134)	SO	27.384%	(2,098,218)	
	SCHMAT	3	(13,316)	TROJD	25.809%	(3,437)	
	SCHMAT	3	1,351,349	UT	0.000%	-	
	SCHMAT	3	(2,379,535)	WA	0.000%	-	
	SCHMAT	3	(875,498)	WYP	0.000%	-	
			127,367,412			39,439,679	
	SCHMDT	3	(344,306)	CA	0.000%	-	
	SCHMDT	3	(48,156)	CN	30.325%	(14,603)	
	SCHMDT	3	(47,465,977)	GPS	27.384%	(12,998,205)	
	SCHMDT	3	2,427,491	ID	0.000%	-	
	SCHMDT	3	(603,616)	OR	100.000%	(603,616)	
	SCHMDT	3	(149,073,972)	OTHER	0.000%	-	
	SCHMDT	3	(29,141,216)	SE	24.687%	(7,194,014)	
	SCHMDT	3	(57,042,788)	SG	26.053%	(14,861,359)	
	SCHMDT	3	16,843,617	SNP	26.420%	4,450,031	
	SCHMDT	3	(2,600,530)	SNPD	26.872%	(698,804)	
	SCHMDT	3	(21,806,549)	SO	27.384%	(5,971,561)	
	SCHMDT	3	(167,451,497)	TAXDEPR	26.398%	(44,203,267)	
	SCHMDT	3	31,013,704	UT	0.000%	-	
	SCHMDT	3	13,847,548	WA	0.000%	-	
	SCHMDT	3	13,665,098	WYP	0.000%	-	
			(397,781,150)			(82,095,398)	
Current Tax Credits	40910	3	57,871	SE	24.687%	14,286	
	40910	3	74,997	SG	26.053%	19,539	
	40910	3	28,863	SO	27.384%	7,904	
			161,731			41,729	

Description of Adjustment:

This adjustment normalizes the Schedule M to an estimated pro forma level of expense for the 12 months ending December 2014 test period. The significant change in tax depreciation is primarily driven by the reduced bonus depreciation available in the test period as compared to the base period. Additional line item detail is included in the tax model which is provided with the Company's electronic work papers.

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Deferred Income Tax Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Deferred Tax Expense Debit	41010	3	(130,667)	CA	0.000%	-	
	41010	3	(18,276)	CN	30.325%	(5,542)	
	41010	3	(18,013,812)	GPS	27.384%	(4,932,948)	
	41010	3	921,257	ID	0.000%	-	
	41010	3	(229,079)	OR	100.000%	(229,079)	
	41010	3	(56,575,063)	OTHER	0.000%	-	
	41010	3	(11,132,048)	SE	24.687%	(2,748,139)	
	41010	3	(21,648,310)	SG	26.053%	(5,640,035)	
	41010	3	6,392,321	SNP	26.420%	1,688,831	
	41010	3	(986,927)	SNPD	26.872%	(265,203)	
	41010	3	(8,275,803)	SO	27.384%	(2,266,267)	
	41010	3	(63,549,517)	TAXDEPR	26.398%	(16,775,582)	
	41010	3	11,770,010	UT	0.000%	-	
	41010	3	5,255,282	WA	0.000%	-	
	41010	3	5,186,042	WYP	0.000%	-	
			(151,034,590)			(31,173,964)	
Deferred Tax Expense Credit	41110	3	1,670,977	BADDEBT	47.407%	792,165	
	41110	3	(99,499)	CA	0.000%	-	
	41110	3	(2,037,515)	CIAC	26.872%	(547,513)	
	41110	3	(11,999)	FERC	0.000%	-	
	41110	3	1,739,033	GPS	27.384%	476,221	
	41110	3	74,456	ID	0.000%	-	
	41110	3	324,412	OR	100.000%	324,412	
	41110	3	14,096,939	OTHER	0.000%	-	
	41110	3	(77,513,752)	SCHMDEXP	27.101%	(21,007,206)	
	41110	3	9,872,333	SE	24.687%	2,437,156	
	41110	3	(148,084)	SG	26.053%	(38,580)	
	41110	3	(5,823,542)	SNP	26.420%	(1,538,562)	
	41110	3	3,627,116	SNPD	26.872%	974,664	
	41110	3	3,231,965	SO	27.384%	885,050	
	41110	3	5,054	TROJD	25.809%	1,304	
	41110	3	4,690,727	UT	0.000%	-	
	41110	3	936,631	WA	0.000%	-	
	41110	3	(252,697)	WYP	0.000%	-	
	41110	3	460,054	WYU	0.000%	-	
			(45,157,391)			(17,240,888)	
Total			(196,191,981)			(48,414,852)	

Description of Adjustment:

This adjustment normalizes the deferred tax expense to an estimated pro forma level of expense for the 12 months ending December 2014 test period. Additional line item detail is included in the tax model which is provided with the Company's electronic work papers.

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma ADIT Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT Balance 190	190	3	(1,299,288)	BADDEBT	47.407%	(615,957)	
	190	3	(18,275)	CN	30.325%	(5,542)	
	190	3	43,091	ID	0.000%	-	
	190	3	(3,417,464)	OR	100.000%	(3,417,464)	
	190	3	(8,568,319)	OTHER	0.000%	-	
	190	3	(37,351,383)	SE	24.687%	(9,220,836)	
	190	3	(41,146,056)	SG	26.053%	(10,719,783)	
	190	3	1,181,491	SNPD	26.872%	317,486	
	190	3	5,730,056	SO	27.384%	1,569,133	
	190	3	(37,781)	TROJD	25.809%	(9,751)	
	190	3	330,325	UT	0.000%	-	
	190	3	165,514	WA	0.000%	-	
	190	3	132,756	WYP	0.000%	-	
			(84,255,333)			(22,102,714)	
ADIT Balance 281	281	3	178,288,826	SG	26.053%	46,449,591	
ADIT Balance 282 - YE	282	3	(85,079,045)	CA	0.000%	-	
	282	3	3,360,555,489	DITBAL	27.058%	909,311,179	
	282	3	(10,869,253)	FERC	0.000%	-	
	282	3	(216,916,085)	ID	0.000%	-	
	282	3	(1,050,494,620)	OR	100.000%	(1,050,494,620)	
	282	3	(60,237,216)	OTHER	0.000%	-	
	282	3	(723,753)	SE	24.687%	(178,671)	
	282	3	14,418,922	SG	26.053%	3,756,562	
	282	3	(1,721,449)	SO	27.384%	(471,406)	
	282	3	(1,678,557,081)	UT	0.000%	-	
	282	3	(235,621,179)	WA	0.000%	-	
	282	3	(447,444,057)	WYP	0.000%	-	
	282	3	(97,110,805)	WYU	0.000%	-	
			(509,800,132)			(138,076,956)	
ADIT Balance 283	283	3	1,190,681	CA	0.000%	-	
	283	3	(1,439,515)	GPS	27.384%	(394,200)	
	283	3	429,992	ID	0.000%	-	
	283	3	(931,022)	OR	100.000%	(931,022)	
	283	3	55,789,590	OTHER	0.000%	-	
	283	3	6,030	SE	24.687%	1,489	
	283	3	92,595	SG	26.053%	24,124	
	283	3	1,030,761	SGCT	26.141%	269,448	
	283	3	747,882	SNP	26.420%	197,588	
	283	3	(1,972,561)	SO	27.384%	(540,171)	
	283	3	(5,055,189)	UT	0.000%	-	
	283	3	2,413,988	WA	0.000%	-	
	283	3	(2,228,056)	WYP	0.000%	-	
			50,075,177			(1,372,746)	
ADIT Balance 255	255	3	290,837	ITC84	70.976%	206,424	
	255	3	1,157,406	ITC85	67.690%	783,448	
	255	3	474,277	ITC86	64.608%	306,421	
	255	3	56,977	ITC88	61.200%	34,870	
	255	3	113,285	ITC89	56.356%	63,842	
	255	3	55,338	ITC90	15.936%	8,819	
			2,148,120			1,403,824	

Description of Adjustment:

This adjustment normalizes the accumulated deferred income tax balances to an estimated pro forma level of rate base balance for the 12 months ending December 2014 test period. Additional line item detail is included in the tax model which is provided with the Company's electronic work papers.

PacifiCorp
Oregon General Rate Case - December 2014
Wyoming Wind Generation Tax

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	1,047,041	SG	26.053%	272,786	7.9.1

Description of Adjustment:

This adjustment normalizes the Wyoming Wind Generation Tax, which became effective January 1, 2012, into test year results. The Wyoming Wind Generation Tax is an excise tax levied upon the privilege of producing electricity from wind resources in the state of Wyoming. The tax is on the production of any electricity produced from wind resources for sale or trade on or after January 1, 2012, and is to be paid by the person producing the electricity. The tax is one dollar for each megawatt hour of electricity produced from wind resources at the point of interconnection with an electric transmission line.

PacifiCorp
Oregon General Rate Case - December 2014
Wyoming Wind Generation Tax Adjustment

	NPC MWH Production	$1/MWH Tax
Total WY Wind MWH	1,725,585	1,725,585
Booked Through the 12 Months Ended June 2012		678,544
Adjustment to the 12 Months Ending December 2014		**1,047,041**
		Ref. 7.9

PacifiCorp
Oregon General Rate Case - December 2014
Franchise and Resource Supplier Taxes

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Taxes Other Than Income	408	3	1,744,011	OR	100.000%	1,744,011	7.10.1

Description of Adjustment:

This adjustment normalizes the base period Oregon Franchise Tax and the Oregon Energy Resource Supplier Assessment to the December 2014 test period level based on pro forma revenues in adjustment 3.1.

PacifiCorp
Oregon General Rate Case - December 2014
Franchise Tax and Oregon Resource Supplier Tax

Franchise Tax:

Pro Forma Oregon General Business Revenues	$1,209,176,480
Franchise Tax Rate	2.33%
Pro Forma Franchise Taxes	28,173,812
Actual Franchise Taxes in the base period	26,426,814
Franchise Tax Adjustment	**1,746,998**

Resource Supplier Tax:

Pro Forma Oregon General Business Revenues	$1,209,176,480
Resource Supplier Tax Rate	0.07%
Pro Forma Oregon Resource Supplier Taxes	846,424
Actual Resource Supplier Taxes in the base period	849,411
Reource Supplier Tax Adjustment	**(2,987)**

Total Adjustment (Account 408 Situs Oregon)	**1,744,011**
	Ref. 7.10

The Company used year-end rate base as of June 2012 as the starting point for establishing the adjustments made to the test period. Test period electric plant in service is reflected using December 2013 ending balances. Other rate base components are reflected using a December 2014 13 month average balance. The following rate base adjustments are included.

8.1 Cash Working Capital
8.2 Trapper Mine Rate Base
8.3 Bridger Mine Rate Base
8.4 Customer Advances for Construction
8.5 Pro Forma Plant Additions
8.6 Plant Retirements
8.7 Miscellaneous Rate Base
8.8 Powerdale Removal
8.9 Regulatory Asset Amortization
8.10 Klamath Hydroelectric Settlement Agreement
8.11 Miscellaneous Asset Sales and Removals
8.12 Remove Rolling Hills
8.13 FERC 105 (PHFU)
8.14 Carbon Plant Closure
8.15 Pension and Other Postretirement Welfare Plan Balances

PacifiCorp
Oregon General Rate Case - December 2014
Tab 8 Adjustment Summary

		8.2	8.3	8.4	8.5	8.6	8.7	8.8
	Total Adjustments	Trapper Mine Rate Base	Bridger Mine Rate Base	Customer Advances for Construction	Pro Forma Plant Additions	Pro Forma Plant Retirements	Miscellaneous Rate Base	Powerdale Hydro Removal
1 Operating Revenues:								
2 General Business Revenues	-	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	-	-
7								
8 Operating Expenses:								
9 Steam Production	-	-	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	32,640	-	-	-	-	-	-	(4,577)
12 Other Power Supply	(67,913)	-	-	-	-	-	-	-
13 Embedded Cost Differential (ECD)	-	-	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-	-
15 Customer Accounting	(388,671)	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-	-
18 Administrative & General	(2,188,437)	-	-	-	-	-	-	-
19								
20 Total O&M Expenses	(2,612,381)	-	-	-	-	-	-	(4,577)
21								
22 Depreciation	10,558,754	-	-	-	-	-	-	-
23 Amortization	(179,681)	-	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-	-
25 Income Taxes - Federal	(4,818,461)	(17,275)	(360,238)	(7,396)	(3,607,750)	859,902	18,563	(325)
26 Income Taxes - State	(654,749)	(2,347)	(48,950)	(1,005)	(490,233)	116,846	2,522	(44)
27 Income Taxes - Def Net	(817,585)	-	-	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-	-
30								
31 Total Operating Expenses:	1,475,897	(19,623)	(409,188)	(8,401)	(4,097,983)	976,748	21,086	(4,947)
32								
33 Operating Rev For Return:	(1,475,897)	19,623	409,188	8,401	4,097,983	(976,748)	(21,086)	4,947
34								
35 Rate Base:								
36 Electric Plant In Service	314,886,851	2,134,101	42,569,860	-	426,333,191	(101,615,894)	-	-
37 Plant Held for Future Use	(13,855,477)	-	-	-	-	-	-	-
38 Misc Deferred Debits	50,395,795	-	-	-	-	-	2,545,608	-
39 Elec Plant Acq Adj	(2,704,773)	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-	-
42 Fuel Stock	(4,739,285)	-	-	-	-	-	(4,739,285)	-
43 Material & Supplies	-	-	-	-	-	-	-	-
44 Working Capital	(255,371)	(93,069)	(8,234)	(169)	(82,459)	19,654	424	(100)
45 Weatherization Loans	-	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-	-
47								
48 Total Electric Plant:	343,727,740	2,041,032	42,561,627	(169)	426,250,732	(101,596,240)	(2,193,252)	(100)
49								
50 Rate Base Deductions:								
51 Accum Prov For Deprec	(9,360,216)	-	-	-	-	-	-	-
52 Accum Prov For Amort	(3,233,009)	-	-	-	-	-	-	-
53 Accum Def Income Tax	16,116,906	-	-	-	-	-	-	219,214
54 Unamortized ITC	-	-	-	-	-	-	-	-
55 Customer Adv For Const	874,029	-	-	874,029	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-	-	-
58								
59 Total Rate Base Deductions	4,397,710	-	-	874,029	-	-	-	219,214
60								
61 Total Rate Base:	348,125,450	2,041,032	42,561,627	873,860	426,250,732	(101,596,240)	(2,193,252)	219,115
62								
63 Return on Rate Base	-0.814%	-0.004%	-0.090%	-0.002%	-0.782%	0.169%	0.004%	0.000%
64								
65 Return on Equity	-1.563%	-0.008%	-0.173%	-0.004%	-1.500%	0.324%	0.007%	-0.001%
66								
67 TAX CALCULATION:								
68 Operating Revenue	(7,766,692)	-	-	-	-	-	-	4,577
69 Other Deductions								
70 Interest (AFUDC)	-	-	-	-	-	-	-	-
71 Interest	8,818,965	51,705	1,078,202	22,137	10,798,090	(2,573,709)	(55,561)	5,551
72 Schedule "M" Additions	-	-	-	-	-	-	-	-
73 Schedule "M" Deductions	(2,163,876)	-	-	-	-	-	-	-
74 Income Before Tax	(14,421,781)	(51,705)	(1,078,202)	(22,137)	(10,798,090)	2,573,709	55,561	(973)
75								
76 State Income Taxes	(654,749)	(2,347)	(48,950)	(1,005)	(490,233)	116,846	2,522	(44)
77 Taxable Income	(13,767,032)	(49,357)	(1,029,251)	(21,132)	(10,307,857)	2,456,863	53,039	(929)
78								
79 Federal Income Taxes + Other	(4,818,461)	(17,275)	(360,238)	(7,396)	(3,607,750)	859,902	18,563	(325)
80								
81 PRICE CHANGE	46,720,813	226,951	4,732,615	97,168	47,396,698	(11,296,934)	(243,877)	19,646

PacifiCorp
Oregon General Rate Case - December 2014
Tab 8 Adjustment Summary

	8.9 Regulatory Asset Amortization	8.10 Klamath Hydroelectric Settlement Agreement	8.11 Miscellaneous Asset Sales and Removals	8.12 Remove Rolling Hills	8.13 FERC 105 (PHFU)	8.14 Carbon Plant Closure	8.15 Pension and Other Postretirement Welfare Plan Balances
1 Operating Revenues:							
2 General Business Revenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	-	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	66,013	(28,796)	-	-	-	-
12 Other Power Supply	(27,822)	-	-	(40,091)	-	-	-
13 Embedded Cost Differential (ECD)	-	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	(388,671)	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	(1,849,554)	-	-	(338,883)	-	-	-
19							
20 Total O&M Expenses	(2,266,047)	66,013	(28,796)	(378,974)	-	-	-
21							
22 Depreciation	-	35,759	-	-	-	10,522,994	-
23 Amortization	(179,681)	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-
25 Income Taxes - Federal	852,075	14,450	27,783	1,096,121	117,249	(3,402,643)	(408,977)
26 Income Taxes - State	115,783	1,964	3,775	148,945	15,932	(462,363)	(55,573)
27 Income Taxes - Def Net	-	-	-	(817,585)	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	(1,477,870)	118,186	2,762	48,508	133,181	6,657,988	(464,550)
32							
33 Operating Rev For Return:	1,477,870	(118,186)	(2,762)	(48,508)	(133,181)	(6,657,988)	464,550
34							
35 Rate Base:							
36 *Electric Plant In Service*	-	28,520	(2,606,099)	(52,291,889)	-	335,060	-
37 Plant Held for Future Use	-	-	-	-	(13,855,477)	-	-
38 Misc Deferred Debits	(479,192)	-	-	-	-	-	48,329,378
39 Elec Plant Acq Adj	(2,704,773)	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-
44 Working Capital	(26,122)	1,659	56	17,427	2,680	(77,771)	(9,348)
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	(3,210,087)	30,179	(2,606,044)	(52,274,461)	(13,852,797)	257,289	48,320,031
49							
50 Rate Base Deductions:							
51 Accum Prov For Deprec	-	(2,521,853)	460,228	6,332,455	-	(13,631,046)	-
52 Accum Prov For Amort	-	(3,233,009)	-	-	-	-	-
53 Accum Def Income Tax	(917,135)	-	-	16,814,826	-	-	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-	-
58							
59 Total Rate Base Deductions	(917,135)	(5,754,862)	460,228	23,147,281	-	(13,631,046)	-
60							
61 Total Rate Base:	(4,127,221)	(5,724,683)	(2,145,816)	(29,127,180)	(13,852,797)	(13,373,757)	48,320,031
62							
63 Return on Rate Base	0.052%	0.008%	0.004%	0.058%	0.025%	-0.172%	-0.083%
64							
65 Return on Equity	0.099%	0.015%	0.008%	0.111%	0.047%	-0.330%	-0.159%
66							
67 TAX CALCULATION:							
68 Operating Revenue	2,445,728	(101,772)	28,796	378,974	-	(10,522,994)	-
69 Other Deductions							
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	(104,554)	(145,022)	(54,359)	(737,871)	(350,929)	(338,794)	1,224,078
72 Schedule "M" Additions	-	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	(2,163,876)	-	-	-
74 Income Before Tax	2,550,282	43,250	83,155	3,280,720	350,929	(10,184,201)	(1,224,078)
75							
76 State Income Taxes	115,783	1,964	3,775	148,945	15,932	(462,363)	(55,573)
77 Taxable Income	2,434,499	41,286	79,380	3,131,775	334,997	(9,721,838)	(1,168,505)
78							
79 Federal Income Taxes + Other	852,075	14,450	27,783	1,096,121	117,249	(3,402,643)	(408,977)
80							
81 PRICE CHANGE	(2,979,753)	(531,655)	(268,283)	(3,623,364)	(1,540,354)	9,359,037	5,372,917

PacifiCorp
Oregon General Rate Case - December 2014
Cash Working Capital

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Cash Working Capital	CWC	3	2,285,442	OR	100.000%	2,285,442	Below
Cash Working Capital June 2012			43,897,857			15,535,918	2.33
Cash Working Capital December 2014			50,163,782			17,821,360	8.1.1
Adjustment:			6,265,925			2,285,442	

Description of Adjustment:

This adjustment is necessary to compute the cash working capital for the normalized results of operations in this filing. Cash working capital is calculated by taking total operation and maintenance expense allocated to the jurisdiction and adding its share of allocated taxes, including state and federal income taxes and taxes other than income. This total is divided by the number of days in the year to determine the Company's average daily cost of service. The daily cost of service is multiplied by net lag days to produce the adjusted cash working capital balance. Net lag days for Oregon are calculated using the Company's 2010 lead lag study. A separate column is not shown for adjustment 8.1 on page 8.0.2, as the cash working capital component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

PacifiCorp
Oregon General Rate Case - December 2014
12 Months Ending December 31, 2014

Lead/Lag Study as of 12/10	TOTAL	CA	OR	WA	WY	UT	ID	FERC
Revenue Lag Days	40.11	42.07	42.41	41.27	37.90	41.07	39.58	35.62
Expense Lag Days	34.90	37.40	35.07	35.20	34.97	35.46	34.86	35.10
Net Lag Days	5.21	4.67	7.34	6.07	2.93	5.60	4.72	0.53
O&M Expense	2,985,518,565	54,990,022	786,658,786	216,418,309	462,189,627	1,269,378,414	186,807,003	9,076,406
Embedded Cost Differential	0	300,195	8,792,171	2,096,760	1,605,652	(11,227,263)	(1,479,936)	(87,577)
Taxes Other than Income	173,216,287	4,380,075	67,523,836	10,681,561	22,086,868	60,411,659	7,789,857	342,433
Federal Income Tax	44,610,521	5,422,330	18,023,392	2,704,626	2,710,065	16,926,319	(79,523)	(1,096,688)
State Income Tax	14,612,136	867,406	4,676,658	1,031,188	1,708,590	5,975,011	473,638	(120,354)
Total	3,217,957,510	65,960,027	885,674,842	232,932,443	490,300,802	1,341,464,139	193,511,038	8,114,219
Divided by Days in Year		365	365	365	365	365	365	365
Avg. Daily Cost of Service	8,816,322	180,712	2,426,506	638,171	1,343,290	3,675,244	530,167	22,231
Net Lag Days		4.67	7.34	6.07	2.93	5.60	4.72	0.53
Cash Working Capital	49,586,526	844,621	17,821,360	3,873,698	3,937,256	20,595,968	2,501,857	11,765
	Ref. 2.33		Ref. 8.1					

PacifiCorp
Oregon General Rate Case - December 2014
Trapper Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	10,068,060	SE	24.687%	2,485,475	Below
Other Tangible Property	399	3	(1,423,330)	SE	24.687%	(351,374)	Below
			8,644,730			2,134,101	Below
Final Reclamation Liability	2533	3	(375,403)	SE	24.687%	(92,675)	8.2.2
Adjustment Detail							
June 2012 Balance			10,068,060				8.2.1
December 2013 Balance			8,644,730				8.2.1
Adjustment to December 2013 Balance			(1,423,330)				Above

Description of Adjustment:

The Company owns a 21.40% interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper includes all operating and maintenance costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine plant investment to the rate base. This adjustment reflects net plant to recognize the depreciation of the investment over time and walks forward the Reclamation Liability to December 2013. The adjustment was stipulated to and approved in Oregon UE 111, and has been included in all subsequent filings.

PacifiCorp
Oregon General Rate Case - December 2014
Trapper Mine Rate Base

	Actual	Actual	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma
DESCRIPTION	**Jun-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
Property, Plant, and Equipment														
Lands and Leases	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186	11,240,186
Development Costs	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815
Equipment and Facilities	119,686,641	116,039,653	116,401,820	116,541,186	116,827,703	116,975,620	117,044,786	117,063,953	117,209,370	117,228,536	117,247,703	117,266,870	118,602,036	118,621,203
Total Property, Plant, and Equipment	**133,761,642**	**130,114,654**	**130,476,821**	**130,616,187**	**130,902,704**	**131,050,621**	**131,119,787**	**131,138,954**	**131,284,371**	**131,303,537**	**131,322,704**	**131,341,871**	**132,677,037**	**132,696,204**
Accumulated Depreciation	(97,389,648)	(94,948,967)	(95,487,081)	(96,025,195)	(96,563,309)	(97,101,423)	(97,639,537)	(98,177,651)	(98,715,765)	(99,253,879)	(99,791,993)	(100,330,107)	(100,868,221)	(101,406,335)
Total Property, Plant, and Equipment	**36,371,994**	**35,165,687**	**34,989,740**	**34,590,992**	**34,339,395**	**33,949,198**	**33,480,250**	**32,961,303**	**32,568,606**	**32,049,658**	**31,530,711**	**31,011,764**	**31,808,816**	**31,289,869**
Other :														
Inventories	6,638,394	6,690,855	6,885,430	6,885,430	6,885,430	6,885,430	6,885,430	6,885,430	6,885,430	6,885,430	6,885,430	6,885,430	6,885,430	6,885,430
Prepaid Expenses	127,530	449,182	315,600	271,000	302,775	258,050	213,325	168,600	123,875	79,150	34,425	447,950	402,475	357,000
Restricted Funds: Self-bonding for Black Lung	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Deferred GE Royalty Amount	3,409,091	2,727,273	2,613,637	2,500,000	2,386,364	2,272,727	2,159,091	2,045,455	1,931,818	1,818,182	1,704,546	1,590,909	1,477,273	1,363,636
Total Other	**10,675,015**	**10,367,310**	**10,314,666**	**10,156,430**	**10,074,569**	**9,916,207**	**9,757,846**	**9,599,485**	**9,441,123**	**9,282,762**	**9,124,400**	**9,424,289**	**9,265,178**	**9,106,066**
Total Rate Base	**47,047,009**	**45,532,997**	**45,304,406**	**44,747,422**	**44,413,964**	**43,865,405**	**43,238,096**	**42,560,788**	**42,009,729**	**41,332,420**	**40,655,111**	**40,436,053**	**41,073,994**	**40,395,935**
PacifiCorp Share	**10,068,060**	**9,744,061**	**9,695,143**	**9,575,948**	**9,504,588**	**9,387,197**	**9,252,953**	**9,108,009**	**8,990,082**	**8,845,138**	**8,700,194**	**8,653,315**	**8,789,835**	**8,644,730**

June 2012 Balance	**10,068,060**	**Ref 8.2**
December 2013 Balance	**8,644,730**	**Ref 8.2**

PacifiCorp
Oregon General Rate Case - December 2014
Trapper Mine
Final Reclamation Liability

12 Months Ended June 2012	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
Final Reclamation Liability	(4,894,482)	(4,918,695)	(4,939,869)	(4,963,096)	(4,983,627)	(5,008,644)	(5,021,079)	(5,043,934)	(5,071,830)	(5,091,462)	(5,118,263)	(5,140,310)

12 Months Ending December 2013	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Final Reclamation Liability	(5,277,679)	(5,294,887)	(5,321,565)	(5,346,844)	(5,372,123)	(5,392,349)	(5,409,024)	(5,426,740)	(5,441,588)	(5,459,235)	(5,473,216)	(5,484,873)

	Average Balance	
June 2012	(5,016,274)	
December 2013	(5,391,677)	
Adjustment to Rate Base	**(375,403)**	**Ref 8.2**

PacifiCorp
Oregon General Rate Case - December 2014
Bridger Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	191,396,786	SE	24.687%	47,249,613	Below
Other Tangible Property	399	3	(18,956,550)	SE	24.687%	(4,679,753)	Below
			172,440,236			42,569,860	

Adjustment Detail:		
June 2012 Balance	191,396,786	8.3.1
December 2013 Balance	172,440,236	8.3.1
Adjustment to December 2013 Balance	(18,956,550)	Above

Description of Adjustment:

PacifiCorp owns a two-thirds interest in the Bridger Coal Company (BCC), which supplies coal to the Jim Bridger generating plant. The Company's investment in BCC is recorded on the books of Pacific Minerals, INC (PMI), a wholly-owned subsidiary. Because of this ownership arrangement, the coal mine investment is not included in Account 101 - Electric Plant in Service. The normalized costs for BCC provide no return on investment. The return on investment for BCC is removed in the fuels credit which the Company has included as an offset to fuel prices leaving no return in results. This adjustment is necessary to properly reflect the BCC plant investment in the 12 month period. The Bridger Mine adjustment was stipulated to and approved in Oregon UE 111, and has been included in all subsequent filings.

PacifiCorp
Oregon General Rate Case - December 2014
Bridger Mine Rate Base
($000's)

Bridger Total	Actual	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma
Description	**Jun-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
1 Structure, Equipment, Mine Dev.	444,618	456,114	456,751	458,382	460,476	461,228	461,798	464,493	466,189	476,037	482,530	487,059	487,632
2 Materials & Supplies	14,942	15,361	15,361	15,361	15,361	15,361	15,361	15,361	15,361	15,361	15,361	15,361	15,361
4 Pit Inventory	56,180	40,947	40,646	37,495	38,784	35,824	36,802	35,677	35,041	31,507	31,054	34,299	30,452
5 Deferred Long Wall Costs	1,243	818	513	239	399	2,972	2,449	1,920	1,501	986	454	300	2,935
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(229,887)	(246,374)	(249,224)	(252,083)	(254,946)	(257,417)	(260,256)	(263,185)	(266,022)	(269,003)	(272,100)	(275,052)	(277,719)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	287,095	266,866	264,047	259,394	260,074	257,968	256,154	254,266	252,070	254,888	257,298	261,966	258,660
PacifiCorp Share (66.67%)	**191,397**	177,910	176,031	172,929	173,382	171,979	170,769	169,511	168,047	169,925	171,532	174,644	**172,440**

Ref 8.3

December 2013 Balance	**172,440**

Ref 8.3

PacifiCorp
Oregon General Rate Case - December 2014
Customer Advances for Construction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Customer Advances	252	1	(47,477)	CA	0.000%	-	
Customer Advances	252	1	(160,733)	OR	100.000%	(160,733)	
Customer Advances	252	1	(163,179)	WA	0.000%	-	
Customer Advances	252	1	(30,634)	ID	0.000%	-	
Customer Advances	252	1	(2,941,662)	UT	0.000%	-	
Customer Advances	252	1	(628,073)	WY	0.000%	-	
Customer Advances	252	1	3,971,757	SG	26.053%	1,034,762	
			-			874,029	8.4.1

Description of Adjustment:

Customer advances for construction are booked into FERC Account 252 and the entries do not reflect the proper allocation. This adjustment corrects the allocation on those entries.

PacifiCorp
Oregon General Rate Case - December 2014
Customer Advances for Construction

YEAR END BASIS:

Account	Booked Allocation	Correct Allocation	Adjustment	Ref.
252CA	-	(47,477)	**(47,477)**	**Page 8.4**
252OR	(1,774,969)	(1,935,702)	**(160,733)**	**Page 8.4**
252WA	-	(163,179)	**(163,179)**	**Page 8.4**
252IDU	(977)	(31,611)	**(30,634)**	**Page 8.4**
252UT	(763,065)	(3,704,728)	**(2,941,662)**	**Page 8.4**
252WYP	(117,592)	(2,234,295)	**(2,116,703)**	**Page 8.4**
252WYU	(1,488,630)	-	**1,488,630**	**Page 8.4**
252SG	(18,645,453)	(14,673,696)	**3,971,757**	**Page 8.4**
252NUTIL	(28,171)	(28,171)	**-**	
Total	**(22,818,857)**	**(22,818,857)**	**0**	

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Plant Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant Additions	312	3	143,362,842	SG	26.053%	37,350,324	
Steam Plant Additions	312	3	25,319,344	SG	26.053%	6,596,449	
			168,682,186			43,946,773	
Hydro Plant Additions	332	3	206,301,632	SG-P	26.053%	53,747,768	
Hydro Plant Additions	332	3	19,851,301	SG-U	26.053%	5,171,860	
			226,152,933			58,919,627	
Other Plant Additions	343	3	35,396,678	SG	26.053%	9,221,897	
Other Plant Additions	343	3	187,180	SG	26.053%	48,766	
Other Plant Additions	343	3	5,667,487	SG-W	26.053%	1,476,550	
			41,251,344			10,747,213	
Transmission Plant Additions	355	3	731,449,493	SG	26.053%	190,564,548	
			731,449,493			190,564,548	
Distribution Plant Additions	360	3	2,622,037	Situs	100.000%	720,610	
Distribution Plant Additions	361	3	3,809,386	Situs	100.000%	1,046,927	
Distribution Plant Additions	362	3	38,664,058	Situs	100.000%	10,625,972	
Distribution Plant Additions	364	3	44,447,695	Situs	100.000%	12,215,479	
Distribution Plant Additions	365	3	29,886,736	Situs	100.000%	8,213,717	
Distribution Plant Additions	366	3	14,089,299	Situs	100.000%	3,872,136	
Distribution Plant Additions	367	3	33,160,035	Situs	100.000%	9,113,312	
Distribution Plant Additions	368	3	50,889,155	Situs	100.000%	13,985,773	
Distribution Plant Additions	369	3	27,400,167	Situs	100.000%	7,530,338	
Distribution Plant Additions	370	3	7,829,903	Situs	100.000%	2,151,878	
Distribution Plant Additions	371	3	392,100	Situs	100.000%	107,760	
Distribution Plant Additions	373	3	2,734,567	Situs	100.000%	751,536	
			255,925,137			70,335,437	
General Plant Additions	397	3	2,748,250	CA	0.000%	-	
General Plant Additions	397	3	4,636,447	ID	0.000%	-	
General Plant Additions	397	3	25,247,238	OR	100.000%	25,247,238	
General Plant Additions	397	3	22,987,843	SG	26.053%	5,989,023	
General Plant Additions	397	3	19,288,443	SO	27.384%	5,281,997	
General Plant Additions	397	3	1,671,276	SG	26.053%	435,417	
General Plant Additions	397	3	26,098,028	UT	0.000%	-	
General Plant Additions	397	3	2,072,007	WA	0.000%	-	
General Plant Additions	397	3	9,465,822	WYP	0.000%	-	
			114,215,354			36,953,675	
Intangible Plant Additions	302	3	7,474,296	SG	26.053%	1,947,278	
Intangible Plant Additions	303	3	25,936,169	SO	27.384%	7,102,427	
			33,410,465			9,049,705	
Mining Plant Additions	399	3	23,560,073	SE	24.687%	5,816,212	
Total Plant Additions			1,594,646,985			426,333,191	8.5.4

Description of Adjustment:

To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be used and useful by December 31, 2013. Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Projects over $5 million (total company basis) are described on pages 8.5.13 through 8.5.18.
The related tax impact is included in adjustments 7.6, 7.7 and 7.8.

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Plant Additions Adjustment

Function	Factor	Jul-12 Plant Adds	Jul-12 Cumulative Adds	Aug-12 Plant Adds	Aug-12 Cumulative Adds	Sep-12 Plant Adds	Sep-12 Cumulative Adds	Oct-12 Plant Adds	Oct-12 Cumulative Adds	Nov-12 Plant Adds	Nov-12 Cumulative Adds
Steam Production											
	SG	5,769,749	5,769,749	9,618,522	15,388,270	3,487,179	18,875,449	4,069,515	22,944,964	3,315,941	26,260,905
	SG - Cholla	172,787	172,787	8,196	180,983	123,211	304,194	10,267	314,461	820,661	1,135,122
Total		5,942,536	5,942,536	9,626,718	15,569,253	3,610,390	19,179,643	4,079,782	23,259,425	4,136,602	27,396,027
Hydro Production											
	SG-U	-	-	-	-	-	-	-	-	19,325,022	19,325,022
	SG-P	946,785	946,785	564,133	1,510,917	20,231,919	21,742,837	76,506,258	98,249,095	22,603,575	120,852,669
Total		946,785	946,785	564,133	1,510,917	20,231,919	21,742,837	76,506,258	98,249,095	41,928,597	140,177,691
Other Production											
	SG	-	-	187,410	187,410	-	187,410	-	187,410	20,149,334	20,336,744
	SG - CT	147,180	147,180	-	147,180	-	147,180	40,000	187,180	-	187,180
Total		147,180	147,180	187,410	334,590	-	334,590	40,000	374,590	20,149,334	20,523,924
Other Production - Wind											
	SG-W	584,392	584,392	377,191	961,583	502,231	1,463,814	813	1,464,627	813	1,465,440
Total		584,392	584,392	377,191	961,583	502,231	1,463,814	813	1,464,627	813	1,465,440
Transmission Plant											
	SG	7,892,952	7,892,952	14,152,277	22,045,229	9,816,376	31,861,605	17,920,589	49,782,195	7,384,447	57,166,642
Total		7,892,952	7,892,952	14,152,277	22,045,229	9,816,376	31,861,605	17,920,589	49,782,195	7,384,447	57,166,642
Distribution Plant											
	CA	265,795	265,795	305,184	570,980	335,086	906,066	208,034	1,114,099	353,867	1,467,966
	ID	644,039	644,039	722,348	1,366,387	520,204	1,886,591	1,120,796	3,007,386	526,969	3,534,355
	OR	3,509,127	3,509,127	3,812,323	7,321,450	2,455,059	9,776,509	3,444,382	13,220,891	3,726,592	16,947,483
	UT	5,947,954	5,947,954	10,779,384	16,727,338	3,973,605	20,700,943	5,012,822	25,713,766	6,164,061	31,877,827
	WA	315,294	315,294	1,172,492	1,487,786	1,326,104	2,813,890	838,464	3,652,354	489,851	4,142,205
	WYP	2,086,843	2,086,843	2,269,457	4,356,300	1,956,002	6,312,303	3,450,201	9,762,504	1,887,427	11,649,931
Total		12,769,051	12,769,051	19,061,189	31,830,241	10,566,061	42,396,301	14,074,699	56,471,000	13,148,767	69,619,767
General Plant											
	CA	58,676	58,676	49,022	107,698	469,085	576,783	66,147	642,930	15,856	658,786
	CN	-	-	-	-	-	-	-	-	-	-
	SE	-	-	-	-	-	-	-	-	-	-
	ID	349,307	349,307	118,458	467,765	111,557	579,322	251,947	831,270	108,089	939,359
	OR	1,375,400	1,375,400	972,106	2,347,506	2,176,909	4,524,415	618,883	5,143,298	2,300,007	7,443,305
	SG	1,747,817	1,747,817	1,734,644	3,482,461	126,796	3,609,257	485,911	4,095,168	899,116	4,994,284
	SO	584,595	584,595	620,776	1,205,370	808,982	2,014,352	1,482,754	3,497,106	1,739,909	5,237,016
	SG - Cholla	-	-	-	-	-	-	-	-	-	-
	UT	1,020,568	1,020,568	435,666	1,456,233	4,478,631	5,934,864	38,237	5,973,101	1,610,886	7,583,987
	WA	(34,400)	(34,400)	26,786	(7,614)	16,699	9,084	182,368	191,453	245,778	437,231
	WYP	963,597	963,597	639,448	1,603,045	1,101,797	2,704,843	1,147,501	3,852,343	659,037	4,511,380
Total		6,065,560	6,065,560	4,596,905	10,662,465	9,290,455	19,952,920	4,273,749	24,226,669	7,578,678	31,805,348
Intangible Plant											
	CN	-	-	-	-	-	-	-	-	-	-
	SG	941,072	941,072	43,336	984,407	-	984,407	-	984,407	-	984,407
	SO	731,746	731,746	519,106	1,250,852	691,057	1,941,909	2,427,456	4,369,365	1,484,767	5,854,132
Total		1,672,818	1,672,818	562,441	2,235,259	691,057	2,926,316	2,427,456	5,353,772	1,484,767	6,838,539
Mining Plant											
	SE	271,593	271,593	2,323,430	2,595,024	98,759	2,693,783	1,634,350	4,328,133	573,002	4,901,135
Total		271,593	271,593	2,323,430	2,595,024	98,759	2,693,783	1,634,350	4,328,133	573,002	4,901,135
Total Plant Additions		36,292,866	36,292,866	51,451,695	87,744,562	54,807,248	142,551,810	120,957,695	263,509,505	96,385,007	359,894,512

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Plant Additions Adjustment

Function	Factor	Dec-12 Plant Adds	Dec-12 Cumulative Adds	Jan-13 Plant Adds	Jan-13 Cumulative Adds	Feb-13 Plant Adds	Feb-13 Cumulative Adds	Mar-13 Plant Adds	Mar-13 Cumulative Adds	Apr-13 Plant Adds	Apr-13 Cumulative Adds
Steam Production											
	SG	22,789,165	49,050,070	43,833	49,093,903	3,984,079	53,077,983	1,601,975	54,679,958	7,554,189	62,234,147
	SG - Cholla	3,912,140	5,047,262	106,801	5,154,064	104,737	5,258,800	104,737	5,363,537	300,009	5,663,546
Total		26,701,306	54,097,333	150,634	54,247,967	4,088,816	58,336,783	1,706,712	60,043,495	7,854,198	67,897,693
Hydro Production											
	SG-U	245,202	19,570,224	-	19,570,224	-	19,570,224	-	19,570,224	-	19,570,224
	SG-P	15,242,749	136,095,418	343,696	136,439,114	4,164,945	140,604,058	208,579	140,812,637	1,183,000	141,995,637
Total		15,487,951	155,665,642	343,696	156,009,338	4,164,945	160,174,282	208,579	160,382,861	1,183,000	161,565,861
Other Production											
	SG	3,338,313	23,675,057	-	23,675,057	1,023,798	24,698,855	-	24,698,855	6,473,540	31,172,395
	SG - CT	-	187,180	-	187,180	-	187,180	-	187,180	-	187,180
Total		3,338,313	23,862,237	-	23,862,237	1,023,798	24,886,035	-	24,886,035	6,473,540	31,359,575
Other Production - Wind											
	SG-W	1,661,769	3,127,209	2,911	3,130,120	2,911	3,133,031	2,911	3,135,942	2,911	3,138,852
Total		1,661,769	3,127,209	2,911	3,130,120	2,911	3,133,031	2,911	3,135,942	2,911	3,138,852
Transmission Plant											
	SG	86,646,755	143,813,396	20,725,062	164,538,458	5,749,594	170,288,052	6,036,508	176,324,560	6,821,979	183,146,539
Total		86,646,755	143,813,396	20,725,062	164,538,458	5,749,594	170,288,052	6,036,508	176,324,560	6,821,979	183,146,539
Distribution Plant											
	CA	418,058	1,886,024	496,089	2,382,114	505,159	2,887,272	579,020	3,466,292	487,307	3,953,600
	ID	497,822	4,032,177	754,874	4,787,051	803,402	5,590,453	855,940	6,446,393	903,476	7,349,869
	OR	4,404,752	21,352,236	2,992,879	24,345,115	3,207,662	27,552,777	3,465,934	31,018,711	3,681,818	34,700,529
	UT	6,818,780	38,696,607	4,832,267	43,528,874	6,007,249	49,536,123	4,705,931	54,242,054	4,910,889	59,152,943
	WA	585,216	4,727,421	579,733	5,307,154	602,669	5,909,823	730,522	6,640,344	656,920	7,297,265
	WYP	1,977,448	13,627,378	1,742,238	15,369,617	1,930,214	17,299,831	1,935,355	19,235,186	1,885,798	21,120,984
Total		14,702,077	84,321,844	11,398,081	95,719,925	13,056,354	108,776,279	12,272,702	121,048,981	12,526,209	133,575,190
General Plant											
	CA	406,124	1,064,910	162,727	1,227,638	70,310	1,297,947	157,695	1,455,642	84,969	1,540,611
	CN	-	-	-	-	-	-	-	-	-	-
	SE	-	-	-	-	-	-	-	-	-	-
	ID	1,184,042	2,123,401	403,431	2,526,831	148,733	2,675,564	306,692	2,982,256	142,177	3,124,433
	OR	3,896,675	11,339,980	236,764	11,576,744	238,907	11,815,651	1,239,822	13,055,473	662,226	13,717,698
	SG	9,405,924	14,400,208	292,370	14,692,578	309,715	15,002,294	307,420	15,309,713	312,813	15,622,526
	SO	2,139,160	7,376,175	1,531,369	8,907,544	505,942	9,413,487	731,933	10,145,420	815,228	10,960,648
	SG - Cholla	384,981	384,981	-	384,981	-	384,981	-	384,981	964,792	1,349,773
	UT	2,992,432	10,576,419	438,803	11,015,222	758,638	11,773,859	1,594,014	13,367,874	401,568	13,769,442
	WA	319,976	757,207	46,631	803,837	245,255	1,049,092	174,065	1,223,157	49,674	1,272,831
	WYP	930,581	5,441,961	447,378	5,889,339	176,282	6,065,621	624,150	6,689,771	169,631	6,859,402
Total		21,659,894	53,465,242	3,559,472	57,024,714	2,453,781	59,478,495	5,135,791	64,614,286	3,603,079	68,217,365
Intangible Plant											
	CN	-	-	-	-	-	-	-	-	-	-
	SG	6,489,889	7,474,296	-	7,474,296	-	7,474,296	-	7,474,296	-	7,474,296
	SO	1,825,470	7,679,602	1,330,198	9,009,800	455,142	9,464,942	648,175	10,113,117	719,074	10,832,191
Total		8,315,359	15,153,898	1,330,198	16,484,097	455,142	16,939,238	648,175	17,587,413	719,074	18,306,487
Mining Plant											
	SE	158,938	5,060,073	4,411,000	9,471,073	439,000	9,910,073	248,000	10,158,073	4,842,000	15,000,073
Total		158,938	5,060,073	4,411,000	9,471,073	439,000	9,910,073	248,000	10,158,073	4,842,000	15,000,073
Total Plant Additions		178,672,361	538,566,873	41,921,055	580,487,928	31,434,340	611,922,268	26,259,377	638,181,646	44,025,989	682,207,634

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Plant Additions Adjustment

Function	Factor	May-13 Plant Adds	May-13 Cumulative Adds	Jun-13 Plant Adds	Jun-13 Cumulative Adds	Jul-13 Plant Adds	Jul-13 Cumulative Adds	Aug-13 Plant Adds	Aug-13 Cumulative Adds	Sep-13 Plant Adds	Sep-13 Cumulative Adds
Steam Production											
	SG	41,034,333	103,268,480	9,195,815	112,464,295	2,264	112,466,559	3,238,817	115,705,376	5,554,680	121,260,056
	SG - Cholla	4,939,854	10,603,399	30,028	10,633,428	4,737	10,638,164	924,910	11,563,075	540,060	12,103,135
Total		45,974,187	113,871,879	9,225,843	123,097,722	7,001	123,104,723	4,163,727	127,268,450	6,094,740	133,363,190
Hydro Production											
	SG-U	-	19,570,224	-	19,570,224	-	19,570,224	-	19,570,224	-	19,570,224
	SG-P	15,698,478	157,694,115	363,162	158,057,277	27,653,907	185,711,184	-	185,711,184	1,150,944	186,862,127
Total		15,698,478	177,264,339	363,162	177,627,501	27,653,907	205,281,408	-	205,281,408	1,150,944	206,432,351
Other Production											
	SG	176,760	31,349,155	296,041	31,645,196	-	31,645,196	876,095	32,521,291	146,016	32,667,307
	SG - CT	-	187,180	-	187,180	-	187,180	-	187,180	-	187,180
Total		176,760	31,536,334	296,041	31,832,375	-	31,832,375	876,095	32,708,471	146,016	32,854,486
Other Production - Wind											
	SG-W	2,911	3,141,763	-	3,141,763	-	3,141,763	-	3,141,763	-	3,141,763
Total		2,911	3,141,763	-	3,141,763	-	3,141,763	-	3,141,763	-	3,141,763
Transmission Plant											
	SG	391,419,196	574,565,735	36,227,481	610,793,217	8,499,387	619,292,604	8,608,106	627,900,710	16,540,341	644,441,051
Total		391,419,196	574,565,735	36,227,481	610,793,217	8,499,387	619,292,604	8,608,106	627,900,710	16,540,341	644,441,051
Distribution Plant											
	CA	505,667	4,459,267	523,765	4,983,032	509,216	5,492,247	596,421	6,088,669	508,436	6,597,104
	ID	869,471	8,219,340	977,282	9,196,622	921,383	10,118,005	1,030,802	11,148,807	917,936	12,066,743
	OR	3,696,149	38,396,678	3,306,704	41,703,382	7,557,373	49,260,755	3,477,673	52,738,427	3,167,079	55,905,506
	UT	12,286,187	71,439,130	5,488,205	76,927,335	5,830,043	82,757,379	6,437,831	89,195,210	6,376,013	95,571,222
	WA	665,003	7,962,268	682,519	8,644,786	642,771	9,287,558	724,227	10,011,784	629,043	10,640,828
	WYP	1,899,741	23,020,725	1,995,541	25,016,266	2,108,397	27,124,663	2,433,180	29,557,844	2,012,820	31,570,664
Total		19,922,218	153,497,408	12,974,015	166,471,423	17,569,183	184,040,606	14,700,134	198,740,741	13,611,326	212,352,067
General Plant											
	CA	80,505	1,621,116	116,091	1,737,207	73,261	1,810,469	87,373	1,897,842	77,804	1,975,646
	CN	-	-	-	-	-	-	-	-	-	-
	SE	-	-	-	-	-	-	-	-	-	-
	ID	145,814	3,270,247	146,986	3,417,233	173,594	3,590,827	176,255	3,767,083	162,315	3,929,398
	OR	244,650	13,962,348	1,957,613	15,919,962	220,704	16,140,665	248,994	16,389,659	745,771	17,135,430
	SG	757,238	16,379,765	748,140	17,127,905	49,310	17,177,216	209,528	17,386,744	30,974	17,417,718
	SO	680,141	11,640,789	758,933	12,399,723	983,330	13,383,052	982,367	14,365,420	728,195	15,093,614
	SG - Cholla	-	1,349,773	-	1,349,773	-	1,349,773	-	1,349,773	-	1,349,773
	UT	413,236	14,182,677	1,515,587	15,698,264	511,526	16,209,790	525,072	16,734,863	793,457	17,528,319
	WA	48,946	1,321,777	51,922	1,373,698	47,788	1,421,487	49,896	1,471,382	46,490	1,517,873
	WYP	173,480	7,032,882	368,820	7,401,703	202,621	7,604,324	205,617	7,809,941	212,930	8,022,870
Total		2,544,010	70,761,376	5,664,092	76,425,468	2,262,136	78,687,604	2,485,103	81,172,706	2,797,936	83,970,642
Intangible Plant											
	CN	-	-	-	-	-	-	-	-	-	-
	SG	-	7,474,296	-	7,474,296	-	7,474,296	-	7,474,296	-	7,474,296
	SO	603,796	11,435,987	671,316	12,107,302	862,524	12,969,827	861,803	13,831,630	4,354,143	18,185,773
Total		603,796	18,910,283	671,316	19,581,598	862,524	20,444,123	861,803	21,305,926	4,354,143	25,660,069
Mining Plant											
	SE	174,000	15,174,073	851,000	16,025,073	1,183,000	17,208,073	1,687,000	18,895,073	799,000	19,694,073
Total		174,000	15,174,073	851,000	16,025,073	1,183,000	17,208,073	1,687,000	18,895,073	799,000	19,694,073
Total Plant Additions		476,515,556	1,158,723,190	66,272,951	1,224,996,141	58,037,138	1,283,033,279	33,381,969	1,316,415,248	45,494,445	1,361,909,693

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Function	Factor	Oct-13 Plant Adds	Oct-13 Cumulative Adds	Nov-13 Plant Adds	Nov-13 Cumulative Adds	Dec-13 Plant Adds	Dec-13 Cumulative Adds	Year End Plant Adds Dec-13	Factor %	Oregon Allocated Year End Plant Adds Dec. 2013	
Steam Production											
	SG	1,203,410	122,463,466	2,432,690	124,896,156	18,466,686	143,362,842	143,362,842	26.05%	37,350,324	
	SG - Cholla	78,060	12,181,195	2,812,035	14,993,230	10,326,113	25,319,344	25,319,344	26.05%	6,596,449	
Total		1,281,470	134,644,661	5,244,725	139,889,386	28,792,799	168,682,186	168,682,186		43,946,773	Ref. 8.5.5
Hydro Production											
	SG-U	-	19,570,224	113,685	19,683,909	167,392	19,851,301	19,851,301	26.05%	5,171,860	
	SG-P	11,404,814	198,266,941	2,925,903	201,192,844	5,108,788	206,301,632	206,301,632	26.05%	53,747,768	
Total		11,404,814	217,837,165	3,039,588	220,876,753	5,276,180	226,152,933	226,152,933		58,919,627	Ref. 8.5.6
Other Production											
	SG	263,671	32,930,978	1,947,736	34,878,714	517,964	35,396,678	35,396,678	26.05%	9,221,897	
	SG - CT	-	187,180	-	187,180	-	187,180	187,180	26.05%	48,766	
Total		263,671	33,118,158	1,947,736	35,065,894	517,964	35,583,858	35,583,858		9,270,663	Ref. 8.5.7
Other Production - Wind											
	SG-W	-	3,141,763	-	3,141,763	2,525,723	5,667,487	5,667,487	26.05%	1,476,550	
Total		-	3,141,763	-	3,141,763	2,525,723	5,667,487	5,667,487		1,476,550	Ref. 8.5.7
Transmission Plant											
	SG	22,421,386	666,862,437	28,690,458	695,552,895	35,896,598	731,449,493	731,449,493	26.05%	190,564,548	
Total		22,421,386	666,862,437	28,690,458	695,552,895	35,896,598	731,449,493	731,449,493		190,564,548	Ref. 8.5.8
Distribution Plant											
	CA	496,841	7,093,946	476,800	7,570,746	590,794	8,161,540	8,161,540	0.00%	-	
	ID	786,580	12,853,322	760,474	13,613,796	859,031	14,472,826	14,472,826	0.00%	-	
	OR	7,945,969	63,851,474	2,687,786	66,539,260	3,796,176	70,335,437	70,335,437	100.00%	70,335,437	
	UT	4,975,254	100,546,477	5,148,545	105,695,022	6,498,034	112,193,056	112,193,056	0.00%	-	
	WA	596,226	11,237,054	476,306	11,713,360	604,138	12,317,498	12,317,498	0.00%	-	
	WYP	3,383,547	34,954,210	1,711,184	36,665,394	1,779,385	38,444,779	38,444,779	0.00%	-	
Total		18,184,416	230,536,483	11,261,096	241,797,579	14,127,559	255,925,137	255,925,137		70,335,437	Ref. 8.5.9
General Plant											
	CA	660,102	2,635,748	57,083	2,692,830	55,419	2,748,250	2,748,250	0.00%	-	
	CN	-	-	-	-	-	-	-	0.00%	-	
	SE	-	-	-	-	-	-	-	0.00%	-	
	ID	373,813	4,303,211	165,111	4,468,321	168,126	4,636,447	4,636,447	0.00%	-	
	OR	4,825,808	21,961,238	243,441	22,204,679	3,042,559	25,247,238	25,247,238	100.00%	25,247,238	
	SG	1,627,223	19,044,942	291,682	19,336,624	3,651,220	22,987,843	22,987,843	26.05%	5,989,023	
	SO	1,105,876	16,199,491	1,445,747	17,645,238	1,643,205	19,288,443	19,288,443	27.38%	5,281,997	
	SG - Cholla	-	1,349,773	-	1,349,773	321,503	1,671,276	1,671,276	26.05%	435,417	
	UT	7,425,944	24,954,263	547,784	25,502,047	595,981	26,098,028	26,098,028	0.00%	-	
	WA	463,651	1,981,524	45,507	2,027,031	44,976	2,072,007	2,072,007	0.00%	-	
	WYP	1,053,251	9,076,121	193,309	9,269,430	196,393	9,465,822	9,465,822	0.00%	-	
Total		17,535,669	101,506,311	2,989,662	104,495,973	9,719,381	114,215,354	114,215,354		36,953,675	Ref. 8.5.10
Intangible Plant											
	CN	-	-	-	-	-	-	-	30.33%	-	
	SG	-	7,474,296	-	7,474,296	-	7,474,296	7,474,296	26.05%	1,947,278	
	SO	1,562,279	19,748,052	1,257,132	21,005,184	4,930,985	25,936,169	25,936,169	27.38%	7,102,427	
Total		1,562,279	27,222,348	1,257,132	28,479,480	4,930,985	33,410,465	33,410,465		9,049,705	Ref. 8.5.11
Mining Plant											
	SE	1,644,000	21,338,073	1,463,000	22,801,073	759,000	23,560,073	23,560,073	24.69%	5,816,212	
Total		1,644,000	21,338,073	1,463,000	22,801,073	759,000	23,560,073	23,560,073		5,816,212	Ref. 8.5.12
Total Plant Additions		74,297,706	1,436,207,399	55,893,397	1,492,100,795	102,546,189	1,594,646,985	**1,594,646,985**		**426,333,191**	**Ref. 8.5**

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Steam Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2013 Year End Balance	Factor %	OR Allocated CY 2013 Year End Balance	Ref.
JB U2 Turbine Upgrade HP/IP/LP REV1	312	SG	May-13	30,973,302	26.05%	8,069,475	8.5.13
Naughton U2 Flue Gas Desulfurization Sys	312	SG	Jul-12 - Dec 13	11,018,255	26.05%	2,870,586	8.5.13
JB U2 Replace Cooling Tower 12/13	312	SG	Jun-13	6,811,781	26.05%	1,774,673	8.5.13
Naughton U1 Flue Gas Desulfurization Sys	312	SG	Jul-12 - Dec 13	6,534,625	26.05%	1,702,466	8.5.13
DJ U4 SO2 & PM Emission Cntrl Upgrades	312	SG	Jul-12 - Dec 13	5,809,514	26.05%	1,513,553	8.5.14
Hunter U1 SO2 Upgrades	312	SG	Jul-12 - Dec 13	2,967,188	26.05%	773,041	
Cholla 4: L-O Turbine Blade Repl	312	SG	Nov-13	2,733,975	26.05%	712,283	
Blundell U1 Turbine Exhaust Casing	312	SG	May-13	2,426,043	26.05%	632,057	
DJ U0 - MILL - 2012	312	SG	Dec-12	2,315,906	26.05%	603,363	
DJ U4 Aux Transformer Replacement	312	SG	Dec-13	2,141,267	26.05%	557,864	
JB U2 Scrubber Ductwork 13	312	SG	May-13	2,049,315	26.05%	533,908	
Craig 2: Generator Liquid Cooled Stator	312	SG	Apr-13	2,044,430	26.05%	532,635	
Naughton U1 NOx LNB	312	SG	Jul-12 - Dec 13	1,968,889	26.05%	512,955	
Cholla 4: Chimney Block Liner-Phase 1	312	SG	Dec-13	1,910,426	26.05%	497,723	
Cholla U4 Circ Water Strand Lines Repl	312	SG	Dec-13	1,861,880	26.05%	485,076	
Craig 2: Boiler Component Repl	312	SG	Apr-13	1,694,946	26.05%	441,584	
DJ U0 - Igniter Fuel Oil System	312	SG	Mar-13	1,563,142	26.05%	407,245	
Craig U5 U1&2 Scrubber Module Cone Modification	312	SG	Aug-13	1,466,564	26.05%	382,084	
Cholla U4 Bottom Ash Area Rebuild	312	SG	May-13	1,286,829	26.05%	335,258	
JB U2 Burners - Major 13	312	SG	May-13	1,224,485	26.05%	319,015	
DJ U0 - Mill -2013	312	SG	Dec-13	1,084,148	26.05%	282,453	
JB New Sewage Treatment Plant or Lagoon	312	SG	Dec-12	1,071,599	26.05%	279,184	
Cholla Comm:Fly Ash Sil Vent Filter Repl	312	SG	Nov-12	1,058,148	26.05%	275,679	
Cholla U4 Fabric Filter Bag Replace Cy13	312	SG	Dec-13	1,048,098	26.05%	273,061	
Craig 2: Generator Excitation Sys Repl	312	SG	Apr-13	1,047,649	26.05%	272,944	
DJ U0 - Pumps And Valves - 2013	312	SG	Dec-13	1,029,941	26.05%	268,331	
Cholla U4 Coal Mill Damper Repl	312	SG	May-13	1,028,898	26.05%	268,059	
DJ U0 - Pumps And Valves - 2012	312	SG	Dec-12	1,013,826	26.05%	264,132	
Projects Less Than $1million	312	SG	Various	55,106,026	26.05%	14,356,774	
Projects Less Than $1million - Cholla	312	SG	Various	14,391,089	26.05%	3,749,311	
				168,682,186		43,946,773	**8.5.4**

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Pro Forma Plant Additions Adjustment
Hydro Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2013 Year End Balance	Factor %	OR Allocated CY 2013 Year End Balance	Ref.
INU 4.1.1/4.1.2 Soda Springs Fish Passag	332	SG-P	Oct-12	74,861,616	26.05%	19,503,698	8.5.14
ILR 4.3 Merwin Upstream Collect & Trans	332	SG-P	May 13 / Jul 13	41,713,000	26.05%	10,867,489	8.5.14
ILR 4.4 Swift Fish Collector	332	SG-P	Various	40,182,552	26.05%	10,468,761	8.5.14
Ashton Dam Seepage Control	332	SG-U	Nov-12	14,539,945	26.05%	3,788,092	8.5.14
IRO Prospect Instream Flow / Automation	332	SG-P	Dec-12	10,880,920	26.05%	2,834,806	8.5.15
Ashton Stability Improvements	332	SG-U	Nov-12	4,413,474	26.05%	1,149,842	
Merwin Spillway Tainter Gate Rehab	332	SG-P	Feb-13	3,883,663	26.05%	1,011,811	
ILR 4.4.3 Release Ponds	332	SG-P	Dec-13	3,478,938	26.05%	906,368	
North Umpqua Coating Projects (Mandated)	332	SG-P	Oct-13	3,283,764	26.05%	855,519	
Swift 1 Station Service/Generator Breake	332	SG-P	Oct-12	2,986,127	26.05%	777,976	
ILR 8.7 Speelyai Hat.Water Intake (Dev)	332	SG-P	Oct-13	2,164,287	26.05%	563,862	
Soda Springs Dam Flood Protection	332	SG-P	Oct-13	1,907,561	26.05%	496,977	
Toketee TIV Replacements	332	SG-P	Nov-13	1,200,381	26.05%	312,735	
ILR 8.7 Speelyai Hatchery Ponds Mod/Co	332	SG-P	Sep-13	1,150,944	26.05%	299,855	
Swift 1 Trunnion Improvements	332	SG-P	May-13	1,128,478	26.05%	294,002	
INU 19.1 Tributary Enhancement	332	SG-P	Oct-13	1,046,955	26.05%	272,763	
Projects Less Than $1million	332	SG-P	Various	16,432,446	26.05%	4,281,145	
Projects Less Than $1million	332	SG-U	Various	897,883	26.05%	233,925	
				226,152,933		58,919,627	**8.5.4**

PacifiCorp
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Pro Forma Plant Additions Adjustment
Other Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2013 Year End Balance	Factor %	OR Allocated CY 2013 Year End Balance	Ref.
Currant Crk U1 CSA Variable fee 24k - CTA MI	343	SG	Nov-12	9,403,645	26.05%	2,449,932	8.5.15
Currant Crk U2 CSA Variable fee 24k - CTB MI	343	SG	Nov-12	9,403,645	26.05%	2,449,932	8.5.15
Lake Side U11 Combustion Overhaul CY13	343	SG	Apr-13	3,247,342	26.05%	846,030	
Lake Side U12 Combustion Overhaul CY13	343	SG	Apr-13	3,226,198	26.05%	840,521	
Chehalis U1 compressor DOD blade replacement S0 & S1	343	SG	Dec-12	1,864,379	26.05%	485,727	
Seven Mile Hill W-1799 Replace / Repair Wind Gearboxes - Cy2013	343	SG-W	Dec-13	1,275,812	26.05%	332,387	
Chehalis U3 IP shim replacement and partial blade rows1-3	343	SG	Nov-12	1,115,509	26.05%	290,624	
Gadsby U4 Generator Rewind	343	SG	Feb-13	1,023,798	26.05%	266,730	
Projects Less Than $1million	343	SG	Various	6,112,162	26.05%	1,592,402	
Projects Less Than $1million	343	SG-W	Various	4,391,674	26.05%	1,144,163	
Projects Less Than $1million - Gadsby	343	SG	Various	187,180	26.05%	48,766	
				41,251,344		10,747,213	**8.5.4**

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Transmission Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2013 Year End Balance	Factor %	OR Allocated CY 2013 Year End Balance	Ref.
Mona - Limber - Oquirrh 500/345 kV line	355	SG	May-13	378,811,426	26.05%	98,691,747	8.5.15
Clover Substation	355	SG	Dec-12	63,024,683	26.05%	16,419,822	8.5.15
Black Rock Substation	355	SG	Nov-13	19,139,636	26.05%	4,986,450	8.5.16
Lake Side 2 Interconnect	355	SG	May-13	18,500,000	26.05%	4,819,805	8.5.16
Data Center Ph2 Tom McCall Ind Park	355	SG	Dec-12	18,316,977	26.05%	4,772,122	8.5.16
Terminal Sub - Replace two 345/138 kV Trans and ten 138 kv breakers	355	SG	Oct-12	17,450,581	26.05%	4,546,400	8.5.16
M7--Mandated - Non-conforming Code Issues	355	SG	Various	16,720,535	26.05%	4,356,201	
Southwest Wyoming-Silver Creek 138 kV Line T Phase1	355	SG	Dec-13	16,010,132	26.05%	4,171,120	8.5.17
Carbon County System Reinforcement	355	SG	Oct-13	13,239,514	26.05%	3,449,291	8.5.17
Line 3 Convert to 115kV - phase 1	355	SG	Dec-12	8,691,341	26.05%	2,264,355	8.5.17
M7--Mandated - Non-conforming Code Issues	355	SG	Various	7,936,261	26.05%	2,067,634	
Ben Lomond Add 2nd 345-139kV Trnsfmr	355	SG	Sep-12	7,609,128	26.05%	1,982,406	8.5.17
MR--Mandated - Regional or National Regulatory	355	SG	Various	7,457,481	26.05%	1,942,898	
Q313 ENEL Cove Fort - LGI	355	SG	Sep-13	6,429,382	26.05%	1,675,047	8.5.17
90th South - West Jordan - Taylorsville Rebuild	355	SG	Jun-13	5,976,604	26.05%	1,557,085	8.5.18
RE--Replace - Overhead Transmission Lines - Poles	355	SG	Various	5,319,560	26.05%	1,385,905	
Union Gap- North Park 115 kV reconductor	355	SG	Jun-13	4,625,543	26.05%	1,205,093	
COPCO II 230-115kV Transformer - TPL002	355	SG	Dec-12	4,531,861	26.05%	1,180,686	
RE--Replace - Overhead Transmission Lines - Poles	355	SG	Various	4,202,597	26.05%	1,094,903	
U1 GSU replacement	355	SG	Dec-12	4,010,753	26.05%	1,044,921	
Red Butte Substation (Casper, WY): Convert to 115 kV Phase I	355	SG	Nov-13	3,984,317	26.05%	1,038,034	
M7--Mandated - Non-conforming Code Issues	355	SG	Various	3,898,022	26.05%	1,015,552	
U3 - GSU Replacement	355	SG	Various	3,669,236	26.05%	955,946	
RI--Replace - Storm and Casualty	355	SG	Various	3,485,965	26.05%	908,199	
U2 GSU Transformer Upgrade Replacement	355	SG	May-13	3,270,513	26.05%	852,067	
U1 Replace / Rewind GSU	355	SG	Jan-13	3,047,236	26.05%	793,896	
U2 Main GSU Transformer	355	SG	Oct-13	2,910,341	26.05%	758,231	
Oregon Basin: Increase Capacity 230-69 kV	355	SG	Jun-13	2,727,671	26.05%	710,640	
Oakley-Kamas, Complete 46 kV Loop	355	SG	Aug-12	2,646,148	26.05%	689,401	
Three Peaks Sub: Install 345 kV Sub	355	SG	Dec-12	2,579,833	26.05%	672,124	
Lone Pine to Baldy 115kV Reconductor	355	SG	Sep-13	2,496,887	26.05%	650,514	
RE--Replace - Overhead Transmission Lines - Poles	355	SG	Various	2,343,161	26.05%	610,464	
U1 - Generator Step-Up Transformer Spare	355	SG	Jan-13	2,300,519	26.05%	599,354	
West of Populus Transmission Path Upgrades - TPL-3	355	SG	Dec-13	1,890,854	26.05%	492,624	
RI--Replace - Storm and Casualty	355	SG	Various	1,790,862	26.05%	466,573	
Cove -Cove Tap 69kV 1.9 Miles Trans Line	355	SG	Oct-12	1,683,170	26.05%	438,516	
R1--Replace - Substation - Switchgear, Breakers, Reclrs	355	SG	Various	1,678,461	26.05%	437,290	
Pavant-Holden Irrigation 46 kV Line: Rebuild 3 Miles	355	SG	Jun-13	1,635,097	26.05%	425,992	
M8--Mmadated - ROW renewal	355	SG	Various	1,550,213	26.05%	403,877	
Fort Douglas: New 138-12.5 kV Substation & Transmission	355	SG	May-13	1,500,000	26.05%	390,795	
RF--Replace - Overhead Transmission Lines - Other	355	SG	Various	1,404,687	26.05%	365,963	
RE--Replace - Overhead Transmission Lines - Poles	355	SG	Various	1,391,147	26.05%	362,436	
Line 37 Conv to 115kV Bld Nickel Mt Sub - Days Creek	355	SG	Dec-13	1,360,000	26.05%	354,321	
RF--Replace - Overhead Transmission Lines - Other	355	SG	Various	1,322,469	26.05%	344,543	
RI--Replace - Storm and Casualty	355	SG	Various	1,221,424	26.05%	318,217	
RI--Replace - Storm and Casualty	355	SG	Various	1,205,461	26.05%	314,059	
DJ - Windstar Reconductor 2.26 miles - TPL-2	355	SG	May-13	1,190,321	26.05%	310,114	
Line 44 115kV BIA Re-Route	355	SG	Jul-12	1,187,404	26.05%	309,354	
UDOT Mountain View Corridor Highway Relocation: I-80 to Camp Williams - T phase 1	355	SG	Oct-12	1,162,206	26.05%	302,789	
MR--Mandated - Regional or National Regulatory	355	SG	Various	1,098,242	26.05%	286,125	
R6--Replace - Substation - Bushings, Glass & Other	355	SG	Various	1,090,779	26.05%	284,181	
MR--Mandated - Regional or National Regulatory	355	SG	Various	1,064,399	26.05%	277,308	
RE--Replace - Overhead Transmission Lines - Poles	355	SG	Various	1,051,825	26.05%	274,032	
Rigby-St. Anthony 69 kV: Rebuild 7 Miles to 161 kV	355	SG	Dec-13	1,029,117	26.05%	268,116	
Populus - Terminal 345 kV line - condemnation settlements	355	SG	Dec-13	1,028,819	26.05%	268,038	
R1--Replace - Substation - Switchgear, Breakers, Reclrs	355	SG	Various	1,022,099	26.05%	266,288	
Energy Transmission - general interconnections	355	SG	Dec-13	1,000,000	26.05%	260,530	
Projects Less Than $1million	355	SG	Various	32,526,596	26.05%	8,474,155	
				731,449,493		190,564,548	**8.5.4**

PacifiCorp
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Pro Forma Plant Additions Adjustment
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2013 Year End Balance	Factor %	OR Allocated CY 2013 Year End Balance	Ref.
M3--Mandated - Environmental	364	CA	Various	1,682,806	0.00%	-	
RI--Replace - Storm and Casualty	364	CA	Various	1,154,638	0.00%	-	
RC--Replace - Overhead Distribution Lines - Poles	364	CA	Various	1,014,521	0.00%	-	
N1--N1--New Revenue/Connection - Residential	364	ID	Various	3,482,183	0.00%	-	
M3--Mandated - Environmental	364	ID	Various	2,083,368	0.00%	-	
N2--N2--New Revenue/Connection - Commercial	364	ID	Various	1,870,120	0.00%	-	
RI--Replace - Storm and Casualty	364	ID	Various	1,531,667	0.00%	-	
RC--Replace - Overhead Distribution Lines - Poles	364	ID	Various	1,411,451	0.00%	-	
RJ--Replace - Customer Meters	364	ID	Various	1,153,956	0.00%	-	
N2--N2--New Revenue/Connection - Commercial	364	OR	Various	9,965,853	100.00%	9,965,853	
N1--N1--New Revenue/Connection - Residential	364	OR	Various	9,831,384	100.00%	9,831,384	
RC--Replace - Overhead Distribution Lines - Poles	364	OR	Various	5,655,338	100.00%	5,655,338	
RI--Replace - Storm and Casualty	364	OR	Various	5,310,045	100.00%	5,310,045	
Line 37 Conv to 115kV Bld Nickel Mt Sub - Dist - Canyonville	364	OR	Oct-13	5,035,791	100.00%	5,035,791	8.5.18
Knott Sub Install 115-12.5 kV Transformer - Dist	364	OR	Jul-13	4,291,901	100.00%	4,291,901	
RD--Replace - Overhead Distribution Lines - Other	364	OR	Various	3,742,733	100.00%	3,742,733	
M1--Mandated - Highway Relocations	364	OR	Various	2,622,479	100.00%	2,622,479	
N3--N3--New Revenue/Connection - Industrial	364	OR	Various	2,567,957	100.00%	2,567,957	
M4--Mandated - Neutral Extensions	364	OR	Various	2,556,919	100.00%	2,556,919	
M3--Mandated - Environmental	364	OR	Various	1,828,180	100.00%	1,828,180	
RJ--Replace - Customer Meters	364	OR	Various	1,574,753	100.00%	1,574,753	
RA--Replace - Underground Cable	364	OR	Various	1,507,417	100.00%	1,507,417	
R1--Replace - Substation - Switchgear, Breakers, Reclrs	364	OR	Various	1,402,318	100.00%	1,402,318	
RB--Replace - Underground - Vaults & Equipment	364	OR	Various	1,395,781	100.00%	1,395,781	
M9--Mandated - Public Accommodations & Other	364	OR	Various	1,293,795	100.00%	1,293,795	
R4--Replace - Substation - Transformers	364	OR	Various	1,288,364	100.00%	1,288,364	
R6--Replace - Substation - Bushings, Glass & Other	364	OR	Various	1,041,435	100.00%	1,041,435	
N1--N1--New Revenue/Connection - Residential	364	UT	Various	25,412,986	0.00%	-	
N2--N2--New Revenue/Connection - Commercial	364	UT	Various	24,805,570	0.00%	-	
RI--Replace - Storm and Casualty	364	UT	Various	8,218,343	0.00%	-	
Fort Douglas: New 138-12.5 kV Substation & Transmission	364	UT	May-13	7,400,919	0.00%	-	
RB--Replace - Underground - Vaults & Equipment	364	UT	Various	5,264,375	0.00%	-	
RC--Replace - Overhead Distribution Lines - Poles	364	UT	Various	5,141,218	0.00%	-	
N7--New Revenue/System Reinforcement - Feeder	364	UT	Various	4,485,427	0.00%	-	
RD--Replace - Overhead Distribution Lines - Other	364	UT	Various	3,848,573	0.00%	-	
M1--Mandated - Highway Relocations	364	UT	Various	3,491,905	0.00%	-	
City Creek Ctr New 40 MW Dev for PRI	364	UT	Dec-12	3,003,378	0.00%	-	
RJ--Replace - Customer Meters	364	UT	Various	2,450,839	0.00%	-	
M3--Mandated - Environmental	364	UT	Various	2,050,351	0.00%	-	
N4--N4--New Revenue/Connection - Irrigation	364	UT	Various	1,935,628	0.00%	-	
M9--Mandated - Public Accommodations & Other	364	UT	Various	1,489,903	0.00%	-	
RA--Replace - Underground Cable	364	UT	Various	1,241,515	0.00%	-	
U1--Functional Upgrade - Feeder Improvements	364	UT	Various	1,230,611	0.00%	-	
N6--New Revenue/Connection - Street Light & Other & Meters	364	UT	Various	1,125,452	0.00%	-	
R4--Replace - Substation - Transformers	364	UT	Various	1,117,988	0.00%	-	
Southwest Wyoming-Silver Creek 138 kV Line - D Phase 1	364	UT	Dec-13	1,000,000	0.00%	-	
N1--N1--New Revenue/Connection - Residential	364	WA	Various	2,430,029	0.00%	-	
N2--N2--New Revenue/Connection - Commercial	364	WA	Various	1,365,876	0.00%	-	
M1--Mandated - Highway Relocations	364	WA	Various	1,338,790	0.00%	-	
RI--Replace - Storm and Casualty	364	WA	Various	1,191,482	0.00%	-	
N2--N2--New Revenue/Connection - Commercial	364	WYP	Various	7,627,154	0.00%	-	
N1--N1--New Revenue/Connection - Residential	364	WYP	Various	6,360,856	0.00%	-	
M3--Mandated - Environmental	364	WYP	Various	5,252,263	0.00%	-	
MR--Mandated - Regional or National Regulatory	364	WYP	Various	3,975,944	0.00%	-	
RI--Replace - Storm and Casualty	364	WYP	Various	2,477,494	0.00%	-	
Center Street Sub: Convert to 12.5 kV	364	WYP	Oct-12	1,922,672	0.00%	-	
N3--N3--New Revenue/Connection - Industrial	364	WYP	Various	1,841,159	0.00%	-	
*FMC - Westvaco	364	WYP	Oct-13	1,534,840	0.00%	-	
RC--Replace - Overhead Distribution Lines - Poles	364	WYP	Various	1,105,218	0.00%	-	
Projects Less Than $1million	364	CA	Various	4,309,576	0.00%	-	
Projects Less Than $1million	364	ID	Various	2,940,082	0.00%	-	
Projects Less Than $1million	364	OR	Various	7,422,997	100.00%	7,422,997	
Projects Less Than $1million	364	UT	Various	7,478,076	0.00%	-	
Projects Less Than $1million	364	WA	Various	5,991,321	0.00%	-	
Projects Less Than $1million	364	WYP	Various	6,347,180	0.00%	-	
				255,925,137		70,335,437	**8.5.4**

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Plant Additions Adjustment
General Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2013 Year End Balance	Factor %	OR Allocated CY 2013 Year End Balance	Ref.
MRR Oregon Mobile Radio Repl Project	397	OR	Oct-13	17,488,446	100.00%	17,488,446	8.5.18
TOM	397	SO	Various	17,132,249	27.38%	4,691,539	
Utah Mobile Radio Replacement Project	397	UT	Oct-13	16,482,181	0.00%	-	
MRRP PacifiCorp Energy	397	SG	Dec-12	9,580,629	26.05%	2,496,042	8.5.18
Wyoming Mobile Radio Replacement Project	397	WYP	Dec-12	5,882,999	0.00%	-	
RV--Replace - Vehicles	397	UT	Various	3,496,241	0.00%	-	
Replace 6GHz MW radios Starvout to Fort Rock	397	OR	Dec-13	2,799,072	100.00%	2,799,072	
Idaho Mobile Radio Replacement Project	397	ID	Dec-12	2,532,336	0.00%	-	
IT Capacity	397	SO	Various	2,156,194	27.38%	590,458	
RV--Replace - Vehicles	397	WYP	Various	2,039,416	0.00%	-	
RQ--Replace - Other General Plant	397	UT	Various	1,725,611	0.00%	-	
MRR California Mobile Radio Repl Project	397	CA	Oct-13	1,599,047	0.00%	-	
6 GHz NEC Microwave Replacement: South Pass to Casper Sub	397	SG	Dec-13	1,469,689	26.05%	382,898	
RV--Replace - Vehicles	397	OR	Various	1,425,326	100.00%	1,425,326	
R9--Replace - Other Communications	397	UT	Various	1,352,911	0.00%	-	
RV--Replace - Vehicles	397	ID	Various	1,317,096	0.00%	-	
MRR Washington Mobile Radio Repl Project	397	WA	Oct-13	1,291,413	0.00%	-	
Blowhard to Beaver Dam Mtn: Microwave Replacement	397	SG	Oct-13	1,258,456	26.05%	327,866	
U0 - Purchase Ash Haul Truck	397	SG	Aug-12	1,254,253	26.05%	326,771	
RT--Replace - Tools	397	UT	Various	1,083,255	0.00%	-	
Replace Coal Handling Dozer - Accel 12	397	SG	Jul-12	1,008,213	26.05%	262,670	
Projects Less Than $1million	397	CA	Various	1,149,202	0.00%	-	
Projects Less Than $1million	397	ID	Various	787,016	0.00%	-	
Projects Less Than $1million	397	UT	Various	1,957,829	0.00%	-	
Projects Less Than $1million	397	OR	Various	3,534,393	100.00%	3,534,393	
Projects Less Than $1million	397	WA	Various	780,593	0.00%	-	
Projects Less Than $1million	397	WYP	Various	1,543,407	0.00%	-	
Projects Less Than $1million - Cholla	397	SG	Various	1,671,276	26.05%	435,417	
Projects Less Than $1million	397	SG	Various	8,416,602	26.05%	2,192,778	
				114,215,354		36,953,675	**8.5.4**

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Plant Additions Adjustment
Intangible Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2013 Year End Balance	Factor %	OR Allocated CY 2013 Year End Balance	Ref.
Upgrades and Enhancements	303	SO	Various	13,163,267	27.38%	3,604,663	
Hunter Plant 300 Adobe Wash Regulating Facility	302	SG	Dec-12	6,089,926	26.05%	1,586,609	8.5.18
Mobility/MWM (Click) Scheduler Upgrade (Obsolescence)	303	SO	Sep-13	3,804,236	27.38%	1,041,762	
Corp Optimization	303	SO	Various	3,296,692	27.38%	902,775	
GIS - Fastgate Replacement Phase 1	303	SO	Dec-13	1,487,099	27.38%	407,231	
Metering Handhel Replacement Project	303	SO	Dec-13	1,351,379	27.38%	370,065	
IP--IT-Asset Performance New Investment	303	SO	Various	1,343,961	27.38%	368,034	
Projects Less Than $1million	302	SG	Various	1,384,370	26.05%	360,670	
Projects Less Than $1million	303	SO	Various	1,489,534	27.38%	407,898	
				33,410,465		9,049,705	**8.5.4**

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Plant Additions Adjustment
Mining Plant Additions

Project Description	FERC Account	Factor	Inservice Date	CY 2013 Year End Balance	Factor %	OR Allocated CY 2013 Year End Balance	Ref.
Cottonwood Prep Plant-System Improvement	399	SE	Jan-13	3,741,000	24.69%	923,531	
Continuous Miner	399	SE	Apr-13	2,665,000	24.69%	657,901	
Section Extension - 2013	399	SE	Various	2,108,000	24.69%	520,396	
60" Terminal Group Upgrades 2Nd West	399	SE	Various	1,686,000	24.69%	416,218	
Self Contained Self Rescuers	399	SE	Various	1,653,000	24.69%	408,072	
Overland Conveyor-Drive Units	399	SE	Jul-12	1,191,203	24.69%	294,069	
Cottonwood Prep Plant-Sampling System	399	SE	Oct-13	1,163,000	24.69%	287,107	
Projects Less Than $1million	399	SE	Various	9,352,870	24.69%	2,308,918	
				23,560,073		5,816,212	**8.5.4**

STEAM PLANT ADDITIONS:

JB U2 Turbine Upgrade HP/IP/LP: **(Reference page 8.5.5)**
This project includes upgrades to the high pressure, intermediate pressure and low pressure turbines at the Jim Bridger Unit 2. This project will be done to increase the turbine/generator output with no increase in fuel input or operating cost thereby improving the heat rate of the units, decrease unit cost for electricity produced and reduce degradation over the life of the turbines. The project will be completed with the unit overhaul in 2013.

Naughton U2 Flue Gas Desulfurization System: **(Reference page 8.5.5)**
The dollars for this project for this test period are final project close-out cost. The majority of the dollars for this project were placed in-service in November 2011.
This environmental improvement project is the construction of a flue gas desulfurization (FGD) system for Naughton Unit 2. The FGD system involves constructing the following components:

- Interconnection at the electrostatic precipitator
- A flue gas transport system, including ductwork and booster fan
- SO2 absorber systems
- Reagent storage and preparation systems
- Makeup water treatment systems
- Electrical systems, including replacement of the auxiliary and start-up transformers
- Control systems, including upgrade of the existing, interfacing local control networks
- FGD waste disposal systems
- Makeup water supply system modifications
- Boiler reinforcement
- New stack and fiberglass flue (shared with Unit 1)

Jim Bridger U2 Replace Cooling Tower: **(Reference page 8.5.5)**
This project replaces the Jim Bridger Unit 2 Cooling Tower (cells 1 through 10) during the 2013 annual overhaul. This section of the cooling tower was replaced 23 years ago and is nearing the end of its expected service life. Strength testing completed during 2009/2011 on lumber from this tower confirms that the tower should be replaced. Waiting any longer increases the risk that the unit would be offline for several days while repairs are made. Depending on the time of year, the unit may be backpressure restricted for the four months minimum that it takes to make final repairs with the tower on line.

Naughton U1 Flue Gas Desulfurization System: **(Reference page 8.5.5)**
The dollars for this project for this test period are final project close-out cost. The majority of the dollars for this project were placed in-service in June 2012.
This environmental improvement project is the construction of a flue gas desulfurization (FGD) system for Naughton Unit 1. The FGD system involves constructing the following components:

- Interconnection at the electrostatic precipitator
- A flue gas transport system, including ductwork and booster fan
- SO2 absorber systems
- Reagent storage and preparation systems

- Makeup water treatment systems
- Electrical systems, including replacement of the auxiliary and start-up transformers
- Control systems, including upgrade of the existing, interfacing local control networks
- FGD waste disposal systems
- Makeup water supply system modifications
- Boiler reinforcement
- New stack and fiberglass flue (shared with Unit 2)

Dave Johnston U4 SO2/PM Emission Controls: **(Reference page 8.5.5)**
The dollars for this project for this test period are final project close-out cost. The majority of the dollars for this project were placed in-service in April 2012. This environmental improvement project is to install a dry flue gas desulfurization system with fabric filter on the Dave Johnston Unit 4. This project is in response to the State of Wyoming's review of the Best Available Retrofit Technology (BART). This review requires installation of appropriate emission controls.

<u>HYDRO PLANT ADDITIONS:</u>
INU 4.1.1/4.1.2 Soda Springs Fish Passage: **(Reference page 8.5.6)**
This project consists of the design and construction of a fish ladder, spillway improvement and fish screen and evaluation facility in order to meet resource agency design criteria to provide upstream and downstream fish passage for anadromous fish at Soda Springs dam. The project fulfills Section 47 of the Federal Energy Regulatory Commission (the FERC) license that incorporates the North Umpqua Settlement Agreement Sections 4.1.1a-e and 4.1.2.

ILR 4.3 Merwin Upstream Collect/Transport: **(Reference page 8.5.6)**
This project fulfills the conditions specified in Section 4.3 of the Lewis River Settlement Agreement. The Lewis River Settlement Agreement stipulates that PacifiCorp must construct and start up an upstream fish collection and transport facility at the Merwin Dam to provide: collection, handling, sorting and transportation of adult salmon and steelhead fish within four and one-half years after the issuance of a new FERC license.

ILR 4.4 Swift Fish Collector: **(Reference page 8.5.6)**
This project fulfills the conditions specified in Section 4.4 of the Lewis River Settlement Agreement. The agreement stipulates that PacifiCorp must construct and start up a downstream fish collection and transport facility at the Swift Dam to provide: collection, handling, sorting and transportation of juvenile salmonids, adult steelhead and bull trout fish within four and one-half years after the issuance of a new FERC license.

Ashton Dam Seepage Control: **(Reference page 8.5.6)**
This project is to reconstruct much of the Ashton dam for the purpose of remediating internal seepage and erosion conditions that threaten the stability and safe operation of the dam. The dam has experienced sinkhole activity at various locations throughout its history which is a result of seepage induced internal erosion of dam materials. The FERC required PacifiCorp Energy to convene and fund a Board of Consultants to review the construction and performance history of

the dam and to engage in the identification and development of a satisfactory engineering design for remediation.

IRO Prospect Instream Flow / Automation: **(Reference page 8.5.6)**
This project insures compliance with regulatory obligations under Section 401 of the Federal Clean Water Act and the new Federal Energy Regulatory Commission license by constructing facilities to reliably release, monitor, and record instream flows below the dams and powerhouses of the Prospect Nos. 1, 2, and 4 hydroelectric projects. The project includes the design, permitting, and construction of automated instream flow release facilities, plant control systems, and associated communications equipment at the Prospect hydroelectric projects.

OTHER PLANT ADDITIONS:

Currant Creek U1 CSA Variable Fee 24k – CTA MI: **(Reference page 8.5.7)**
This project is to remove and replace the gas turbine combustion, hot gas path section and inspect the compressor section parts in accordance with the long term maintenance plan. The program parts include: baskets, nozzle assemblies, combustor transition parts, support housing components, blades, vanes and ring segments.

Currant Creek U2 CSA Variable Fee 24k – CTB MI: **(Reference page 8.5.7)**
This project is to remove and replace the gas turbine combustion, hot gas path section and inspect the compressor section parts in accordance with the long term maintenance plan. The program parts include: baskets, nozzle assemblies, combustor transition parts, support housing components, blades, vanes and ring segments.

TRANSMISSION PLANT ADDITIONS:

Mona – Limber – Oquirrh 500/345 kV line: **(Reference page 8.5.8)**
As part of the Energy Gateway Program (Gateway Central), the Mona – Oquirrh project will construct a new transmission line approximately 100 miles in length between Mona/Clover Substations and Oquirrh Substation. The line is being built to maintain adequate transmission capacity for network load and reliability. A new single circuit 500 kilovolt transmission line will be constructed from the Mona/Clover Substations near Mona, Utah to the future Limber Substation near Tooele, Utah which is between Mona and Oquirrh. This line segment will be approximately 65 miles in length and will initially be energized at 345 kilovolts. A 35 mile double circuit 345 kilovolt line will be constructed from the future Limber Substation to the existing Oquirrh Substation in West Jordan, Utah.

Clover Substation: **(Reference page 8.5.8)**
This projects builds a new 345/138 kV substation approximately three miles south of Mona, Utah. An existing 450 MVA 345/138 kV transformer will be relocated from Terminal Substation to the Clover Substation. The existing Mona-Sigurd 345 kilovolt #1 (East) and Mona-Sigurd 345 kilovolt #2 (West) lines will be looped in and out of the Clover Substation along with the existing Nebo-Ashgrove single circuit 138 kilovolt line by constructing 1.5 miles of double

circuit 138 kV line between the transmission line and the new substation. A new 345 kV double circuit line will be constructed between Clover Substation and Mona Substation. The new Clover-Limber-Oquirrh 345 kilovolt double circuit line will be terminated at Clover.

Black Rock Substation: (Reference page 8.5.8)
This project will be a new 230-69 kilovolt substation to be located in Millard County, Utah. It will consist of looping in and out the Pavant-Gonder 230 kilovolt line and the Delta-Graymont 69 kilovolt line. This project will also install a 75 MVA 230/69 kilovolt transformer and the relay settings on the 46-46 kilovolt regulator will be changed at Delta to enable forward and reverse power operation. This substation will provide support to the area under N-0 to solve any low voltage issues. In addition, it will help solve any risks under N-1 conditions of overloading the Pavant to Delta and Pavant to McCornick 46 kilovolt lines as well as overloading the 230-46 kilovolt transformers.

Lake Side 2 Interconnect: (Reference page 8.5.8)
The interconnection of the Lakeside 2 generation facility into the existing 345 kilovolt Camp Williams-Hunter/Emery transmission line will require the construction of a new 345 kilovolt point of interconnection substation. The point of interconnection substation shall be configured to accommodate a six (6) breaker ring bus layout with three (3) breakers installed for this project. The substation will be located adjacent to the existing Lakeside Generating facility. Equipment replacement, control modifications and communications upgrades will also be required at the Camp Williams, Emery, Sigurd, Dynamo, and Timp substations and the Salt Lake and Portland control centers.

Data Center Ph2 Tom McCall Ind Park: (Reference page 8.5.8)
This project is required for interconnection of the second phase of a Data Center near Prineville, Oregon. Houston Lake Substation serves as the point of interconnection substation and, as part of this project, has been expanded to its full six (6) breaker ring bus build-out with two 115 kV feeds to the data centers. Additionally, a second 230-115 kV, 250 MVA transformer is being added to Ponderosa Substation, along with expansion of the 115 kV bus to three bays of breaker-and-a-half layout. A new 115 kV transmission line, approximately 7.7 miles has been constructed from Ponderosa to Houston Lake Substation. Four 12.47 kV distribution circuit breakers and two sets of 115 kV fuses are being replaced at Prineville Substation to accommodate increased system fault duty.

Terminal Substation - Replace 345/138 kV Transformers and Breakers: (Reference page 8.5.8)
This project will replace the two existing 345-138 kilovolt transformers at Terminal Substation (#9 & #10), build a new six bay breaker and half 138 kilovolt substation bus bay and replace five 138 kilovolt over-dutied circuit breakers. This project will also install two new 345 kilovolt circuit breakers and move two transformers to Ben Lomond and Clover substations. Expansion of the Terminal substation fence will necessitate re-organizing the laydown areas (including removal of old paving and installation of new paving) in the Distribution Equipment Maintenance Center/DEMC yard adjacent to the Terminal substation and replacement of those removed.

Southwest Wyoming-Silver Creek 138 kV Line Phase I: **(Reference page 8.5.8)**
This project will rebuild approximately 70 miles of 46 kilovolt transmission line to 138 kilovolts, build the new Croydon substation (near Henefer, Utah), convert the Coalville substation to 138 kilovolts, and convert the remaining single phase 46 kilovolt substations along the route to 12.47 kilovolt (distribution). Phase I includes rebuilding the transmission line from the Evanston, WY area down to the Devils Slide, UT area.

Carbon County System Reinforcement: **(Reference page 8.5.8)**
This project will install a new substation near Wellington, Utah with a 138-46 kV, 75 MVA transformer and associated 138 kV and 46 kV bus work. In addition, the 138 kV Helper-Moab line and the 46 kV Helper-Coal Creek #2 line will be modified to come in and out of this new substation.

Line 3 Convert to 115kV - phase 1: **(Reference page 8.5.8)**
The Line 3 Conversion Project will improve the reliability of 115 kilovolt and 69 kilovolt transmission supply to customers in the Medford, Oregon and Ashland, Oregon areas. Line 3 and Talent Substation are being converted from 69 kilovolt to 115 kilovolt operation to provide redundant 115 kilovolt transmission supply to Talent, Ashland, Mountain Avenue and Oak Knoll substations. Circuit breakers and protective relaying are being installed at Ashland and Oak Knoll substations and at Baldy Switching Station to reduce the transmission line-miles of outage exposure, reducing the number of customers interrupted by each transmission outage. Fully redundant 69 kilovolt transmission capacity will be restored to Belknap and Foothill Road substations.

Ben Lomond Add 2nd 345-139kV Trnsfmr: **(Reference page 8.5.8)**
This project will be to add a second 345-138 kilovolt transformer at the Ben Lomond substation by moving the Terminal #10 345-138 kilovolt, 448 MVA transformer to Bend Lomond, adding a new 345 kilovolt bay at Ben Lomond with two 345 kilovolt circuit breakers, extending the 138 kilovolt buses at Ben Lomond and adding a new bay with one 138 kV circuit breaker. Adding the second 345-138 kilovolt transformer at the Ben Lomond substation removes the need for load shedding upon the loss of one of the Ben Lomond or Syracuse transformers

Q313 ENEL Cove Fort – LGI: **(Reference page 8.5.8)**
This interconnection project includes a new 138 kilovolt three (3) breaker ring bus point of interconnection substation, as well as a loop-in of the existing Sigurd-Cameron 138 kilovolt transmission line to the new point of interconnection substation. This project also includes installation of 23.8 miles of fiber optic communication cable on the existing Sigurd-Cameron line between the new point of interconnection substation and proposed Cove Fort substation and protection and communications upgrades at Sigurd substation. Communications upgrades will occur at Salt Lake Control Center, Scipio Pass, Milford and Blundell.

90th South - West Jordan - Taylorsville Rebuild: **(Reference page 8.5.8)**
This project is to rebuild the 90th South- West Jordan- Taylorsville 138 kilovolt line with new transmission poles and 1557 ACSR conductor. Distance is approximately 7.27 miles. The project also includes relocating approximately 4.2 miles of 12.5 kilovolt distribution underbuild facilities from existing transmission poles to the new transmission poles. Increasing the capacity of this line will increase the transfer capability of the Wasatch Front south boundary and is necessary in order to meet NERC transmission planning system performance standard (TPL-003-0a Category C-5).

DISTRIBUTION PLANT ADDITIONS:

Line 37 Conv to 115kV Bld Nickel Mt Sub - Dist – Canyonville: **(Reference page 8.5.9)**
As part of the larger project to convert Line 37 in southern Douglas County from 69 kV to 115 kV, this project includes construction of a new 115 kV to 12.5 kV distribution substation near Canyonville to replace the 69 kV Gazley Substation. The project will increase capacity in the area from 15 MVA to 26 MVA. The new substation will include a new transformer, standard metal clad switchgear, and a capacitor for reactive compensation. Get-away cables will connect to the existing feeders currently supplied by Gazley Substation. The project includes removal of the Gazley Substation equipment and redeployment of the Gazley site for use with a mobile backup transformer. Gazley is an aging wood structure substation that is not suitable for conversion to 115 kV and must be replaced.

GENERAL PLANT ADDITIONS:

MRR Oregon Mobile Radio Repl Project: **(Reference page 8.5.10)**
Replace existing wideband mobile radio system with FCC compliant narrowband radio system for efficient crew dispatch, daily crew operations, and emergency response.

Mobile Radio Replacement Project - PacifiCorp Energy: **(Reference page 8.5.10)**
Replace existing wideband mobile radio system with FCC compliant narrowband radio system for efficient crew dispatch, daily crew operations, and emergency response.

INTANGIBLE PLANT ADDITIONS):

Hunter Plant - Adobe Wash Regulating Facility: **(Reference page 8.5.11)**
This project provides funding to secure a firm, long-term and cost effective water supply for the Hunter plant. The project funds a share of the construction of Adobe Wash Regulating Reservoir owned by the Cottonwood Creek Consolidated Irrigation Company (CCCIC). In addition, CCCIC and PacifiCorp have negotiated an agreement ("Cottonwood Agreement") that requires PacifiCorp to provide capital funding toward the Cottonwood Project in exchange for added benefits to PacifiCorp – most importantly, securing, by contract, a per share assessment structure which is cost effective to PacifiCorp as compared to other options.

PacifiCorp
Oregon General Rate Case - December 2014
Pro Forma Plant Retirements

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant Retirements	312	3	(43,856,900)	SG	26.053%	(11,426,039)	
Steam Plant Retirements	312	3	(39,475,412)	SG	26.053%	(10,284,530)	
Steam Plant Retirements	312	3	(32,732,222)	SG	26.053%	(8,527,726)	
Steam Plant Retirements	312	3	(23,817,381)	SG	26.053%	(6,205,143)	
Hydro Plant Retirements	332	3	(4,470,091)	SG	26.053%	(1,164,593)	
Hydro Plant Retirements	332	3	(1,251,829)	SG	26.053%	(326,139)	
Hydro Plant Retirements	332	3	(3,835,471)	SG-P	26.053%	(999,255)	
Hydro Plant Retirements	332	3	(1,006,254)	SG-U	26.053%	(262,159)	
Other Plant Retirements	343	3	(198,235)	SG	26.053%	(51,646)	
Other Plant Retirements	343	3	(12,162,652)	SG	26.053%	(3,168,736)	
Other Plant Retirements	343	3	(1,366,452)	SG-W	26.053%	(356,002)	
Other Plant Retirements	343	3	(1,073,609)	SG	26.053%	(279,707)	
Transmission Plant Retirements	355	3	(8,296,430)	SG	26.053%	(2,161,469)	
Transmission Plant Retirements	355	3	(6,432,684)	SG	26.053%	(1,675,907)	
Transmission Plant Retirements	355	3	(23,532,182)	SG	26.053%	(6,130,840)	
Distribution Plant Retirements	360	3	(787,188)	OR	Situs	(137,571)	
Distribution Plant Retirements	361	3	(1,143,654)	OR	Situs	(199,868)	
Distribution Plant Retirements	362	3	(11,607,726)	OR	Situs	(2,028,600)	
Distribution Plant Retirements	364	3	(13,344,089)	OR	Situs	(2,332,052)	
Distribution Plant Retirements	365	3	(8,972,597)	OR	Situs	(1,568,077)	
Distribution Plant Retirements	366	3	(4,229,890)	OR	Situs	(739,228)	
Distribution Plant Retirements	367	3	(9,955,307)	OR	Situs	(1,739,819)	
Distribution Plant Retirements	368	3	(15,277,945)	OR	Situs	(2,670,018)	
Distribution Plant Retirements	369	3	(8,226,080)	OR	Situs	(1,437,614)	
Distribution Plant Retirements	370	3	(2,350,694)	OR	Situs	(410,814)	
Distribution Plant Retirements	371	3	(117,716)	OR	Situs	(20,572)	
Distribution Plant Retirements	373	3	(820,972)	OR	Situs	(143,475)	
General Plant Retirements	397	3	(785,738)	CA	0.000%	-	
General Plant Retirements	397	3	(10,699,418)	OR	100.000%	(10,699,418)	
General Plant Retirements	397	3	(2,263,088)	WA	0.000%	-	
General Plant Retirements	397	3	(3,764,099)	WYP	0.000%	-	
General Plant Retirements	397	3	(9,906,425)	UT	0.000%	-	
General Plant Retirements	397	3	(2,516,616)	ID	0.000%	-	
General Plant Retirements	397	3	(840,152)	WYU	0.000%	-	
General Plant Retirements	397	3	(2,329,890)	SG	26.053%	(607,006)	
General Plant Retirements	397	3	(4,786,831)	SG	26.053%	(1,247,113)	
General Plant Retirements	397	3	(8,039,891)	SG	26.053%	(2,094,633)	
General Plant Retirements	397	3	(29,400,110)	SO	27.384%	(8,051,001)	
General Plant Retirements	397	3	(606,050)	SG	26.053%	(157,894)	
General Plant Retirements	397	3	(23,294)	SG	26.053%	(6,069)	
General Plant Retirements	397	3	(2,064,814)	CN	30.325%	(626,158)	
General Plant Retirements	397	3	(123,759)	SE	24.687%	(30,552)	
Mining Plant Retirements	399	3	(15,086,906)	SE	24.687%	(3,724,464)	
			(373,578,744)			(93,691,910)	

Description of Adjustment:

Retirements are included as a five-year average retirement amount. The five-year average is calculated from CY 2007 to CY 2011. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of reserve balances in the Depreciation and Amortization Reserve Adjustment (page 6.2).

PacifiCorp
Oregon General Rate Case - December 2014
(cont.) Pro Forma Plant Retirements

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Plant Retirements	303	3	-	CA	0.000%	-	
Intangible Plant Retirements	303	3	(320,139)	CN	30.325%	(97,083)	
Intangible Plant Retirements	302	3	(956,836)	SG	26.053%	(249,285)	
Intangible Plant Retirements	303	3	(23,578)	SG	26.053%	(6,143)	
Intangible Plant Retirements	303	3	-	ID	0.000%	-	
Intangible Plant Retirements	303	3	(2,065)	OR	100.000%	(2,065)	
Intangible Plant Retirements	303	3	(112,076)	SE	24.687%	(27,668)	
Intangible Plant Retirements	302	3	(12,334,902)	SG	26.053%	(3,213,612)	
Intangible Plant Retirements	302	3	(2,482,299)	SG-P	26.053%	(646,713)	
Intangible Plant Retirements	303	3	(154,134)	SG-U	26.053%	(40,156)	
Intangible Plant Retirements	303	3	(13,296,910)	SO	27.384%	(3,641,260)	
Intangible Plant Retirements	303	3	-	SG	26.053%	-	
Intangible Plant Retirements	303	3	(1,479)	UT	0.000%	-	
Intangible Plant Retirements	303	3	(255)	WA	0.000%	-	
Intangible Plant Retirements	303	3	(15,412)	WYP	0.000%	-	
Intangible Plant Retirements	303	3	-	WYU	0.000%	-	
			(29,700,083)			(7,923,984)	
		Total:	**(403,278,828)**			**(101,615,894)**	8.6.5

Description of Adjustment:

Retirements are included as a five-year average retirement amount. The five-year average is calculated from CY 2007 to CY 2011. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of reserve balances in the Depreciation and Amortization Reserve Adjustment (page 6.2).

PacifiCorp
Oregon General Rate Case - December 2014
Cumulative Monthly Plant Retirements Summary

Description	Factor	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13
Steam Production Plant:											
Pre-merger Pacific	SG	(2,436,494)	(4,872,989)	(7,309,483)	(9,745,978)	(12,182,472)	(14,618,967)	(17,055,461)	(19,491,956)	(21,928,450)	(24,364,944)
Pre-merger Utah	SG	(2,193,078)	(4,386,157)	(6,579,235)	(8,772,314)	(10,965,392)	(13,158,471)	(15,351,549)	(17,544,627)	(19,737,706)	(21,930,784)
Post-merger	SG	(1,818,457)	(3,636,914)	(5,455,370)	(7,273,827)	(9,092,284)	(10,910,741)	(12,729,197)	(14,547,654)	(16,366,111)	(18,184,568)
Renewable - Blundell	SG	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(1,323,188)	(2,646,376)	(3,969,563)	(5,292,751)	(6,615,939)	(7,939,127)	(9,262,315)	(10,585,503)	(11,908,690)	(13,231,878)
Total Steam Plant		(7,771,217)	(15,542,435)	(23,313,652)	(31,084,870)	(38,856,087)	(46,627,305)	(54,398,522)	(62,169,740)	(69,940,957)	(77,712,175)
Hydro Production Plant:											
Pre-merger Pacific	SG	(248,338)	(496,677)	(745,015)	(993,354)	(1,241,692)	(1,490,030)	(1,738,369)	(1,986,707)	(2,235,046)	(2,483,384)
Pre-merger Utah	SG	(69,546)	(139,092)	(208,638)	(278,184)	(347,730)	(417,276)	(486,822)	(556,368)	(625,914)	(695,460)
Post-merger	SG-P	(213,082)	(426,163)	(639,245)	(852,327)	(1,065,409)	(1,278,490)	(1,491,572)	(1,704,654)	(1,917,736)	(2,130,817)
Post-merger	SG-U	(55,903)	(111,806)	(167,709)	(223,612)	(279,515)	(335,418)	(391,321)	(447,224)	(503,127)	(559,030)
Total Hydro Plant		(586,869)	(1,173,738)	(1,760,607)	(2,347,477)	(2,934,346)	(3,521,215)	(4,108,084)	(4,694,953)	(5,281,822)	(5,868,692)
Other Production Plant:											
Pre-merger Utah	SG	(11,013)	(22,026)	(33,039)	(44,052)	(55,065)	(66,078)	(77,092)	(88,105)	(99,118)	(110,131)
Post-merger	SG	(675,703)	(1,351,406)	(2,027,109)	(2,702,812)	(3,378,515)	(4,054,217)	(4,729,920)	(5,405,623)	(6,081,326)	(6,757,029)
Post-merger Wind	SG-W	(75,914)	(151,828)	(227,742)	(303,656)	(379,570)	(455,484)	(531,398)	(607,312)	(683,226)	(759,140)
Post-merger	SG	(59,645)	(119,290)	(178,935)	(238,580)	(298,225)	(357,870)	(417,515)	(477,159)	(536,804)	(596,449)
Total Other Plant		(822,275)	(1,644,550)	(2,466,825)	(3,289,100)	(4,111,375)	(4,933,649)	(5,755,924)	(6,578,199)	(7,400,474)	(8,222,749)
Transmission Plant:											
Pre-merger Pacific	SG	(460,913)	(921,826)	(1,382,738)	(1,843,651)	(2,304,564)	(2,765,477)	(3,226,389)	(3,687,302)	(4,148,215)	(4,609,128)
Pre-merger Utah	SG	(357,371)	(714,743)	(1,072,114)	(1,429,485)	(1,786,857)	(2,144,228)	(2,501,599)	(2,858,971)	(3,216,342)	(3,573,714)
Post-merger	SG	(1,307,343)	(2,614,687)	(3,922,030)	(5,229,374)	(6,536,717)	(7,844,061)	(9,151,404)	(10,458,748)	(11,766,091)	(13,073,435)
Total Transmission Plant		(2,125,628)	(4,251,255)	(6,376,883)	(8,502,510)	(10,628,138)	(12,753,765)	(14,879,393)	(17,005,021)	(19,130,648)	(21,256,276)
Distribution Plant:											
California	CA	(81,355)	(162,711)	(244,066)	(325,422)	(406,777)	(488,132)	(569,488)	(650,843)	(732,198)	(813,554)
Oregon	OR	(745,984)	(1,491,968)	(2,237,952)	(2,983,935)	(3,729,919)	(4,475,903)	(5,221,887)	(5,967,871)	(6,713,855)	(7,459,838)
Washington	WA	(383,966)	(767,932)	(1,151,898)	(1,535,864)	(1,919,830)	(2,303,796)	(2,687,762)	(3,071,728)	(3,455,693)	(3,839,659)
Eastern Wyoming	WYP	(417,417)	(834,835)	(1,252,252)	(1,669,669)	(2,087,087)	(2,504,504)	(2,921,921)	(3,339,339)	(3,756,756)	(4,174,174)
Utah	UT	(2,374,455)	(4,748,911)	(7,123,366)	(9,497,821)	(11,872,276)	(14,246,732)	(16,621,187)	(18,995,642)	(21,370,097)	(23,744,553)
Idaho	ID	(186,247)	(372,494)	(558,741)	(744,988)	(931,235)	(1,117,482)	(1,303,729)	(1,489,976)	(1,676,223)	(1,862,470)
Western Wyoming	WYU	(79,123)	(158,246)	(237,369)	(316,492)	(395,614)	(474,737)	(553,860)	(632,983)	(712,106)	(791,229)
Total Distribution Plant		(4,268,548)	(8,537,095)	(12,805,643)	(17,074,191)	(21,342,739)	(25,611,286)	(29,879,834)	(34,148,382)	(38,416,929)	(42,685,477)

PacifiCorp
Oregon General Rate Case - December 2014
Cumulative Monthly Plant Retirements Summary

Description	Factor	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13
General Plant:											
California	CA	(43,652)	(87,304)	(130,956)	(174,608)	(218,261)	(261,913)	(305,565)	(349,217)	(392,869)	(436,521)
Oregon	OR	(594,412)	(1,188,824)	(1,783,236)	(2,377,649)	(2,972,061)	(3,566,473)	(4,160,885)	(4,755,297)	(5,349,709)	(5,944,121)
Washington	WA	(125,727)	(251,454)	(377,181)	(502,908)	(628,636)	(754,363)	(880,090)	(1,005,817)	(1,131,544)	(1,257,271)
Eastern Wyoming	WYP	(209,117)	(418,233)	(627,350)	(836,466)	(1,045,583)	(1,254,700)	(1,463,816)	(1,672,933)	(1,882,050)	(2,091,166)
Utah	UT	(550,357)	(1,100,714)	(1,651,071)	(2,201,428)	(2,751,785)	(3,302,142)	(3,852,499)	(4,402,856)	(4,953,213)	(5,503,570)
Idaho	ID	(139,812)	(279,624)	(419,436)	(559,248)	(699,060)	(838,872)	(978,684)	(1,118,496)	(1,258,308)	(1,398,120)
Western Wyoming	WYU	(46,675)	(93,350)	(140,025)	(186,700)	(233,376)	(280,051)	(326,726)	(373,401)	(420,076)	(466,751)
Pre-merger Pacific	SG	(129,438)	(258,877)	(388,315)	(517,753)	(647,192)	(776,630)	(906,069)	(1,035,507)	(1,164,945)	(1,294,384)
Pre-merger Utah	SG	(265,935)	(531,870)	(797,805)	(1,063,740)	(1,329,675)	(1,595,610)	(1,861,545)	(2,127,480)	(2,393,415)	(2,659,350)
Post-merger	SG	(446,661)	(893,321)	(1,339,982)	(1,786,643)	(2,233,303)	(2,679,964)	(3,126,624)	(3,573,285)	(4,019,946)	(4,466,606)
General Office	SO	(1,633,339)	(3,266,679)	(4,900,018)	(6,533,358)	(8,166,697)	(9,800,037)	(11,433,376)	(13,066,715)	(14,700,055)	(16,333,394)
General Office	SG	(33,669)	(67,339)	(101,008)	(134,678)	(168,347)	(202,017)	(235,686)	(269,355)	(303,025)	(336,694)
General Office	SG	(1,294)	(2,588)	(3,882)	(5,177)	(6,471)	(7,765)	(9,059)	(10,353)	(11,647)	(12,941)
Customer Service	CN	(114,712)	(229,424)	(344,136)	(458,848)	(573,559)	(688,271)	(802,983)	(917,695)	(1,032,407)	(1,147,119)
Fuel Related	SE	(6,875)	(13,751)	(20,626)	(27,502)	(34,377)	(41,253)	(48,128)	(55,004)	(61,879)	(68,755)
Total General Plant		(4,341,676)	(8,683,353)	(13,025,029)	(17,366,706)	(21,708,382)	(26,050,059)	(30,391,735)	(34,733,411)	(39,075,088)	(43,416,764)
Mining Plant:											
Coal Mine	SE	(838,161)	(1,676,323)	(2,514,484)	(3,352,646)	(4,190,807)	(5,028,969)	(5,867,130)	(6,705,292)	(7,543,453)	(8,381,615)
Total Mining Plant		(838,161)	(1,676,323)	(2,514,484)	(3,352,646)	(4,190,807)	(5,028,969)	(5,867,130)	(6,705,292)	(7,543,453)	(8,381,615)
Intangible Plant:											
California	CA	-	-	-	-	-	-	-	-	-	-
Customer Service	CN	(17,785)	(35,571)	(53,356)	(71,142)	(88,927)	(106,713)	(124,498)	(142,284)	(160,069)	(177,855)
Pre-merger Pacific	SG	(53,158)	(106,315)	(159,473)	(212,630)	(265,788)	(318,945)	(372,103)	(425,260)	(478,418)	(531,576)
Pre-merger Utah	SG	(1,310)	(2,620)	(3,930)	(5,239)	(6,549)	(7,859)	(9,169)	(10,479)	(11,789)	(13,099)
Idaho	ID	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(115)	(229)	(344)	(459)	(574)	(688)	(803)	(918)	(1,032)	(1,147)
Fuel Related	SE	(6,226)	(12,453)	(18,679)	(24,906)	(31,132)	(37,359)	(43,585)	(49,812)	(56,038)	(62,265)
Post-merger	SG	(685,272)	(1,370,545)	(2,055,817)	(2,741,089)	(3,426,362)	(4,111,634)	(4,796,906)	(5,482,178)	(6,167,451)	(6,852,723)
Hydro Relicensing	SG-P	(137,905)	(275,811)	(413,716)	(551,622)	(689,527)	(827,433)	(965,338)	(1,103,244)	(1,241,149)	(1,379,055)
Hydro Relicensing	SG-U	(8,563)	(17,126)	(25,689)	(34,252)	(42,815)	(51,378)	(59,941)	(68,504)	(77,067)	(85,630)
General Office	SO	(738,717)	(1,477,434)	(2,216,152)	(2,954,869)	(3,693,586)	(4,432,303)	(5,171,020)	(5,909,738)	(6,648,455)	(7,387,172)
Cholla Intangible	SG	-	-	-	-	-	-	-	-	-	-
Utah	UT	(82)	(164)	(247)	(329)	(411)	(493)	(575)	(657)	(740)	(822)
Washington	WA	(14)	(28)	(42)	(57)	(71)	(85)	(99)	(113)	(127)	(142)
Eastern Wyoming	WYP	(856)	(1,712)	(2,569)	(3,425)	(4,281)	(5,137)	(5,994)	(6,850)	(7,706)	(8,562)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant		(1,650,005)	(3,300,009)	(4,950,014)	(6,600,019)	(8,250,023)	(9,900,028)	(11,550,032)	(13,200,037)	(14,850,042)	(16,500,046)
Total		(22,404,379)	(44,808,759)	(67,213,138)	(89,617,517)	(112,021,897)	(134,426,276)	(156,830,655)	(179,235,035)	(201,639,414)	(224,043,793)

*Retirements lag behind by a month

PacifiCorp
Oregon General Rate Case - December 2014
Cumulative Monthly Plant Retirements Summary

Description	Factor	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Test Period* Year End Balance
Steam Production Plant:										
Pre-merger Pacific	SG	(26,801,439)	(29,237,933)	(31,674,428)	(34,110,922)	(36,547,417)	(38,983,911)	(41,420,406)	(43,856,900)	(43,856,900)
Pre-merger Utah	SG	(24,123,863)	(26,316,941)	(28,510,019)	(30,703,098)	(32,896,176)	(35,089,255)	(37,282,333)	(39,475,412)	(39,475,412)
Post-merger	SG	(20,003,024)	(21,821,481)	(23,639,938)	(25,458,395)	(27,276,851)	(29,095,308)	(30,913,765)	(32,732,222)	(32,732,222)
Renewable - Blundell	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger	SG	(14,555,066)	(15,878,254)	(17,201,442)	(18,524,630)	(19,847,817)	(21,171,005)	(22,494,193)	(23,817,381)	(23,817,381)
Total Steam Plant		(85,483,392)	(93,254,609)	(101,025,827)	(108,797,044)	(116,568,262)	(124,339,479)	(132,110,697)	(139,881,914)	(139,881,914)
Hydro Production Plant:										
Pre-merger Pacific	SG	(2,731,722)	(2,980,061)	(3,228,399)	(3,476,738)	(3,725,076)	(3,973,415)	(4,221,753)	(4,470,091)	(4,470,091)
Pre-merger Utah	SG	(765,006)	(834,552)	(904,098)	(973,644)	(1,043,190)	(1,112,736)	(1,182,283)	(1,251,829)	(1,251,829)
Post-merger	SG-P	(2,343,899)	(2,556,981)	(2,770,063)	(2,983,144)	(3,196,226)	(3,409,308)	(3,622,390)	(3,835,471)	(3,835,471)
Post-merger	SG-U	(614,933)	(670,836)	(726,739)	(782,642)	(838,545)	(894,448)	(950,351)	(1,006,254)	(1,006,254)
Total Hydro Plant		(6,455,561)	(7,042,430)	(7,629,299)	(8,216,168)	(8,803,037)	(9,389,907)	(9,976,776)	(10,563,645)	(10,563,645)
Other Production Plant:										
Pre-merger Utah	SG	(121,144)	(132,157)	(143,170)	(154,183)	(165,196)	(176,209)	(187,222)	(198,235)	(198,235)
Post-merger	SG	(7,432,732)	(8,108,435)	(8,784,138)	(9,459,841)	(10,135,544)	(10,811,247)	(11,486,949)	(12,162,652)	(12,162,652)
Post-merger Wind	SG-W	(835,054)	(910,968)	(986,882)	(1,062,796)	(1,138,710)	(1,214,624)	(1,290,538)	(1,366,452)	(1,366,452)
Post-merger	SG	(656,094)	(715,739)	(775,384)	(835,029)	(894,674)	(954,319)	(1,013,964)	(1,073,609)	(1,073,609)
Total Other Plant		(9,045,024)	(9,867,299)	(10,689,574)	(11,511,849)	(12,334,124)	(13,156,399)	(13,978,674)	(14,800,948)	(14,800,948)
Transmission Plant:										
Pre-merger Pacific	SG	(5,070,040)	(5,530,953)	(5,991,866)	(6,452,779)	(6,913,691)	(7,374,604)	(7,835,517)	(8,296,430)	(8,296,430)
Pre-merger Utah	SG	(3,931,085)	(4,288,456)	(4,645,828)	(5,003,199)	(5,360,570)	(5,717,942)	(6,075,313)	(6,432,684)	(6,432,684)
Post-merger	SG	(14,380,778)	(15,688,122)	(16,995,465)	(18,302,809)	(19,610,152)	(20,917,495)	(22,224,839)	(23,532,182)	(23,532,182)
Total Transmission Plant		(23,381,903)	(25,507,531)	(27,633,158)	(29,758,786)	(31,884,414)	(34,010,041)	(36,135,669)	(38,261,296)	(38,261,296)
Distribution Plant:										
California	CA	(894,909)	(976,265)	(1,057,620)	(1,138,975)	(1,220,331)	(1,301,686)	(1,383,042)	(1,464,397)	(1,464,397)
Oregon	OR	(8,205,822)	(8,951,806)	(9,697,790)	(10,443,774)	(11,189,758)	(11,935,741)	(12,681,725)	(13,427,709)	(13,427,709)
Washington	WA	(4,223,625)	(4,607,591)	(4,991,557)	(5,375,523)	(5,759,489)	(6,143,455)	(6,527,421)	(6,911,387)	(6,911,387)
Eastern Wyoming	WYP	(4,591,591)	(5,009,008)	(5,426,426)	(5,843,843)	(6,261,260)	(6,678,678)	(7,096,095)	(7,513,512)	(7,513,512)
Utah	UT	(26,119,008)	(28,493,463)	(30,867,918)	(33,242,374)	(35,616,829)	(37,991,284)	(40,365,739)	(42,740,195)	(42,740,195)
Idaho	ID	(2,048,717)	(2,234,964)	(2,421,211)	(2,607,458)	(2,793,705)	(2,979,952)	(3,166,199)	(3,352,446)	(3,352,446)
Western Wyoming	WYU	(870,352)	(949,475)	(1,028,598)	(1,107,721)	(1,186,843)	(1,265,966)	(1,345,089)	(1,424,212)	(1,424,212)
Total Distribution Plant		(46,954,025)	(51,222,572)	(55,491,120)	(59,759,668)	(64,028,216)	(68,296,763)	(72,565,311)	(76,833,859)	(76,833,859)

PacifiCorp
Oregon General Rate Case - December 2014
Cumulative Monthly Plant Retirements Summary

Description	Factor	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Test Period* Year End Balance
General Plant:										
California	CA	(480,173)	(523,825)	(567,477)	(611,130)	(654,782)	(698,434)	(742,086)	(785,738)	(785,738)
Oregon	OR	(6,538,533)	(7,132,946)	(7,727,358)	(8,321,770)	(8,916,182)	(9,510,594)	(10,105,006)	(10,699,418)	(10,699,418)
Washington	WA	(1,382,998)	(1,508,725)	(1,634,453)	(1,760,180)	(1,885,907)	(2,011,634)	(2,137,361)	(2,263,088)	(2,263,088)
Eastern Wyoming	WYP	(2,300,283)	(2,509,399)	(2,718,516)	(2,927,633)	(3,136,749)	(3,345,866)	(3,554,983)	(3,764,099)	(3,764,099)
Utah	UT	(6,053,926)	(6,604,283)	(7,154,640)	(7,704,997)	(8,255,354)	(8,805,711)	(9,356,068)	(9,906,425)	(9,906,425)
Idaho	ID	(1,537,932)	(1,677,744)	(1,817,556)	(1,957,368)	(2,097,180)	(2,236,992)	(2,376,804)	(2,516,616)	(2,516,616)
Western Wyoming	WYU	(513,426)	(560,101)	(606,777)	(653,452)	(700,127)	(746,802)	(793,477)	(840,152)	(840,152)
Pre-merger Pacific	SG	(1,423,822)	(1,553,260)	(1,682,699)	(1,812,137)	(1,941,575)	(2,071,014)	(2,200,452)	(2,329,890)	(2,329,890)
Pre-merger Utah	SG	(2,925,285)	(3,191,220)	(3,457,155)	(3,723,090)	(3,989,025)	(4,254,961)	(4,520,896)	(4,786,831)	(4,786,831)
Post-merger	SG	(4,913,267)	(5,359,928)	(5,806,588)	(6,253,249)	(6,699,909)	(7,146,570)	(7,593,231)	(8,039,891)	(8,039,891)
General Office	SO	(17,966,734)	(19,600,073)	(21,233,412)	(22,866,752)	(24,500,091)	(26,133,431)	(27,766,770)	(29,400,110)	(29,400,110)
General Office	SG	(370,364)	(404,033)	(437,703)	(471,372)	(505,042)	(538,711)	(572,380)	(606,050)	(606,050)
General Office	SG	(14,235)	(15,530)	(16,824)	(18,118)	(19,412)	(20,706)	(22,000)	(23,294)	(23,294)
Customer Service	CN	(1,261,831)	(1,376,543)	(1,491,255)	(1,605,966)	(1,720,678)	(1,835,390)	(1,950,102)	(2,064,814)	(2,064,814)
Fuel Related	SE	(75,630)	(82,506)	(89,381)	(96,257)	(103,132)	(110,008)	(116,883)	(123,759)	(123,759)
Total General Plant		(47,758,441)	(52,100,117)	(56,441,794)	(60,783,470)	(65,125,146)	(69,466,823)	(73,808,499)	(78,150,176)	(78,150,176)
Mining Plant:										
Coal Mine	SE	(9,219,776)	(10,057,938)	(10,896,099)	(11,734,260)	(12,572,422)	(13,410,583)	(14,248,745)	(15,086,906)	(15,086,906)
Total Mining Plant		(9,219,776)	(10,057,938)	(10,896,099)	(11,734,260)	(12,572,422)	(13,410,583)	(14,248,745)	(15,086,906)	(15,086,906)
Intangible Plant:										
California	CA	-	-	-	-	-	-	-	-	-
Customer Service	CN	(195,640)	(213,426)	(231,211)	(248,997)	(266,782)	(284,568)	(302,353)	(320,139)	(320,139)
Pre-merger Pacific	SG	(584,733)	(637,891)	(691,048)	(744,206)	(797,363)	(850,521)	(903,679)	(956,836)	(956,836)
Pre-merger Utah	SG	(14,409)	(15,718)	(17,028)	(18,338)	(19,648)	(20,958)	(22,268)	(23,578)	(23,578)
Idaho	ID	-	-	-	-	-	-	-	-	-
Oregon	OR	(1,262)	(1,377)	(1,491)	(1,606)	(1,721)	(1,835)	(1,950)	(2,065)	(2,065)
Fuel Related	SE	(68,491)	(74,717)	(80,944)	(87,170)	(93,397)	(99,623)	(105,850)	(112,076)	(112,076)
Post-merger	SG	(7,537,995)	(8,223,268)	(8,908,540)	(9,593,812)	(10,279,085)	(10,964,357)	(11,649,629)	(12,334,902)	(12,334,902)
Hydro Relicensing	SG-P	(1,516,960)	(1,654,866)	(1,792,771)	(1,930,677)	(2,068,582)	(2,206,488)	(2,344,393)	(2,482,299)	(2,482,299)
Hydro Relicensing	SG-U	(94,193)	(102,756)	(111,319)	(119,882)	(128,445)	(137,008)	(145,571)	(154,134)	(154,134)
General Office	SO	(8,125,889)	(8,864,606)	(9,603,324)	(10,342,041)	(11,080,758)	(11,819,475)	(12,558,193)	(13,296,910)	(13,296,910)
Cholla Intangible	SG	-	-	-	-	-	-	-	-	-
Utah	UT	(904)	(986)	(1,068)	(1,150)	(1,233)	(1,315)	(1,397)	(1,479)	(1,479)
Washington	WA	(156)	(170)	(184)	(198)	(212)	(227)	(241)	(255)	(255)
Eastern Wyoming	WYP	(9,418)	(10,275)	(11,131)	(11,987)	(12,843)	(13,700)	(14,556)	(15,412)	(15,412)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		(18,150,051)	(19,800,056)	(21,450,060)	(23,100,065)	(24,750,070)	(26,400,074)	(28,050,079)	(29,700,083)	(29,700,083)
Total		(246,448,173)	(268,852,552)	(291,256,931)	(313,661,311)	(336,065,690)	(358,470,069)	(380,874,449)	(403,278,828)	**(403,278,828)**

*Retirements lag behind by a month

Ref 8.6.1

PacifiCorp
Oregon General Rate Case - December 2014
5 Year Average Retirement Amount

Function	Factor	CY2007 Retirements	CY2008 Retirements	CY2009 Retirements	CY2010 Retirements	CY2011 Retirements	5 Year Avg	Monthly Amount
STMP	DGP	(17,038,677)	(18,958,977)	(25,683,003)	(36,651,987)	(47,857,023)	(29,237,933)	(2,436,494)
STMP	DGU	(33,313,403)	(7,132,284)	(9,463,708)	(13,052,143)	(68,623,167)	(26,316,941)	(2,193,078)
STMP	SG	(8,399,939)	(7,337,289)	(21,193,958)	(33,369,740)	(38,806,479)	(21,821,481)	(1,818,457)
STMP	SSGCH	(3,029,052)	(70,945,405)	(834,858)	(1,267,065)	(3,314,888)	(15,878,254)	(1,323,188)
		(61,781,072)	(104,373,955)	(57,175,528)	(84,340,935)	(158,601,558)	(93,254,609)	(7,771,217)
HYDP	DGP	(7,131,087)	(630,912)	(1,679,621)	(1,457,317)	(4,001,368)	(2,980,061)	(248,338)
HYDP	DGU	(2,031,123)	(446,272)	(540,872)	(282,865)	(871,630)	(834,552)	(69,546)
HYDP	SG-P	(7,291,036)	(384,218)	(922,173)	(862,245)	(3,325,232)	(2,556,981)	(213,082)
HYDP	SG-U	(1,823,768)	(52,350)	(778,674)	(212,447)	(486,941)	(670,836)	(55,903)
		(18,277,013)	(1,513,753)	(3,921,340)	(2,814,873)	(8,685,171)	(7,042,430)	(586,869)
OTHP	DGU	-	(6,564)	(20,557)	(26)	(633,637)	(132,157)	(11,013)
OTHP	SG	(4,277,556)	(4,265,667)	(17,222,593)	(1,537,569)	(13,238,789)	(8,108,435)	(675,703)
OTHP	SG-W	(36,675)	(56,062)	(332,700)	(416,590)	(3,712,813)	(910,968)	(75,914)
OTHP	SSGCT	-	(958,733)	(1,011,018)	(1,608,945)	-	(715,739)	(59,645)
		(4,314,231)	(5,287,026)	(18,586,868)	(3,563,130)	(17,585,240)	(9,867,299)	(822,275)
TRNP	DGP	(1,099,904)	(12,803,099)	(3,353,021)	(4,630,878)	(5,767,862)	(5,530,953)	(460,913)
TRNP	DGU	(2,845,977)	(3,532,603)	(3,021,489)	(6,122,824)	(5,919,388)	(4,288,456)	(357,371)
TRNP	SG	(3,130,597)	(19,162,969)	(4,216,411)	(30,542,011)	(21,388,620)	(15,688,122)	(1,307,343)
		(7,076,478)	(35,498,671)	(10,590,921)	(41,295,714)	(33,075,870)	(25,507,531)	(2,125,628)
DSTP	CA	(923,925)	(968,266)	(1,388,257)	(635,184)	(965,692)	(976,265)	(81,355)
DSTP	ID	(1,683,162)	(2,746,168)	(1,879,040)	(1,564,264)	(3,302,188)	(2,234,964)	(186,247)
DSTP	OR	(8,654,976)	(10,915,158)	(7,618,956)	(9,234,877)	(8,335,062)	(8,951,806)	(745,984)
DSTP	UT	(34,638,026)	(36,706,559)	(14,136,501)	(30,227,161)	(26,759,069)	(28,493,463)	(2,374,455)
DSTP	WA	(2,022,782)	(2,880,426)	(2,149,285)	(11,403,711)	(4,581,753)	(4,607,591)	(383,966)
DSTP	WYP	(2,598,850)	(4,696,054)	(5,925,831)	(3,936,985)	(7,887,322)	(5,009,008)	(417,417)
DSTP	WYU	(537,473)	(986,221)	(735,143)	(426,182)	(2,062,355)	(949,475)	(79,123)
		(51,059,194)	(59,898,852)	(33,833,012)	(57,428,364)	(53,893,442)	(51,222,572)	(4,268,548)
GNLP	SSGCH	(649,703)	(535,171)	(133,992)	(656,377)	(44,923)	(404,033)	(33,669)
GNLP	SSGCT	(14,821)	(62,827)	-	-	-	(15,530)	(1,294)
GNLP	SG	(7,734,197)	(4,044,362)	(6,327,721)	(5,970,281)	(2,723,077)	(5,359,928)	(446,661)
GNLP	DGP	(968,747)	(1,231,061)	(953,180)	(3,516,751)	(1,096,563)	(1,553,260)	(129,438)
GNLP	SE	(56,071)	(104,788)	(178,219)	(26,020)	(47,430)	(82,506)	(6,875)
GNLP	SO	(19,405,976)	(22,499,174)	(29,183,394)	(17,015,786)	(9,896,035)	(19,600,073)	(1,633,339)
GNLP	CN	(730,399)	(1,054,366)	(2,824,163)	(1,277,537)	(996,248)	(1,376,543)	(114,712)
GNLP	CA	(565,904)	(872,209)	(570,210)	(431,554)	(179,250)	(523,825)	(43,652)
GNLP	ID	(1,351,786)	(1,670,801)	(3,265,414)	(979,866)	(1,120,851)	(1,677,744)	(139,812)
GNLP	DGU	(1,436,955)	(2,884,761)	(2,909,314)	(7,314,851)	(1,410,220)	(3,191,220)	(265,935)
GNLP	OR	(6,799,797)	(8,965,121)	(7,368,773)	(6,914,822)	(5,616,216)	(7,132,946)	(594,412)
GNLP	UT	(6,233,239)	(8,592,151)	(5,602,567)	(7,379,855)	(5,213,605)	(6,604,283)	(550,357)
GNLP	WA	(1,203,870)	(2,258,225)	(1,375,903)	(1,149,121)	(1,556,509)	(1,508,725)	(125,727)
GNLP	WYU	(663,602)	(784,091)	(295,382)	(767,727)	(289,706)	(560,101)	(46,675)
GNLP	WYP	(2,648,216)	(2,818,678)	(3,086,636)	(2,271,434)	(1,722,033)	(2,509,399)	(209,117)
		(50,463,282)	(58,377,785)	(64,074,867)	(55,671,983)	(31,912,668)	(52,100,117)	(4,341,676)
MNGP	SE	(6,078,187)	(4,748,218)	(4,818,201)	(27,280,185)	(7,364,897)	(10,057,938)	(838,161)
		(6,078,187)	(4,748,218)	(4,818,201)	(27,280,185)	(7,364,897)	(10,057,938)	(838,161)
INTP	DGP	(2,844,878)	-	(344,575)	-	-	(637,891)	(53,158)
INTP	DGU	(78,592)	-	-	-	-	(15,718)	(1,310)
INTP	SG-P	(4,478,459)	(3,795,871)	-	-	-	(1,654,866)	(137,905)
INTP	SG-U	(462,400)	-	-	-	(51,379)	(102,756)	(8,563)
INTP	SG	(3,941,683)	(6,887,755)	(13,650,347)	(5,214,500)	(11,422,054)	(8,223,268)	(685,272)
INTP	SO	(17,255,902)	(19,148,528)	(3,272,906)	(1,713,568)	(2,932,129)	(8,864,606)	(738,717)
INTP	CN	(80,772)	(922,863)	(2,224)	(60,507)	(764)	(213,426)	(17,785)
INTP	SE	-	-	(356,067)	(13,128)	(4,392)	(74,717)	(6,226)
INTP	CA	-	-	-	-	-	-	-
INTP	ID	-	-	-	-	-	-	-
INTP	OR	-	-	-	(6,883)	-	(1,377)	(115)
INTP	UT	-	(875)	-	-	(4,055)	(986)	(82)
INTP	WA	-	(540)	-	-	(310)	(170)	(14)
INTP	WYU	-	-	-	-	-	-	-
INTP	WYP	-	-	-	-	(51,373)	(10,275)	(856)
		(29,142,686)	(30,756,432)	(17,626,119)	(7,008,585)	(14,466,456)	(19,800,056)	(1,650,005)
		(228,192,144)	(300,454,692)	(210,626,855)	(279,403,768)	(325,585,301)	(268,852,552)	(22,404,379)

PacifiCorp
Oregon General Rate Case - December 2014
Miscellaneous Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
1 - Fuel Stock - Pro Forma	151	3	(19,194,049)	SE	24.687%	(4,738,383)	
1 - Fuel Stock - Pro Forma	151	3	680,087	SE	24.687%	167,891	
			(18,513,962)			(4,570,492)	8.7.1
1 - Fuel Stock - Working Capital Deposit	25316	3	(314,923)	SE	24.687%	(77,744)	8.7.1
1 - Fuel Stock - Working Capital Deposit	25317	3	(368,815)	SE	24.687%	(91,048)	8.7.1
2 - Prepaid Overhauls	186M	3	9,770,883	SG	26.053%	2,545,608	8.7.1

Description of Adjustment:

1 - The Company's December 2014 fuel stock will decrease from June 2012 levels as a result of a reduction in the number of tons stored at each site. The reduction in tonnage offsets the increase in stockpile unit costs. The adjustment also reflects the working capital deposits which are an offset to fuel stock costs.

2 - Balances for prepaid overhauls at the Lake Side, Chehalis and Currant Creek gas plants are walked forward to reflect payments and transfers of capital to electric plant in service during the year ending December 2014 on a 13 month average basis.

PacifiCorp
Oregon General Rate Case - December 2014
Miscellaneous Rate Base

			Actuals	Pro Forma		
1 - Coal Fuel Stock Balances by Plant	**Account**	**Factor**	**Jun-2012 Balance**	**Dec-2014 13-Mo Avg**	**Adjustment**	
Bridger	151	SE	25,431,862	28,377,034	2,945,173	
Carbon	151	SE	2,127,971	2,867,901	739,930	
Cholla	151	SE	10,115,124	10,795,211	680,087	
Colstrip	151	SE	1,357,450	1,488,149	130,699	
Craig	151	SE	7,838,540	8,167,005	328,465	
Hayden	151	SE	3,503,674	2,251,784	(1,251,890)	
Hunter	151	SE	75,700,450	71,755,822	(3,944,628)	
Huntington	151	SE	23,726,118	30,769,690	7,043,572	
Johnston	151	SE	8,120,960	6,678,408	(1,442,552)	
Naughton	151	SE	10,434,628	10,622,656	188,028	
Deer Creek	151	SE	51,833	514,743	462,910	
Prep Plant	151	SE	59,276,385	38,582,415	(20,693,970)	
Rock Garden	151	SE	34,433,925	30,734,140	(3,699,785)	
Total			262,118,919	243,604,958	**(18,513,962)**	**To 8.7**
1 - Working Capital Deposits						
UAMPS Working Capital Deposit	25316	SE	(3,235,000)	(3,549,923)	**(314,923)**	**To 8.7**
DPEC Working Capital Deposit	25317	SE	(2,489,934)	(2,858,749)	**(368,815)**	**To 8.7**
2 - Overhaul Prepayments by Plant	**Account**	**Factor**				
Lake Side	186M	SG	14,560,464	20,729,966	6,169,503	
Chehalis	186M	SG	8,483,816	16,846,561	8,362,746	
Currant Creek	186M	SG	14,633,371	9,872,007	(4,761,365)	
Total			37,677,651	47,448,534	**9,770,883**	**To 8.7**

PacifiCorp
Oregon General Rate Case - December 2014
Powerdale Hydro Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove O&M Expense	535	1	(4,600)	SG-P	26.053%	(1,198)	
	537	1	(7,966)	SG-P	26.053%	(2,075)	
	539	1	(1,822)	SG-P	26.053%	(475)	
	545	1	(3,181)	SG-P	26.053%	(829)	
			(17,570)			(4,577)	8.8
Adjustment to Tax:							
13-Month Average ADIT Balance	283	1	841,417	SG	26.053%	219,214	

Description of Adjustment:

This adjustment removes the O&M costs related to the Powerdale hydroelectric plant from results. The Powerdale unrecovered plant regulatory asset balance authorized by the Commission in Docket No. UM 1298 and was fully amortized as of December 2010. The associated decommissioning regulatory asset was also fully amortized as of November 2011. As of the end of the June 2012 base period, the only transactions to remove from results are residual O&M expense and any related tax impacts associated with the Powerdale plant.

PacifiCorp
Oregon General Rate Case - December 2014
Powerdale Hydro Removal

Operation & Maintenance Expense

Description	Account	Factor	12 Months Ended June 2012 Expense
Operation & Maintenance Expense	535	SG-P	4,600
Hydraulic Expense	537	SG-P	7,966
Misc. Hydro Expense	539	SG-P	1,822
Maintenance of Misc. Hydro Plant	545	SG-P	3,181
			17,570
			Ref 8.8

PacifiCorp
Oregon General Rate Case - December 2014
Regulatory Asset Amortization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Adjust amortization expense from base period to pro forma period							
Cholla Transaction Costs	557	3	(83,492)	SGCT	26.141%	(21,825)	8.9.1
Cholla Trans costs - OR Disallowance	557	3	4,003	OR	100.000%	4,003	8.9.2
Pension and Post-retirement Curtailment	920	3	60,148	OR	100.000%	60,148	8.9.3
Electric Plant Acq Adj - Amort Expense	406	3	(689,674)	SG	26.053%	(179,681)	8.9.4
Remove amortization expense of Reg Assets that have been collected under Tariff Riders							
GRID West - Oregon	904	1	(388,671)	OR	100.000%	(388,671)	8.9.5
MEHC Transition Plan - 2006	920	1	(1,909,702)	OR	100.000%	(1,909,702)	8.9.6
Oregon Independent Evaluator Fees	557	1	(38,381)	SG	26.053%	(9,999)	8.9.7
Adjustment to Rate Base:							
Adjust amortization expense from base period to pro forma period							
Cholla Transaction costs	182M	3	(2,244,850)	SGCT	26.141%	(586,818)	8.9.1
Cholla Trans costs - OR Disallowance	182M	3	107,626	OR	100.000%	107,626	8.9.2
Electric Plant Acq Adj - Accum Amortization	115	3	(10,381,808)	SG	26.053%	(2,704,773)	8.9.4
Adjustment to Tax:							
Pension MMT & CTG	283	3	(1,763,671)	OR	100.000%	(1,763,671)	
Retirement MMT - OR	283	3	335,540	OR	100.000%	335,540	
Accrued CIC Severance	190	3	9,805	SO	27.384%	2,685	
Pension Retirment Accrual	190	3	(898,220)	SO	27.384%	(245,971)	
OR _RCAC Sep-Dec 07 Deferred	283	3	(5,459)	OR	100.000%	(5,459)	
Electric Plant Acq Adj	282	3	2,888,144	SG	26.053%	752,448	
Cholla Transaction Costs	283	3	34,168	SGCT	26.141%	8,932	
Cholla Trans Costs - OR Disallowance	283	3	(1,638)	OR	100.000%	(1,638)	

Description of Adjustment:

This adjustment normalizes regulatory assets from the base period to the pro forma period. In addition, in UE 210, the Company agreed to set up tariff riders to collect the balance of the GRID - West Reg Asset, the 2000 Transition Plan Reg Asset and the Oregon MEHC Transition Plan Reg Asset. These tariff riders are credited to revenues when collected and removed from revenues in the Pro Forma Revenue adjustment 3.1. These regulatory assets are amortized in unadjusted results by charging expense. This adjustment removes that expense.

PacifiCorp
Oregon General Rate Case - December 2014
Regulatory Asset Amortization
Cholla Transaction Costs
Account 187050

	Amortization Expense	Rate Base
Pro Forma (Rate Base 13 Month Avg)	1,122,425	3,460,811
Base Period (Rate Base June 2012)	1,205,917	5,705,661
Adjustment	**(83,492)**	**(2,244,850)**
	8.9	**8.9**

		Beg Balance	Amortization	End Balance	Avg Balance
2011	July	6,828,086	(93,535)	6,734,550	
	August	6,734,550	(93,535)	6,641,015	
	September	6,641,015	(93,535)	6,547,479	
	October	6,547,479	(93,535)	6,453,944	
	November	6,453,944	(93,535)	6,360,409	
	December	6,360,409	(93,535)	6,266,873	
2012	January	6,266,873	(93,535)	6,173,338	
	February	6,173,338	(93,535)	6,079,802	
	March	6,079,802	(93,535)	5,986,267	
	April	5,986,267	(93,535)	5,892,731	
	May	5,892,731	(93,535)	5,799,196	
	June	5,799,196	(93,535)	**5,705,661**	
	Base Period Amortization =		(1,122,425)		
	Escalation Rate =		107.44%		
			(1,205,917)		
	July	5,705,661	(93,535)	5,612,125	
	August	5,612,125	(93,535)	5,518,590	
	September	5,518,590	(93,535)	5,425,054	
	October	5,425,054	(93,535)	5,331,519	
	November	5,331,519	(93,535)	5,237,984	
	December	5,237,984	(93,535)	5,144,448	
2013	January	5,144,448	(93,535)	5,050,913	
	February	5,050,913	(93,535)	4,957,377	
	March	4,957,377	(93,535)	4,863,842	
	April	4,863,842	(93,535)	4,770,306	
	May	4,770,306	(93,535)	4,676,771	
	June	4,676,771	(93,535)	4,583,236	
	July	4,583,236	(93,535)	4,489,700	
	August	4,489,700	(93,535)	4,396,165	
	September	4,396,165	(93,535)	4,302,629	
	October	4,302,629	(93,535)	4,209,094	
	November	4,209,094	(93,535)	4,115,558	
	December	4,115,558	(93,535)	4,022,023	
2014	January	4,022,023	(93,535)	3,928,488	
	February	3,928,488	(93,535)	3,834,952	
	March	3,834,952	(93,535)	3,741,417	
	April	3,741,417	(93,535)	3,647,881	
	May	3,647,881	(93,535)	3,554,346	
	June	3,554,346	(93,535)	3,460,811	
	July	3,460,811	(93,535)	3,367,275	
	August	3,367,275	(93,535)	3,273,740	
	September	3,273,740	(93,535)	3,180,204	
	October	3,180,204	(93,535)	3,086,669	
	November	3,086,669	(93,535)	2,993,133	
	December	2,993,133	(93,535)	2,899,598	**3,460,811**
	Pro Forma Amortization =		**(1,122,425)**		

PacifiCorp
Oregon General Rate Case - December 2014
Regulatory Asset Amortization
Cholla Transaction Costs - Oregon Disallowance
Account 187060

	Amortization Expense	Rate Base
Pro Forma (Rate Base 13 Month Avg)	(53,813)	(165,924)
Base Period (Rate Base June 2012)	(57,816)	(273,550)
Adjustment	**4,003**	**107,626**
	Ref 8.9	**Ref 8.9**

		Beg Balance	Amortization	End Balance	Avg Balance
2011	July	(327,363)	4,484	(322,879)	
	August	(322,879)	4,484	(318,394)	
	September	(318,394)	4,484	(313,910)	
	October	(313,910)	4,484	(309,425)	
	November	(309,425)	4,484	(304,941)	
	December	(304,941)	4,484	(300,456)	
2012	January	(300,456)	4,484	(295,972)	
	February	(295,972)	4,484	(291,488)	
	March	(291,488)	4,484	(287,003)	
	April	(287,003)	4,484	(282,519)	
	May	(282,519)	4,484	(278,034)	
	June	(278,034)	4,484	**(273,550)**	
	Base Period Amortization =		53,813		
	Escalation Rate =		107.44%		
			57,816		
	July	(273,550)	4,484	(269,066)	
	August	(269,066)	4,484	(264,581)	
	September	(264,581)	4,484	(260,097)	
	October	(260,097)	4,484	(255,612)	
	November	(255,612)	4,484	(251,128)	
	December	(251,128)	4,484	(246,643)	
2013	January	(246,643)	4,484	(242,159)	
	February	(242,159)	4,484	(237,675)	
	March	(237,675)	4,484	(233,190)	
	April	(233,190)	4,484	(228,706)	
	May	(228,706)	4,484	(224,221)	
	June	(224,221)	4,484	(219,737)	
	July	(219,737)	4,484	(215,252)	
	August	(215,252)	4,484	(210,768)	
	September	(210,768)	4,484	(206,284)	
	October	(206,284)	4,484	(201,799)	
	November	(201,799)	4,484	(197,315)	
	December	(197,315)	4,484	(192,830)	
2014	January	(192,830)	4,484	(188,346)	
	February	(188,346)	4,484	(183,862)	
	March	(183,862)	4,484	(179,377)	
	April	(179,377)	4,484	(174,893)	
	May	(174,893)	4,484	(170,408)	
	June	(170,408)	4,484	(165,924)	
	July	(165,924)	4,484	(161,439)	
	August	(161,439)	4,484	(156,955)	
	September	(156,955)	4,484	(152,471)	
	October	(152,471)	4,484	(147,986)	
	November	(147,986)	4,484	(143,502)	
	December	(143,502)	4,484	(139,017)	**(165,924)**
	Pro Forma Amortization =		**53,813**		

PacifiCorp
Oregon General Rate Case - December 2014
Regulatory Asset Amortization
Pension and Postretirement Curtailment and Date Change

Deferral and Amortization of Pension Curtailment and Pension and Postretirement Date Change

	Original Amount	Additional Local 127
Oregon Portion	(7,558,051)	(586,649)
Amortization Period	120 months	107 months

	Amortization Expense
Pro Forma Period	(821,597)
Base Period	(881,745)
	60,148
	Ref 8.9

		Beginning Balance	Amortization	Ending Balance
2011	July	(6,161,981)	68,466	(6,093,515)
	August	(6,093,515)	68,466	(6,025,048)
	September	(6,025,048)	68,466	(5,956,582)
	October	(5,956,582)	68,466	(5,888,115)
	November	(5,888,115)	68,466	(5,819,649)
	December	(5,819,649)	68,466	(5,751,182)
2012	January	(5,751,182)	68,466	(5,682,716)
	February	(5,682,716)	68,466	(5,614,249)
	March	(5,614,249)	68,466	(5,545,783)
	April	(5,545,783)	68,466	(5,477,316)
	May	(5,477,316)	68,466	(5,408,850)
	June	(5,408,850)	68,466	(5,340,384)
		Base Period Amort =	821,597	
		Escalation Rate =	107.32%	
			881,745	
	July	(5,340,384)	68,466	(5,271,917)
	August	(5,271,917)	68,466	(5,203,451)
	September	(5,203,451)	68,466	(5,134,984)
	October	(5,134,984)	68,466	(5,066,518)
	November	(5,066,518)	68,466	(4,998,051)
	December	(4,998,051)	68,466	(4,929,585)
2013	January	(4,929,585)	68,466	(4,861,118)
	February	(4,861,118)	68,466	(4,792,652)
	March	(4,792,652)	68,466	(4,724,185)
	April	(4,724,185)	68,466	(4,655,719)
	May	(4,655,719)	68,466	(4,587,253)
	June	(4,587,253)	68,466	(4,518,786)
	July	(4,518,786)	68,466	(4,450,320)
	August	(4,450,320)	68,466	(4,381,853)
	September	(4,381,853)	68,466	(4,313,387)
	October	(4,313,387)	68,466	(4,244,920)
	November	(4,244,920)	68,466	(4,176,454)
	December	(4,176,454)	68,466	(4,107,987)
2014	January	(4,107,987)	68,466	(4,039,521)
	February	(4,039,521)	68,466	(3,971,054)
	March	(3,971,054)	68,466	(3,902,588)
	April	(3,902,588)	68,466	(3,834,122)
	May	(3,834,122)	68,466	(3,765,655)
	June	(3,765,655)	68,466	(3,697,189)
	July	(3,697,189)	68,466	(3,628,722)
	August	(3,628,722)	68,466	(3,560,256)
	September	(3,560,256)	68,466	(3,491,789)
	October	(3,491,789)	68,466	(3,423,323)
	November	(3,423,323)	68,466	(3,354,856)
	December	(3,354,856)	68,466	(3,286,390)
		Pro Forma Amort =	**821,597**	

PacifiCorp
Oregon General Rate Case - December 2014
Regulatory Asset Amortization
Electric Plant Acquisition Adjustment
Account 115

	Account 114		Amortization of Account 115: Amort Expense	Amortization of Account 115: Accum Amort
Pro Forma (Rate Base 13 Mo Avg)	159,175,508		4,834,295	(120,513,028)
Base Period (Rate Base YE)	159,175,508		5,523,970	(110,131,219)
Adjustment	-		**(689,674)**	**(10,381,808)**
			Ref 8.9	**Ref 8.9**

		Account 114 End Balance	Account 115 Beg Balance	Account 115 Amortization	Account 115 End Balance	Avg Balance
2011	July	159,175,508	(104,607,250)	(460,331)	(105,067,581)	
	August	159,175,508	(105,067,581)	(460,331)	(105,527,911)	
	September	159,175,508	(105,527,911)	(460,331)	(105,988,242)	
	October	159,175,508	(105,988,242)	(460,331)	(106,448,573)	
	November	159,175,508	(106,448,573)	(460,331)	(106,908,904)	
	December	159,175,508	(106,908,904)	(460,331)	(107,369,235)	
2012	January	159,175,508	(107,369,235)	(460,331)	(107,829,565)	
	February	159,175,508	(107,829,565)	(460,331)	(108,289,896)	
	March	159,175,508	(108,289,896)	(460,331)	(108,750,227)	
	April	159,175,508	(108,750,227)	(460,331)	(109,210,558)	
	May	159,175,508	(109,210,558)	(460,331)	(109,670,889)	
	June	**159,175,508**	(109,670,889)	(460,331)	**(110,131,219)**	
			Base Period Amort =	**(5,523,970)**		
	July	159,175,508	(110,131,219)	(460,331)	(110,591,550)	
	August	159,175,508	(110,591,550)	(460,331)	(111,051,881)	
	September	159,175,508	(111,051,881)	(460,331)	(111,512,212)	
	October	159,175,508	(111,512,212)	(460,331)	(111,972,543)	
	November	159,175,508	(111,972,543)	(460,331)	(112,432,873)	
	December	159,175,508	(112,432,873)	(460,331)	(112,893,204)	
2013	January	159,175,508	(112,893,204)	(460,331)	(113,353,535)	
	February	159,175,508	(113,353,535)	(460,331)	(113,813,866)	
	March	159,175,508	(113,813,866)	(460,331)	(114,274,197)	
	April	159,175,508	(114,274,197)	(460,331)	(114,734,527)	
	May	159,175,508	(114,734,527)	(460,331)	(115,194,858)	
	June	159,175,508	(115,194,858)	(460,331)	(115,655,189)	
	July	159,175,508	(115,655,189)	(405,177)	(116,060,366)	
	August	159,175,508	(116,060,366)	(405,177)	(116,465,542)	
	September	159,175,508	(116,465,542)	(405,177)	(116,870,719)	
	October	159,175,508	(116,870,719)	(405,177)	(117,275,895)	
	November	159,175,508	(117,275,895)	(405,177)	(117,681,072)	
	December	159,175,508	(117,681,072)	(405,177)	(118,086,249)	
2014	January	159,175,508	(118,086,249)	(405,177)	(118,491,425)	
	February	159,175,508	(118,491,425)	(405,177)	(118,896,602)	
	March	159,175,508	(118,896,602)	(405,177)	(119,301,778)	
	April	159,175,508	(119,301,778)	(405,177)	(119,706,955)	
	May	159,175,508	(119,706,955)	(405,177)	(120,112,132)	
	June	159,175,508	(120,112,132)	(405,177)	(120,517,308)	
	July	159,175,508	(120,517,308)	(405,177)	(120,922,485)	
	August	159,175,508	(120,922,485)	(405,177)	(121,327,661)	
	September	159,175,508	(121,327,661)	(405,177)	(121,732,838)	
	October	159,175,508	(121,732,838)	(395,902)	(122,128,740)	
	November	159,175,508	(122,128,740)	(395,902)	(122,524,642)	
	December	159,175,508	(122,524,642)	(395,902)	(122,920,544)	**(120,513,028)**
			Pro Forma Amort =	**(4,834,295)**		

PacifiCorp
Oregon General Rate Case - December 2014
Regulatory Asset Amortization
Oregon Grid West Loan - Account 187081

This regulatory asset should not affect results of operations since it is being collected through an Oregon tariff rider.
Remove costs charged to expense in unadjusted results when the GRID West - Oregon was amortized:

Year	Period	Account	Text	RefDoc.No.	FERC Acct	Locatn	Allocator	Amount	Pstng Date
2011	007	550785	Rev OR RTO Grid West NR est amor - Jun 11	121416083	9040000	000108	OR	(30,000)	07/20/2011
2011	007	550785	OR RTO Grid West NR est amort - July 11	121416083	9040000	000108	OR	30,000	07/20/2011
2011	007	550785	OR RTO Grid West NR actual amort - Jun 11	121416083	9040000	000108	OR	29,693	07/20/2011
2011	008	550785	Rev OR RTO Grid West NR est amor - July 11	121499222	9040000	000108	OR	(30,000)	08/16/2011
2011	008	550785	OR RTO Grid West NR est amort - Aug 11	121499222	9040000	000108	OR	29,000	08/16/2011
2011	008	550785	OR RTO Grid West NR actual amort - July 11	121499222	9040000	000108	OR	30,121	08/16/2011
2011	009	550785	Rev OR RTO Grid West NR est amor - Aug 11	121592691	9040000	000108	OR	(29,000)	09/21/2011
2011	009	550785	OR RTO Grid West NR est amort - Sep 11	121592691	9040000	000108	OR	30,000	09/21/2011
2011	009	550785	OR RTO Grid West NR actual amort - Aug 11	121592691	9040000	000108	OR	31,866	09/21/2011
2011	010	550785	Rev OR RTO Grid West NR est amor - Sept 11	121888660	9040000	000108	OR	(30,000)	10/17/2011
2011	010	550785	OR RTO Grid West NR est amort - Oct 11	121888660	9040000	000108	OR	32,000	10/17/2011
2011	010	550785	OR RTO Grid West NR actual amort - Sept 11	121888660	9040000	000108	OR	32,369	10/17/2011
2011	011	550785	OR RTO Grid West NR rev est amor - Oct 11	121985745	9040000	000108	OR	(32,000)	11/15/2011
2011	011	550785	OR RTO Grid West NR est amort - Nov 11	121985745	9040000	000108	OR	31,000	11/15/2011
2011	011	550785	OR RTO Grid West NR actual amort - Oct 11	121985745	9040000	000108	OR	29,060	11/15/2011
2011	012	550785	OR RTO Grid West NR rev est amor - Nov 11	122089445	9040000	000108	OR	(31,000)	12/19/2011
2011	012	550785	OR RTO Grid West NR est amort - Dec 11	122089445	9040000	000108	OR	32,500	12/19/2011
2011	012	550785	OR RTO Grid West NR actual amort - Nov 11	122089445	9040000	000108	OR	31,231	12/19/2011
2012	001	550785	OR RTO Grid West NR rev est amor - Nov 11	122371463	9040000	000108	OR	(32,500)	01/12/2012
2012	001	550785	OR RTO Grid West NR est amort - Dec 11	122371463	9040000	000108	OR	37,500	01/12/2012
2012	001	550785	OR RTO Grid West NR actual amort - Nov 11	122371463	9040000	000108	OR	38,303	01/12/2012
2012	002	550785	OR RTO Grid West NR rev est amor - Jan 12	122446544	9040000	000108	OR	(37,500)	02/08/2012
2012	002	550785	OR RTO Grid West NR est amort - Feb 12	122446544	9040000	000108	OR	38,500	02/08/2012
2012	002	550785	OR RTO Grid West NR actual amort - Jan 12	122446544	9040000	000108	OR	38,928	02/08/2012
2012	003	550785	OR RTO Grid West NR rev est amor - Feb 12	122531922	9040000	000108	OR	(38,500)	03/12/2012
2012	003	550785	OR RTO Grid West NR est amort - Mar 12	122531922	9040000	000108	OR	35,000	03/12/2012
2012	003	550785	OR RTO Grid West NR actual amort - Feb 12	122531922	9040000	000108	OR	34,319	03/12/2012
2012	004	550785	OR RTO Grid West NR rev est amor - Mar	122830943	9040000	000108	OR	(35,000)	04/17/2012
2012	004	550785	OR RTO Grid West NR est amort - Apr	122830943	9040000	000108	OR	34,000	04/17/2012
2012	004	550785	OR RTO Grid West NR actual amort - Mar	122830943	9040000	000108	OR	33,370	04/17/2012
2012	005	550785	OR RTO Grid West NR rev est amor - Apr 12	122891719	9040000	000108	OR	(34,000)	05/11/2012
2012	005	550785	OR RTO Grid West NR est amort - May 12	122891719	9040000	000108	OR	32,000	05/11/2012
2012	005	550785	OR RTO Grid West NR actual amort - Apr 12	122891719	9040000	000108	OR	31,886	05/11/2012
2012	006	550785	OR RTO Grid West NR rev est amor - May 12	122967441	9040000	000108	OR	(32,000)	06/13/2012
2012	006	550785	OR RTO Grid West NR est amort - Jun 12	122967441	9040000	000108	OR	29,000	06/13/2012
2012	006	550785	OR RTO Grid West NR actual amort - May 12	122967441	9040000	000108	OR	28,525	06/13/2012
								388,671	
								Ref 8.9	

PacifiCorp
Oregon General Rate Case - December 2014
Regulatory Asset Amortization
MEHC Transition Plan - Account 187214

This Regulatory asset should not affect pro forma results of operations since it expires September, 2012.

Amortization charged to results in 12 months ended June 2012 (allocated situs to Oregon)	**1,909,702**
	Ref 8.9

PacifiCorp
Oregon General Rate Case - December 2014
Regulatory Asset Amortization
Oregon Indpendent Evaluator Fees - Account 187957

This Regulatory asset should not affect results of operations since it is being collected through an Oregon Tariff Rider.
Remove Costs charged to expense in unadjusted results when the Oregon Independent Evaluator Fees were amortized:

Year	Period	Account	RefDoc.No.	FERC Acct	Locatn	Allocator	Text	Amount	Pstng Date
2011	007	530055	121460973	5570000	000001	SG	OR Independent Evaluator actual amor - June 11	38,228	07/31/2011
2011	008	530055	121555351	5570000	000001	SG	OR Independent Evaluator actual amor - July 11	153	08/31/2011
								38,381	
								Ref 8.9	

PacifiCorp
Oregon General Rate Case - December 2014
Klamath Hydroelectric Settlement Agreement

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Operation & Maintenance	537	3	253,380	SG-P	26.053%	66,013	8.10.1
Adjustment to Rate Base:							
Existing Klamath	332	3	109,470	SG-P	26.053%	28,520	8.10.2
Relicensing & Settlement Process Costs	302	3	-	SG-P	26.053%	-	8.10.3
Adjustment to Depreciation Expense:							
Existing Klamath	403HP	3	137,256	SG-P	26.053%	35,759	8.10.2
Relicensing & Settlement Process Costs	404IP	3	-	SG-P	26.053%	-	8.10.3
Adjustment to Depreciation Reserve:							
Existing Klamath	108HP	3	(9,679,701)	SG-P	26.053%	(2,521,853)	8.10.2
Relicensing & Settlement Process Costs	111IP	3	(12,409,355)	SG-P	26.053%	(3,233,009)	8.10.3

Description of Adjustment:

This adjustment accounts for the total test period costs related to the Klamath Hydroelectric Settlement Agreement (KHSA). Depreciation of existing Klamath facilities is accelerated so that assets are fully depreciated by December 31, 2019. Relicensing and settlement process costs are also amortized at a rate that will achieve a zero net book value by December 31, 2019. This treatment was approved in Docket UE-219.

PacifiCorp
Oregon General Rate Case - December 2014
Klamath Hydroelectric Settlement Agreement
O&M

	12 Months Ended June 2012 Actuals	12 Months Ended Dec 14 Forecast	Increase to Test Period	Inflation*	Adjustment	
	(A)	(B)	(C = B - A)	(D)	(E = C - D)	
Administration/Management	534,802	620,719	85,917	17,578	68,339	
Aquatic Habitat/Hatcheries	1,947,453	2,098,641	151,188	64,010	87,179	
Terrestrial Improvements	165,128	35,615	(129,513)	5,427	(134,940)	
Water Measurement/Monitoring	480,876	548,436	67,559	15,806	51,754	
Water Quality Improvement	364,696	557,731	193,035	11,987	181,048	
Klamath Implementation Total	3,492,955	3,861,142	368,187	114,808	**253,380**	**Ref 8.10**

** Inflation is included in Adjustment 4.12*
The escalation factor used in this adjustment is an average based on operations and maintenance FERC account balances at June 2012.
Hydro average: 3.287%

PacifiCorp
Oregon General Rate Case - December 2014
Klamath Hydroelectric Settlement Agreement

Existing Klamath:	June 2012	Y/E	
Gross EPIS	86,740,594	86,740,594	(A)
Depreciation Reserve	(37,423,279)	(37,423,279)	(B)
Depreciation Expense	6,318,364 (C)		

	Capital Additions	EPIS Balance		Depreciation Expense		Depreciation Reserve	
				7.433%	(D)		
Jun-12		86,740,594	(A)			(37,423,279)	(B)
Jul-12	-	86,740,594		537,290		(37,960,569)	
Aug-12	-	86,740,594		537,290		(38,497,859)	
Sep-12	-	86,740,594		537,290		(39,035,149)	
Oct-12	-	86,740,594		537,290		(39,572,440)	
Nov-12	-	86,740,594		537,290		(40,109,730)	
Dec-12	109,470	86,850,064		537,629		(40,647,359)	
Jan-13	-	86,850,064		537,968		(41,185,328)	
Feb-13	-	86,850,064		537,968		(41,723,296)	
Mar-13	-	86,850,064		537,968		(42,261,264)	
Apr-13	-	86,850,064		537,968		(42,799,233)	
May-13	-	86,850,064		537,968		(43,337,201)	
Jun-13	-	86,850,064		537,968		(43,875,169)	
Jul-13	-	86,850,064		537,968		(44,413,138)	
Aug-13	-	86,850,064		537,968		(44,951,106)	
Sep-13	-	86,850,064		537,968		(45,489,074)	
Oct-13	-	86,850,064		537,968		(46,027,043)	
Nov-13	-	86,850,064		537,968		(46,565,011)	
Dec-13	-	86,850,064		537,968		(47,102,979)	
	109,470	86,850,064	(E)	6,455,620	(F)	(47,102,979)	(G)
		Year End		12 Months Ending Dec.13		Year End	
				6,455,620	(H = D * E)	-	(I = F - H)
				Annualized Dec.13		Incremental Reserve	
						(47,102,979)	(J = G + I)
						Adjusted Reserve	
	Adjustments:	**109,470**	(K = E - A)	**137,256**	(L = H - C)	**(9,679,701)**	(M = J - B)
		Ref. 8.10		**Ref. 8.10**		**Ref. 8.10**	

Projects related to Klamath Implementation:

Project	RP Factor	In-Service	Amount (July12-Dec13)
IKL IM4 IG Hatchery Bogus Creek Weir Installation	SG-P	Dec-12	109,470

PacifiCorp
Oregon General Rate Case - December 2014
Klamath Hydroelectric Settlement Agreement

	June 2012	Y/E	
Gross EPIS	74,111,750	74,111,750	(A)
Amortization Reserve	(12,409,680)	(12,409,680)	(B)
Amortization Expense	8,272,903	(C)	

	EPIS Balance		Depreciation Expense		Depreciation Reserve	
			11.163%	(D)		
Jun-12	74,111,750	(A)			(12,409,680)	(B)
Jul-12	74,111,750		689,409		(13,099,089)	
Aug-12	74,111,750		689,409		(13,788,497)	
Sep-12	74,111,750		689,409		(14,477,906)	
Oct-12	74,111,750		689,409		(15,167,314)	
Nov-12	74,111,750		689,409		(15,856,723)	
Dec-12	74,111,750		689,409		(16,546,132)	
Jan-13	74,111,750		689,409		(17,235,540)	
Feb-13	74,111,750		689,409		(17,924,949)	
Mar-13	74,111,750		689,409		(18,614,357)	
Apr-13	74,111,750		689,409		(19,303,766)	
May-13	74,111,750		689,409		(19,993,175)	
Jun-13	74,111,750		689,409		(20,682,583)	
Jul-13	74,111,750		689,409		(21,371,992)	
Aug-13	74,111,750		689,409		(22,061,400)	
Sep-13	74,111,750		689,409		(22,750,809)	
Oct-13	74,111,750		689,409		(23,440,218)	
Nov-13	74,111,750		689,409		(24,129,626)	
Dec-13	74,111,750		689,409		(24,819,035)	
	74,111,750	(E)	8,272,903	(F)	(24,819,035)	(G)
	Year End		Year End Dec.13		Year End	
			8,272,903	(H = D * E)	-	(I = F - H)
			Annualized Dec.13		Incremental Reserve	
					(24,819,035)	(J = G + I)
					Adjusted Reserve	
Adjustments:	-	(K = E - A)	**0**	(L = H - C)	**(12,409,355)**	(M = J - B)
	Ref. 8.10		**Ref. 8.10**		**Ref. 8.10**	

PacifiCorp
Oregon General Rate Case - December 2014
Miscellaneous Asset Sales and Removals

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Remove Deseret Power Electric Plant	314	1	(7,928,886)	SG	26.053%	(2,065,713)	8.11.1
Remove Condit EPIS - Hydro	332	1	(1,151,080)	SG-P	26.053%	(299,891)	8.11.1
Remove Condit EPIS - Trans	353	1	(923,102)	SG	26.053%	(240,496)	8.11.1
			(2,074,181)			(540,387)	
Adjustment to Depreciation Reserve:							
Remove Deseret Power Dep. Res.	108SP	1	287,234	SG	26.053%	74,833	8.11.1
Remove Condit Dep. Res. - Hydro	108HP	1	1,000,642	SG-P	26.053%	260,697	
Remove Condit Dep. Res. - Trans	108TP	1	478,629	SG	26.053%	124,697	
			1,479,271			385,394	8.11.1
Adjustment to Expense:							
Remove Snake Creek O&M Exp	539	1	(32,582)	SG-U	26.053%	(8,488)	8.11.1
Remove Condit O&M Exp	539	1	(77,947)	SG-P	26.053%	(20,308)	8.11.1

Description of Adjustment:

This adjusts the Company's filing for various assets that were sold or removed, including the sale of Snake Creek hydroelectric plant to Heber Light and Power Company, the removal of Deseret Power's portion of the Hunter unit 2 scrubber and turbine upgrade, the decommissioning of the Condit hydroelectric plant, and the removal of the Goose Creek switching station.

PacifiCorp
Oregon General Rate Case - December 2014
Miscellaneous Asset Sales and Removals

	June 2012 Year-End Balance	Adjustment	
Deseret Power - Hunter Projects			
EPIS - 314	7,928,886	**(7,928,886)**	**Ref. 8.11**
Depreciation Reserve	(287,234)	**287,234**	**Ref. 8.11**
Condit Hydroelectric Project			
EPIS - Hydro	1,151,080	**(1,151,080)**	**Ref. 8.11**
EPIS - Trans	923,102	**(923,102)**	**Ref. 8.11**
Dep. Res. - Hydro	(1,000,642)	**1,000,642**	**Ref. 8.11**
Dep. Res. - Trans	(478,629)	**478,629**	**Ref. 8.11**

	12 ME June 2012	Adjustment	
Snake Creek			
O&M Expense	26,287	(26,287)	
	7,050	(7,050)	
	(63)	63	
	(691)	691	
	32,582	**(32,582)**	**Ref. 8.11**
Condit Hydroelectric Project			
O&M Expense	6,187	(6,187)	
	50,547	(50,547)	
	9,000	(9,000)	
	2,857	(2,857)	
	1,231	(1,231)	
	8,124	(8,124)	
	77,947	**(77,947)**	**Ref. 8.11**

PacifiCorp
Oregon General Rate Case - December 2014
Remove Rolling Hills

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Plant	341	1	(3,100,293)	SG	26.053%	(807,719)	
Other Plant	343	1	(178,882,663)	SG	26.053%	(46,604,303)	
Other Plant	344	1	(5,850,373)	SG	26.053%	(1,524,198)	
Other Plant	345	1	(12,211,951)	SG	26.053%	(3,181,580)	
Other Plant	346	1	(659,497)	SG	26.053%	(171,819)	
General Plant	391	1	(8,713)	SG	26.053%	(2,270)	
			(200,713,490)			(52,291,889)	8.12.1
Adjustment to Depreciation Reserve:							
Other Plant	108OP	1	24,305,809	SG	26.053%	6,332,393	
General Plant	108GP	1	239	SG	26.053%	62	
			24,306,048			6,332,455	8.12.1
Adjustment to O&M Expense:							
Rolling Hills	549	1	(153,882)	SG	26.053%	(40,091)	
Rolling Hills	929	1	(1,237,510)	SO	27.384%	(338,883)	
			(1,391,392)			(378,974)	8.12.1
Adjustment to Tax:							
Schedule M Deduction	SCHMDT	1	(8,197,227)	TAXDEPR	26.398%	(2,163,876)	
Deferred Tax Expense	41010	1	(3,110,930)	TAXDEPR	26.398%	(821,213)	
Deferred Tax Expense	41110	1	3,628	OR	100.000%	3,628	
Deferred Tax Balance	282	1	16,814,826	OR	100.000%	16,814,826	

Description of Adjustment:

This adjustment removes the gross plant, accumulated depreciation, and O&M expense related to the Rolling Hills wind resource from the 12 months ended June 2012 results. Depreciation expense is removed in the depreciation expense adjustment no. 6.1. This treatment is consistent with Commission Order No. 08-548.

PacifiCorp
Oregon General Rate Case - December 2014
Rolling Hills Wind Resource Removal

Rate Base Amounts	Balance at June 2012	Ref.
Capital		
Other Plant - 341	3,100,293	
Other Plant - 343	178,882,663	
Other Plant - 344	5,850,373	
Other Plant - 345	12,211,951	
Other Plant - 346	659,497	
General Plant - 391	8,713	
	200,713,490	**8.12**
Depreciation Reserve		
Other Plant	(24,305,809)	
General Plant	(239)	
	(24,306,048)	**8.12**

Expense Amounts	Amount in 12 Months Ended June 2012	Ref.
Operation & Maintenance Expense		
Account 549	153,882	
Account 929	1,237,510	
	1,391,392	**8.12**

PacifiCorp
Oregon General Rate Case - December 2014
FERC 105 (PHFU)

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Remove PHFU	105	1	(11,919,938)	SG	26.053%	(3,105,502)	
Remove PHFU	105	1	(3,009,062)	UT	0.000%	-	
Remove PHFU	105	1	(4,254,106)	OR	100.000%	(4,254,106)	
Remove PHFU	105	1	(26,313,198)	SE	24.687%	(6,495,869)	
Remove PHFU	105	1	(682,262)	CA	0.000%	-	
			(46,178,566)			(13,855,477)	8.13.1

Description of Adjustment:

This adjustment removes all Plant Held for Future Use (PHFU) assets from FERC account 105. The company is making this adjustment in compliance with UE 116, Order No. 01-787, Appendix A, page 4 of 5.

PacifiCorp
Oregon General Rate Case - December 2014
FERC 105 (PHFU)
From BW Report (SAP)

Primary Account		Secondary Account		Alloc	Balance at June 2012 ($000s)
1050000	EL PLT HLD FTR USE	3401000	LAND OWNED IN FEE	SG	8,923
1050000	EL PLT HLD FTR USE	3501000	LAND OWNED IN FEE	SG	2,841
1050000	EL PLT HLD FTR USE	3502000	LAND RIGHTS	SG	156
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	UT	3,009
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	OR	746
1050000	EL PLT HLD FTR USE	3891000	LAND OWNED IN FEE	OR	3,508
1050000	EL PLT HLD FTR USE-O	3992200	LAND RIGHTS	SE	953
1059000	EL PLT HLD FTR USE-O	0	ELECTRIC PLANT HELD FOR FUTURE USE-OTHER	SE	25,360
1059000	EL PLT HLD FTR USE-O	3601000	ELECTRIC PLANT HELD FOR FUTURE USE-OTHER	CA	682
Total (000's)					**46,179**

SG	11,919,938	
UT	3,009,062	
OR	4,254,106	
SE	26,313,198	
CA	682,262	
Total	**46,178,566**	**Ref. 8.13.1**

PacifiCorp
Oregon General Rate Case - December 2014
Carbon Plant Closure

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Carbon Plant	312	3	1,286,070	SG	26.053%	335,060	8.14.1
Adjustment to Depreciation Expense:							
Carbon Plant	403SP	3	40,390,718	SG	26.053%	10,522,994	8.14.1
Adjustment to Depreciation Reserve:							
Carbon Plant	108SP	3	(52,320,444)	SG	26.053%	(13,631,046)	8.14.1

Description of Adjustment:

This adjustment includes accelerated depreciation for the Carbon plant. Depreciation of the Carbon plant is accelerated so that assets are fully depreciated by April 2015. The Carbon plant is depreciated using approved rates through December 31, 2012, but the annualized level of depreciation included in this adjustment uses the accelerated rate.

The Company currently anticipates that the Carbon plant will discontinue operations as early as April 2015. Compliance with recently promulgated EPA mercury and air toxics standards (MATS) will likely require significant investment in emissions control equipment for the Carbon units. Such emissions control equipment is likely uneconomical to retrofit at Carbon. Alternatives to such emissions control equipment at the Carbon plant, such as conversion of the units to natural gas, will also likely not be economic for customers. Nonetheless, the Company continues to evaluate compliance options and transmission system impacts that will ultimately contribute to the Company's decision-making process regarding this facility.

It is important to note that the MATS regulations currently include provisions for requesting extension of compliance deadlines under certain system reliability and compliance project timing scenarios. There is also the potential that the MATS regulations driving an accelerated plant closure may be subject to a series of delays from appeals, thereby prolonging the closure.

PacifiCorp
Oregon General Rate Case - December 2014
Carbon Plant Closure

Base Year Ended June 2012

Carbon Plant Steam Plant:	Actuals: June12 YE	
Gross EPIS*	120,165,643	(A)
Depreciation Reserve	(65,822,540)	(B)
Depreciation Reserve Adjusted**	(71,595,946)	(C)
Depreciation Expense	3,632,357	(D)

*The balance does not include land as land is not depreciated. The balance also does not include general or transmission assets.
**The adjusted balance includes the increase in reserve to account for the different depreciation rates Oregon is using for the coal-fired generating plants.

Test Year Ending December 2014

	Capital Additions	EPIS Balance		Depreciation Expense*** 4.20% 36.95%		Depreciation Reserve	
Jun-12		120,165,643	(A)			(71,595,946)	(C)
Jul-12	-	120,165,643		420,660		(72,016,607)	
Aug-12	-	120,165,643		420,660		(72,437,267)	
Sep-12	-	120,165,643		420,660		(72,857,928)	
Oct-12	-	120,165,643		420,660		(73,278,588)	
Nov-12	-	120,165,643		420,660		(73,699,249)	
Dec-12	-	120,165,643		420,660		(74,119,909)	
Jan-13	-	120,165,643		3,700,578		(77,820,487)	
Feb-13	-	120,165,643		3,700,578		(81,521,066)	
Mar-13	-	120,165,643		3,700,578		(85,221,644)	
Apr-13	-	120,165,643		3,700,578		(88,922,222)	
May-13	-	120,165,643		3,700,578		(92,622,800)	
Jun-13	687,403	120,853,046		3,711,163		(96,333,963)	
Jul-13	-	120,853,046		3,721,747		(100,055,710)	
Aug-13	-	120,853,046		3,721,747		(103,777,457)	
Sep-13	-	120,853,046		3,721,747		(107,499,205)	
Oct-13	-	120,853,046		3,721,747		(111,220,952)	
Nov-13	598,667	121,451,714		3,730,965		(114,951,917)	
Dec-13	-	121,451,714		3,740,184		(118,692,101)	
	1,286,070	121,451,714	(E)	44,572,192	(F)	(118,692,101)	(G)
		Y/E Dec.2013				Y/E Dec.2013	
		Annualized Dec.13 Using the Proposed Rate**** 36.247% (H)		44,023,075	(I = E * H)	549,117 Incremental Reserve	(J = F - I)
						(118,142,984) Adjusted Reserve	(K = G + J)
Adjustments:		**1,286,070** Ref. 8.14	(L = E - A)	**40,390,718** Ref. 8.14	(M = I - D)	**(52,320,444)** Ref. 8.14	(N = K - B)

***4.20% is the Carbon composite rate used through December 2012. The accelerated depreciation rate is 36.95% starting in January 2013.
****The proposed Carbon accelerated composite rate from the filed depreciation study.

Carbon Plant Projects:

Project	Factor	In-Service	Amount (12 Months Ending Dec 2013)
U2 Burner Tips And Nozzles (CY 2012 & 2013)	SG	Nov-13	486,700
U1 Burner Tips & Nozzles (CY 2013)	SG	Jun-13	364,966
U1 I.D. Fan Blade Replacement CY 2012	SG	Jun-13	322,437
U2 Coal Mill Blast Gate Drives CY 2011	SG	Nov-13	111,967
			1,286,070

PacifiCorp
Oregon General Rate Case - December 2014
Pension and Other Postretirement Welfare Plan Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Net Prepaid Balance	182M	3	176,486,001	SO	27.384%	48,329,378	Conf. Ex. PAC/901

Description of Adjustment:

This adjustment adds into rate base the company's pension and other postretirement welfare balance, net of the accumulated deferred income tax liability. Adding this balance to rate base would compensate the company for its required investments in its employee's pension benefits. The contributions for financial and regulatory purposes are recognized under Generally Accepted Accounting Principles (GAAP) Accounting Standards Code 715.

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	DECEMBER 2014
FILE:	OR JAM Dec 2014 GRC
PREPARED BY:	Revenue Requirement Department
DATE:	2/12/2013
TIME:	5:46:53 PM
TYPE OF RATE BASE:	Year End
ALLOCATION METHOD:	**REVISED PROTOCOL**
FERC JURISDICTION:	Separate Jurisdiction
8 OR 12 CP:	12 Coincidental Peaks
DEMAND %	75% Demand
ENERGY %	25% Energy

TAX INFORMATION

TAX RATE ASSUMPTIONS:	TAX RATE
FEDERAL RATE	35.00%
STATE EFFECTIVE RATE	4.54%
TAX GROSS UP FACTOR	1.661
FEDERAL/STATE COMBINED RATE	37.951%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	47.60%	5.322%	2.533%
PREFERRED	0.30%	5.427%	0.016%
COMMON	52.10%	9.800%	5.106%
	100.00%		7.655%

OTHER INFORMATION

The stipulated capital structure and cost of capital from UE-246 was used to develop the results and subsequent revenue requirement for this case.

REVISED PROTOCOL
Year End

RESULTS OF OPERATIONS SUMMARY

			JUNE 2012 UNADJUSTED RESULTS		DECEMBER 2014 PRO FORMA RESULTS	
	Description of Account Summary:	**Ref**	**TOTAL**	**OREGON**	**TOTAL**	**OREGON**
1	Operating Revenues					
2	General Business Revenues	2.3	4,092,063,041	1,128,512,328	4,462,720,886	1,209,176,480
3	Interdepartmental	2.3	0	0	0	0
4	Special Sales	2.3	339,615,342	86,880,114	482,210,526	124,030,465
5	Other Operating Revenues	2.4	249,987,732	56,503,728	172,625,748	39,568,176
6	Total Operating Revenues	2.4	4,681,666,114	1,271,896,170	5,117,557,160	1,372,775,121
7						
8	Operating Expenses:					
9	Steam Production	2.5	1,033,981,927	259,906,153	1,179,365,066	296,259,705
10	Nuclear Production	2.6	0	0	0	0
11	Hydro Production	2.7	38,494,364	10,028,937	42,694,317	11,123,151
12	Other Power Supply	2.9	958,605,486	225,890,622	1,085,961,655	275,459,232
13	Embedded Cost Differential (ECD)		0	(12,204,362)	0	(9,334,603)
14	Transmission	2.10	205,329,189	53,364,883	205,984,992	53,595,523
15	Distribution	2.12	208,601,621	65,912,168	217,864,397	71,951,511
16	Customer Accounting	2.12	94,659,859	35,169,515	97,119,698	35,929,744
17	Customer Service & Infor	2.13	109,993,566	27,253,445	18,895,566	4,067,911
18	Sales	2.13	0	0	0	0
19	Administrative & General	2.14	152,548,405	47,503,730	141,901,957	47,675,501
20						
21	Total O & M Expenses	2.14	2,802,214,417	712,825,090	2,989,787,648	786,727,676
22						
23	Depreciation	2.16	549,502,550	154,138,355	779,010,766	211,352,416
24	Amortization	2.17	52,427,146	14,069,820	54,063,663	14,534,328
25	Taxes Other Than Income	2.17	157,778,830	62,066,641	173,216,287	67,548,825
26	Income Taxes - Federal	2.20	(117,200,405)	(13,907,517)	71,410,691	17,968,841
27	Income Taxes - State	2.20	(6,488,594)	568,732	18,253,834	4,669,245
28	Income Taxes - Def Net	2.19	368,714,954	93,484,394	169,493,895	44,244,472
29	Investment Tax Credit Adj.	2.17	(1,862,752)	0	(1,862,752)	0
30	Misc Revenue & Expense	2.4	(764,772)	(188,103)	(364,815)	(90,211)
31						
32	Total Operating Expenses	2.20	3,804,321,374	1,023,057,412	4,253,009,219	1,146,955,592
33						
34	Operating Revenue for Return		877,344,740	248,838,758	864,547,942	225,819,529
35						
36	Rate Base:					
37	Electric Plant in Service	2.30	23,253,605,964	6,376,458,720	24,416,813,071	6,691,438,966
38	Plant Held for Future Use	2.31	46,178,566	13,855,477	0	0
39	Misc Deferred Debits	2.33	281,108,847	23,476,751	465,228,507	73,909,238
40	Elec Plant Acq Adj	2.31	49,044,288	12,777,509	38,662,480	10,072,737
41	Nuclear Fuel	2.31	0	0	0	0
42	Prepayments	2.32	26,323,174	7,200,322	26,323,174	7,200,322
43	Fuel Stock	2.32	264,151,338	65,267,018	244,953,638	60,531,544
44	Material & Supplies	2.32	200,372,004	58,651,779	200,372,004	58,651,779
45	Working Capital	2.33	83,827,698	26,857,088	89,716,067	29,027,951
46	Weatherization Loans	2.31	(5,877,664)	(1,220)	(5,877,664)	(1,220)
47	Miscellaneous Rate Base	2.34	0	0	0	0
48						
49	Total Electric Plant		24,198,734,214	6,584,543,444	25,476,191,276	6,930,831,316
50						
51	Rate Base Deductions:					
52	Accum Prov For Depr	2.38	(7,170,108,718)	(2,109,083,656)	(8,071,766,363)	(2,361,714,700)
53	Accum Prov For Amort	2.39	(501,645,416)	(140,247,499)	(544,774,074)	(152,183,040)
54	Accum Def Income Taxes	2.35	(3,458,822,902)	(913,606,365)	(3,812,324,071)	(1,014,598,099)
55	Unamortized ITC	2.35	(3,233,092)	(1,997,073)	(1,084,972)	(593,249)
56	Customer Adv for Const	2.34	(22,790,686)	(6,632,669)	(22,790,686)	(5,758,640)
57	Customer Service Deposits	2.34	0	0	0	0
58	Misc. Rate Base Deductions	2.34	(62,558,327)	(8,046,858)	(62,680,062)	(8,076,910)
59						
60	Total Rate Base Deductions		(11,219,159,141)	(3,179,614,121)	(12,515,420,228)	(3,542,924,638)
61						
62	Total Rate Base		12,979,575,072	3,404,929,323	12,960,771,048	3,387,906,678
63						
64	Return on Rate Base		6.759%	7.308%	6.670%	6.665%
65						
66	Return on Equity		8.080%	9.134%	7.910%	7.900%
67	Net Power Costs		1,393,001,321	348,176,354	1,457,051,989	363,448,388
68	100 Basis Points in Equity:					
69	Revenue Requirement Impact		108,984,168	28,589,795	108,826,278	28,446,863
70	Rate Base Decrease		(928,841,092)	(226,583,825)	(938,964,587)	(245,614,619)

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
Sales to Ultimate Customers								
440	Residential Sales							
		0	S		1,538,606,880	548,352,337	1,680,851,141	583,299,297
				B1	1,538,606,880	548,352,337	1,680,851,141	583,299,297
442	Commercial & Industrial Sales							
		0	S		2,514,992,419	573,646,675	2,747,001,471	621,158,232
		P	SE		-	-	-	-
		PT	SG		-	-	-	-
				B1	2,514,992,419	573,646,675	2,747,001,471	621,158,232
444	Public Street & Highway Lighting							
		0	S		20,929,527	6,513,316	18,254,607	4,718,952
		0	SO		-	-	-	-
				B1	20,929,527	6,513,316	18,254,607	4,718,952
445	Other Sales to Public Authority							
		0	S		17,534,215	-	16,613,667	-
				B1	17,534,215	-	16,613,667	-
448	Interdepartmental							
		DPW	S		-	-	-	-
		GP	SO		-	-	-	-
				B1	-	-	-	-
Total Sales to Ultimate Customers				**B1**	**4,092,063,041**	**1,128,512,328**	**4,462,720,886**	**1,209,176,480**
447	Sales for Resale-Non NPC							
		P	S		10,074,303	1,024,807	10,074,303	1,024,807
					10,074,303	1,024,807	10,074,303	1,024,807
447NPC	Sales for Resale-NPC							
		P	SG		329,539,169	85,854,845	472,136,224	123,005,658
		P	SE		1,870	462	-	-
		P	SG		-	-	-	-
					329,541,039	85,855,307	472,136,224	123,005,658
	Total Sales for Resale			B1	339,615,342	86,880,114	482,210,526	124,030,465
449	Provision for Rate Refund							
		P	S		-	-	-	-
		P	SG		-	-	-	-
				B1	-	-	-	-
Total Sales from Electricity				**B1**	**4,431,678,382**	**1,215,392,442**	**4,944,931,412**	**1,333,206,945**
450	Forfeited Discounts & Interest							
		CUST	S		8,704,074	3,713,451	8,704,074	3,713,451
		CUST	SO		-	-	-	-
				B1	8,704,074	3,713,451	8,704,074	3,713,451
451	Misc Electric Revenue							
		CUST	S		6,239,419	1,449,104	6,239,419	1,449,104
		CUST	SG		-	-	-	-
		CUST	SO		4,129	1,132	4,129	1,132
				B1	6,243,548	1,450,236	6,243,548	1,450,236
453	Water Sales							
		P	SG		12,096	3,151	12,096	3,151
				B1	12,096	3,151	12,096	3,151
454	Rent of Electric Property							
		DPW	S		10,740,536	5,032,337	10,740,536	5,032,337
		T	SG		5,635,964	1,468,338	5,635,964	1,468,338
		GP	SO		3,624,836	993,388	3,624,836	993,388
				B1	20,001,336	7,494,063	20,001,336	7,494,063

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Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
456	Other Electric Revenue							
		DMSC	S		85,315,923	10,204,815	33,788,726	-
		CUST	CN		-	-	-	-
		OTHSE	SE		11,357,475	2,803,790	11,357,475	2,803,790
		OTHSO	SO		(26,572)	(7,282)	(26,572)	(7,282)
		OTHSGR	SG		118,379,851	30,841,505	92,545,065	24,110,767
				B1	215,026,677	43,842,827	137,664,694	26,907,275
Total Other Electric Revenues				**B1**	**249,987,732**	**56,503,728**	**172,625,748**	**39,568,176**
Total Electric Operating Revenues				**B1**	**4,681,666,114**	**1,271,896,170**	**5,117,557,160**	**1,372,775,121**
Summary of Revenues by Factor								
	S				4,213,137,296	1,149,936,843	4,532,267,943	1,220,396,180
	CN				-	-	-	-
	SE				11,359,345	2,804,251	11,357,475	2,803,790
	SO				3,602,393	987,237	3,602,393	987,237
	SG				453,567,081	118,167,839	570,329,349	148,587,915
	DGP				-	-	-	-
Total Electric Operating Revenues					4,681,666,114	1,271,896,170	5,117,557,160	1,372,775,121
Miscellaneous Revenues								
41160	Gain on Sale of Utility Plant - CR							
		DPW	S		-	-	-	-
		T	SG		-	-	-	-
		G	SO		-	-	-	-
		T	SG		-	-	-	-
		P	SG		-	-	-	-
				B1	-	-	-	-
41170	Loss on Sale of Utility Plant							
		DPW	S		-	-	-	-
		T	SG		-	-	-	-
				B1	-	-	-	-
4118	Gain from Emission Allowances							
		P	S		-	-	-	-
		P	SE		(1,814)	(448)	(206,119)	(50,884)
				B1	(1,814)	(448)	(206,119)	(50,884)
41181	Gain from Disposition of NOX Credits							
		P	SE		-	-	-	-
				B1	-	-	-	-
4194	Impact Housing Interest Income							
		P	SG		-	-	-	-
				B1	-	-	-	-
421	(Gain) / Loss on Sale of Utility Plant							
		DPW	S		(4,903)	11,947	(5,126)	165
		T	SG		-	-	-	-
		T	SG		(26,947)	(7,020)	(26,947)	(7,020)
		CUST	CN		-	-	-	-
		PTD	SO		(155,792)	(42,695)	38,278	10,490
		P	SG		(575,317)	(149,887)	(164,901)	(42,962)
				B1	(762,958)	(187,656)	(158,696)	(39,327)
Total Miscellaneous Revenues					**(764,772)**	**(188,103)**	**(364,815)**	**(90,211)**
Miscellaneous Expenses								
4311	Interest on Customer Deposits							
		CUST	S		-	-	-	-
				B1	-	-	-	-
Total Miscellaneous Expenses					-	-	-	-
Net Misc Revenue and Expense				**B1**	**(764,772)**	**(188,103)**	**(364,815)**	**(90,211)**

REVISED PROTOCOL

Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
500	Operation Supervision & Engineering							
		P	SG		17,858,424	4,652,656	16,479,062	4,293,290
		P	SSGCH		2,065,704	555,919	2,162,093	581,859
				B2	19,924,129	5,208,574	18,641,155	4,875,149
501	Fuel Related-Non NPC							
		P	SE		16,121,513	3,979,875	16,760,530	4,137,627
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SSECT		-	-	-	-
		P	SSECH		3,257,603	822,451	3,409,608	860,827
				B2	19,379,116	4,802,325	20,170,138	4,998,455
501NPC	Fuel Related-NPC							
		P	S		659,235	-	-	-
		P	SE		642,970,169	158,728,328	764,151,498	188,644,039
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SSECT		-	-	-	-
		P	SSECH		53,938,291	13,617,860	59,706,693	15,074,215
				B2	697,567,695	172,346,188	823,858,191	203,718,254
	Total Fuel Related				716,946,810	177,148,513	844,028,329	208,716,709
502	Steam Expenses							
		P	SG		29,033,421	7,564,078	30,372,100	7,912,844
		P	SSGCH		8,911,067	2,398,130	9,326,871	2,510,031
				B2	37,944,489	9,962,208	39,698,972	10,422,875
503	Steam From Other Sources-Non-NPC							
		P	SE		-	-	(109)	(27)
				B2	-	-	(109)	(27)
503NPC	Steam From Other Sources-NPC							
		P	SE		3,975,674	981,464	3,374,877	833,147
				B2	3,975,674	981,464	3,374,877	833,147
505	Electric Expenses							
		P	SG		3,101,340	807,992	3,244,154	845,200
		P	SSGCH		1,014,290	272,964	1,061,618	285,701
				B2	4,115,629	1,080,956	4,305,772	1,130,900
506	Misc. Steam Expense							
		P	SG		56,484,552	14,715,921	59,070,240	15,389,570
		P	SE		-	-	-	-
		P	SSGCH		1,824,538	491,016	1,909,674	513,928
				B2	58,309,091	15,206,938	60,979,914	15,903,498
507	Rents							
		P	SG		333,631	86,921	349,199	90,977
		P	SSGCH		-	-	-	-
				B2	333,631	86,921	349,199	90,977
510	Maint Supervision & Engineering							
		P	SG		4,264,472	1,111,023	(2,772,454)	(722,307)
		P	SSGCH		2,038,200	548,517	2,089,967	562,448
				B2	6,302,672	1,659,540	(682,486)	(159,859)
511	Maintenance of Structures							
		P	SG		23,163,124	6,034,689	24,106,297	6,280,414
		P	SSGCH		858,103	230,931	891,395	239,891
				B2	24,021,227	6,265,620	24,997,692	6,520,305
512	Maintenance of Boiler Plant							
		P	SG		106,024,128	27,622,468	125,319,889	32,649,593
		P	SSGCH		5,320,169	1,431,754	5,525,830	1,487,101
				B2	111,344,298	29,054,222	130,845,719	34,136,694
513	Maintenance of Electric Plant							
		P	SG		37,946,481	9,886,197	39,494,978	10,289,627
		P	SSGCH		610,812	164,381	634,517	170,760
				B2	38,557,293	10,050,578	40,129,495	10,460,387
514	Maintenance of Misc. Steam Plant							
		P	SG		9,839,461	2,563,475	10,237,147	2,667,084
		P	SSGCH		2,367,524	637,144	2,459,391	661,867
				B2	12,206,985	3,200,619	12,696,538	3,328,951
Total Steam Power Generation				**B2**	**1,033,981,927**	**259,906,153**	**1,179,365,066**	**296,259,705**

REVISED PROTOCOL
Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
296	517	Operation Super & Engineering							
297			P	SG		-	-	-	-
298					B2	-	-	-	-
299									
300	518	Nuclear Fuel Expense							
301			P	SE		-	-	-	-
302									
303					B2	-	-	-	-
304									
305	519	Coolants and Water							
306			P	SG		-	-	-	-
307					B2	-	-	-	-
308									
309	520	Steam Expenses							
310			P	SG		-	-	-	-
311					B2	-	-	-	-
312									
313									
314									
315	523	Electric Expenses							
316			P	SG		-	-	-	-
317					B2	-	-	-	-
318									
319	524	Misc. Nuclear Expenses							
320			P	SG		-	-	-	-
321					B2	-	-	-	-
322									
323	528	Maintenance Super & Engineering							
324			P	SG		-	-	-	-
325					B2	-	-	-	-
326									
327	529	Maintenance of Structures							
328			P	SG		-	-	-	-
329					B2	-	-	-	-
330									
331	530	Maintenance of Reactor Plant							
332			P	SG		-	-	-	-
333					B2	-	-	-	-
334									
335	531	Maintenance of Electric Plant							
336			P	SG		-	-	-	-
337					B2	-	-	-	-
338									
339	532	Maintenance of Misc Nuclear							
340			P	SG		-	-	-	-
341					B2	-	-	-	-
342									
343	**Total Nuclear Power Generation**				**B2**	-	-	-	-
344									
345	535	Operation Super & Engineering							
346			P	DGP		-	-	-	-
347			P	SG		5,037,384	1,312,390	7,628,533	1,987,462
348			P	SG		(845,964)	(220,399)	(569,127)	(148,275)
349									
350					B2	4,191,420	1,091,991	7,059,406	1,839,187
351									
352	536	Water For Power							
353			P	DGP		-	-	-	-
354			P	SG		222,131	57,872	230,128	59,955
355			P	SG		-	-	-	-
356									
357					B2	222,131	57,872	230,128	59,955
358									

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
537	Hydraulic Expenses							
		P	DGP		-	-	-	-
		P	SG		3,539,452	922,133	3,901,253	1,016,394
		P	SG		302,079	78,701	312,451	81,403
				B2	3,841,530	1,000,834	4,213,704	1,097,796
538	Electric Expenses							
		P	DGP		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B2	-	-	-	-
539	Misc. Hydro Expenses							
		P	DGP		-	-	-	-
		P	SG		14,672,822	3,822,711	15,120,579	3,939,365
		P	SG		6,989,478	1,820,969	7,238,455	1,885,835
				B2	21,662,300	5,643,679	22,359,034	5,825,200
540	Rents (Hydro Generation)							
		P	DGP		-	-	-	-
		P	SG		(165,850)	(43,209)	(174,996)	(45,592)
		P	SG		33,495	8,726	34,519	8,993
				B2	(132,355)	(34,482)	(140,477)	(36,599)
541	Maint Supervision & Engineering							
		P	DGP		-	-	-	-
		P	SG		388	101	404	105
		P	SG		-	-	-	-
				B2	388	101	404	105
542	Maintenance of Structures							
		P	DGP		-	-	-	-
		P	SG		926,329	241,336	966,108	251,700
		P	SG		205,962	53,659	215,029	56,022
				B2	1,132,291	294,996	1,181,137	307,722
543	Maintenance of Dams & Waterways							
		P	DGP		-	-	-	-
		P	SG		1,709,562	445,392	1,781,414	464,112
		P	SG		568,608	148,139	593,510	154,627
				B2	2,278,170	593,532	2,374,924	618,739
544	Maintenance of Electric Plant							
		P	DGP		-	-	-	-
		P	SG		2,013,460	524,567	2,100,959	547,363
		P	SG		476,270	124,083	497,279	129,556
				B2	2,489,730	648,649	2,598,239	676,919
545	Maintenance of Misc. Hydro Plant							
		P	DGP		-	-	-	-
		P	SG		2,022,348	526,882	2,028,465	528,476
		P	SG		786,410	204,884	789,352	205,650
				B2	2,808,758	731,766	2,817,818	734,126
Total Hydraulic Power Generation				**B2**	**38,494,364**	**10,028,937**	**42,694,317**	**11,123,151**

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
546	Operation Super & Engineering							
		P	SG		474,373	123,588	509,659	132,781
		P	SSGCT		-	-	-	-
				B2	474,373	123,588	509,659	132,781
547	Fuel-Non-NPC							
		P	SE		-	-	-	-
		P	SSECT		-	-	-	-
				B2	-	-	-	-
547NPC	Fuel-NPC							
		P	SE		385,597,558	95,191,439	334,359,033	82,542,321
		P	SSECT		9,132,801	2,256,731	7,134,120	1,762,853
				B2	394,730,359	97,448,170	341,493,153	84,305,174
548	Generation Expense							
		P	SG		17,018,069	4,433,718	15,042,752	3,919,088
		P	SSGCT		726,180	192,527	772,387	204,777
				B2	17,744,249	4,626,245	15,815,139	4,123,866
549	Miscellaneous Other							
		P	S		-	-	-	-
		P	SG		14,405,059	3,752,950	13,032,903	3,395,462
		P	SSGCT		-	-	-	-
				B2	14,405,059	3,752,950	13,032,903	3,395,462
550	Rents							
		P	S		-	-	384,295	384,295
		P	SG		4,241,932	1,105,151	4,557,470	1,187,358
		P	SSGCT		-	-	-	-
				B2	4,241,932	1,105,151	4,941,764	1,571,652
551	Maint Supervision & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
552	Maintenance of Structures							
		P	SG		1,423,389	370,836	1,481,480	385,970
		P	SSGCT		83,600	22,164	87,182	23,114
				B2	1,506,988	393,000	1,568,662	409,084
553	Maint of Generation & Electric Plant							
		P	SG		14,021,506	3,653,023	16,804,413	4,378,054
		P	SSGCT		948,421	251,448	986,877	261,644
				B2	14,969,927	3,904,471	17,791,290	4,639,698
554	Maintenance of Misc. Other							
		P	SG		4,146,189	1,080,207	4,312,762	1,123,604
		P	SSGCT		238,501	63,232	248,401	65,857
				B2	4,384,691	1,143,439	4,561,162	1,189,461
Total Other Power Generation				**B2**	**452,457,579**	**112,497,014**	**399,713,732**	**99,767,179**
555	Purchased Power-Non NPC							
		DMSC	S		(39,697,756)	(29,094,524)	-	-
					(39,697,756)	(29,094,524)	-	-
555NPC	Purchased Power-NPC							
		P	S		-	-	(138,381)	(138,381)
		P	SG		501,391,831	130,627,622	591,180,527	154,020,272
		P	SE		(16,365,455)	(4,040,096)	25,882,481	6,389,539
	Seasonal Co	P	SSGC		-	-	-	-
			DGP		-	-	-	-
					485,026,376	126,587,526	616,924,627	160,271,430
	Total Purchased Power			B2	445,328,620	97,493,002	616,924,627	160,271,430
556	System Control & Load Dispatch							
		P	SG		1,766,410	460,203	1,869,969	487,183
				B2	1,766,410	460,203	1,869,969	487,183

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
557	Other Expenses							
		P	S		(183,792)	(53,813)	9,937,337	(53,813)
		P	SG		62,527,920	16,290,400	56,512,684	14,723,251
		P	SGCT		1,122,425	293,409	1,122,425	293,409
		P	SE		(4,413,675)	(1,089,592)	(119,119)	(29,407)
		P	SSGCT		-	-	-	-
		P	TROJP		-	-	-	-
				B2	59,052,877	15,440,404	67,453,327	14,933,440
Total Other Power Supply				**B2**	**506,147,907**	**113,393,609**	**686,247,922**	**175,692,053**
Total Production Expense				**B2**	**2,031,081,777**	**495,825,712**	**2,308,021,038**	**582,842,088**
Embedded Cost Differentials								
	Company Owned Hy(	P	DGP		(40,046,461)	(21,829,054)	(30,430,908)	(16,587,681)
	Company Owned Hy(	P	SG		40,046,461	10,433,305	30,430,908	7,928,165
	Mid-C Contract	P	MC		(15,316,473)	(6,384,309)	(17,230,521)	(7,182,134)
	Mid-C Contract	P	SG		15,316,473	3,990,401	17,230,521	4,489,068
	Existing QF Contract:	P	S		21,940,979	7,301,578	18,496,102	6,836,769
	Existing QF Contract:	P	SG		(21,940,979)	(5,716,284)	(18,496,102)	(4,818,790)
				B2	-	(12,204,362)	-	(9,334,603)
2010 Protocol Stipulated Embedded Cost Differential and Adjustment								
	Company Owned Hy(	P	DGP		-	-	-	-
	Company Owned Hy(	P	SG		-	-	-	-
	Mid-C Contract	P	MC		-	-	-	-
	Mid-C Contract	P	SG		-	-	-	-
					-	-	-	-
Summary of Production Expense by Factor								
	S				(17,281,335)	(21,846,759)	28,679,353	7,028,870
	SG				981,382,032	255,679,477	1,083,064,874	282,170,909
	SE				1,027,885,784	253,751,417	1,144,409,190	282,517,239
	SNPPH				-	-	-	-
	TROJP				-	-	-	-
	SGCT				1,122,425	293,409	1,122,425	293,409
	DGP				(40,046,461)	(21,829,054)	(30,430,908)	(16,587,681)
	DEU				-	-	-	-
	DEP				-	-	-	-
	SNPPS				-	-	-	-
	SNPPO				-	-	-	-
	DGU				-	-	-	-
	MC				(15,316,473)	(6,384,309)	(17,230,521)	(7,182,134)
	SSGCT				1,996,702	529,372	2,094,846	555,392
	SSECT				9,132,801	2,256,731	7,134,120	1,762,853
	SSGC				-	-	-	-
	SSGCH				25,010,408	6,730,756	26,061,356	7,013,585
	SSECH				57,195,894	14,440,311	63,116,301	15,935,042
Total Production Expense by Factor					2,031,081,777	483,621,351	2,308,021,038	573,507,485
560	Operation Supervision & Engineering							
		T	SG		4,908,370	1,278,778	4,697,736	1,223,901
				B2	4,908,370	1,278,778	4,697,736	1,223,901
561	Load Dispatching							
		T	SG		9,118,261	2,375,581	9,550,236	2,488,123
				B2	9,118,261	2,375,581	9,550,236	2,488,123
562	Station Expense							
		T	SG		2,627,632	684,577	2,779,785	724,217
				B2	2,627,632	684,577	2,779,785	724,217
563	Overhead Line Expense							
		T	SG		339,363	88,414	359,594	93,685
				B2	339,363	88,414	359,594	93,685
564	Underground Line Expense							
		T	SG		-	-	-	-
				B2	-	-	-	-

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL (1)	DECEMBER 2014 PRO FORMA RESULTS OREGON (1)	DECEMBER 2014 PRO FORMA RESULTS TOTAL (2)	DECEMBER 2014 PRO FORMA RESULTS OREGON (2)
565	Transmission of Electricity by Others							
		T	SG		-	-	-	-
		T	SE		-	-	-	-
					-	-	-	-
565NPC	Transmission of Electricity by Others-NPC							
		T	SG		131,761,383	34,327,795	138,432,164	36,065,734
		T	SE		9,480,873	2,340,518	5,105,200	1,260,307
					141,242,257	36,668,313	143,537,364	37,326,041
	Total Transmission of Electricity by Others			B2	141,242,257	36,668,313	143,537,364	37,326,041
566	Misc. Transmission Expense							
		T	SG		2,907,403	757,466	2,284,500	595,181
				B2	2,907,403	757,466	2,284,500	595,181
567	Rents - Transmission							
		T	SG		2,203,116	573,978	2,343,169	610,466
				B2	2,203,116	573,978	2,343,169	610,466
568	Maint Supervision & Engineering							
		T	SG		2,208,687	575,429	2,304,521	600,397
				B2	2,208,687	575,429	2,304,521	600,397
569	Maintenance of Structures							
		T	SG		4,505,090	1,173,711	4,677,117	1,218,529
				B2	4,505,090	1,173,711	4,677,117	1,218,529
570	Maintenance of Station Equipment							
		T	SG		10,419,175	2,714,508	10,838,960	2,823,874
				B2	10,419,175	2,714,508	10,838,960	2,823,874
571	Maintenance of Overhead Lines							
		T	SG		23,045,623	6,004,076	20,749,618	5,405,898
				B2	23,045,623	6,004,076	20,749,618	5,405,898
572	Maintenance of Underground Lines							
		T	SG		95,533	24,889	99,206	25,846
				B2	95,533	24,889	99,206	25,846
573	Maint of Misc. Transmission Plant							
		T	SG		1,708,680	445,162	1,763,187	459,363
				B2	1,708,680	445,162	1,763,187	459,363
Total Transmission Expense				**B2**	**205,329,189**	**53,364,883**	**205,984,992**	**53,595,523**
Summary of Transmission Expense by Factor								
	SE				9,480,873	2,340,518	5,105,200	1,260,307
	SG				195,848,316	51,024,365	200,879,792	52,335,215
	SNPT				-	-	-	-
Total Transmission Expense by Factor					205,329,189	53,364,883	205,984,992	53,595,523
580	Operation Supervision & Engineering							
		DPW	S		779,159	247,019	126,342	(3,245)
		DPW	SNPD		13,635,673	3,664,124	13,365,989	3,591,656
				B2	14,414,832	3,911,143	13,492,332	3,588,411
581	Load Dispatching							
		DPW	S		-	-	1	1
		DPW	SNPD		13,180,858	3,541,908	13,784,196	3,704,034
				B2	13,180,858	3,541,908	13,784,196	3,704,035
582	Station Expense							
		DPW	S		4,005,727	1,107,778	4,202,153	1,162,254
		DPW	SNPD		36,385	9,777	38,099	10,238
				B2	4,042,112	1,117,555	4,240,252	1,172,492

	REVISED PROTOCOL								
	Year End					DECEMBER 2014 PRO FORMA RESULTS		DECEMBER 2014 PRO FORMA RESULTS	
	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
657	583	Overhead Line Expenses							
658			DPW	S		6,383,357	2,918,711	6,680,976	3,054,562
659			DPW	SNPD		17,871	4,802	18,709	5,027
660					B2	6,401,228	2,923,514	6,699,685	3,059,589
661									
662	584	Underground Line Expense							
663			DPW	S		135	-	142	-
664			DPW	SNPD		1,041	280	1,095	294
665					B2	1,175	280	1,236	294
666									
667	585	Street Lighting & Signal Systems							
668			DPW	S		-	-	-	-
669			DPW	SNPD		220,491	59,250	230,460	61,928
670					B2	220,491	59,250	230,460	61,928
671									
672	586	Meter Expenses							
673			DPW	S		6,547,433	3,146,157	6,853,656	3,293,344
674			DPW	SNPD		1,235,796	332,078	1,293,869	347,683
675					B2	7,783,229	3,478,236	8,147,525	3,641,027
676									
677	587	Customer Installation Expenses							
678			DPW	S		12,971,313	4,500,312	13,577,719	4,710,389
679			DPW	SNPD		-	-	-	-
680					B2	12,971,313	4,500,312	13,577,719	4,710,389
681									
682	588	Misc. Distribution Expenses							
683			DPW	S		1,544,650	83,894	1,620,234	89,574
684			DPW	SNPD		3,476,291	934,135	3,634,283	976,590
685					B2	5,020,941	1,018,029	5,254,517	1,066,164
686									
687	589	Rents							
688			DPW	S		2,900,913	1,691,500	3,050,785	1,778,965
689			DPW	SNPD		48,772	13,106	51,303	13,786
690					B2	2,949,685	1,704,606	3,102,088	1,792,751
691									
692	590	Maint Supervision & Engineering							
693			DPW	S		827,494	304,836	861,973	317,553
694			DPW	SNPD		3,490,454	937,941	3,657,608	982,858
695					B2	4,317,947	1,242,777	4,519,582	1,300,411
696									
697	591	Maintenance of Structures							
698			DPW	S		2,074,458	922,370	2,127,932	946,146
699			DPW	SNPD		144,949	38,950	148,685	39,954
700					B2	2,219,407	961,320	2,276,617	986,101
701									
702	592	Maintenance of Station Equipment							
703			DPW	S		10,509,327	3,064,090	10,891,081	3,168,320
704			DPW	SNPD		1,707,646	458,872	1,786,706	480,116
705					B2	12,216,973	3,522,962	12,677,786	3,648,436
706	593	Maintenance of Overhead Lines							
707			DPW	S		87,421,162	28,563,973	93,316,113	33,549,409
708			DPW	SNPD		1,288,093	346,131	1,078,853	289,905
709					B2	88,709,255	28,910,105	94,394,966	33,839,314
710									
711	594	Maintenance of Underground Lines							
712			DPW	S		21,126,297	5,759,231	21,927,613	5,981,807
713			DPW	SNPD		6,367	1,711	6,612	1,777
714					B2	21,132,664	5,760,942	21,934,225	5,983,583
715									
716	595	Maintenance of Line Transformers							
717			DPW	S		-	-	-	-
718			DPW	SNPD		870,008	233,785	905,592	243,347
719					B2	870,008	233,785	905,592	243,347
720									
721	596	Maint of Street Lighting & Signal Sys.							
722			DPW	S		3,933,543	1,185,321	4,073,638	1,233,766
723			DPW	SNPD		-	-	-	-
724					B2	3,933,543	1,185,321	4,073,638	1,233,766
725									

REVISED PROTOCOL

Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
597	Maintenance of Meters							
		DPW	S		4,982,631	1,192,317	5,190,585	1,242,254
		DPW	SNPD		1,180,007	317,087	1,230,074	330,540
				B2	6,162,638	1,509,404	6,420,659	1,572,794
598	Maint of Misc. Distribution Plant							
		DPW	S		2,615,897	481,896	2,685,425	495,575
		DPW	SNPD		(562,577)	(151,173)	(554,104)	(148,897)
				B2	2,053,320	330,722	2,131,321	346,679
Total Distribution Expense				**B2**	**208,601,621**	**65,912,168**	**217,864,397**	**71,951,511**
Summary of Distribution Expense by Factor								
	S				168,623,497	55,169,405	177,186,367	61,020,673
	SNPD				39,978,124	10,742,763	40,678,029	10,930,839
Total Distribution Expense by Factor					208,601,621	65,912,168	217,864,397	71,951,511
901	Supervision							
		CUST	S		10	162	11	169
		CUST	CN		2,902,463	880,177	3,034,419	920,192
				B2	2,902,474	880,339	3,034,430	920,362
902	Meter Reading Expense							
		CUST	S		18,436,323	9,515,684	19,274,515	9,948,404
		CUST	CN		2,345,596	711,306	2,452,213	743,637
				B2	20,781,919	10,226,989	21,726,728	10,692,042
903	Customer Receipts & Collections							
		CUST	S		8,281,326	2,310,850	8,027,410	2,108,965
		CUST	CN		47,182,937	14,308,301	48,356,661	14,664,234
				B2	55,464,262	16,619,151	56,384,071	16,773,200
904	Uncollectible Accounts							
		CUST	S		15,054,589	7,300,290	15,497,299	7,394,970
		P	SG		-	-	-	-
		CUST	CN		269,596	81,756	281,697	85,425
				B2	15,324,186	7,382,046	15,778,995	7,480,395
905	Misc. Customer Accounts Expense							
		CUST	S		6,138	6,138	6,413	6,413
		CUST	CN		180,880	54,852	189,061	57,333
				B2	187,018	60,990	195,475	63,747
Total Customer Accounts Expense				**B2**	**94,659,859**	**35,169,515**	**97,119,698**	**35,929,744**
Summary of Customer Accts Exp by Factor								
	S				41,778,387	19,133,124	42,805,648	19,458,922
	CN				52,881,472	16,036,391	54,314,050	16,470,822
	SG				-	-	-	-
Total Customer Accounts Expense by Factor					94,659,859	35,169,515	97,119,698	35,929,744
907	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		298,102	90,400	311,563	94,482
				B2	298,102	90,400	311,563	94,482
908	Customer Assistance							
		CUST	S		103,173,557	25,032,153	12,107,194	1,857,183
		CUST	CN		1,579,122	478,871	1,580,386	479,255
				B2	104,752,679	25,511,024	13,687,581	2,336,438

REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
909	Informational & Instructional Adv							
		CUST	S		1,483,391	602,954	1,537,383	618,357
		CUST	CN		3,341,512	1,013,319	3,236,360	981,431
				B2	4,824,903	1,616,273	4,773,744	1,599,789
910	Misc. Customer Service							
		CUST	S		-	-	-	-
		CUST	CN		117,882	35,748	122,679	37,203
				B2	117,882	35,748	122,679	37,203
Total Customer Service Expense				**B2**	**109,993,566**	**27,253,445**	**18,895,566**	**4,067,911**
Summary of Customer Service Exp by Factor								
	S				104,656,948	25,635,107	13,644,578	2,475,541
	CN				5,336,618	1,618,338	5,250,988	1,592,371
Total Customer Service Expense by Factor				B2	109,993,566	27,253,445	18,895,566	4,067,911
911	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
912	Demonstration & Selling Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
913	Advertising Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
916	Misc. Sales Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
Total Sales Expense				**B2**	-	-	-	-
Total Sales Expense by Factor								
	S				-	-	-	-
	CN				-	-	-	-
Total Sales Expense by Factor					-	-	-	-
Total Customer Service Exp Including Sales				**B2**	**109,993,566**	**27,253,445**	**18,895,566**	**4,067,911**
920	Administrative & General Salaries							
		PTD	S		(2,954,533)	1,088,137	(5,264,131)	(843,151)
		CUST	CN		-	-	-	-
		PTD	SO		73,783,837	20,220,495	74,311,413	20,365,077
				B2	70,829,304	21,308,632	69,047,282	19,521,926
921	Office Supplies & expenses							
		PTD	S		250,630	59,631	263,411	62,672
		CUST	CN		71,100	21,561	74,726	22,661
		PTD	SO		8,831,411	2,420,252	9,226,866	2,528,627
				B2	9,153,141	2,501,444	9,565,003	2,613,959
922	A&G Expenses Transferred							
		PTD	S		-	-	-	-
		CUST	CN		-	-	-	-
		PTD	SO		(25,112,617)	(6,882,124)	(27,588,760)	(7,560,713)
				B2	(25,112,617)	(6,882,124)	(27,588,760)	(7,560,713)

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
859	923	Outside Services							
860			PTD	S		299,393	125,132	316,387	132,235
861			CUST	CN		-	-	-	-
862			PTD	SO		6,903,286	1,891,849	6,530,965	1,789,814
863					B2	7,202,679	2,016,981	6,847,352	1,922,049
864									
865	924	Property Insurance							
866			DPW	S		7,962,669	5,285,806	9,570,157	6,959,234
867			PT	SG		-	-	-	-
868			PTD	SO		8,814,109	2,415,511	6,818,574	1,868,633
869					B2	16,776,778	7,701,316	16,388,731	8,827,867
870									
871	925	Injuries & Damages							
872			PTD	S		-	-	3,369,178	3,369,178
873			PTD	SO		15,065,328	4,128,660	3,939,183	1,079,535
874					B2	15,065,328	4,128,660	7,308,360	4,448,713
875									
876	926	Employee Pensions & Benefits							
877			LABOR	S		-	-	-	-
878			CUST	CN		-	-	-	-
879			LABOR	SO		-	-	-	-
880					B2	-	-	-	-
881									
882	927	Franchise Requirements							
883			DMSC	S		-	-	-	-
884			DMSC	SG		-	-	-	-
885					B2	-	-	-	-
886									
887	928	Regulatory Commission Expense							
888			DMSC	S		17,601,734	4,700,388	18,572,681	4,961,857
889			CUST	CN		-	-	-	-
890			DMSC	SO		2,550,990	699,100	2,692,485	737,877
891			FERC	SG		3,702,587	964,635	3,916,240	1,020,298
892					B2	23,855,311	6,364,123	25,181,406	6,720,032
893									
894	929	Duplicate Charges							
895			LABOR	S		-	-	-	-
896			LABOR	SO		(6,339,512)	(1,737,346)	(8,107,044)	(2,221,739)
897					B2	(6,339,512)	(1,737,346)	(8,107,044)	(2,221,739)
898									
899	930	Misc General Expenses							
900			PTD	S		136,067	41,387	1,089,835	919,899
901			CUST	CN		-	-	-	-
902			CUST	SG		1,449	378	1,521	396
903			LABOR	SO		11,354,504	3,111,707	11,194,601	3,067,886
904					B2	11,492,021	3,153,472	12,285,956	3,988,181
905									
906	931	Rents							
907			PTD	S		1,154,787	1,098,296	1,296,945	1,233,499
908			PTD	SO		5,580,226	1,529,264	6,267,168	1,717,520
909					B2	6,735,013	2,627,559	7,564,113	2,951,019
910									
911	935	Maintenance of General Plant							
912			G	S		347,662	142,394	356,125	145,770
913			CUST	CN		21,160	6,417	21,654	6,566
914			G	SO		22,522,137	6,172,202	23,031,778	6,311,870
915					B2	22,890,959	6,321,012	23,409,557	6,464,206
916									
917	**Total Administrative & General Expense**				**B2**	**152,548,405**	**47,503,730**	**141,901,957**	**47,675,501**
918									
919	Summary of A&G Expense by Factor								
920		S				24,798,409	12,541,170	29,570,588	16,941,193
921		SO				123,953,700	33,969,569	108,317,229	29,684,387
922		SG				3,704,036	965,013	3,917,760	1,020,694
923		CN				92,261	27,978	96,380	29,227
924	Total A&G Expense by Factor					152,548,405	47,503,730	141,901,957	47,675,501
925									
926	**Total O&M Expense**				**B2**	**2,802,214,417**	**712,825,090**	**2,989,787,648**	**786,727,676**

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Line	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
927	403SP	Steam Depreciation							
928			P	SG		20,827,113	5,426,088	47,878,880	12,473,885
929			P	SG		23,906,020	6,228,236	43,283,377	11,276,619
930			P	SG		83,869,689	21,850,572	245,246,369	63,894,040
931			P	SSGCH		7,904,603	2,127,273	24,650,417	6,633,876
932					B3	136,507,425	35,632,168	361,059,042	94,278,420
933									
934	403NP	Nuclear Depreciation							
935			P	SG		-	-	-	-
936					B3	-	-	-	-
937									
938	403HP	Hydro Depreciation							
939			P	SG		3,604,046	938,962	4,963,572	1,293,159
940			P	SG		984,010	256,364	1,361,340	354,670
941			P	SG		13,197,864	3,438,440	20,792,015	5,416,944
942			P	SG		4,042,573	1,053,212	5,477,288	1,426,998
943					B3	21,828,493	5,686,978	32,594,215	8,491,771
944									
945	403OP	Other Production Depreciation							
946			P	S		-	-	-	-
947			P	SG		87,069	22,684	-	-
948			P	SG		113,016,274	29,444,132	98,899,230	25,766,218
949			P	SSGCT		2,646,606	701,676	3,163,767	838,787
950			P	SSGCH		-	-	-	-
951					B3	115,749,949	30,168,492	102,062,997	26,605,005
952									
953	403TP	Transmission Depreciation							
954			T	S		-	-	-	-
955			T	SG		10,907,803	2,841,810	10,013,919	2,608,927
956			T	SG		12,462,921	3,246,965	11,497,556	2,995,458
957			T	SG		62,098,401	16,178,497	73,484,839	19,145,006
958					B3	85,469,125	22,267,273	94,996,315	24,749,391
959									
960									
961									
962	403	Distribution Depreciation							
963	360	Land & Land Rights	DPW	S		342,296	71,413	317,677	35,535
964	361	Structures	DPW	S		1,357,638	324,407	1,321,871	272,282
965	362	Station Equipment	DPW	S		19,217,105	4,522,423	18,854,076	3,993,370
966	363	Storage Battery Eq	DPW	S		-	-	-	-
967	364	Poles & Towers	DPW	S		36,253,454	12,926,373	35,836,121	12,318,181
968	365	OH Conductors	DPW	S		19,946,377	7,060,332	19,665,761	6,651,382
969	366	UG Conduit	DPW	S		8,124,531	2,202,698	7,992,242	2,009,910
970	367	UG Conductor	DPW	S		18,059,095	3,838,524	17,747,746	3,384,785
971	368	Line Trans	DPW	S		28,738,900	11,311,787	28,261,086	10,615,455
972	369	Services	DPW	S		12,278,603	4,627,852	12,021,335	4,252,927
973	370	Meters	DPW	S		6,092,819	2,168,342	6,019,302	2,061,203
974	371	Inst Cust Prem	DPW	S		484,777	119,333	481,095	113,968
975	372	Leased Property	DPW	S		-	-	-	-
976	373	Street Lighting	DPW	S		2,160,196	676,460	2,134,520	639,042
977					B3	153,055,790	49,849,943	150,652,831	46,348,040
978									
979	403GP	General Depreciation							
980			G-SITUS	S		13,171,446	4,075,918	13,855,709	4,416,126
981			G-DGP	SG		155,614	40,542	48,207	12,559
982			G-DGU	SG		178,000	46,374	30,059	7,831
983			P	SE		15,835	3,909	17,457	4,309
984			CUST	CN		1,748,089	530,111	1,617,486	490,505
985			G-SG	SG		6,534,978	1,702,558	7,451,965	1,941,461
986			PTD	SO		14,944,608	4,095,577	14,456,988	3,961,944
987			P	SSGCT		6,010	1,593	5,947	1,577
988			P	SSGCH		137,187	36,919	161,548	43,476
989					B3	36,891,768	10,533,502	37,645,366	10,879,788
990									
991	403GV0	General Vehicles							
992			G-SG	SG		-	-	-	-
993					B3	-	-	-	-
994									
995	403MP	Mining Depreciation							
996			P	SE		-	-	-	-
997					B3	-	-	-	-
998									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
999	403EP	Experimental Plant Depreciation							
1000			P	SG		-	-	-	-
1001			P	SG		-	-	-	-
1002					B3	-	-	-	-
1003	4031	ARO Depreciation							
1004			P	S		-	-	-	-
1005					B3	-	-	-	-
1006									
1007									
1008	**Total Depreciation Expense**				**B3**	**549,502,550**	**154,138,355**	**779,010,766**	**211,352,416**
1009									
1010	Summary	S				166,227,236	53,925,861	164,508,540	50,764,166
1011		DGP				-	-	-	-
1012		DGU				-	-	-	-
1013		SG				355,872,375	92,715,436	570,428,616	148,613,777
1014		SO				14,944,608	4,095,577	14,456,988	3,961,944
1015		CN				1,748,089	530,111	1,617,486	490,505
1016		SE				15,835	3,909	17,457	4,309
1017		SSGCH				8,041,790	2,164,192	24,811,965	6,677,351
1018		SSGCT				2,652,616	703,269	3,169,713	840,364
1019	Total Depreciation Expense By Factor					549,502,550	154,138,355	779,010,766	211,352,416
1020									
1021	404GP	Amort of LT Plant - Capital Lease Gen							
1022			I-SITUS	S		1,337,374	445,579	705,903	231,371
1023			I-SG	SG		-	-	-	-
1024			PTD	SO		1,270,053	348,058	1,278,904	350,484
1025			I-DGU	SG		-	-	-	-
1026			CUST	CN		273,367	82,899	273,367	82,899
1027			I-DGP	SG		-	-	-	-
1028					B4	2,880,793	876,536	2,258,174	664,754
1029									
1030	404SP	Amort of LT Plant - Cap Lease Steam							
1031			P	SG		-	-	-	-
1032			P	SG		-	-	-	-
1033					B4	-	-	-	-
1034									
1035	404IP	Amort of LT Plant - Intangible Plant							
1036			I-SITUS	S		190,856	13,810	189,210	11,762
1037			P	SE		55,997	13,824	336,152	82,985
1038			I-SG	SG		10,083,201	2,626,976	6,787,294	1,768,294
1039			PTD	SO		15,468,250	4,239,081	21,183,084	5,805,234
1040			CUST	CN		6,015,598	1,824,240	6,419,226	1,946,640
1041			I-SG	SG		10,888,019	2,836,656	10,822,615	2,819,616
1042			I-SG	SG		307,800	80,191	301,628	78,583
1043			I-DGP	SG		-	-	-	-
1044			I-SG	SSGCT		-	-	-	-
1045			I-SG	SSGCH		156,748	42,184	-	-
1046			I-DGU	SG		16,758	4,366	16,101	4,195
1047					B4	43,183,227	11,681,328	46,055,309	12,517,309
1048									
1049	404MP	Amort of LT Plant - Mining Plant							
1050			P	SE		-	-	-	-
1051					B4	-	-	-	-
1052									
1053	404OP	Amort of LT Plant - Other Plant							
1054			P	SSGCT		-	-	-	-
1055					B4	-	-	-	-
1056									
1057									
1058	404HP	Amortization of Other Electric Plant							
1059			P	SG		232,997	60,703	311,610	81,184
1060			P	SG		46,417	12,093	44,532	11,602
1061			P	SG		-	-	-	-
1062					B4	279,414	72,796	356,143	92,786
1063									
1064	**Total Amortization of Limited Term Plant**				**B4**	**46,343,434**	**12,630,660**	**48,669,626**	**13,274,849**
1065									
1066									
1067	405	Amortization of Other Electric Plant							
1068			GP	S		-	-	-	-
1069									
1070					B4	-	-	-	-
1071									

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
1072	406	Amortization of Plant Acquisition Adj							
1073			P	S		-	-	-	-
1074			P	SG		-	-	-	-
1075			P	SG		-	-	-	-
1076			P	SG		5,523,970	1,439,160	4,834,296	1,259,479
1077			P	SO		-	-	-	-
1078					B4	5,523,970	1,439,160	4,834,296	1,259,479
1079	407	Amort of Prop Losses, Unrec Plant, etc							
1080			DPW	S		559,742	-	559,742	-
1081			GP	SO		-	-	-	-
1082			P	SG-P		-	-	-	-
1083			P	SE		-	-	-	-
1084			P	SG		-	-	-	-
1085			P	TROJP		-	-	-	-
1086					B4	559,742	-	559,742	-
1087									
1088	**Total Amortization Expense**				**B4**	**52,427,146**	**14,069,820**	**54,063,663**	**14,534,328**
1089									
1090									
1091									
1092	Summary of Amortization Expense by Factor								
1093		S				2,087,972	459,389	1,454,855	243,132
1094		SE				55,997	13,824	336,152	82,985
1095		TROJP				-	-	-	-
1096		DGP				-	-	-	-
1097		SG-P				-	-	-	-
1098		SO				16,738,303	4,587,140	22,461,988	6,155,718
1099		SSGCT				-	-	-	-
1100		SSGCH				156,748	42,184	-	-
1101		CN				6,288,965	1,907,138	6,692,593	2,029,539
1102		SG				27,099,162	7,060,145	23,118,076	6,022,953
1103	Total Amortization Expense by Factor					52,427,146	14,069,820	54,063,663	14,534,328
1104	408	Taxes Other Than Income							
1105			DMSC	S		30,702,755	27,276,225	32,446,766	29,020,236
1106			GP	GPS		116,729,123	31,986,288	129,375,528	35,451,675
1107			GP	SO		8,848,595	2,424,962	8,848,595	2,424,962
1108			P	SE		819,813	202,385	819,813	202,385
1109			P	SG		678,544	176,781	1,725,585	449,567
1110			DMSC	OPRV-ID		-	-	-	-
1111			GP	EXCTAX		-	-	-	-
1112			GP	SG		-	-	-	-
1113									
1114									
1115									
1116	**Total Taxes Other Than Income**				**B5**	**157,778,830**	**62,066,641**	**173,216,287**	**67,548,825**
1117									
1118									
1119	41140	Deferred Investment Tax Credit - Fed							
1120			PTD	DGU		(1,862,752)	-	(1,862,752)	-
1121									
1122					B7	(1,862,752)	-	(1,862,752)	-
1123									
1124	41141	Deferred Investment Tax Credit - Idaho							
1125			PTD	DGU		-	-	-	-
1126									
1127					B7	-	-	-	-
1128									
1129	**Total Deferred ITC**				**B7**	**(1,862,752)**	**-**	**(1,862,752)**	**-**
1130									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1131									
1132	427	Interest on Long-Term Debt							
1133			GP	S		327,928,207	86,256,121	326,446,633	85,824,891
1134			GP	SNP		-	-	-	-
1135					B6	327,928,207	86,256,121	326,446,633	85,824,891
1136									
1137	428	Amortization of Debt Disc & Exp							
1138			GP	SNP		-	-	-	-
1139					B6	-	-	-	-
1140									
1141	429	Amortization of Premium on Debt							
1142			GP	SNP		-	-	-	-
1143					B6	-	-	-	-
1144									
1145	431	Other Interest Expense							
1146			NUTIL	OTH		-	-	-	-
1147			GP	SO		-	-	-	-
1148			GP	SNP		-	-	-	-
1149					B6	-	-	-	-
1150									
1151	432	AFUDC - Borrowed							
1152			GP	SNP		-	-	-	-
1153						-	-	-	-
1154									
1155		Total Elec. Interest Deductions for Tax			B6	327,928,207	86,256,121	326,446,633	85,824,891
1156									
1157		Non-Utility Portion of Interest							
1158		427	NUTIL	NUTIL		-	-	-	-
1159		428	NUTIL	NUTIL		-	-	-	-
1160		429	NUTIL	NUTIL		-	-	-	-
1161		431	NUTIL	NUTIL		-	-	-	-
1162									
1163		Total Non-utility Interest				-	-	-	-
1164									
1165		Total Interest Deductions for Tax			B6	327,928,207	86,256,121	326,446,633	85,824,891
1166									
1167									
1168	419	Interest & Dividends							
1169			GP	S		-	-	-	-
1170			GP	SNP		(54,338,671)	(14,367,167)	(63,623,361)	(16,822,043)
1171		Total Operating Deductions for Tax			B6	(54,338,671)	(14,367,167)	(63,623,361)	(16,822,043)
1172									
1173									
1174	41010	Deferred Income Tax - Federal-DR							
1175			GP	S		37,958,773	249,502	4,156,555	20,423
1176			P	SCHMDEXP		-	-	-	-
1177			PT	SSGCH		37,085	9,980	37,085	9,980
1178			LABOR	SO		7,353,797	2,015,311	(922,006)	(252,676)
1179			GP	SNP		29,910,347	7,908,308	36,302,668	9,598,441
1180			P	SE		12,842,500	3,170,394	1,788,676	441,566
1181			PT	SG		76,326,248	19,885,279	54,677,938	14,245,244
1182			GP	GPS		39,932,361	10,942,325	21,918,549	6,006,154
1183			TAXDEPR	TAXDEPR		496,822,238	131,149,417	430,161,791	113,552,622
1184			CUST	BADDEBT		-	-	-	-
1185			CUST	CN		18,276	5,542	-	-
1186			IBT	IBT		-	-	-	-
1187			DPW	SNPD		986,927	265,203	-	-
1188					B7	702,188,552	175,601,261	548,121,256	143,621,753
1189									

REVISED PROTOCOL
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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1190									
1191									
1192	41110	Deferred Income Tax - Federal-CR							
1193			GP	S		(33,964,770)	(925,515)	(13,742,118)	(597,475)
1194			P	SE		(9,872,333)	(2,437,156)	-	-
1195			CUST	BADDEBT		(1,670,977)	(792,165)	(0)	(0)
1196			GP	SNP		(20,189,415)	(5,338,090)	(26,012,957)	(6,877,837)
1197			PT	SG		150,392	39,182	2,308	601
1198			DPW	CIAC		(15,616,054)	(4,196,284)	(17,653,569)	(4,743,797)
1199			LABOR	SO		(8,378,162)	(2,296,039)	(5,146,197)	(1,410,318)
1200			PT	SNPD		(3,627,116)	(974,664)	-	-
1201			P	GPS		(1,739,033)	(476,532)	-	-
1202			P	SGCT		(425,972)	(111,352)	(425,972)	(111,352)
1203			GP	SCHMDEXP		(237,594,428)	(64,461,441)	(315,108,180)	(85,491,598)
1204			P	TROJD		(5,054)	(1,304)	-	-
1205			IBT	IBT		-	-	-	-
1206			0	DGP		-	-	-	-
1207			0	DGU		-	-	-	-
1208			0	SG-U		-	-	-	-
1209			0	SSGCH		(540,676)	(145,506)	(540,676)	(145,506)
1210			0	SSGCT		-	-	-	-
1211					B7	(333,473,598)	(82,116,867)	(378,627,361)	(99,377,281)
1212									
1213	**Total Deferred Income Taxes**				**B7**	**368,714,954**	**93,484,394**	**169,493,895**	**44,244,472**
1214	SCHMAF	Additions - Flow Through							
1215			SCHMAF	S		-	-	-	-
1216			SCHMAF	SNP		-	-	-	-
1217			SCHMAF	SO		-	-	-	-
1218			SCHMAF	SE		-	-	-	-
1219			SCHMAF	TROJP		-	-	-	-
1220			SCHMAF	SG		-	-	-	-
1221					B6	-	-	-	-
1222									
1223	SCHMAP	Additions - Permanent							
1224			P	S		(7,137)	-	-	-
1225			P	SE		82,060	20,258	18,000	4,444
1226			LABOR	SNP		-	-	-	-
1227			SCHMAP-SO	SO		7,528,967	2,063,317	679,971	186,346
1228			SCHMAP	SG		-	-	-	-
1229			DPW	SCHMDEXP		-	-	71,461	19,388
1230					B6	7,603,890	2,083,575	769,432	210,178
1231									
1232	SCHMAT	Additions - Temporary							
1233			SCHMAT-SITUS	S		83,565,307	7,491,514	36,228,455	-
1234			P	SG-P		-	-	-	-
1235			DPW	CIAC		41,147,935	11,057,110	46,516,739	12,499,794
1236			SCHMAT-SNP	SNP		53,198,636	14,065,742	68,543,531	18,122,938
1237			P	TROJD		13,316	3,437	-	-
1238			CUST	BADDEBT		4,402,986	2,087,337	0	0
1239			SCHMAT-SE	SE		26,031,778	6,426,395	-	-
1240			P	SG		(1,993,526)	(519,373)	-	-
1241			SCHMAT-GPS	CN		-	-	-	-
1242			SCHMAT-SO	SO		21,222,244	5,815,966	13,560,110	3,716,154
1243			SCHMAT-SNP	SNPD		9,557,365	2,568,217	-	-
1244			P	SGCT		1,122,425	293,409	1,122,425	293,409
1245			TAXDEPR	DGP		-	-	-	-
1246			BOOKDEPR	SCHMDEXP		626,055,776	169,854,393	830,302,706	225,268,367
1247			0	DGU		-	-	-	-
1248			0	GPS		4,582,312	1,255,652	-	-
1249			0	SSGCH		-	-	-	-
1250			0	SSGCT		-	-	-	-
1251					B6	868,906,554	220,399,799	996,273,966	259,900,663
1252									
1253	TOTAL SCHEDULE - M ADDITIONS				B6	876,510,444	222,483,373	997,043,398	260,110,841
1254									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1255	SCHMDF	Deductions - Flow Through							
1256			SCHMDF	S		-	-	-	-
1257			SCHMDF	DGP		-	-	-	-
1258			SCHMDF	DGU		-	-	-	-
1259					B6	-	-	-	-
1260	SCHMDP	Deductions - Permanent							
1261			SCHMDP	S		-	-	-	-
1262			P	SE		474,854	117,226	493,869	121,920
1263			PTD	SNP		382,696	101,185	381,062	100,753
1264			SCHMDEXP	IBT		257,021	66,082	357,168	91,831
1265			P	SG		-	-	-	-
1266			SCHMDP-SO	SO		11,495,969	3,150,476	-	-
1267					B6	12,610,540	3,434,969	1,232,099	314,504
1268									
1269	SCHMDT	Deductions - Temporary							
1270			GP	S		100,020,473	657,429	10,952,419	53,813
1271			CUST	BADDEBT		-	-	-	-
1272			SCHMDT-SNP	SNP		78,813,067	20,838,208	95,656,684	25,291,667
1273			SCHMDT	CN		48,156	14,603	-	-
1274			SCHMDT	SSGCH		97,718	26,298	97,718	26,298
1275			P	DGP		-	-	-	-
1276			P	SE		33,648,216	8,306,645	4,713,119	1,163,515
1277			SCHMDT-SG	SG		201,117,881	52,397,245	144,075,093	37,535,886
1278			SCHMDT-GPS	GPS		105,220,837	28,832,771	57,754,860	15,826,073
1279			SCHMDT-SO	SO		19,377,084	5,310,299	(2,429,465)	(665,796)
1280			TAXDEPR	TAXDEPR		1,309,115,012	345,575,654	1,133,466,288	299,208,512
1281			DPW	SNPD		2,600,530	698,804	-	-
1282					B6	1,850,058,974	462,657,956	1,444,286,716	378,439,968
1283									
1284	TOTAL SCHEDULE - M DEDUCTIONS				B6	1,862,669,514	466,092,925	1,445,518,815	378,754,472
1285									
1286	**TOTAL SCHEDULE - M ADJUSTMENTS**				**B6**	**(986,159,070)**	**(243,609,551)**	**(448,475,417)**	**(118,643,631)**
1287									
1288									
1289									
1290	40911	State Income Taxes							
1291			IBT	IBT		(6,321,526)	612,258	18,638,739	4,769,525
1292			IBT	IBT		-	-	-	-
1293		REC	P	SG		(167,068)	(43,526)	(384,905)	(100,279)
1294			IBT	IBT		-	-	-	-
1295	**Total State Tax Expense**					**(6,488,594)**	**568,732**	**18,253,834**	**4,669,245**
1296									
1297									
1298	Calculation of Taxable Income:								
1299		Operating Revenues				4,681,666,114	1,271,896,170	5,117,557,160	1,372,775,121
1300		Operating Deductions:							
1301		O & M Expenses				2,802,214,417	712,825,090	2,989,787,648	786,727,676
1302		Depreciation Expense				549,502,550	154,138,355	779,010,766	211,352,416
1303		Amortization Expense				52,427,146	14,069,820	54,063,663	14,534,328
1304		Taxes Other Than Income				157,778,830	62,066,641	173,216,287	67,548,825
1305		Interest & Dividends (AFUDC-Equity)				(54,338,671)	(14,367,167)	(63,623,361)	(16,822,043)
1306		Misc Revenue & Expense				(764,772)	(188,103)	(364,815)	(90,211)
1307		Total Operating Deductions				3,506,819,500	928,544,636	3,932,090,188	1,063,250,991
1308		Other Deductions:							
1309		Interest Deductions				327,928,207	86,256,121	326,446,633	85,824,891
1310		Interest on PCRBS				-	-	-	-
1311		Schedule M Adjustments				(986,159,070)	(243,609,551)	(448,475,417)	(118,643,631)
1312									
1313		Income Before State Taxes				(139,240,663)	13,485,862	410,544,921	105,055,609
1314									
1315		State Income Taxes				(6,488,594)	568,732	18,253,834	4,669,245
1316									
1317	Total Taxable Income					(132,752,069)	12,917,130	392,291,087	100,386,363
1318									
1319	Tax Rate					35.0%	35.0%	35.0%	35.0%
1320									
1321	Federal Income Tax - Calculated					(46,463,224)	4,520,995	137,301,880	35,135,227
1322									
1323	Adjustments to Calculated Tax:								
1324	40910	PMI	P	SE		(75,871)	(18,730)	(18,000)	(4,444)
1325	40910	REC	P	SG		(70,632,447)	(18,401,873)	(65,873,189)	(17,161,943)
1326	40911	State Energy Cr	P	SO		(28,863)	(7,910)	-	-
1327	40910	IRS Settle	LABOR	S		-	-	-	-
1328	**Federal Income Tax Expense**					**(117,200,405)**	**(13,907,517)**	**71,410,691**	**17,968,841**
1329									
1330	**Total Operating Expenses**					**3,804,321,374**	**1,023,057,412**	**4,253,009,219**	**1,146,955,592**

	REVISED PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
1331	310	Land and Land Rights							
1332			P	SG		2,328,228	606,573	2,328,228	606,573
1333			P	SG		34,798,446	9,066,040	34,798,446	9,066,040
1334			P	SG		53,412,167	13,915,473	53,412,167	13,915,473
1335			P	S		-	-	-	-
1336			P	SSGCH		2,468,743	664,384	2,468,743	664,384
1337					B8	93,007,584	24,252,469	93,007,584	24,252,469
1338									
1339	311	Structures and Improvements							
1340			P	SG		233,321,135	60,787,159	233,321,135	60,787,159
1341			P	SG		324,156,573	84,452,517	324,156,573	84,452,517
1342			P	SG		351,799,294	91,654,276	351,799,294	91,654,276
1343			P	SSGCH		60,162,131	16,190,724	60,162,131	16,190,724
1344					B8	969,439,133	253,084,676	969,439,133	253,084,676
1345									
1346	312	Boiler Plant Equipment							
1347			P	SG		626,136,118	163,127,253	582,279,218	151,701,214
1348			P	SG		563,119,063	146,709,419	523,643,651	136,424,889
1349			P	SG		2,642,215,151	688,376,356	2,754,131,841	717,534,013
1350			P	SSGCH		326,012,913	87,736,007	327,514,876	88,140,212
1351					B8	4,157,483,245	1,085,949,034	4,187,569,587	1,093,800,328
1352									
1353	314	Turbogenerator Units							
1354			P	SG		121,781,725	31,727,795	121,781,725	31,727,795
1355			P	SG		134,947,365	35,157,839	134,947,365	35,157,839
1356			P	SG		645,203,132	168,094,782	637,274,246	166,029,069
1357			P	SSGCH		66,201,616	17,816,060	66,201,616	17,816,060
1358					B8	968,133,838	252,796,476	960,204,952	250,730,763
1359									
1360	315	Accessory Electric Equipment							
1361			P	SG		86,687,072	22,584,584	86,687,072	22,584,584
1362			P	SG		137,089,386	35,715,900	137,089,386	35,715,900
1363			P	SG		162,218,902	42,262,893	162,218,902	42,262,893
1364			P	SSGCH		67,334,063	18,120,822	67,334,063	18,120,822
1365					B8	453,329,423	118,684,199	453,329,423	118,684,199
1366									
1367									
1368									
1369	316	Misc Power Plant Equipment							
1370			P	SG		4,633,610	1,207,194	4,633,610	1,207,194
1371			P	SG		5,085,197	1,324,846	5,085,197	1,324,846
1372			P	SG		19,683,635	5,128,178	19,683,635	5,128,178
1373			P	SSGCH		4,155,009	1,118,188	4,155,009	1,118,188
1374					B8	33,557,450	8,778,407	33,557,450	8,778,407
1375									
1376	317	Steam Plant ARO							
1377			P	S		-	-	-	-
1378					B8	-	-	-	-
1379									
1380	SP	Unclassified Steam Plant - Account 300							
1381			P	SG		(22,737,202)	(5,923,724)	(22,737,202)	(5,923,724)
1382					B8	(22,737,202)	(5,923,724)	(22,737,202)	(5,923,724)
1383									
1384									
1385	**Total Steam Production Plant**				**B8**	**6,652,213,470**	**1,737,621,537**	**6,674,370,926**	**1,743,407,119**
1386									
1387									
1388	Summary of Steam Production Plant by Factor								
1389		S				-	-	-	-
1390		DGP				-	-	-	-
1391		DGU				-	-	-	-
1392		SG				6,125,878,995	1,595,975,353	6,146,534,488	1,601,356,729
1393		SSGCH				526,334,475	141,646,184	527,836,438	142,050,389
1394	Total Steam Production Plant by Factor					6,652,213,470	1,737,621,537	6,674,370,926	1,743,407,119
1395	320	Land and Land Rights							
1396			P	SG		-	-	-	-
1397			P	SG		-	-	-	-
1398					B8	-	-	-	-
1399									
1400	321	Structures and Improvements							
1401			P	SG		-	-	-	-
1402			P	SG	B8	-	-	-	-
1403						-	-	-	-

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
322	Reactor Plant Equipment							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
323	Turbogenerator Units							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
324	Land and Land Rights							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
325	Misc. Power Plant Equipment							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B8	-	-	-	-
NP	Unclassified Nuclear Plant - Acct 300							
		P	SG		-	-	-	-
				B8	-	-	-	-
Total Nuclear Production Plant				**B8**	**-**	**-**	**-**	**-**
Summary of Nuclear Production Plant by Factor								
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				-	-	-	-
Total Nuclear Plant by Factor					-	-	-	-
330	Land and Land Rights							
		P	SG		10,551,027	2,748,859	10,551,027	2,748,859
		P	SG		5,266,732	1,372,142	5,266,732	1,372,142
		P	SG		15,039,610	3,918,270	15,039,610	3,918,270
		P	SG		672,873	175,304	672,873	175,304
				B8	31,530,243	8,214,575	31,530,243	8,214,575
331	Structures and Improvements							
		P	SG		20,523,158	5,346,899	20,523,158	5,346,899
		P	SG		5,241,539	1,365,578	5,241,539	1,365,578
		P	SG		107,540,371	28,017,495	107,540,371	28,017,495
		P	SG		8,830,412	2,300,587	8,830,412	2,300,587
				B8	142,135,480	37,030,559	142,135,480	37,030,559
332	Reservoirs, Dams & Waterways							
		P	SG		147,899,455	38,532,247	143,429,363	37,367,654
		P	SG		19,502,638	5,081,023	18,250,810	4,754,884
		P	SG		137,824,060	35,907,305	339,248,611	88,384,446
		P	SG		53,789,787	14,013,854	72,634,834	18,923,555
				B8	359,015,940	93,534,429	573,563,619	149,430,539
333	Water Wheel, Turbines, & Generators							
		P	SG		30,070,051	7,834,151	30,070,051	7,834,151
		P	SG		8,441,577	2,199,284	8,441,577	2,199,284
		P	SG		50,067,352	13,044,048	50,067,352	13,044,048
		P	SG		30,405,968	7,921,667	30,405,968	7,921,667
				B8	118,984,948	30,999,150	118,984,948	30,999,150
334	Accessory Electric Equipment							
		P	SG		4,102,459	1,068,814	4,102,459	1,068,814
		P	SG		3,495,538	910,693	3,495,538	910,693
		P	SG		51,337,502	13,374,960	51,337,502	13,374,960
		P	SG		7,490,384	1,951,470	7,490,384	1,951,470
				B8	66,425,883	17,305,936	66,425,883	17,305,936

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Line	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1477									
1478									
1479	335	Misc. Power Plant Equipment							
1480			P	SG		1,145,017	298,311	1,145,017	298,311
1481			P	SG		157,719	41,091	157,719	41,091
1482			P	SG		1,043,475	271,857	1,043,475	271,857
1483			P	SG		12,582	3,278	12,582	3,278
1484					B8	2,358,793	614,536	2,358,793	614,536
1485									
1486	336	Roads, Railroads & Bridges							
1487			P	SG		4,597,710	1,197,841	4,597,710	1,197,841
1488			P	SG		822,766	214,355	822,766	214,355
1489			P	SG		10,714,114	2,791,348	10,714,114	2,791,348
1490			P	SG		726,716	189,331	726,716	189,331
1491					B8	16,861,306	4,392,876	16,861,306	4,392,876
1492									
1493	337	Hydro Plant ARO							
1494			P	S		-	-	-	-
1495					B8	-	-	-	-
1496									
1497	HP	Unclassified Hydro Plant - Acct 300							
1498			P	S		-	-	-	-
1499			P	SG		-	-	-	-
1500			P	SG		-	-	-	-
1501			P	SG		-	-	-	-
1502					B8	-	-	-	-
1503									
1504	**Total Hydraulic Production Plant**				**B8**	**737,312,593**	**192,092,062**	**951,860,271**	**247,988,172**
1505									
1506	Summary of Hydraulic Plant by Factor								
1507		S				-	-	-	-
1508		SG				737,312,593	192,092,062	951,860,271	247,988,172
1509		DGP				-	-	-	-
1510		DGU				-	-	-	-
1511	Total Hydraulic Plant by Factor					737,312,593	192,092,062	951,860,271	247,988,172
1512									
1513	340	Land and Land Rights							
1514			P	S		-	-	75,000	75,000
1515			P	SG		28,894,615	7,527,915	28,894,615	7,527,915
1516			P	SG		-	-	-	-
1517			P	SSGCT		-	-	-	-
1518					B8	28,894,615	7,527,915	28,969,615	7,602,915
1519									
1520	341	Structures and Improvements							
1521			P	SG		159,580,327	41,575,465	156,480,034	40,767,746
1522			P	SG		163,512	42,600	163,512	42,600
1523			P	SSGCT		4,240,304	1,124,202	4,240,304	1,124,202
1524					B8	163,984,143	42,742,267	160,883,850	41,934,547
1525									
1526	342	Fuel Holders, Producers & Accessories							
1527			P	SG		8,424,526	2,194,842	8,424,526	2,194,842
1528			P	SG		-	-	-	-
1529			P	SSGCT		2,462,148	652,772	2,462,148	652,772
1530					B8	10,886,674	2,847,614	10,886,674	2,847,614
1531									
1532	343	Prime Movers							
1533			P	S		-	-	-	-
1534			P	SG		242,141	63,085	43,906	11,439
1535			P	SG		2,441,616,585	636,114,408	2,290,268,983	596,683,815
1536			P	SSGCT		54,729,341	14,510,004	53,842,912	14,274,991
1537					B8	2,496,588,068	650,687,498	2,344,155,801	610,970,245
1538									
1539	344	Generators							
1540			P	S		-	-	-	-
1541			P	SG		-	-	-	-
1542			P	SG		336,222,815	87,596,135	330,372,442	86,071,938
1543			P	SSGCT		15,944,197	4,227,172	15,944,197	4,227,172
1544					B8	352,167,012	91,823,308	346,316,639	90,299,110

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	OREGON
345	Accessory Electric Plant							
		P	SG		246,082,037	64,111,757	233,870,087	60,930,177
		P	SG		156,586	40,795	156,586	40,795
		P	SSGCT		3,007,064	797,242	3,007,064	797,242
				B8	249,245,687	64,949,794	237,033,737	61,768,214
346	Misc. Power Plant Equipment							
		P	SG		12,474,935	3,250,095	11,815,438	3,078,276
		P	SG		11,813	3,078	11,813	3,078
				B8	12,486,748	3,253,173	11,827,251	3,081,354
347	Other Production ARO							
		P	S		-	-	-	-
				B8	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300							
		P	S		-	-	-	-
		P	SG		-	-	-	-
					-	-	-	-
Total Other Production Plant				**B8**	**3,314,252,948**	**863,831,567**	**3,140,073,567**	**818,503,999**
Summary of Other Production Plant by Factor								
	S				-	-	75,000	75,000
	DGU				-	-	-	-
	SG				3,233,869,894	842,520,176	3,060,501,942	797,352,620
	SSGCT				80,383,054	21,311,392	79,496,625	21,076,379
Total of Other Production Plant by Factor					3,314,252,948	863,831,567	3,140,073,567	818,503,999
Experimental Plant								
103	Experimental Plant							
		P	SG		-	-	-	-
Total Experimental Production Plant				**B8**	**-**	**-**	**-**	**-**
Total Production Plant				**B8**	**10,703,779,011**	**2,793,545,167**	**10,766,304,764**	**2,809,899,290**
350	Land and Land Rights							
		T	SG		21,116,232	5,501,412	21,116,232	5,501,412
		T	SG		48,469,541	12,627,770	48,469,541	12,627,770
		T	SG		125,199,107	32,618,125	125,199,107	32,618,125
				B8	194,784,879	50,747,308	194,784,879	50,747,308
352	Structures and Improvements							
		T	S		-	-	-	-
		T	SG		7,433,421	1,936,629	7,433,421	1,936,629
		T	SG		18,083,218	4,711,221	18,083,218	4,711,221
		T	SG		129,700,598	33,790,899	129,700,598	33,790,899
				B8	155,217,238	40,438,749	155,217,238	40,438,749
353	Station Equipment							
		T	SG		121,389,908	31,625,715	121,389,908	31,625,715
		T	SG		179,206,263	46,688,610	179,206,263	46,688,610
		T	SG		1,361,438,651	354,695,634	1,360,515,549	354,455,138
				B8	1,662,034,821	433,009,959	1,661,111,719	432,769,463
354	Towers and Fixtures							
		T	SG		155,435,933	40,495,726	155,435,933	40,495,726
		T	SG		133,295,649	34,727,518	133,295,649	34,727,518
		T	SG		695,554,276	181,212,767	695,554,276	181,212,767
				B8	984,285,858	256,436,010	984,285,858	256,436,010
355	Poles and Fixtures							
		T	S		-	-	-	-
		T	SG		65,808,250	17,145,025	57,511,821	14,983,556
		T	SG		116,294,040	30,298,088	109,861,355	28,622,181
		T	SG		474,042,596	123,502,325	1,181,959,906	307,936,033
				B8	656,144,886	170,945,438	1,349,333,082	351,541,770

REVISED PROTOCOL

	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1615	356	Clearing and Grading							
1616			T	SG		185,272,868	48,269,143	185,272,868	48,269,143
1617			T	SG		157,446,338	41,019,497	157,446,338	41,019,497
1618			T	SG		560,225,539	145,955,569	560,225,539	145,955,569
1619					B8	902,944,745	235,244,209	902,944,745	235,244,209
1620									
1621	357	Underground Conduit							
1622			T	SG		6,371	1,660	6,371	1,660
1623			T	SG		91,651	23,878	91,651	23,878
1624			T	SG		3,170,534	826,019	3,170,534	826,019
1625					B8	3,268,556	851,557	3,268,556	851,557
1626									
1627	358	Underground Conductors							
1628			T	SG		-	-	-	-
1629			T	SG		1,087,552	283,340	1,087,552	283,340
1630			T	SG		6,389,533	1,664,665	6,389,533	1,664,665
1631					B8	7,477,085	1,948,005	7,477,085	1,948,005
1632									
1633	359	Roads and Trails							
1634			T	SG		1,863,032	485,376	1,863,032	485,376
1635			T	SG		440,513	114,767	440,513	114,767
1636			T	SG		9,283,137	2,418,536	9,283,137	2,418,536
1637					B8	11,586,681	3,018,678	11,586,681	3,018,678
1638									
1639	TP	Unclassified Trans Plant - Acct 300							
1640			T	SG		6,334,193	1,650,247	6,334,193	1,650,247
1641					B8	6,334,193	1,650,247	6,334,193	1,650,247
1642									
1643	TS0	Unclassified Trans Sub Plant - Acct 300							
1644			T	SG		-	-	-	-
1645					B8	-	-	-	-
1646									
1647	**Total Transmission Plant**				**B8**	**4,584,078,943**	**1,194,290,161**	**5,276,344,037**	**1,374,645,997**
1648	Summary of Transmission Plant by Factor								
1649			DGP			-	-	-	-
1650			DGU			-	-	-	-
1651			SG			4,584,078,943	1,194,290,161	5,276,344,037	1,374,645,997
1652	Total Transmission Plant by Factor					4,584,078,943	1,194,290,161	5,276,344,037	1,374,645,997
1653	360	Land and Land Rights							
1654			DPW	S		58,999,246	13,164,238	60,834,094	13,747,277
1655					B8	58,999,246	13,164,238	60,834,094	13,747,277
1656									
1657	361	Structures and Improvements							
1658			DPW	S		85,716,168	22,195,790	88,381,900	23,042,848
1659					B8	85,716,168	22,195,790	88,381,900	23,042,848
1660									
1661	362	Station Equipment							
1662			DPW	S		869,991,777	212,939,062	897,048,109	221,536,435
1663					B8	869,991,777	212,939,062	897,048,109	221,536,435
1664									
1665	363	Storage Battery Equipment							
1666			DPW	S		-	-	-	-
1667					B8	-	-	-	-
1668									
1669	364	Poles, Towers & Fixtures							
1670			DPW	S		1,000,131,154	332,414,679	1,031,234,760	342,298,106
1671					B8	1,000,131,154	332,414,679	1,031,234,760	342,298,106
1672									
1673	365	Overhead Conductors							
1674			DPW	S		672,490,564	237,217,176	693,404,702	243,862,816
1675					B8	672,490,564	237,217,176	693,404,702	243,862,816
1676									

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
366	Underground Conduit							
		DPW	S		317,027,620	85,675,877	326,887,029	88,808,786
				B8	317,027,620	85,675,877	326,887,029	88,808,786
367	Underground Conductors							
		DPW	S		746,144,068	159,274,223	769,348,795	166,647,716
				B8	746,144,068	159,274,223	769,348,795	166,647,716
368	Line Transformers							
		DPW	S		1,145,072,411	396,579,456	1,180,683,621	407,895,211
				B8	1,145,072,411	396,579,456	1,180,683,621	407,895,211
369	Services							
		DPW	S		616,539,518	228,911,524	635,713,605	235,004,248
				B8	616,539,518	228,911,524	635,713,605	235,004,248
370	Meters							
		DPW	S		176,183,046	59,644,428	181,662,255	61,385,492
				B8	176,183,046	59,644,428	181,662,255	61,385,492
371	Installations on Customers' Premises							
		DPW	S		8,822,755	2,506,290	9,097,139	2,593,477
				B8	8,822,755	2,506,290	9,097,139	2,593,477
372	Leased Property							
		DPW	S		-	-	-	-
				B8	-	-	-	-
373	Street Lights							
		DPW	S		61,531,317	22,303,399	63,444,912	22,911,460
				B8	61,531,317	22,303,399	63,444,912	22,911,460
DP	Unclassified Dist Plant - Acct 300							
		DPW	S		28,945,772	5,984,241	28,945,772	5,984,241
				B8	28,945,772	5,984,241	28,945,772	5,984,241
DS0	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		-	-	-	-
				B8	-	-	-	-
Total Distribution Plant				**B8**	**5,787,595,414**	**1,778,810,385**	**5,966,686,693**	**1,835,718,113**
Summary of Distribution Plant by Factor								
	S				5,787,595,414	1,778,810,385	5,966,686,693	1,835,718,113
Total Distribution Plant by Factor					5,787,595,414	1,778,810,385	5,966,686,693	1,835,718,113

REVISED PROTOCOL

Line	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1727	389	Land and Land Rights							
1728			G-SITUS	S		12,748,785	4,601,321	12,748,785	4,601,321
1729			CUST	CN		1,128,506	342,221	1,128,506	342,221
1730			G-DGU	SG		332	87	332	87
1731			G-SG	SG		1,228	320	1,228	320
1732			PTD	SO		5,596,700	1,533,778	5,596,700	1,533,778
1733					B8	19,475,551	6,477,727	19,475,551	6,477,727
1734									
1735	390	Structures and Improvements							
1736			G-SITUS	S		114,694,304	33,734,032	114,694,304	33,734,032
1737			G-DGP	SG		355,153	92,528	355,153	92,528
1738			G-DGU	SG		1,633,901	425,680	1,633,901	425,680
1739			CUST	CN		12,317,880	3,735,417	12,317,880	3,735,417
1740			G-SG	SG		5,353,435	1,394,731	5,353,435	1,394,731
1741			PTD	SO		103,108,968	28,257,060	103,108,968	28,257,060
1742					B8	237,463,641	67,639,448	237,463,641	67,639,448
1743									
1744	391	Office Furniture & Equipment							
1745			G-SITUS	S		11,227,878	3,217,356	11,227,878	3,217,356
1746			G-DGP	SG		-	-	-	-
1747			G-DGU	SG		5,295	1,380	5,295	1,380
1748			CUST	CN		8,637,133	2,619,224	8,637,133	2,619,224
1749			G-SG	SG		4,566,605	1,189,738	4,557,892	1,187,468
1750			P	SE		33,537	8,279	33,537	8,279
1751			PTD	SO		55,298,622	15,154,613	55,298,622	15,154,613
1752			P	SSGCH		90,667	24,400	90,667	24,400
1753			P	SSGCT		-	-	-	-
1754					B8	79,859,736	22,214,990	79,851,023	22,212,720
1755									
1756	392	Transportation Equipment							
1757			G-SITUS	S		78,250,993	23,846,950	78,250,993	23,846,950
1758			PTD	SO		7,379,542	2,022,367	7,379,542	2,022,367
1759			G-SG	SG		17,816,559	4,641,748	17,816,559	4,641,748
1760			CUST	CN		-	-	-	-
1761			G-DGU	SG		779,129	202,986	779,129	202,986
1762			P	SE		448,363	110,686	448,363	110,686
1763			G-DGP	SG		119,116	31,033	119,116	31,033
1764			P	SSGCH		343,984	92,572	343,984	92,572
1765			P	SSGCT		44,655	11,839	44,655	11,839
1766					B8	105,182,341	30,960,183	105,182,341	30,960,183
1767									
1768	393	Stores Equipment							
1769			G-SITUS	S		8,551,583	2,815,609	8,551,583	2,815,609
1770			G-DGP	SG		69,750	18,172	69,750	18,172
1771			G-DGU	SG		144,970	37,769	144,970	37,769
1772			PTD	SO		318,705	87,341	318,705	87,341
1773			G-SG	SG		4,887,374	1,273,308	4,887,374	1,273,308
1774			P	SSGCT		53,971	14,309	53,971	14,309
1775					B8	14,026,352	4,246,507	14,026,352	4,246,507

REVISED PROTOCOL
Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1776									
1777	394	Tools, Shop & Garage Equipment							
1778			G-SITUS	S		33,591,288	10,862,111	33,591,288	10,862,111
1779			G-DGP	SG		1,077,687	280,770	1,077,687	280,770
1780			G-SG	SG		21,609,243	5,629,856	21,609,243	5,629,856
1781			PTD	SO		3,774,723	1,034,464	3,774,723	1,034,464
1782			P	SE		5,617	1,387	5,617	1,387
1783			G-DGU	SG		558,757	145,573	558,757	145,573
1784			P	SSGCH		1,842,348	495,809	1,842,348	495,809
1785			P	SSGCT		89,913	23,838	89,913	23,838
1786					B8	62,549,577	18,473,809	62,549,577	18,473,809
1787									
1788	395	Laboratory Equipment							
1789			G-SITUS	S		24,502,509	9,673,147	24,502,509	9,673,147
1790			G-DGP	SG		1,518	395	1,518	395
1791			G-DGU	SG		5,371	1,399	5,371	1,399
1792			PTD	SO		5,280,671	1,447,170	5,280,671	1,447,170
1793			P	SE		7,593	1,875	7,593	1,875
1794			G-SG	SG		6,447,255	1,679,703	6,447,255	1,679,703
1795			P	SSGCH		253,001	68,087	253,001	68,087
1796			P	SSGCT		14,022	3,717	14,022	3,717
1797					B8	36,511,939	12,875,495	36,511,939	12,875,495
1798									
1799	396	Power Operated Equipment							
1800			G-SITUS	S		114,772,768	34,331,104	114,772,768	34,331,104
1801			G-DGP	SG		845,108	220,176	845,108	220,176
1802			G-SG	SG		34,189,753	8,907,457	34,189,753	8,907,457
1803			PTD	SO		1,919,236	525,968	1,919,236	525,968
1804			G-DGU	SG		1,574,205	410,128	1,574,205	410,128
1805			P	SE		45,031	11,117	45,031	11,117
1806			P	SSGCT		-	-	-	-
1807			P	SSGCH		999,837	269,074	999,837	269,074
1808					B8	154,345,939	44,675,024	154,345,939	44,675,024
1809	397	Communication Equipment							
1810			DPW	S		131,979,895	45,080,205	171,472,150	59,628,025
1811			G-DGP	SG		1,301,936	339,193	(1,027,955)	(267,813)
1812			G-DGU	SG		1,544,068	402,276	(3,242,763)	(844,837)
1813			PTD	SO		58,258,262	15,965,704	48,146,596	13,194,597
1814			CUST	CN		2,855,125	865,821	790,311	239,663
1815			G-SG	SG		110,649,879	28,827,615	125,597,831	32,722,005
1816			P	SE		232,898	57,495	109,139	26,943
1817			G-SG	SSGCH		619,180	166,633	1,684,406	453,304
1818			G-SG	SSGCT		1,590	422	(21,704)	(5,754)
1819					B8	307,442,833	91,705,364	343,508,011	105,146,133
1820									
1821	398	Misc. Equipment							
1822			G-SITUS	S		2,121,606	1,082,798	2,121,606	1,082,798
1823			G-DGP	SG		-	-	-	-
1824			G-DGU	SG		-	-	-	-
1825			CUST	CN		215,589	65,378	215,589	65,378
1826			PTD	SO		2,960,972	811,456	2,960,972	811,456
1827			P	SE		1,668	412	1,668	412
1828			G-SG	SG		2,069,905	539,272	2,069,905	539,272
1829			G-SG	SSGCT		-	-	-	-
1830					B8	7,369,740	2,499,316	7,369,740	2,499,316
1831									
1832	399	Coal Mine							
1833			P	SE		292,563,015	72,224,250	482,121,148	119,019,960
1834	MP		P	SE		-	-	-	-
1835					B8	292,563,015	72,224,250	482,121,148	119,019,960
1836									
1837	399L	WIDCO Capital Lease							
1838			P	SE	Tab 8	-	-	-	-
1839						-	-	-	-
1840									
1841		Remove Capital Leases				-	-	-	-
1842					Tab 8	-	-	-	-
1843									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1844	1011390	General Capital Leases							
1845			G-SITUS	S		18,984,156	5,882,166	18,984,156	5,882,166
1846			P	SG		33,744,912	8,791,562	33,744,912	8,791,562
1847			PTD	SO		12,664,054	3,470,590	12,664,054	3,470,590
1848					B9	65,393,121	18,144,319	65,393,121	18,144,319
1849									
1850		Remove Capital Leases				(65,393,121)	(18,144,319)	(65,393,121)	(18,144,319)
1851						-	-	-	-
1852									
1853	1011346	General Gas Line Capital Leases							
1854			P	SG		-	-	-	-
1855					B9	-	-	-	-
1856									
1857		Remove Capital Leases				-	-	-	-
1858						-	-	-	-
1859									
1860	GP	Unclassified Gen Plant - Acct 300							
1861			G-SITUS	S		-	-	-	-
1862			PTD	SO		7,401,397	2,028,356	7,401,397	2,028,356
1863			CUST	CN		-	-	-	-
1864			G-SG	SG		-	-	-	-
1865			G-DGP	SG		-	-	-	-
1866			G-DGU	SG		-	-	-	-
1867					B8	7,401,397	2,028,356	7,401,397	2,028,356
1868									
1869	399G	Unclassified Gen Plant - Acct 300							
1870			G-SITUS	S		-	-	-	-
1871			PTD	SO		-	-	-	-
1872			G-SG	SG		-	-	-	-
1873			G-DGP	SG		-	-	-	-
1874			G-DGU	SG		-	-	-	-
1875					B8	-	-	-	-
1876									
1877	**Total General Plant**				**B8**	**1,324,192,060**	**376,020,467**	**1,549,806,658**	**436,254,676**
1878									
1879	Summary of General Plant by Factor								
1880		S				551,425,763	175,126,799	590,918,018	189,674,619
1881		DGP				-	-	-	-
1882		DGU				-	-	-	-
1883		SG				251,352,443	65,484,856	259,174,961	67,522,857
1884		SO				263,961,851	72,338,868	253,850,185	69,567,761
1885		SE				293,337,722	72,415,500	482,772,097	119,180,658
1886		CN				25,154,232	7,628,061	23,089,418	7,001,903
1887		DEU				-	-	-	-
1888		SSGCT				204,151	54,125	180,857	47,949
1889		SSGCH				4,149,017	1,116,576	5,214,243	1,403,248
1890		Less Capital Leases				(65,393,121)	(18,144,319)	(65,393,121)	(18,144,319)
1891	Total General Plant by Factor					1,324,192,060	376,020,467	1,549,806,658	436,254,676
1892	301	Organization							
1893			I-SITUS	S		-	-	-	-
1894			PTD	SO		-	-	-	-
1895			I-SG	SG		-	-	-	-
1896					B8	-	-	-	-
1897	302	Franchise & Consent							
1898			I-SITUS	S		1,000,000	-	1,000,000	-
1899			I-SG	SG		10,419,206	2,714,516	5,558,601	1,448,182
1900			I-SG	SG		173,622,224	45,233,801	171,139,925	44,587,087
1901			I-SG	SG		9,189,363	2,394,105	9,035,229	2,353,948
1902			I-DGP	SG		-	-	(956,836)	(249,285)
1903			I-DGU	SG		600,993	156,577	577,415	150,434
1904					B8	194,831,786	50,498,998	186,354,334	48,290,368
1905									

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Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1906	303	Miscellaneous Intangible Plant							
1907			I-SITUS	S		10,757,522	3,994,986	10,738,312	3,992,922
1908			I-SG	SG		138,585,578	36,105,703	138,585,578	36,105,703
1909			PTD	SO		383,331,947	105,052,298	395,971,206	108,516,093
1910			P	SE		3,666,461	905,129	3,554,385	877,462
1911			CUST	CN		122,787,241	37,235,426	122,467,102	37,138,343
1912			P	SG		-	-	-	-
1913			I-DGP	SSGCT		-	-	-	-
1914					B8	659,128,750	183,293,543	671,316,583	186,630,523
1915	303	Less Non-Utility Plant							
1916			I-SITUS	S		-	-	-	-
1917						659,128,750	183,293,543	671,316,583	186,630,523
1918	IP	Unclassified Intangible Plant - Acct 300							
1919			I-SITUS	S		-	-	-	-
1920			I-SG	SG		-	-	-	-
1921			I-DGU	SG		-	-	-	-
1922			PTD	SO		-	-	-	-
1923						-	-	-	-
1924									
1925	**Total Intangible Plant**				**B8**	**853,960,537**	**233,792,542**	**857,670,918**	**234,920,890**
1926									
1927	Summary of Intangible Plant by Factor								
1928		S				11,757,522	3,994,986	11,738,312	3,992,922
1929		DGP				-	-	-	-
1930		DGU				-	-	-	-
1931		SG				332,417,365	86,604,701	323,939,913	84,396,071
1932		SO				383,331,947	105,052,298	395,971,206	108,516,093
1933		CN				122,787,241	37,235,426	122,467,102	37,138,343
1934		SSGCT				-	-	-	-
1935		SSGCH				-	-	-	-
1936		SE				3,666,461	905,129	3,554,385	877,462
1937	Total Intangible Plant by Factor					853,960,537	233,792,542	857,670,918	234,920,890
1938	Summary of Unclassified Plant (Account 106)								
1939		DP				28,945,772	5,984,241	28,945,772	5,984,241
1940		DS0				-	-	-	-
1941		GP				7,401,397	2,028,356	7,401,397	2,028,356
1942		HP				-	-	-	-
1943		NP				-	-	-	-
1944		OP				-	-	-	-
1945		TP				6,334,193	1,650,247	6,334,193	1,650,247
1946		TS0				-	-	-	-
1947		IP				-	-	-	-
1948		MP							
1949		SP				(22,737,202)	(5,923,724)	(22,737,202)	(5,923,724)
1950	Total Unclassified Plant by Factor					19,944,160	3,739,121	19,944,160	3,739,121
1951									
1952	**Total Electric Plant In Service**				**B8**	**23,253,605,964**	**6,376,458,720**	**24,416,813,071**	**6,691,438,966**

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Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
1953	Summary of Electric Plant by Factor								
1954		S				6,350,778,700	1,957,932,171	6,569,418,023	2,029,460,653
1955		SE				297,004,184	73,320,629	486,326,482	120,058,119
1956		DGU				-	-	-	-
1957		DGP				-	-	-	-
1958		SG				15,264,910,232	3,976,967,309	16,018,355,612	4,173,262,446
1959		SO				647,293,799	177,391,166	649,821,391	178,083,854
1960		CN				147,941,474	44,863,487	145,556,521	44,140,246
1961		DEU				-	-	-	-
1962		SSGCH				530,483,493	142,762,760	533,050,681	143,453,637
1963		SSGCT				80,587,205	21,365,517	79,677,482	21,124,328
1964		Less Capital Leases				(65,393,121)	(18,144,319)	(65,393,121)	(18,144,319)
1965						23,253,605,964	6,376,458,720	24,416,813,071	6,691,438,966
1966	105	Plant Held For Future Use							
1967			DPW	S		7,945,429	4,254,106	-	-
1968			P	SG		-	-	-	-
1969			P	SG		2,996,636	780,714	-	-
1970			P	SG		8,923,302	2,324,788	-	-
1971			P	SE		26,313,198	6,495,869	-	-
1972			G	SG		-	-	-	-
1973									
1974									
1975	**Total Plant Held For Future Use**				**B10**	**46,178,566**	**13,855,477**	**-**	**-**
1976									
1977	114	Electric Plant Acquisition Adjustments							
1978			P	S		-	-	-	-
1979			P	SG		144,614,797	37,676,495	144,614,797	37,676,495
1980			P	SG		14,560,711	3,793,502	14,560,711	3,793,502
1981	**Total Electric Plant Acquisition Adjustment**				**B15**	**159,175,508**	**41,469,998**	**159,175,508**	**41,469,998**
1982									
1983	115	Accum Provision for Asset Acquisition Adjustments							
1984			P	S		-	-	-	-
1985			P	SG		(96,250,428)	(25,076,125)	(106,632,236)	(27,780,898)
1986			P	SG		(13,880,792)	(3,616,363)	(13,880,792)	(3,616,363)
1987					B15	(110,131,220)	(28,692,489)	(120,513,028)	(31,397,261)
1988									
1989	120	Nuclear Fuel							
1990			P	SE		-	-	-	-
1991	**Total Nuclear Fuel**				**B15**	**-**	**-**	**-**	**-**
1992									
1993	124	Weatherization							
1994			DMSC	S		1,714,949	0	1,714,949	0
1995			DMSC	SO		(4,454)	(1,221)	(4,454)	(1,221)
1996					B16	1,710,495	(1,220)	1,710,495	(1,220)
1997									
1998	182W	Weatherization							
1999			DMSC	S		(7,588,159)	-	(7,588,159)	-
2000			DMSC	SG		-	-	-	-
2001			DMSC	SGCT		-	-	-	-
2002			DMSC	SO		-	-	-	-
2003					B16	(7,588,159)	-	(7,588,159)	-
2004									
2005	186W	Weatherization							
2006			DMSC	S		-	-	-	-
2007			DMSC	CN		-	-	-	-
2008			DMSC	CNP		-	-	-	-
2009			DMSC	SG		-	-	-	-
2010			DMSC	SO		-	-	-	-
2011					B16	-	-	-	-
2012									
2013	**Total Weatherization**				**B16**	**(5,877,664)**	**(1,220)**	**(5,877,664)**	**(1,220)**

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Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
151	Fuel Stock							
		P	DEU		-	-	-	-
		P	SE		259,761,148	64,126,541	240,567,099	59,388,157
		P	SSECT		-	-	-	-
		P	SSECH		10,115,124	2,553,776	10,795,211	2,725,479
Total Fuel Stock				**B13**	**269,876,272**	**66,680,317**	**251,362,310**	**62,113,636**
152	Fuel Stock - Undistributed							
		P	SE		-	-	-	-
					-	-	-	-
25316	DG&T Working Capital Deposit							
		P	SE		(3,235,000)	(798,616)	(3,549,923)	(876,360)
				B13	(3,235,000)	(798,616)	(3,549,923)	(876,360)
25317	DG&T Working Capital Deposit							
		P	SE		(2,489,934)	(614,683)	(2,858,749)	(705,732)
				B13	(2,489,934)	(614,683)	(2,858,749)	(705,732)
25319	Provo Working Capital Deposit							
		P	SE		-	-	-	-
					-	-	-	-
	Total Fuel Stock			B13	264,151,338	65,267,018	244,953,638	60,531,544
154	Materials and Supplies							
		MSS	S		91,436,270	30,297,434	91,436,270	30,297,434
		MSS	SG		4,700,056	1,224,506	4,700,056	1,224,506
		MSS	SE		5,973,797	1,474,735	5,973,797	1,474,735
		MSS	SO		203,687	55,821	203,687	55,821
		MSS	SNPPS		93,226,734	24,358,523	93,226,734	24,358,523
		MSS	SNPPH		1,563	407	1,563	407
		MSS	SNPD		(2,280,591)	(612,831)	(2,280,591)	(612,831)
		MSS	SG		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SG		-	-	-	-
		MSS	SSGCT		-	-	-	-
		MSS	SNPPO		7,383,487	1,924,514	7,383,487	1,924,514
		MSS	SSGCH		-	-	-	-
Total Materials and Supplies				**B13**	**200,645,004**	**58,723,109**	**200,645,004**	**58,723,109**
163	Stores Expense Undistributed							
		MSS	SO		-	-	-	-
				B13	-	-	-	-
25318	Provo Working Capital Deposit							
		MSS	SNPPS		(273,000)	(71,330)	(273,000)	(71,330)
				B13	(273,000)	(71,330)	(273,000)	(71,330)
	Total Materials & Supplies			B13	200,372,004	58,651,779	200,372,004	58,651,779
165	Prepayments							
		DMSC	S		8,415,026	2,425,369	8,415,026	2,425,369
		GP	GPS		216,127	59,223	216,127	59,223
		PT	SG		3,397,261	885,088	3,397,261	885,088
		P	SE		3,194,786	788,688	3,194,786	788,688
		PTD	SO		11,099,974	3,041,953	11,099,974	3,041,953
Total Prepayments				**B15**	**26,323,174**	**7,200,322**	**26,323,174**	**7,200,322**

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	Year End					DECEMBER 2014		DECEMBER 2014	
	FERC		BUS			PRO FORMA RESULTS		PRO FORMA RESULTS	
	ACCT	DESCRIP	FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
2075	182M	Misc Regulatory Assets							
2076			DDS2	S		171,580,102	(273,550)	171,687,728	(165,924)
2077			DEFSG	SG		-	-	-	-
2078			P	SGCT		5,705,661	1,491,496	3,460,811	904,678
2079			DEFSG	SG-P		-	-	-	-
2080			P	SE		-	-	-	-
2081			P	SSGCT		-	-	-	-
2082			DDSO2	SO		10,028,834	2,748,407	186,514,834	51,114,477
2083					B11	187,314,597	3,966,353	361,663,373	51,853,231
2084									
2085	186M	Misc Deferred Debits							
2086			LABOR	S		18,192,572	-	18,192,572	-
2087			P	SG		-	-	-	-
2088			P	SG		-	-	-	-
2089			DEFSG	SG		61,941,029	16,137,497	71,711,913	18,683,106
2090			LABOR	SO		19,594	5,370	19,594	5,370
2091			P	SE		13,641,055	3,367,531	13,641,055	3,367,531
2092			P	SNPPS		-	-	-	-
2093			GP	EXCTAX		-	-	-	-
2094	**Total Misc. Deferred Debits**				**B11**	**93,794,250**	**19,510,398**	**103,565,134**	**22,056,006**
2095									
2096	Working Capital								
2097	CWC	Cash Working Capital							
2098			CWC	S		43,896,281	15,569,379	50,160,053	17,832,917
2099			CWC	SO		-	-	-	-
2100			CWC	SE		-	-	-	-
2101					B14	43,896,281	15,569,379	50,160,053	17,832,917
2102									
2103	OWC	Other Work. Cap.							
2104	131	Cash	GP	SNP		-	-	-	-
2105	135	Working Funds	P	SG		-	-	-	-
2106	141	Notes Receivabl	GP	SO		-	-	-	-
2107	143	Other A/R	GP	SO		57,855,649	15,855,367	57,855,649	15,855,367
2108	232	A/P	PTD	S		(6,379)	-	(6,379)	-
2109	232	A/P	PTD	SO		(5,265,990)	(1,443,147)	(5,265,990)	(1,443,147)
2110	232	A/P	P	SE		(2,204,099)	(544,120)	(2,204,099)	(544,120)
2111	232	A/P	T	SG		(86,375)	(22,503)	(86,375)	(22,503)
2112	2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2113	2533	Other Msc. Df. Crd.	P	SE		(6,534,614)	(1,613,183)	(6,910,016)	(1,705,857)
2114	230	Asset Retir. Oblig.	P	SE		(2,849,851)	(703,535)	(2,849,851)	(703,535)
2115	230	Asset Retir. Oblig.	P	S		-	-	-	-
2116	254105	ARO Reg Liability	P	S		-	-	-	-
2117	254105	ARO Reg Liability	P	SE		(976,925)	(241,171)	(976,925)	(241,171)
2118	2533	Cholla Reclamation	P	SSECH		-	-	-	-
2119					B14	39,931,417	11,287,709	39,556,014	11,195,034
2120									
2121	**Total Working Capital**				**B14**	**83,827,698**	**26,857,088**	**89,716,067**	**29,027,951**
2122	Miscellaneous Rate Base								
2123	18221	Unrec Plant & Reg Study Costs							
2124			P	S		-	-	-	-
2125									
2126					B15	-	-	-	-
2127									
2128	18222	Nuclear Plant - Trojan							
2129			P	S		-	-	-	-
2130			P	TROJP		-	-	-	-
2131			P	TROJD		-	-	-	-
2132					B15	-	-	-	-
2133									
2134									

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2135									
2136	1869	Misc Deferred Debits-Trojan							
2137			P	S		-	-	-	-
2138			P	SNPPN		-	-	-	-
2139					B15	-	-	-	-
2140									
2141	**Total Miscellaneous Rate Base**				**B15**	**-**	**-**	**-**	**-**
2142									
2143	**Total Rate Base Additions**				**B15**	**945,128,249**	**208,084,723**	**1,059,378,205**	**239,392,350**
2144	235	Customer Service Deposits							
2145			CUST	S		-	-	-	-
2146			CUST	CN		-	-	-	-
2147	**Total Customer Service Deposits**				B15	-	-	-	-
2148									
2149	2281	Prop Ins	PTD	SO		-	-	-	-
2150	2282	Inj & Dam	PTD	SO		(12,639,000)	(3,463,724)	(12,639,000)	(3,463,724)
2151	2283	Pen & Ben	PTD	SO		(3,057,213)	(837,831)	(3,057,213)	(837,831)
2152	254	Ins Prov	PTD	SO		-	-	-	-
2153	254	Reg Liabilitie	P	SE		-	-	-	-
2154					B15	(15,696,213)	(4,301,554)	(15,696,213)	(4,301,554)
2155									
2156	22844	Accum Hydro Relicensing Obligation							
2157			P	S		-	-	-	-
2158			P	SG		-	-	-	-
2159					B15	-	-	-	-
2160									
2161	22841	Chehalis Rat	P	SG		(1,479,562)	(385,470)	(1,479,562)	(385,470)
2162	230	ARO	P	TROJP		-	-	-	-
2163	254105	ARO	P	TROJP		(3,236,234)	(836,419)	(3,236,234)	(836,419)
2164	254		P	S		(31,648,165)	298,028	(31,648,165)	298,028
2165					B15	(36,363,961)	(923,862)	(36,363,961)	(923,862)
2166									
2167	252	Customer Advances for Construction							
2168			DPW	S		(4,145,233)	(1,774,969)	(8,116,990)	(1,935,702)
2169			DPW	SE		-	-	-	-
2170			T	SG		(18,645,453)	(4,857,700)	(14,673,696)	(3,822,938)
2171			DPW	SO		-	-	-	-
2172			CUST	CN		-	-	-	-
2173	**Total Customer Advances for Construction**				**B19**	**(22,790,686)**	**(6,632,669)**	**(22,790,686)**	**(5,758,640)**
2174									
2175	25398	SO2 Emissions							
2176			P	SE		-	-	(121,735)	(30,052)
2177					B19	-	-	(121,735)	(30,052)
2178									
2179	25399	Other Deferred Credits							
2180			P	S		(809,095)	(297,151)	(809,095)	(297,151)
2181			LABOR	SO		-	-	-	-
2182			P	SG		(9,689,058)	(2,524,291)	(9,689,058)	(2,524,291)
2183			P	SE		-	-	-	-
2184					B19	(10,498,153)	(2,821,441)	(10,498,153)	(2,821,441)

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	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2185									
2186	190	Accumulated Deferred Income Taxes							
2187			P	S		32,624,509	5,571,396	20,838,367	1,681,887
2188			CUST	CN		28,936	8,775	10,661	3,233
2189			LABOR	SO		78,367,323	21,476,601	81,133,803	22,234,756
2190			P	GPS		-	-	-	-
2191			IBT	IBT		-	-	-	-
2192			P	SG-P		-	-	-	-
2193			P	SG-U		-	-	-	-
2194			CUST	BADDEBT		5,515,134	2,614,576	4,215,846	1,998,619
2195			P	TROJD		1,917,975	495,006	1,880,194	485,256
2196			P	SG		44,555,610	11,608,074	3,409,554	888,291
2197			P	SE		5,811,555	1,434,683	(31,493,628)	(7,774,748)
2198			PTD	SNP		-	-	-	-
2199			DPW	SNPD		806,637	216,756	1,988,128	534,242
2200			P	SSGCT		-	-	-	-
2201	**Total Accum Deferred Income Taxes**				**B19**	**169,627,679**	**43,425,868**	**81,982,925**	**20,051,535**
2202									
2203	281	Accumulated Deferred Income Taxes							
2204			P	S		-	-	-	-
2205			PT	SG		(178,288,826)	(46,449,591)	-	-
2206			T	SG		-	-	-	-
2207					B19	(178,288,826)	(46,449,591)	-	-
2208									
2209	282	Accumulated Deferred Income Taxes							
2210			GP	S		-	-	(3,865,514,515)	(1,033,679,794)
2211			GP	CN		-	-	-	-
2212			TAXDEPR	DGU		-	-	-	-
2213			ACCMDIT	DITBAL		(3,360,555,483)	(909,311,178)	6	2
2214			P	DGP		-	-	-	-
2215			DPW	SG-P		-	-	-	-
2216			P	SSGCH		-	-	-	-
2217			PT	SG-U		-	-	-	-
2218			LABOR	SO		22,811,348	6,251,461	21,089,899	5,779,697
2219			GP	SSGCT		-	-	-	-
2220			P	SE		(5,108,635)	(1,261,155)	(5,832,388)	(1,439,826)
2221			P	SG		(4,458,160)	(1,161,484)	12,848,905	3,347,526
2222					B19	(3,347,310,930)	(905,482,357)	(3,837,408,093)	(1,025,992,396)
2223									
2224	283	Accumulated Deferred Income Taxes							
2225			GP	S		(76,689,057)	1,894,728	(26,514,301)	(471,523)
2226			P	SG		(2,807,889)	(731,539)	(1,873,877)	(488,201)
2227			P	SE		(2,611,320)	(644,650)	(2,605,290)	(643,161)
2228			LABOR	SO		(8,742,187)	(2,395,800)	(14,278,359)	(3,912,991)
2229			GP	GPS		(5,949,550)	(1,630,305)	(7,389,065)	(2,024,763)
2230			PTD	SNP		(3,672,481)	(971,006)	(2,924,599)	(773,265)
2231			P	TROJD		-	-	-	-
2232			P	SSGCT		-	-	-	-
2233			P	SGCT		(2,378,341)	(621,714)	(1,313,412)	(343,334)
2234			P	IBT		-	-	-	-
2235					B19	(102,850,825)	(5,100,285)	(56,898,902)	(8,657,238)
2236									
2237	**Total Accum Deferred Income Tax**				**B19**	**(3,458,822,902)**	**(913,606,365)**	**(3,812,324,071)**	**(1,014,598,099)**
2238	255	Accumulated Investment Tax Credit							
2239			PTD	S		-	-	-	-
2240			PTD	ITC84		(290,837)	(206,424)	-	-
2241			PTD	ITC85		(1,347,412)	(912,063)	(190,006)	(128,615)
2242			PTD	ITC86		(863,199)	(557,696)	(388,922)	(251,275)
2243			PTD	ITC88		(148,176)	(90,684)	(91,199)	(55,814)
2244			PTD	ITC89		(339,502)	(191,329)	(226,217)	(127,487)
2245			PTD	ITC90		(243,966)	(38,877)	(188,628)	(30,059)
2246			PTD	DGU		-	-	-	-
2247	**Total Accumlated ITC**				**B19**	(3,233,092)	(1,997,073)	(1,084,972)	(593,249)
2248									
2249	**Total Rate Base Deductions**					**(3,547,405,008)**	**(930,282,966)**	**(3,898,879,791)**	**(1,029,026,898)**
2250									

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
108SP	Steam Prod Plant Accumulated Depr							
		P	S		-	-	-	-
		P	SG		(755,843,347)	(196,919,879)	(775,000,005)	(201,910,764)
		P	SG		(814,203,937)	(212,124,565)	(831,327,873)	(216,585,864)
		P	SG		(675,402,811)	(175,962,705)	(1,105,123,069)	(287,917,731)
		P	SSGCH		(172,395,851)	(46,394,860)	(197,909,136)	(53,260,949)
				B17	(2,417,845,946)	(631,402,010)	(2,909,360,083)	(759,675,308)
108NP	Nuclear Prod Plant Accumulated Depr							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B17	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr							
		P	S		-	-	-	-
		P	SG		(154,655,295)	(40,292,347)	(155,927,854)	(40,623,886)
		P	SG		(29,281,162)	(7,628,622)	(29,864,357)	(7,780,561)
		P	SG		(57,986,251)	(15,107,159)	(77,056,297)	(20,075,478)
		P	SG		(21,132,737)	(5,505,712)	(26,946,882)	(7,020,472)
				B17	(263,055,446)	(68,533,840)	(289,795,388)	(75,500,397)
108OP	Other Production Plant - Accum Depr							
		P	S		-	-	-	-
		P	SG		(1,000,886)	(260,761)	(829,117)	(216,010)
		P	SG		-	-	-	-
		P	SG		(512,725,603)	(133,580,410)	(626,071,697)	(163,110,469)
		P	SSGCT		(22,545,768)	(5,977,400)	(25,970,172)	(6,885,288)
				B17	(536,272,257)	(139,818,571)	(652,870,986)	(170,211,768)
108EP	Experimental Plant - Accum Depr							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
					-	-	-	-
Total Production Plant Accum Depreciation				**B17**	**(3,217,173,648)**	**(839,754,420)**	**(3,852,026,457)**	**(1,005,387,473)**
Summary of Prod Plant Depreciation by Factor								
	S				-	-	-	-
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				(3,022,232,029)	(787,382,159)	(3,628,147,149)	(945,241,235)
	SSGCH				(172,395,851)	(46,394,860)	(197,909,136)	(53,260,949)
	SSGCT				(22,545,768)	(5,977,400)	(25,970,172)	(6,885,288)
Total of Prod Plant Depreciation by Factor					(3,217,173,648)	(839,754,420)	(3,852,026,457)	(1,005,387,473)
108TP	Transmission Plant Accumulated Depr							
		T	S		-	-	-	-
		T	SG		(369,658,339)	(96,307,093)	(376,788,696)	(98,164,765)
		T	SG		(398,638,323)	(103,857,249)	(409,900,684)	(106,791,432)
		T	SG		(483,569,188)	(125,984,288)	(565,124,573)	(147,231,914)
Total Trans Plant Accum Depreciation				**B17**	**(1,251,865,849)**	**(326,148,630)**	**(1,351,813,952)**	**(352,188,111)**

REVISED PROTOCOL

	Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
2307	108360	Land and Land Rights							
2308			DPW	S		(7,638,160)	(2,439,164)	(9,198,016)	(3,036,579)
2309					B17	(7,638,160)	(2,439,164)	(9,198,016)	(3,036,579)
2310									
2311	108361	Structures and Improvements							
2312			DPW	S		(15,519,872)	(3,885,172)	(17,786,085)	(4,753,117)
2313					B17	(15,519,872)	(3,885,172)	(17,786,085)	(4,753,117)
2314									
2315	108362	Station Equipment							
2316			DPW	S		(216,923,165)	(60,646,672)	(239,924,509)	(69,456,044)
2317					B17	(216,923,165)	(60,646,672)	(239,924,509)	(69,456,044)
2318									
2319	108363	Storage Battery Equipment							
2320			DPW	S		-	-	-	-
2321					B17	-	-	-	-
2322									
2323	108364	Poles, Towers & Fixtures							
2324			DPW	S		(569,064,966)	(219,323,380)	(595,507,011)	(229,450,519)
2325					B17	(569,064,966)	(219,323,380)	(595,507,011)	(229,450,519)
2326									
2327	108365	Overhead Conductors							
2328			DPW	S		(306,896,598)	(132,370,285)	(324,676,291)	(139,179,797)
2329					B17	(306,896,598)	(132,370,285)	(324,676,291)	(139,179,797)
2330									
2331	108366	Underground Conduit							
2332			DPW	S		(128,927,979)	(37,892,880)	(137,309,739)	(41,103,042)
2333					B17	(128,927,979)	(37,892,880)	(137,309,739)	(41,103,042)
2334									
2335	108367	Underground Conductors							
2336			DPW	S		(294,642,008)	(62,560,236)	(314,368,995)	(70,115,550)
2337					B17	(294,642,008)	(62,560,236)	(314,368,995)	(70,115,550)
2338									
2339	108368	Line Transformers							
2340			DPW	S		(387,610,097)	(175,369,931)	(417,884,183)	(186,964,718)
2341					B17	(387,610,097)	(175,369,931)	(417,884,183)	(186,964,718)
2342									
2343	108369	Services							
2344			DPW	S		(186,188,983)	(72,184,238)	(202,489,410)	(78,427,201)
2345					B17	(186,188,983)	(72,184,238)	(202,489,410)	(78,427,201)
2346									
2347	108370	Meters							
2348			DPW	S		(69,851,398)	(33,197,639)	(74,509,427)	(34,981,635)
2349					B17	(69,851,398)	(33,197,639)	(74,509,427)	(34,981,635)
2350									
2351									
2352									
2353	108371	Installations on Customers' Premises							
2354			DPW	S		(7,545,086)	(2,526,538)	(7,778,347)	(2,615,875)
2355					B17	(7,545,086)	(2,526,538)	(7,778,347)	(2,615,875)
2356									
2357	108372	Leased Property							
2358			DPW	S		-	-	-	-
2359					B17	-	-	-	-
2360									
2361	108373	Street Lights							
2362			DPW	S		(27,313,402)	(8,973,182)	(28,940,203)	(9,596,236)
2363					B17	(27,313,402)	(8,973,182)	(28,940,203)	(9,596,236)
2364									
2365	108D00	Unclassified Dist Plant - Acct 300							
2366			DPW	S		-	-	-	-
2367					B17	-	-	-	-
2368									
2369	108DS	Unclassified Dist Sub Plant - Acct 300							
2370			DPW	S		-	-	-	-
2371					B17	-	-	-	-
2372									
2373	108DP	Unclassified Dist Sub Plant - Acct 300							
2374			DPW	S		1,741,637	817,585	1,741,637	817,585
2375					B17	1,741,637	817,585	1,741,637	817,585
2376									
2377									
2378	**Total Distribution Plant Accum Depreciation**				**B17**	**(2,216,380,077)**	**(810,551,730)**	**(2,368,630,579)**	**(868,862,729)**
2379									
2380	Summary of Distribution Plant Depr by Factor								
2381		S				(2,216,380,077)	(810,551,730)	(2,368,630,579)	(868,862,729)
2382									
2383	Total Distribution Depreciation by Factor					(2,216,380,077)	(810,551,730)	(2,368,630,579)	(868,862,729)

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
108GP	General Plant Accumulated Depr							
		G-SITUS	S		(166,793,901)	(50,557,550)	(173,802,498)	(51,479,635)
		G-DGP	SG		(2,572,738)	(670,276)	(402,915)	(104,971)
		G-DGU	SG		(3,676,496)	(957,838)	814,832	212,288
		G-SG	SG		(59,966,753)	(15,623,139)	(67,440,897)	(17,570,378)
		CUST	CN		(8,786,738)	(2,664,592)	(9,220,436)	(2,796,112)
		PTD	SO		(78,928,937)	(21,630,512)	(72,319,411)	(19,819,168)
		P	SE		(310,133)	(76,562)	(257,640)	(63,603)
		P	SSGCT		(51,569)	(13,672)	(41,478)	(10,997)
		P	SSGCH		(2,102,292)	(565,765)	(1,837,545)	(494,517)
				B17	(323,189,557)	(92,759,905)	(324,507,988)	(92,127,093)
108MP	Mining Plant Accumulated Depr.							
		P	S		-	-	-	-
		P	SE		(161,499,586)	(39,868,971)	(174,787,386)	(43,149,295)
				B17	(161,499,586)	(39,868,971)	(174,787,386)	(43,149,295)
108MP	Less Centralia Situs Depreciation							
		P	S		-	-	-	-
				B17	(161,499,586)	(39,868,971)	(174,787,386)	(43,149,295)
1081390	Accum Depr - Capital Lease							
		PTD	SO	B17	-	-	-	-
					-	-	-	-
	Remove Capital Leases				-	-	-	-
				B17	-	-	-	-
1081399	Accum Depr - Capital Lease							
		P	S		-	-	-	-
		P	SE	B17	-	-	-	-
					-	-	-	-
	Remove Capital Leases				-	-	-	-
				B17	-	-	-	-
Total General Plant Accum Depreciation				**B17**	**(484,689,143)**	**(132,628,876)**	**(499,295,374)**	**(135,276,388)**
Summary of General Depreciation by Factor								
	S				(166,793,901)	(50,557,550)	(173,802,498)	(51,479,635)
	DGP				-	-	-	-
	DGU				-	-	-	-
	SE				(161,809,718)	(39,945,533)	(175,045,026)	(43,212,898)
	SO				(78,928,937)	(21,630,512)	(72,319,411)	(19,819,168)
	CN				(8,786,738)	(2,664,592)	(9,220,436)	(2,796,112)
	SG				(66,215,988)	(17,251,252)	(67,028,980)	(17,463,061)
	DEU				-	-	-	-
	SSGCT				(51,569)	(13,672)	(41,478)	(10,997)
	SSGCH				(2,102,292)	(565,765)	(1,837,545)	(494,517)
	Remove Capital Leases				-	-	-	-
Total General Depreciation by Factor					(484,689,143)	(132,628,876)	(499,295,374)	(135,276,388)
Total Accum Depreciation - Plant In Service				**B17**	**(7,170,108,718)**	**(2,109,083,656)**	**(8,071,766,363)**	**(2,361,714,700)**
111SP	Accum Prov for Amort-Steam							
		P	SSGCH		-	-	-	-
		P	SSGCT		-	-	-	-
				B18	-	-	-	-
111GP	Accum Prov for Amort-General							
		G-SITUS	S		(10,105,921)	(3,943,245)	(11,164,775)	(4,290,302)
		CUST	CN		(3,134,593)	(950,570)	(3,544,644)	(1,074,919)
		I-SG	SG		-	-	-	-
		PTD	SO		(12,094,200)	(3,314,421)	(14,012,557)	(3,840,148)
		P	SE		-	-	-	-
				B18	(25,334,715)	(8,208,237)	(28,721,975)	(9,205,368)

REVISED PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON	DECEMBER 2014 PRO FORMA RESULTS TOTAL	DECEMBER 2014 PRO FORMA RESULTS OREGON
111HP	Accum Prov for Amort-Hydro							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		(473,877)	(123,459)	(941,292)	(245,235)
		P	SG		(506,676)	(132,004)	(573,475)	(149,407)
				B18	(980,553)	(255,464)	(1,514,767)	(394,642)
111IP	Accum Prov for Amort-Intangible Plant							
		I-SITUS	S		(1,263,532)	(61,511)	(1,528,757)	(77,091)
		I-DGP	SG		-	-	956,836	249,285
		I-DGU	SG		(374,534)	(97,577)	(375,381)	(97,798)
		P	SE		(1,794,223)	(442,935)	(2,190,791)	(540,835)
		I-SG	SG		(52,567,449)	(13,695,398)	(50,513,331)	(13,160,239)
		I-SG	SG		(30,399,471)	(7,919,975)	(44,178,273)	(11,509,766)
		I-SG	SG		(3,831,411)	(998,197)	(4,131,863)	(1,076,474)
		CUST	CN		(103,869,877)	(31,498,705)	(113,185,569)	(34,323,704)
		P	SSGCT		-	-	-	-
		P	SSGCH		(327,836)	(88,227)	(327,836)	(88,227)
		PTD	SO		(280,901,816)	(76,981,273)	(299,062,366)	(81,958,180)
				B18	(475,330,148)	(131,783,799)	(514,537,332)	(142,583,029)
111IP	Less Non-Utility Plant							
		NUTIL	OTH		-	-	-	-
					(475,330,148)	(131,783,799)	(514,537,332)	(142,583,029)
111390	Accum Amtr - Capital Lease							
		G-SITUS	S		(5,325,839)	(2,469,170)	(5,325,839)	(2,469,170)
		P	SG		(5,217,177)	(1,359,231)	(5,217,177)	(1,359,231)
		PTD	SO		428,996	117,567	428,996	117,567
					(10,114,020)	(3,710,835)	(10,114,020)	(3,710,835)
	Remove Capital Lease Amtr				10,114,020	3,710,835	10,114,020	3,710,835
Total Accum Provision for Amortization				**B18**	**(501,645,416)**	**(140,247,499)**	**(544,774,074)**	**(152,183,040)**
Summary of Amortization by Factor								
	S				(16,695,291)	(6,473,926)	(18,019,371)	(6,836,562)
	DGP				-	-	-	-
	DGU				-	-	-	-
	SE				(1,794,223)	(442,935)	(2,190,791)	(540,835)
	SO				(292,567,021)	(80,178,128)	(312,645,927)	(85,680,762)
	CN				(107,004,470)	(32,449,276)	(116,730,213)	(35,398,622)
	SSGCT				-	-	-	-
	SSGCH				(327,836)	(88,227)	(327,836)	(88,227)
	SG				(93,370,594)	(24,325,842)	(104,973,957)	(27,348,867)
	Less Capital Lease				10,114,020	3,710,835	10,114,020	3,710,835
Total Provision For Amortization by Factor					(501,645,416)	(140,247,499)	(544,774,074)	(152,183,040)

Oregon General Rate Case
Pro Forma Factors December 31, 2014
2010 Protocol Factors

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2014

DESCRIPTION	2010 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Situs	S	-	-	-	-	-	-	-			Situs
System Generation	SG	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%			Pg 11.17
System Generation (Pac. Power Costs on SG)	SG-P	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%			Pg 11.17
System Generation (R.M.P. Costs on SG)	SG-U	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%			Pg 11.17
Divisional Generation - Pac. Power	DGP	3.1958%	54.5093%	16.2403%	0.0000%	0.0000%	26.0546%	0.0000%			Pg 11.17
Divisional Generation - R.M.P.	DGU	0.0000%	0.0000%	0.0000%	82.3322%	10.8527%	6.1728%	0.6422%			Pg 11.17
System Capacity	SC	1.5360%	26.5084%	7.9038%	43.1617%	5.4452%	15.1183%	0.3264%			Pg 11.17
System Energy	SE	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%			Pg 11.17
System Energy (Pac. Power Costs on SE)	SE-P	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%			Pg 11.17
System Energy (R.M.P. Costs on SE)	SE-U	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%			Pg 11.17
Divisional Energy - Pac. Power	DEP	3.1836%	52.3359%	15.5546%	0.0000%	0.0000%	28.9260%	0.0000%			Pg 10.17
Divisional Energy - R.M.P.	DEU	0.0000%	0.0000%	0.0000%	80.3316%	11.9756%	7.0080%	0.6848%			Pg 10.17
System Overhead	SO	2.1676%	27.3843%	7.5604%	42.7546%	5.5274%	14.3643%	0.2414%			Pg 10.8
System Overhead (Pac. Power Costs on SO)	SO-P	2.1676%	27.3843%	7.5604%	42.7546%	5.5274%	14.3643%	0.2414%			Pg 10.8
System Overhead (R.M.P. Costs on SO)	SO-U	2.1676%	27.3843%	7.5604%	42.7546%	5.5274%	14.3643%	0.2414%			Pg 10.8
Divisional Overhead - Pac. Power	DOP	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Divisional Overhead - R.M.P.	DOU	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Gross Plant-System	GPS	2.1676%	27.3843%	7.5604%	42.7546%	5.5274%	14.3643%	0.2414%			Pg 10.7
System Gross Plant - Pac. Power	SGPP	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
System Gross Plant - R.M.P.	SGPU	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
System Net Plant	SNP	1.9976%	26.4197%	7.3560%	43.9964%	5.4916%	14.4896%	0.2491%			Pg 10.7
Seasonal System Capacity Combustion Turbine	SSCCT	1.5537%	27.1130%	8.0709%	42.6292%	5.2344%	15.0692%	0.3296%			Pg 10.19
Seasonal System Energy Combustion Turbine	SSECT	1.4953%	24.7102%	7.3836%	42.4990%	6.2502%	17.2933%	0.3683%			Pg 10.18
Seasonal System Capacity Cholla	SSCCH	1.5631%	27.4667%	8.1167%	41.7439%	5.3552%	15.4467%	0.3077%			Pg 10.20
Seasonal System Energy Cholla	SSECH	1.4847%	25.2471%	7.5861%	41.8597%	5.9743%	17.4959%	0.3523%			Pg 10.19
Seasonal System Generation Cholla	SSGCH	1.5435%	26.9118%	7.9841%	41.7728%	5.5100%	15.9590%	0.3188%			Pg 10.20
Seasonal System Capacity Purchases	SSCP	1.4318%	24.8097%	7.6803%	46.7506%	4.9884%	13.9390%	0.4002%			Pg 10.21
Seasonal System Energy Purchases	SSEP	1.4976%	23.2909%	6.9931%	44.3813%	6.8377%	16.5922%	0.4071%			Pg 10.20
Seasonal System Generation Contracts	SSGC	1.4482%	24.4300%	7.5085%	46.1583%	5.4507%	14.6023%	0.4019%			Pg 10.21
Seasonal System Generation Combustion Turbine	SSGCT	1.5391%	26.5123%	7.8991%	42.5966%	5.4884%	15.6252%	0.3393%			Pg 10.19
Mid-Columbia	MC	1.1327%	41.6826%	9.2352%	31.8744%	4.2016%	11.6248%	0.2486%			Pg 10.18
Division Net Plant Distribution	SNPD	3.3878%	26.8716%	6.1390%	48.2023%	4.7372%	10.6621%	0.0000%			Pg 10.6
Divisional Generation - Huntington	DGUH	0.0000%	0.0000%	0.0000%	82.3322%	10.8527%	6.1728%	0.6422%			Pg 10.17
Divisional Energy - Huntington	DEUH	0.0000%	0.0000%	0.0000%	80.3316%	11.9756%	7.0080%	0.6848%			Pg 10.17
Division Net Plant General-Mine - Pac. Power	DNPGMP	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant General-Mine - R.M.P.	DNPGMU	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%			Pg 10.6
Division Net Plant Intangible - Pac. Power	DNPIP	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Intangible - R.M.P.	DNPIU	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Steam - Pac. Power	DNPPSP	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Steam - R.M.P.	DNPPSU	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Hydro - Pac. Power	DNPPHP	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Division Net Plant Hydro - R.M.P.	DNPPHU	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
System Net Hydro Plant-Pac. Power	SNPPH-P	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%			Pg 10.4
System Net Hydro Plant-R.M.P.	SNPPH-U	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%			Pg 10.4
Customer - System	CN	2.4697%	30.3252%	6.9301%	48.9622%	3.8567%	7.4561%	0.0000%	0.0000%	0.0000%	Pg 10.11
Customer - Pac. Power	CNP	5.3301%	65.4476%	14.9565%	0.0000%	0.0000%	14.2659%	0.0000%	0.0000%	0.0000%	Pg 10.11
Customer - R.M.P.	CNU	0.0000%	0.0000%	0.0000%	91.2369%	7.1866%	1.5765%	0.0000%	0.0000%	0.0000%	Pg 10.11
Washington Business Tax	WBTAX	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Situs
Operating Revenue - Idaho	OPRV-ID	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Operating Revenue - Wyoming	OPRVWY	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			Not Used
Excise Tax - superfund	EXCTAX	4.6822%	25.6295%	5.6948%	32.9544%	2.6611%	9.4967%	-0.6378%	27.6495%	-8.1304%	Pg 10.12
Interest	INT	1.9976%	26.4197%	7.3560%	43.9964%	5.4916%	14.4896%	0.2491%		0.0000%	Pg 10.8
CIAC	CIAC	3.3878%	26.8716%	6.1390%	48.2023%	4.7372%	10.6621%	0.0000%			Pg 10.11

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2014

DESCRIPTION	2010 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Idaho State Income Tax	IDSIT	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%		0.0000%	Pg 10.11
Blank	DONOTUSE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Bad Debt Expense	BADDEBT	3.8302%	47.4073%	14.1454%	24.6282%	4.5851%	5.4038%	0.0000%	0.0000%	0.0000%	Pg 10.10
Blank	DONOTUSE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Blank	DONOTUSE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Accumulated Investment Tax Credit 1984	ITC84	3.2870%	70.9760%	14.1800%			10.9460%			0.6110%	Fixed
Accumulated Investment Tax Credit 1985	ITC85	5.4200%	67.6900%	13.3600%			11.6100%			1.9200%	Fixed
Accumulated Investment Tax Credit 1986	ITC86	4.7890%	64.6080%	13.1260%			15.5000%			1.9770%	Fixed
Accumulated Investment Tax Credit 1988	ITC88	4.2700%	61.2000%	14.9600%			16.7100%			2.8600%	Fixed
Accumulated Investment Tax Credit 1989	ITC89	4.8806%	56.3558%	15.2688%			20.6776%			2.8172%	Fixed
Accumulated Investment Tax Credit 1990	ITC90	1.5047%	15.9356%	3.9132%	46.9355%	13.9815%	17.3435%			0.3860%	Fixed
Other Electric	OTHER	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	Situs
Non-Utility	NUTIL	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	Situs
System Net Steam Plant	SNPPS	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%			Pg 10.4
System Net Transmission Plant	SNPT	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%			Pg 10.5
System Net Production Plant	SNPP	1.5274%	26.0538%	7.7620%	42.9807%	5.6656%	15.6752%	0.3353%			Pg 10.5
System Net Hydro Plant	SNPPH	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%			Pg 10.4
System Net Nuclear Plant	SNPPN	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	0.0000%	0.3353%			Pg 10.4
System Net Other Production Plant	SNPPO	1.5274%	26.0552%	7.7619%	42.9798%	5.6654%	15.6749%	0.3353%			Pg 10.5
System Net General Plant	SNPG	2.4410%	30.2105%	7.0829%	39.5329%	6.2456%	14.3587%	0.1285%			Pg 10.6
System Net Intangible Plant	SNPI	1.7913%	26.9051%	7.8770%	42.6552%	5.5909%	14.8907%	0.2898%			Pg 10.7
Trojan Plant Allocator	TROJP	1.5235%	25.8455%	7.6975%	42.8988%	5.7660%	15.9293%	0.3393%			Pg 10.13
Trojan Decommissioning Allocator	TROJD	1.5229%	25.8088%	7.6861%	42.8843%	5.7838%	15.9741%	0.3400%			Pg 10.13
Income Before Taxes	IBT	4.7069%	25.7473%	5.7191%	33.0965%	2.6704%	9.5344%	-0.6417%	27.3429%	-8.1758%	Pg 10.8
DIT Expense	DITEXP	1.8715%	25.8651%	3.6799%	43.5936%	5.0036%	14.7421%	0.2403%	0.0000%	5.0040%	Pg 10.9
DIT Balance	DITBAL	2.1914%	27.0584%	6.0691%	43.2358%	5.5873%	14.0265%	0.2800%	0.0000%	1.5516%	Pg 10.10
Tax Depreciation	TAXDEPR	1.9895%	26.3977%	4.5251%	43.9698%	5.4408%	14.4734%	0.2560%	0.0000%	2.9477%	Pg 10.14
Blank	DONOTUSE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Blank	DONOTUSE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
Blank	DONOTUSE	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	Not Used
SCHMAT Depreciation Expense	SCHMDEXP	2.0573%	27.1013%	7.7709%	42.4326%	5.4402%	14.9357%	0.2620%	0.0000%	0.0000%	Pg 10.14
SCHMDT Amortization Expense	SCHMAEXP	1.8867%	26.8751%	7.5354%	42.4933%	5.2751%	14.6532%	0.2459%	1.0353%	0.0000%	Pg 10.13
System Generation Cholla Transaction	SGCT	1.5326%	26.1406%	7.7882%	43.1257%	5.6847%	15.7282%				Pg 10.17

CALCULATION OF INTERNAL FACTORS
Pro Forma Factors December 31, 2014

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other
STEAM :									
STEAM PRODUCTION PLANT									
	DGP	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	
	SG	6,674,370,926	101,947,838	1,738,873,965	518,072,352	2,868,719,915	378,144,066	22,377,245	
	SSGCH	0	0	0	0	0	0	0	
		6,674,370,926	101,947,838	1,738,873,965	518,072,352	2,868,719,915	378,144,066	22,377,245	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2014

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
LESS ACCUMULATED DEPRECIATION												
	DGP	(775,000,005)	(11,837,756)	(201,910,764)	(60,156,392)	(333,103,745)	(43,908,506)	(2,598,352)				
	DGU	(831,327,873)	(12,698,137)	(216,585,864)	(64,528,626)	(357,314,098)	(47,099,825)	(2,787,203)				
	SG	(1,105,123,069)	(16,880,229)	(287,917,731)	(85,780,924)	(474,994,361)	(62,612,003)	(3,705,160)				
	SSGCH	(197,909,136)	(3,022,968)	(51,561,270)	(15,361,935)	(85,063,579)	(11,212,767)	(663,532)				
		(2,909,360,083)	(44,439,090)	(757,975,629)	(225,827,878)	(1,250,475,783)	(164,833,100)	(9,754,247)				
TOTAL NET STEAM PLANT		3,765,010,843	57,508,748	980,898,336	292,244,474	1,618,244,132	213,310,966	12,622,998				
SNPPS												
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	0.3353%				
<u>NUCLEAR :</u>		<u>TOTAL</u>	<u>California</u>	<u>Oregon</u>	<u>Washington</u>	<u>Utah</u>	<u>Idaho</u>	<u>FERC</u>				
NUCLEAR PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	0	0	0	0	0	0	0				
		0	0	0	0	0	0	0				
LESS ACCUMULATED DEPRECIATION												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	0	0	0	0	0	0	0				
		0	0	0	0	0	0	0				
TOTAL NUCLEAR PLANT		0	0	0	0	0	0	0				
SNPPN												
SYSTEM NET PLANT PRODUCTION NUCLEAR		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%				
<u>HYDRO :</u>		<u>TOTAL</u>	<u>California</u>	<u>Oregon</u>	<u>Washington</u>	<u>Utah</u>	<u>Idaho</u>	<u>FERC</u>				
HYDRO PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	951,860,271	14,539,212	247,988,172	73,884,490	409,120,282	53,928,725	3,191,314				
		951,860,271	14,539,212	247,988,172	73,884,490	409,120,282	53,928,725	3,191,314				
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)												
	DGP	(155,927,854)	(2,381,724)	(40,623,886)	(12,103,299)	(67,019,550)	(8,834,270)	(522,781)				
	DGU	(29,864,357)	(456,164)	(7,780,561)	(2,318,106)	(12,836,037)	(1,691,999)	(100,127)				
	SG	(105,517,945)	(1,611,736)	(27,490,592)	(8,190,424)	(45,352,803)	(5,978,239)	(353,771)				
		(291,310,155)	(4,449,624)	(75,895,039)	(22,611,829)	(125,208,391)	(16,504,508)	(976,679)				
TOTAL NET HYDRO PRODUCTION PLANT		660,550,116	10,089,588	172,093,132	51,272,660	283,911,891	37,424,217	2,214,634				
SNPPH												
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	0.3353%				
<u>OTHER :</u>		<u>TOTAL</u>	<u>California</u>	<u>Oregon</u>	<u>Washington</u>	<u>Utah</u>	<u>Idaho</u>	<u>FERC</u>				
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)												
	S	75000	0	75000	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	3,139,998,567	47,961,983	818,063,877	243,730,302	1,349,606,805	177,900,185	10,527,512				
	SSGCT	0	0	0	0	0	0	0				
		3,140,073,567	47,961,983	818,138,877	243,730,302	1,349,606,805	177,900,185	10,527,512				

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2014

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
LESS ACCUMULATED DEPRECIATION												
	S	0	0	0	0	0	0	0				
	DGU	(829,117)	(12,664)	(216,010)	(64,357)	(356,364)	(46,975)	(2,780)				
	SG	(626,071,697)	(9,562,947)	(163,110,469)	(48,596,406)	(269,092,678)	(35,470,803)	(2,099,038)				
	SSGCT	(25,970,172)	(396,682)	(6,766,009)	(2,015,835)	(11,162,273)	(1,471,370)	(87,071)				
		(652,870,986)	(9,972,293)	(170,092,488)	(50,676,597)	(280,611,314)	(36,989,147)	(2,188,889)				
TOTAL NET OTHER PRODUCTION PLANT		2,487,202,581	37,989,690	648,046,389	193,053,705	1,068,995,491	140,911,038	8,338,623				
SNPPO												
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.5274%	26.0552%	7.7619%	42.9798%	5.6654%	0.3353%				
PRODUCTION :		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC				
TOTAL PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	10,766,304,764	164,449,033	2,805,001,014	835,687,144	4,627,447,002	609,972,977	36,096,071				
	SSGCH	0	0	0	0	0	0	0				
	SSGCT	0	0	0	0	0	0	0				
		10,766,304,764	164,449,033	2,805,001,014	835,687,144	4,627,447,002	609,972,977	36,096,071				
LESS ACCUMULATED DEPRECIATION												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	(3,853,541,224)	(58,861,007)	(1,003,963,157)	(299,116,305)	(1,656,295,488)	(218,326,755)	(12,919,815)				
	SSGCH	0	0	0	0	0	0	0				
	SSGCT	0	0	0	0	0	0	0				
		(3,853,541,224)	(58,861,007)	(1,003,963,157)	(299,116,305)	(1,656,295,488)	(218,326,755)	(12,919,815)				
TOTAL NET PRODUCTION PLANT		6,912,763,540	105,588,026	1,801,037,857	536,570,840	2,971,151,514	391,646,221	23,176,256				
SNPP												
SYSTEM NET PRODUCTION PLANT		100.0000%	1.5274%	26.0538%	7.7620%	42.9807%	5.6656%	0.3353%				
TRANSMISSION :		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC				
TRANSMISSION PLANT												
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SG	5,276,344,037	80,593,643	1,374,645,997	409,555,896	2,267,832,187	298,937,265	17,690,063				
		5,276,344,037	80,593,643	1,374,645,997	409,555,896	2,267,832,187	298,937,265	17,690,063				
LESS ACCUMULATED DEPRECIATION												
	DGP	(376,788,696)	(5,755,268)	(98,164,765)	(29,246,772)	(161,948,032)	(21,347,392)	(1,263,264)				
	DGU	(409,900,684)	(6,261,038)	(106,791,432)	(31,816,963)	(176,179,938)	(23,223,389)	(1,374,279)				
	SG	(565,124,573)	(8,632,009)	(147,231,914)	(43,865,620)	(242,896,916)	(32,017,775)	(1,894,700)				
		(1,351,813,952)	(20,648,314)	(352,188,111)	(104,929,355)	(581,024,886)	(76,588,555)	(4,532,243)				
TOTAL NET TRANSMISSION PLANT		3,924,530,085	59,945,328	1,022,457,886	304,626,542	1,686,807,301	222,348,710	13,157,820				
SNPT												
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	0.3353%				
DISTRIBUTION :		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC				
DISTRIBUTION PLANT - PACIFIC POWER												
	S	3,020,043,532	234,147,937	1,835,718,113	415,352,112	0	0	0				
LESS ACCUMULATED DEPRECIATION												
	S	(1,385,060,768)	(112,254,001)	(868,862,729)	(194,468,611)	0	0	-				
		1,634,982,764	121,893,937	966,855,384	220,883,501	0	0	0				

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
DNPDP												
DIVISION NET PLANT DISTRIBUTION PACIFIC POWER		100.0000%	7.4554%	59.1355%	13.5098%	0.0000%	0.0000%	0.0000%				
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER												
	S	2,946,643,161	0	0	0	2,549,031,689	298,859,188	0				
LESS ACCUMULATED DEPRECIATION												
	S	(983,569,811)	0	0	0	(814,685,513)	(128,411,173)	0				
		1,963,073,350	0	0	0	1,734,346,176	170,448,015	0				
DNPDU												
DIVISION NET PLANT DISTRIBUTION R.M.P.		100.0000%	0.0000%	0.0000%	0.0000%	88.3485%	8.6827%	0.0000%				
TOTAL NET DISTRIBUTION PLANT		3,598,056,114	121,893,937	966,855,384	220,883,501	1,734,346,176	170,448,015	0				
DNPD & SNPD												
SYSTEM NET PLANT DISTRIBUTION		100.0000%	3.3878%	26.8716%	6.1390%	48.2023%	4.7372%	0.0000%				
GENERAL :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
GENERAL PLANT												
	S	590,918,018	16,541,752	189,674,619	46,939,373	215,187,859	37,386,406	0				
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SE	650,949	9,775	160,698	47,761	276,258	41,184	2,355				
	SG	264,570,061	4,041,182	68,928,442	20,536,233	113,715,197	14,989,517	887,027				
	SO	253,850,185	5,502,565	69,514,985	19,192,017	108,532,589	14,031,360	612,810				
	CN	23,089,418	570,239	7,001,903	1,600,121	11,305,090	890,491	0				
	DEU	0	0	0	0	0	0	0				
	SSGCT	0	0	0	0	0	0	0				
	SSGCH	0	0	0	0	0	0	0				
	Remove Capital Lease	(65,393,121)	(789,949)	(18,141,686)	(3,576,768)	(31,632,641)	(2,611,851)	(143,709)				
		1,067,685,510	25,875,564	317,138,961	84,738,735	417,384,352	64,727,106	1,358,483				
LESS ACCUMULATED DEPRECIATION												
	S	(184,967,273)	(5,192,838)	(55,769,937)	(21,355,329)	(62,051,976)	(10,920,779)	0				
	DGP	(402,915)	(6,154)	(104,971)	(31,275)	(173,177)	(22,828)	(1,351)				
	DGU	814,832	12,446	212,288	63,248	350,224	46,165	2,732				
	SE	(257,640)	(3,869)	(63,603)	(18,903)	(109,341)	(16,300)	(932)				
	SG	(67,440,897)	(1,030,128)	(17,570,378)	(5,234,840)	(28,986,858)	(3,820,941)	(226,110)				
	SO	(86,331,968)	(1,871,368)	(23,641,367)	(6,527,017)	(36,910,873)	(4,771,928)	(208,411)				
	CN	(12,765,080)	(315,259)	(3,871,031)	(884,633)	(6,250,066)	(492,312)	0				
	SSGCT	(41,478)	(634)	(10,806)	(3,220)	(17,828)	(2,350)	(139)				
	SSGCH	(1,837,545)	(28,068)	(478,736)	(142,632)	(789,797)	(104,108)	(6,161)				
		(353,229,963)	(8,435,872)	(101,298,541)	(34,134,602)	(134,939,692)	(20,105,380)	(440,371)				
TOTAL NET GENERAL PLANT		714,455,547	17,439,692	215,840,420	50,604,133	282,444,660	44,621,726	918,112				
SNPG												
SYSTEM NET GENERAL PLANT		100.0000%	2.4410%	30.2105%	7.0829%	39.5329%	6.2456%	0.1285%				
MINING :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**FERC**				
GENERAL MINING PLANT												
	SE	482,121,148	7,240,039	119,019,960	35,373,546	204,608,990	30,502,461	1,744,230				
LESS ACCUMULATED DEPRECIATION												
	SE	(174,787,386)	(2,624,792)	(43,149,295)	(12,824,266)	(74,178,598)	(11,058,311)	(632,350)				
		307,333,762	4,615,248	75,870,665	22,549,281	130,430,393	19,444,151	1,111,880				
SNPM												
SYSTEM NET PLANT MINING		100.0000%	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	0.3618%				

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
INTANGIBLE :		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC				
INTANGIBLE PLANT												
	S	11,738,312	353,808	3,992,922	1,464,977	3,002,582	1,431,992	0				
	DGP	0	0	0	0	0	0	0				
	DGU	0	0	0	0	0	0	0				
	SE	3,554,385	53,376	877,462	260,788	1,508,457	224,876	12,859				
	CN	122,467,102	3,024,568	37,138,343	8,487,097	59,962,601	4,723,196	0				
	SG	323,939,913	4,948,028	84,396,071	25,144,589	139,233,029	18,353,184	1,086,077				
	SO	395,971,206	8,583,240	108,433,769	29,936,894	169,295,840	21,886,982	955,899				
	SSGCT	0	0	0	0	0	0	0				
	SSGCH	0	0	0	0	0	0	0				
		857,670,918	16,963,021	234,838,566	65,294,344	373,002,510	46,620,230	2,054,835				
LESS ACCUMULATED AMORTIZATION												
	S	(1,528,757)	0	(77,091)	255	(61,144)	(817,237)	0				
	DGP	956,836	14,615	249,285	74,271	411,259	54,211	3,208				
	DGU	(375,381)	(5,734)	(97,798)	(29,138)	(161,343)	(21,268)	(1,259)				
	SE	(2,190,791)	(32,899)	(540,835)	(160,740)	(929,757)	(138,605)	(7,926)				
	CN	(113,185,569)	(2,795,342)	(34,323,704)	(7,843,877)	(55,418,157)	(4,365,234)	0				
	SG	(98,823,467)	(1,509,481)	(25,746,480)	(7,670,791)	(42,475,441)	(5,598,956)	(331,327)				
	SO	(299,062,366)	(6,482,603)	(81,896,004)	(22,610,226)	(127,862,869)	(16,530,426)	(721,955)				
	SSGCT	0	0	0	0	0	0	0				
	SSGCH	(327,836)	(5,008)	(85,411)	(25,447)	(140,907)	(18,574)	(1,099)				
		(514,537,332)	(10,816,452)	(142,518,037)	(38,265,693)	(226,638,360)	(27,436,089)	(1,060,357)				
TOTAL NET INTANGIBLE PLANT		343,133,586	6,146,569	92,320,529	27,028,652	146,364,149	19,184,141	994,478				
SNPI												
SYSTEM NET INTANGIBLE PLANT		100.0000%	1.7913%	26.9051%	7.8770%	42.6552%	5.5909%	0.2898%				
GROSS PLANT :		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC				
PRODUCTION PLANT		10,766,304,764	164,449,033	2,805,001,014	835,687,144	4,627,447,002	609,972,977	36,096,071				
TRANSMISSION PLANT		5,276,344,037	80,593,643	1,374,645,997	409,555,896	2,267,832,187	298,937,265	17,690,063				
DISTRIBUTION PLANT		5,966,686,693	234,147,937	1,835,718,113	415,352,112	2,549,031,689	298,859,188	0				
GENERAL PLANT		1,549,806,658	33,115,603	436,158,921	120,112,281	621,993,343	95,229,568	3,102,713				
INTANGIBLE PLANT		857,670,918	16,963,021	234,838,566	65,294,344	373,002,510	46,620,230	2,054,835				
TOTAL GROSS PLANT		24,416,813,071	529,269,237	6,686,362,611	1,846,001,778	10,439,306,730	1,349,619,227	58,943,682				
GPS												
GROSS PLANT-SYSTEM FACTOR		100.0000%	2.1676%	27.3843%	7.5604%	42.7546%	5.5274%	0.2414%				
ACCUMULATED DEPRECIATION AND AMORTIZATION												
PRODUCTION PLANT		(3,853,541,224)	(58,861,007)	(1,003,963,157)	(299,116,305)	(1,656,295,488)	(218,326,755)	(12,919,815)				
TRANSMISSION PLANT		(1,351,813,952)	(20,648,314)	(352,188,111)	(104,929,355)	(581,024,886)	(76,588,555)	(4,532,243)				
DISTRIBUTION PLANT		(2,368,630,579)	(112,254,001)	(868,862,729)	(194,468,611)	(814,685,513)	(128,411,173)	0				
GENERAL PLANT		(528,017,350)	(11,060,663)	(144,447,836)	(46,958,867)	(209,118,290)	(31,163,691)	(1,072,722)				
INTANGIBLE PLANT		(514,537,332)	(10,816,452)	(142,518,037)	(38,265,693)	(226,638,360)	(27,436,089)	(1,060,357)				
		(8,616,540,437)	(213,640,438)	(2,511,979,870)	(683,738,830)	(3,487,762,537)	(481,926,263)	(19,585,137)				
NET PLANT		15,800,272,634	315,628,800	4,174,382,741	1,162,262,948	6,951,544,194	867,692,964	39,358,545				
SNP												
SYSTEM NET PLANT FACTOR (SNP)		100.0000%	1.9976%	26.4197%	7.3560%	43.9964%	5.4916%	0.2491%				

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
NON-UTILITY RELATED INTEREST PERCENTAGE		0.0000%										
INT												
INTEREST FACTOR SNP - NON-UTILITY		100.0000%	1.9976%	26.4197%	7.3560%	43.9964%	5.4916%	0.2491%				
TOTAL GROSS PLANT (LESS SO FACTOR)		23,766,991,680	515,183,432	6,508,413,857	1,796,872,867	10,161,478,301	1,313,700,885	57,374,974				
SO												
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	2.1676%	27.3843%	7.5604%	42.7546%	5.5274%	0.2414%				

IBT	TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
INCOME BEFORE TAXES									
Adjustment to 10.5% Target ROE	0	=-(UTCR!K150-(U'	=-(UTCR!L150-(UTC	=-(UTCR!M150-(UT(	=-(UTCR!P150-(UTC	=-(UTCR!Q150-(UTCR!Q178*Report!J96))*(1/NetToGross)			
INCOME BEFORE STATE TAXES	433,077,966	19,381,129	106,978,232	37,827,782	139,750,987	11,480,617	(2,595,697)	113,625,084	(33,411,553)
Interest Synchronization	(10,415,617)	(171,990)	(2,274,668)	(633,330)	(3,787,974)	(472,816)	(21,447)	(1,806,405)	533
INCOME BEFORE TAXES AT 10.5% ROE	422,662,349	19,209,139	104,703,564	37,194,452	135,963,013	11,007,802	(2,617,144)	111,818,679	(33,411,020)
INCOME BEFORE TAXES (FACTOR)	100.0000%	4.5448%	24.7724%	8.8000%	32.1682%	2.6044%	-0.6192%	26.4558%	-7.9049%

See Calculation of EXCTAX

DITEXP:		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Pre-Merger - PPL										
Prod / Hydro	S	(3,033,484)	(105,487)	(1,599,499)	(415,040)	(124,851)	0	0	0	0
Transmission	S	(803,012)	(29,729)	(431,265)	(115,820)	(36,383)	0	0	0	0
Distribution	S	(3,927,317)	(250,186)	(2,528,615)	(397,928)	0	0	0	0	0
General	S	52,373	0	33,965	0	6,074	0	19	0	0
Mining	S	0	0	0	0	0	0	0	0	0
Non Utility	NUTIL	4,098,667	0	0	0	0	0	0	0	4,098,667
Total PPL		(3,612,773)	(385,402)	(4,525,414)	(928,788)	(155,160)	0	19	0	4,098,667
Pre-Merger - UPL										
Production	S	(6,518,742)	0	0	0	(4,832,238)	(1,216,735)	(55,161)	0	0
Transmission	S	(2,162,631)	0	0	0	(1,762,538)	(278,336)	(12,990)	0	0
Distribution	S	(3,248,624)	0	0	0	(2,532,966)	(527,723)	0	0	0
General	S	73,937	130	7,329	423	4,536	41,317	685	0	0
Mining Plant	S	0	0	0	0	0	0	0	0	0
Non-Utility	NUTIL	0								
Total UPL		(11,856,060)	130	7,329	423	(9,123,206)	(1,981,477)	(67,466)	0	0
Post-Merger (Vintages beginning 2006 and forward except for WCA which is 2007 and forward)										
Prod / Other Prod	S	11,496,381	178,203	2,665,460	994,394	5,082,133	702,184	30,562	0	0
Cholla Unit 4	S	2,028,843	30,096	512,958	0	881,191	114,386	6,010	0	162,067
Gadsby Unit 4, 5 & 6	S	408,344	6,587	104,318	0	172,319	22,870	1,053	0	32,868
Hydro-PPL	S	370,184	4,914	62,130	34,467	183,683	29,242	1,093	0	0
Hydro-UPL	S	324,682	5,114	81,376	25,795	141,621	17,917	970	0	0

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Transmission	S	8,777,359	107,702	2,463,748	686,652	3,635,553	397,820	28,543	0	0		
Distribution	S	102,173,400	3,080,862	29,321,481	6,781,057	47,997,706	4,498,501	0	0	185		
General/ Intangibles	S	(12,063,658)	(324,943)	(4,006,412)	(669,996)	(4,707,903)	(715,403)	(17,350)	0	(2,248)		
Mining	S	(1,380,690)	(18,234)	(458,226)	(79,987)	(513,164)	(55,676)	(4,747)	0	0		
WCA - CAEE 2007+	S	7,052,222	112,597	1,663,775	0	3,048,586	453,092	23,397	0	527,972		
WCA - CAGE 2007+	S	365,423,014	5,921,410	93,327,988	0	158,001,435	19,641,305	1,104,198	0	29,769,723		
WCA - CAGW 2007+	S	37,759,974	608,022	9,699,537	8,415,900	16,320,491	2,060,282	114,826	0	(5,452,268)		
WCA_CAGW 2007+ -Marengo	S	0	0	0	0	0	0	0	0	0		
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0	0	0		
WCA - General 2007+	S	41,736,140	959,248	11,018,096	3,755,404	18,207,799	2,235,071	93,266	0	(454,396)		
WCA - JBG 2007+	S	6,755,042	108,354	1,725,251	1,423,814	2,960,394	371,566	20,168	0	(929,524)		
Non Utility	NUTIL	40,813	0	0	0	0	0	0	0	40,813		
Total PC (Post Merger)		570,902,050	10,779,932	148,181,480	21,367,500	251,411,844	29,773,157	1,401,989	0	23,695,192		
Total Deferred Taxes		555,433,217	10,394,660	143,663,395	20,439,135	242,133,478	27,791,680	1,334,542	0	27,793,859		
Percentage of Total (DITEXP)		100.0000%	1.8715%	25.8651%	3.6799%	43.5936%	5.0036%	0.2403%	0.0000%	5.0040%		

DITBAL :		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Pre-Merger - PPL										
Prod / Hydro	S	47,695,929	1,647,140	26,489,225	6,610,722	1,829,926	0	0		0
Transmission	S	19,347,896	737,641	10,520,895	2,886,556	838,582	0	0		0
Distribution	S	29,511,039	2,887,108	16,851,441	4,591,903	0	0	0		0
General	S	(419,397)	314	(273,097)	420	(47,279)	27	(141)		0
Mining	S	1,466,683	52	808	248	1,323	190	11		1,463,497
Non Utility	NUTIL	(5,915)	0	(59)	(32)	0	0	0		(5,824)
Total PPL		97,596,235	5,272,255	53,589,213	14,089,817	2,622,552	217	(130)	0	1,457,673
Pre-Merger - UPL										
Prod / Hydro	S	73,928,436	0	0	0	57,800,985	11,636,668	534,557		0
Transmission	S	45,233,026	0	0	0	38,025,646	5,233,137	235,405		0
Distribution	S	36,271,099	0	0	0	29,357,533	5,037,018	0		0
General	S	(743,056)	289	(75,448)	967	(211,413)	(298,713)	(4,585)		0
Mining	S	8,464	137	2,146	658	3,518	505	29		0
Non-Utility Plant	NUTIL	0								
Total UPL		154,697,969	426	(73,302)	1,625	124,976,269	21,608,615	765,406	0	0
Post-Merger (Vintages beginning 2006 and forward except for WCA which is 2007 and forward)										
Prod / Other Prod	S	493,022,750	9,040,990	142,839,166	39,525,810	199,708,030	26,499,067	1,755,935	0	0
Cholla Unit 4	S	16,035,461	180,614	3,157,701	0	6,114,658	455,149	36,163		3,508,404
Gadsby Unit 4, 5 & 6	S	4,388,935	71,519	1,120,126	0	1,923,101	246,014	17,376		358,823
Hydro-PPL	S	42,102,279	804,824	12,540,345	3,468,476	16,722,863	2,150,421	134,596		0
Hydro-UPL	S	11,051,320	232,876	3,381,675	972,603	4,310,438	554,416	31,401		0
Transmission	S	265,487,396	5,092,739	78,054,419	21,306,246	107,421,347	14,179,674	856,065		0

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DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Distribution	S	760,838,670	28,752,511	219,148,850	47,943,173	356,496,581	38,311,496	0		6,504		
General/ Intangibles	S	98,109,190	2,324,747	31,309,722	7,594,727	37,119,145	5,499,203	171,102		7		
Mining	S	8,324,394	135,426	2,454,701	614,416	3,184,852	467,227	30,597		0		
WCA - CAEE 2007+	S	24,635,778	356,946	6,338,519	0	10,083,688	1,395,188	87,291		1,993,618		
WCA - CAGE 2007+	S	1,382,656,278	22,879,344	368,632,476	0	577,549,812	75,315,800	5,090,400		115,663,379		
WCA - CAGW 2007+	S	349,813,240	5,851,033	96,474,200	75,426,395	147,370,892	19,373,875	1,322,906		(51,268,988)		
WCA_CAGW 2007+ -Marengo	S	0	0	0	0	0	0	0		0		
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0		0		
WCA - General 2007+	S	124,456,187	2,803,538	36,236,171	8,659,258	50,771,910	6,713,917	287,390		740,387		
WCA - JBG 2007+	S	75,964,439	1,279,255	20,680,928	16,018,602	32,180,939	4,145,803	282,751		(10,761,660)		
OREGON EXTRA BOOK DEPR	S	(25,390,288)	0	(25,390,288)	0	0	0	0		0		
Non Utility	NUTIL	(1,460,896)	0	0	0	0	0	0		(1,460,896)		
Total PC (Post Merger)		3,630,035,133	79,806,362	996,978,711	221,529,706	1,550,958,256	195,307,250	10,103,973	0	58,779,578		
Total Deferred Taxes		3,882,329,337	85,079,043	1,050,494,622	235,621,148	1,678,557,077	216,916,082	10,869,249	0	60,237,251		
Percentage of Total (DITBAL)		100.0000%	2.1914%	27.0584%	6.0691%	43.2358%	5.5873%	0.2800%	0.0000%	1.5516%		

OPRV-WY

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues	0	0	0
	0.0000%	0.0000%	0.0000%

OPRV-ID

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Interstate Sales for Resale			
Montana Power	0	0	0
Portland General Electric	0	0	0
Puget Sound Power & Light	0	0	0
Washington Water Power Co.	0	0	0
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues	0	0	0
	0.0000%	0.0000%	0.0000%

BADDEBT

		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER
Account 904 Balance	15,778,995	604,362	7,480,395	2,232,007	3,886,085	723,486	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT	100%	3.8302%	47.4073%	14.1454%	24.6282%	4.5851%	0.0000%	0.0000%	0.0000%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2014

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.

Customer Factors	TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Total Electric Customers	1,905,253	47,054	577,771	132,036	932,854	73,480	0	0	0
CN									
Customer System factor - CN		2.4697%	30.3252%	6.9301%	48.9622%	3.8567%	0.0000%	0.0000%	0.0000%
Pacific Power Customers	882,800	47,054	577,771	132,036	0	0	0	0	0
CNP									
Customer Service Pacific Power factor - CNP		5.33%	65.45%	14.96%	0.00%	0.00%	0.00%	0.00%	0.00%
Rocky Mountain Power Customers	1,022,453	0	0	0	932,854	73,480	0	0	0
CNU									
Customer Service R.M.P. factor - CNU		0.00%	0.00%	0.00%	91.24%	7.19%	0.00%	0.00%	0.00%

CIAC	TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
TOTAL NET DISTRIBUTION PLANT	3,598,056,114	121,893,937	966,855,384	220,883,501	1,734,346,176	170,448,015	0	0	0
CIAC FACTOR: Same as (SNPD Factor)	100.00%	3.39%	26.87%	6.14%	48.20%	4.74%	0.00%	0.00%	0.00%

IDSIT		Total Company	Idaho - PPL	Idaho - UPL	Idaho Total
	Payroll	0	0	0	0
Idaho State Income Tax Allocation			0.00%	0.00%	0.00%
	Property	0	0	0	0
			0.00%	0.00%	0.00%
	Sales	0	0	0	0
			0.00%	0.00%	0.00%
	Average		0.00%	0.00%	
		Idaho - PPL Factor	0.00%	0.00%	
		Idaho - UPL Factor	0.00%	0.00%	
			0.00%	0.00%	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2014

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
EXCTAX												
Excise Tax (Superfund)		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility		
Total Taxable Income		413,801,131	18,507,105	102,221,700	36,140,278	133,571,729	10,981,205	(2,476,562)	108,466,505	(31,894,668)		
Less Other Electric Items:												
419	OTH	0	0	0	0	0	0	0	0	0		
432	OTH	0	0	0	0	0	0	0	0	0		
40910	OTH	0	0	0	0	0	0	0	0	0		
SCHMDT	OTH	0	0	0	0	0	0	0	0	0		
SCHMDT (Steam)	OTH											
Total Taxable Income Excluding Other		413,801,131	18,507,105	102,221,700	36,140,278	133,571,729	10,981,205	(2,476,562)	108,466,505	(31,894,668)		
Excise Tax (Superfund) Factor - EXCTAX		100.0000%	4.4725%	24.7031%	8.7337%	32.2792%	2.6537%	-0.5985%	26.2122%	-7.7077%		
Trojan Allocators		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility		
Premerger												
Dec 1991 Plant		16,918,976										
Dec 1992 Plant		17,094,202										
Average	SG	17,006,589	259,768	4,430,727	1,320,071	7,309,624	963,528	57,018	0	0		
Dec 1991 Reserve		(7,851,432)										
Dec 1992 Reserve		(8,434,030)										
Average	SG	(8,142,731)	(124,376)	(2,121,426)	(632,048)	(3,499,838)	(461,336)	(27,300)	0	0		
Postmerger												
Dec 1991 Plant		4,284,960										
Dec 1992 Plant		3,485,613										
Average	SG	3,885,287	59,346	1,012,234	301,580	1,669,940	220,125	13,026	0	0		
Dec 1991 Reserve		(129,394)										
Dec 1992 Reserve		(240,609)										
Average	SG	(185,002)	(2,826)	(48,199)	(14,360)	(79,516)	(10,481)	(620)	0	0		
Net Plant		12,564,143	191,911	3,273,336	975,243	5,400,210	711,836	42,124	0	0		
Division Net Plant Nuclear Pacific Power	DNPPNP	100.0000%	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	0.3353%	0.0000%	0.0000%		
Division Net Plant Nuclear Rocky Mountain Power	DNPPNP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
System Net Nuclear Plant	SNNP	100.0000%	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	0.3353%	0.0000%	0.0000%		
Account 182.22		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility		
Pre-merger (101)	SG	17,094,202	261,106	4,453,553	1,326,872	7,347,281	968,491	57,312	0	0		
(108)	SG	(8,434,030)	(128,826)	(2,197,318)	(654,659)	(3,625,041)	(477,840)	(28,277)	0	0		
Post-merger (101)	SG	3,485,613	53,241	908,107	270,557	1,498,156	197,481	11,686	0	0		
(108)	SG	(240,609)	(3,675)	(62,686)	(18,676)	(103,416)	(13,632)	(807)	0	0		
(107)	SG	1,778,549	27,166	463,365	138,053	764,440	100,766	5,963	0	0		
(120)	SE	1,975,759	29,670	487,750	144,963	838,499	125,001	7,148	0	0		

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2014

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
	(228) SG	7,220,849	110,295	1,881,248	560,491	3,103,602	409,105	24,209	0	0		
	(228) SG	1,472,376	22,490	383,598	114,288	632,844	83,419	4,936	0	0		
	(228) SNNP	3,531,000	53,934	919,931	274,080	1,517,664	200,053	11,838	0	0		
	(228) SE	1,743,025	26,175	430,296	127,887	739,728	110,276	6,306	0	0		
Total Acct 182.22		29,626,734	451,577	7,667,845	2,283,855	12,713,756	1,703,121	100,316	0	0		
Revised Study (228)	SNNP	112,680	1,721	29,357	8,746	48,431	6,384	378	0	0		
	(228) SE	941,950	14,145	232,537	69,111	399,757	59,595	3,408	0	0		
December 1993 Adj.		1,054,630	15,866	261,893	77,858	448,188	65,979	3,786	0	0		
Adjusted Acct 182.22		30,681,364	467,443	7,929,738	2,361,712	13,161,945	1,769,100	104,101	0	0		
TROJP		100.0000%	1.5235%	25.8455%	7.6975%	42.8988%	5.7660%	0.3393%	0.0000%	0.0000%		
Trojan Plant Allocator												

Account 228.42		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Plant - Premerger	SG	7,220,849	110,295	1,881,248	560,491	3,103,602	409,105	24,209	0	0
- Postmerger	SG	1,472,376	22,490	383,598	114,288	632,844	83,419	4,936	0	0
Storage Facility	SE	1,743,025	26,175	430,296	127,887	739,728	110,276	6,306	0	0
Transition Costs	SNNP	3,531,000	53,934	919,931	274,080	1,517,664	200,053	11,838	0	0
Total Acct 228.42		13,967,250	212,894	3,615,073	1,076,745	5,993,838	802,854	47,290	0	0
Transition Costs	SNNP	112,680	1,721	29,357	8,746	48,431	6,384	378	0	0
Storage Facility	SE	941,950	14,145	232,537	69,111	399,757	59,595	3,408	0	0
December 1993 Adj.		1,054,630	15,866	261,893	77,858	448,188	65,979	3,786	0	0
Adjusted Acct 228.42		15,021,880	228,761	3,876,967	1,154,603	6,442,026	868,832	51,076	0	0
TROJD		100.0000%	1.5229%	25.8088%	7.6861%	42.8843%	5.7838%	0.3400%	0.0000%	0.0000%
Trojan Decommissioning Allocator										

SCHMA		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Amortization Expense :										
Amortization of Limited Term Plant	Acct 404	48,669,626	946,197	13,270,179	3,698,668	20,895,592	2,578,003	116,741	0	0
Amortization of Other Electric Plant	Acct 405	0	0	0	0	0	0	0	0	0
Amortization of Plant Acquisitions	Acct 406	4,834,296	73,842	1,259,479	375,244	2,077,835	273,893	16,208	0	0
Amort of Prop. Losses, Unrecovered Plant, etc.	Acct 407	559,742	0	0	0	0	0	0	559,742	0
Total Amortization Expense :		54,063,663	1,020,038	14,529,658	4,073,912	22,973,427	2,851,895	132,949	559,742	0
Schedule M Amortization Factor		100.0000%	1.8867%	26.8751%	7.5354%	42.4933%	5.2751%	0.2459%	1.0353%	0.0000%

SCHMD		TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Depreciation Expense :										
Steam	Acct 403.1	361,059,042	5,515,005	94,066,718	28,025,818	155,187,249	20,456,210	1,210,527	0	0
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0
Hydro	Acct 403.3	32,594,215	497,861	8,491,771	2,530,000	14,009,361	1,846,662	109,279	0	0
Other	Acct 403.4	102,062,997	1,558,964	26,590,474	7,922,247	43,867,827	5,782,495	342,188	0	0
Transmission	Acct 403.5	94,996,315	1,451,023	24,749,391	7,373,723	40,830,488	5,382,124	318,495	0	0
Distribution	Acct 403.6	150,652,831	6,207,976	46,348,040	11,634,596	61,832,541	6,760,893	0	0	0
General	Acct 403.7&8	37,645,366	796,138	10,875,368	3,049,498	14,827,157	2,151,463	60,771	0	0
Mining	Acct 403.9	0	0	0	0	0	0	0	0	0
Experimental	Acct 403.4	0	0	0	0	0	0	0	0	0

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2014

DESCRIPTION	2010 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Postmerger Hydro Step I Adjustment		0	0	0	0	0	0	0	0	0		
Total Depreciation Expense :		779,010,766	16,026,967	211,121,763	60,535,884	330,554,624	42,379,848	2,041,261	0	0		
Schedule M Depreciation Factor		100.0000%	2.0573%	27.1013%	7.7709%	42.4326%	5.4402%	0.2620%	0.0000%	0.0000%		

Tax Depreciation by Function	TOTAL	California	Oregon	Washington	Utah	Idaho	FERC	Other	Non-Utility
Based on Tax Depreciation Schedule M Differences	1,141,663,514	22,713,806	301,372,387	51,661,091	501,987,002	62,115,175	2,923,110	-	33,653,185
Tax Depr factor	100.0000%	1.9895%	26.3977%	4.5251%	43.9698%	5.4408%	0.2560%	0.0000%	2.9477%

Pro Forma Factors December 31, 2014
Oregon General Rate Case - December 2014
COINCIDENTAL PEAKS

			FORECAST LOADS (CP)							
			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-14	16	8	150	2,633	819	3,285	445	1,318	22	8,671
Feb-14	11	8	138	2,397	666	3,169	430	1,270	26	8,096
Mar-14	13	8	133	2,261	646	3,034	414	1,280	19	7,785
Apr-14	9	8	121	2,214	561	2,909	410	1,211	23	7,450
May-14	20	14	117	1,871	552	3,792	523	1,192	24	8,071
Jun-14	26	15	132	2,006	660	4,285	669	1,274	29	9,054
Jul-14	21	16	139	2,318	736	4,595	681	1,291	46	9,806
Aug-14	28	16	135	2,346	724	4,521	544	1,272	36	9,579
Sep-14	11	15	113	2,051	617	4,104	423	1,212	26	8,547
Oct-14	6	18	106	1,931	582	3,577	426	1,226	27	7,875
Nov-14	26	18	126	2,290	693	3,627	457	1,335	24	8,552
Dec-14	17	18	140	2,431	719	3,679	475	1,375	28	8,846
			1,550	26,749	7,975	44,577	5,896	15,255	329	102,333

- (less)

Subtract: DSM programs, MagCorp Buy-through (UT) - Grossed up for Line Losses

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-14	16	8	-	-	-	92	-	-	-	92
Feb-14	11	8	-	-	-	17	-	-	-	17
Mar-14	13	8	-	-	-	9	-	-	-	9
Apr-14	9	8	-	-	-	19	-	-	-	19
May-14	20	14	-	-	-	17	-	-	-	17
Jun-14	26	15	-	-	-	189	104	-	-	293
Jul-14	21	16	-	-	-	249	164	-	-	413
Aug-14	28	16	-	-	-	221	134	-	-	355
Sep-14	11	15	-	-	-	89	-	-	-	89
Oct-14	6	18	-	-	-	-	-	-	-	-
Nov-14	26	18	-	-	-	25	-	-	-	25
Dec-14	17	18	-	-	-	97	-	-	-	97
			-	-	-	1,024	402	-	-	1,426

= equals

			COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES							
			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-14	16	8	150	2,633	819	3,193	445	1,318	22	8,580
Feb-14	11	8	138	2,397	666	3,152	430	1,270	26	8,079
Mar-14	13	8	133	2,261	646	3,025	414	1,280	19	7,776
Apr-14	9	8	121	2,214	561	2,890	410	1,211	23	7,431
May-14	20	14	117	1,871	552	3,775	523	1,192	24	8,053
Jun-14	26	15	132	2,006	660	4,097	565	1,274	29	8,762
Jul-14	21	16	139	2,318	736	4,346	517	1,291	46	9,393
Aug-14	28	16	135	2,346	724	4,300	410	1,272	36	9,225
Sep-14	11	15	113	2,051	617	4,014	423	1,212	26	8,458
Oct-14	6	18	106	1,931	582	3,577	426	1,226	27	7,875
Nov-14	26	18	126	2,290	693	3,602	457	1,335	24	8,527
Dec-14	17	18	140	2,431	719	3,582	475	1,375	28	8,749
			1,550	26,749	7,975	43,553	5,495	15,255	329	100,907

+ plus

Add: Monsanto Curtailment (ID) - Grossed up for Line Losses (No adjustment - Forecast Loads assumes no curta

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-14	16	8	-	-	-	-	-	-	-	-
Feb-14	11	8	-	-	-	-	-	-	-	-
Mar-14	13	8	-	-	-	-	-	-	-	-
Apr-14	9	8	-	-	-	-	-	-	-	-
May-14	20	14	-	-	-	-	-	-	-	-
Jun-14	26	15	-	-	-	-	-	-	-	-
Jul-14	21	16	-	-	-	-	-	-	-	-
Aug-14	28	16	-	-	-	-	-	-	-	-
Sep-14	11	15	-	-	-	-	-	-	-	-
Oct-14	6	18	-	-	-	-	-	-	-	-
Nov-14	26	18	-	-	-	-	-	-	-	-
Dec-14	17	18	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-

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			LOADS FOR JURISDICTIONAL ALLOCATION (CP)							
			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-14	16	8	150	2,633	819	3,193	445	1,318	22	8,580
Feb-14	11	8	138	2,397	666	3,152	430	1,270	26	8,079
Mar-14	13	8	133	2,261	646	3,025	414	1,280	19	7,776
Apr-14	9	8	121	2,214	561	2,890	410	1,211	23	7,431
May-14	20	14	117	1,871	552	3,775	523	1,192	24	8,053
Jun-14	26	15	132	2,006	660	4,097	565	1,274	29	8,762
Jul-14	21	16	139	2,318	736	4,346	517	1,291	46	9,393
Aug-14	28	16	135	2,346	724	4,300	410	1,272	36	9,225
Sep-14	11	15	113	2,051	617	4,014	423	1,212	26	8,458
Oct-14	6	18	106	1,931	582	3,577	426	1,226	27	7,875
Nov-14	26	18	126	2,290	693	3,602	457	1,335	24	8,527
Dec-14	17	18	140	2,431	719	3,582	475	1,375	28	8,749
			1,550	26,749	7,975	43,553	5,495	15,255	329	100,907

Pro Forma Factors December 31, 2014
Oregon General Rate Case - December 2014
ENERGY

FORECAST LOADS (MWh)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2014	Jan	80,760	1,384,900	426,740	2,149,860	299,210	903,360	18,578	5,263,408
2014	Feb	70,000	1,196,800	359,030	1,909,870	261,220	802,100	15,832	4,614,852
2014	Mar	72,620	1,251,550	359,770	1,989,580	288,750	889,600	16,960	4,868,830
2014	Apr	69,730	1,156,750	323,890	1,916,220	278,700	846,480	16,193	4,607,963
2014	May	75,170	1,158,290	324,330	2,045,320	331,410	849,210	16,188	4,799,918
2014	Jun	78,650	1,148,040	329,540	2,131,680	377,440	828,000	17,748	4,911,098
2014	Jul	84,300	1,245,500	370,210	2,424,280	407,410	875,670	22,275	5,429,645
2014	Aug	79,470	1,238,280	371,400	2,403,240	364,380	882,390	22,493	5,361,653
2014	Sep	68,720	1,134,440	344,930	2,077,960	282,780	819,980	18,426	4,747,236
2014	Oct	66,520	1,165,380	359,730	2,054,270	293,370	871,790	16,572	4,827,632
2014	Nov	69,340	1,228,560	376,410	2,030,660	276,700	852,070	16,066	4,849,806
2014	Dec	78,940	1,391,710	423,020	2,167,670	292,760	908,760	18,100	5,280,960
		894,220	14,700,200	4,369,000	25,300,610	3,754,130	10,329,410	215,430	59,563,000

- (less)

Subtract: MagCorp **Buy-Throughs and Load No Longer Served (Reductions to Load)**

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2014	Jan				6,442		-		6,442
2014	Feb				-		-		-
2014	Mar				-		-		-
2014	Apr				-		-		-
2014	May				-		-		-
2014	Jun				4,419		-		4,419
2014	Jul				5,024		-		5,024
2014	Aug				5,824		-		5,824
2014	Sep				4,273		-		4,273
2014	Oct				-		-		-
2014	Nov				-		-		-
2014	Dec				6,943		-		6,943
		-	-	-	32,924	-	-	-	32,924

= equals

LOADS SERVED FROM COMPANY RESOURCES (NPC)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2014	Jan	80,760	1,384,900	426,740	2,143,418	299,210	903,360	18,578	5,256,966
2014	Feb	70,000	1,196,800	359,030	1,909,870	261,220	802,100	15,832	4,614,852
2014	Mar	72,620	1,251,550	359,770	1,989,580	288,750	889,600	16,960	4,868,830
2014	Apr	69,730	1,156,750	323,890	1,916,220	278,700	846,480	16,193	4,607,963
2014	May	75,170	1,158,290	324,330	2,045,320	331,410	849,210	16,188	4,799,918
2014	Jun	78,650	1,148,040	329,540	2,127,261	377,440	828,000	17,748	4,906,679
2014	Jul	84,300	1,245,500	370,210	2,419,256	407,410	875,670	22,275	5,424,621
2014	Aug	79,470	1,238,280	371,400	2,397,416	364,380	882,390	22,493	5,355,829
2014	Sep	68,720	1,134,440	344,930	2,073,687	282,780	819,980	18,426	4,742,964
2014	Oct	66,520	1,165,380	359,730	2,054,270	293,370	871,790	16,572	4,827,632
2014	Nov	69,340	1,228,560	376,410	2,030,660	276,700	852,070	16,066	4,849,806
2014	Dec	78,940	1,391,710	423,020	2,160,727	292,760	908,760	18,100	5,274,017
		894,220	14,700,200	4,369,000	25,267,686	3,754,130	10,329,410	215,430	59,530,076

+ plus

Add: Monsanto Curtailment (ID), Nucor Curtailment (UT), Magcorp Curtailment (UT) - Grossed up for Line Losses

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2014	Jan				376	487	-		863
2014	Feb				372	329	-		702
2014	Mar				276	322	-		598
2014	Apr				323	334	-		657
2014	May				295	420	-		715
2014	Jun				324	934	-		1,258
2014	Jul				352	2,549	-		2,900
2014	Aug				321	2,567	-		2,888
2014	Sep				186	627	-		813
2014	Oct				312	700	-		1,012
2014	Nov				244	2,088	-		2,333
2014	Dec				267	1,883	-		2,149
		-	-	-	3,647	13,240	-	-	16,888

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (MWh)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2014	Jan	80,760	1,384,900	426,740	2,143,794	299,697	903,360	18,578	5,257,828
2014	Feb	70,000	1,196,800	359,030	1,910,242	261,549	802,100	15,832	4,615,554
2014	Mar	72,620	1,251,550	359,770	1,989,856	289,072	889,600	16,960	4,869,428
2014	Apr	69,730	1,156,750	323,890	1,916,543	279,034	846,480	16,193	4,608,620
2014	May	75,170	1,158,290	324,330	2,045,615	331,830	849,210	16,188	4,800,634
2014	Jun	78,650	1,148,040	329,540	2,127,585	378,374	828,000	17,748	4,907,937
2014	Jul	84,300	1,245,500	370,210	2,419,607	409,959	875,670	22,275	5,427,522
2014	Aug	79,470	1,238,280	371,400	2,397,737	366,947	882,390	22,493	5,358,717
2014	Sep	68,720	1,134,440	344,930	2,073,873	283,407	819,980	18,426	4,743,777
2014	Oct	66,520	1,165,380	359,730	2,054,582	294,070	871,790	16,572	4,828,644
2014	Nov	69,340	1,228,560	376,410	2,030,904	278,788	852,070	16,066	4,852,139
2014	Dec	78,940	1,391,710	423,020	2,160,994	294,643	908,760	18,100	5,276,167
		894,220	14,700,200	4,369,000	25,271,333	3,767,370	10,329,410	215,430	59,546,964

Pro Forma Factors December 31, 2014
Oregon General Rate Case - December 2014

	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC		
Subtotal	894,220	14,700,200	4,369,000	25,271,333	3,767,370	10,329,410	215,430	**59,546,964**	**Ref Page 10.16**
System Energy Factor	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%	100.00%	
Divisional Energy - Pacific	3.1836%	52.3359%	15.5546%	0.0000%	0.0000%	28.9260%	0.0000%	100.00%	
Divisional Energy - Utah	0.0000%	0.0000%	0.0000%	80.3316%	11.9756%	7.0080%	0.6848%	100.00%	
System Generation Factor	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%	100.00%	
Divisional Generation - Pacific	3.1958%	54.5093%	16.2403%	0.0000%	0.0000%	26.0546%	0.0000%	100.00%	
Divisional Generation - Utah	0.0000%	0.0000%	0.0000%	82.3322%	10.8527%	6.1728%	0.6422%	100.00%	
System Capacity (kw)									
Accord	1,550.0	26,748.9	7,975.5	43,553.2	5,494.6	15,255.5	329.4	**100,907**	**Ref Page 10.15**
Modified Accord	1,550.0	26,748.9	7,975.5	43,553.2	5,494.6	15,255.5	329.4	**100,907**	**Ref Page 10.15**
Rolled-In	1,550.0	26,748.9	7,975.5	43,553.2	5,494.6	15,255.5	329.4	**100,907**	**Ref Page 10.15**
Rolled-In with Hydro Adj.	1,550.0	26,748.9	7,975.5	43,553.2	5,494.6	15,255.5	329.4	**100,907**	**Ref Page 10.15**
Rolled-In with Off-Sys Adj.	1,550.0	26,748.9	7,975.5	43,553.2	5,494.6	15,255.5	329.4	**100,907**	**Ref Page 10.15**
System Capacity Factor									
Accord	1.5360%	26.5084%	7.9038%	43.1617%	5.4452%	15.1183%	0.3264%	100.00%	
Modified Accord	1.5360%	26.5084%	7.9038%	43.1617%	5.4452%	15.1183%	0.3264%	100.00%	
Rolled-In	1.5360%	26.5084%	7.9038%	43.1617%	5.4452%	15.1183%	0.3264%	100.00%	
Rolled-In with Hydro Adj.	1.5360%	26.5084%	7.9038%	43.1617%	5.4452%	15.1183%	0.3264%	100.00%	
Rolled-In with Off-Sys Adj.	1.5360%	26.5084%	7.9038%	43.1617%	5.4452%	15.1183%	0.3264%	100.00%	
System Energy (kwh)									
Accord	894,220	14,700,200	4,369,000	25,271,333	3,767,370	10,329,410	215,430	59,546,964	
Modified Accord	894,220	14,700,200	4,369,000	25,271,333	3,767,370	10,329,410	215,430	59,546,964	
Rolled-In	894,220	14,700,200	4,369,000	25,271,333	3,767,370	10,329,410	215,430	59,546,964	
Rolled-In with Hydro Adj.	894,220	14,700,200	4,369,000	25,271,333	3,767,370	10,329,410	215,430	59,546,964	
Rolled-In with Off-Sys Adj.	894,220	14,700,200	4,369,000	25,271,333	3,767,370	10,329,410	215,430	59,546,964	
System Energy Factor									
Accord	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%	100.00%	
Modified Accord	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%	100.00%	
Rolled-In	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%	100.00%	
Rolled-In with Hydro Adj.	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%	100.00%	
Rolled-In with Off-Sys Adj.	1.5017%	24.6867%	7.3371%	42.4393%	6.3267%	17.3467%	0.3618%	100.00%	
System Generation Factor									
Accord	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%	100.00%	
Modified Accord	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%	100.00%	
Rolled-In	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%	100.00%	
Rolled-In with Hydro Adj.	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%	100.00%	
Rolled-In with Off-Sys Adj.	1.5275%	26.0530%	7.7621%	42.9811%	5.6656%	15.6754%	0.3353%	100.00%	

Pro Forma Factors December 31, 2014
Oregon General Rate Case - December 2014

Oregon General Rate Case - December 2014
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE MID COLUMBIA CONTRACTS

Contract	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Wells	3,863	65,884	19,629	108,693	14,328	39,641	848	
Rocky Reach	-	-	-	-	-	-	-	
Wanapum		-	-			-		
Priority		-				-		
Displacement		-				-		
Surplus		76,255	11,863			-		
0		-				-		
Total	4,256	141,175	31,936	109,617	14,210	38,934	828	
MC Factor	1.1327%	41.6826%	9.2352%	31.8744%	4.2016%	11.6248%	0.2486%	100%

Oregon General Rate Case - December 2014
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE ENERGY OF THE COMBUSTION TURBINES

MONTH	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Jan-14	18,944	8.52%	11,262	193,119	59,507	298,944	41,792	125,970	2,591	
Feb-14	16,497	7.42%	7,720	131,988	39,595	210,669	28,845	88,459	1,746	
Mar-14	18,944	8.52%	8,430	145,285	41,764	230,991	33,557	103,268	1,969	
Apr-14	18,333	8.24%	5,399	89,556	25,076	148,380	21,603	65,535	1,254	
May-14	18,944	8.52%	2,365	36,444	10,205	64,362	10,440	26,719	509	
Jun-14	18,333	8.24%	1,156	16,869	4,842	31,262	5,560	12,166	261	
Jul-14	18,944	8.52%	8,642	127,680	37,951	248,041	42,026	89,767	2,283	
Aug-14	18,944	8.52%	11,432	178,131	53,427	344,923	52,787	126,935	3,236	
Sep-14	18,333	8.24%	6,306	104,104	31,653	190,312	26,007	75,247	1,691	
Oct-14	18,944	8.52%	5,088	89,132	27,513	157,141	22,491	66,677	1,267	
Nov-14	18,333	8.24%	4,774	84,581	25,914	139,818	19,193	58,661	1,106	
Dec-14	18,944	8.52%	2,143	37,781	11,484	58,665	7,999	24,670	491	
	222,439	100.00%	74,715	1,234,668	368,931	2,123,507	312,299	864,075	18,404	
SSECT Factor			1.50%	24.71%	7.38%	42.50%	6.25%	17.29%	0.37%	100%

Oregon General Rate Case - December 2014
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF THE COMBUSTION TURBINES

MONTH	MWH	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Jan-14	11,913	13.94%	20.9	367.2	114.2	445.3	62.1	183.7	3.0	
Feb-14	9,422	11.03%	15.2	264.3	73.5	347.6	47.4	140.1	2.9	
Mar-14	9,917	11.61%	15.4	262.4	75.0	351.2	48.0	148.5	2.2	
Apr-14	6,614	7.74%	9.4	171.4	43.5	223.7	31.8	93.7	1.8	
May-14	2,688	3.15%	3.7	58.9	17.4	118.8	16.4	37.5	0.8	
Jun-14	1,255	1.47%	1.9	29.5	9.7	60.2	8.3	18.7	0.4	
Jul-14	8,758	10.25%	14.2	237.7	75.5	445.5	53.0	132.3	4.7	
Aug-14	12,290	14.39%	19.5	337.5	104.2	618.6	59.0	183.0	5.2	
Sep-14	7,840	9.18%	10.4	188.2	56.7	368.4	38.9	111.3	2.4	
Oct-14	6,534	7.65%	8.1	147.7	44.5	273.6	32.6	93.8	2.1	
Nov-14	5,882	6.88%	8.7	157.7	47.7	248.0	31.5	91.9	1.7	
Dec-14	2,319	2.71%	3.8	66.0	19.5	97.2	12.9	37.3	0.8	
	85,432	100.00%	131	2,288	681	3,598	442	1,272	28	
SSCCT Factor			1.55%	27.11%	8.07%	42.63%	5.23%	15.07%	0.33%	100%
SSGCT Factor			1.54%	26.51%	7.90%	42.60%	5.49%	15.63%	0.34%	100%

Oregon General Rate Case - December 2014
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE ENERGY OF CHOLLA IV/APS

	MWH											
MONTH	Cholla IV	APS	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Jan-14	236,173	142,560	378,733	14.24%	11,502	197,240	60,777	305,324	42,684	128,658	2,646	
Feb-14	214,225	68,925	283,150	10.65%	7,453	127,433	38,229	203,400	27,849	85,406	1,686	
Mar-14	221,770	-	221,770	8.34%	6,056	104,375	30,004	165,947	24,108	74,189	1,414	
Apr-14	210,961	-	210,961	7.93%	5,532	91,767	25,695	152,043	22,136	67,153	1,285	
May-14	185,607	(77,920)	107,687	4.05%	3,044	46,906	13,134	82,839	13,438	34,389	656	
Jun-14	175,540	(137,820)	37,720	1.42%	1,116	16,285	4,674	30,179	5,367	11,745	252	
Jul-14	215,643	(142,570)	73,073	2.75%	2,316	34,225	10,173	66,488	11,265	24,062	612	
Aug-14	249,468	(142,560)	106,908	4.02%	3,195	49,782	14,931	96,395	14,752	35,474	904	
Sep-14	240,283	(68,690)	171,593	6.45%	4,434	73,202	22,257	133,821	18,287	52,911	1,189	
Oct-14	237,815	78,285	316,100	11.89%	7,907	138,528	42,761	244,226	34,956	103,629	1,970	
Nov-14	228,575	137,775	366,350	13.78%	9,553	169,253	51,856	279,788	38,407	117,386	2,213	
Dec-14	242,503	142,680	385,183	14.48%	11,434	201,586	61,273	313,015	42,678	131,632	2,622	
	2,658,564	665	2,659,228	100.00%	73,543	1,250,582	375,765	2,073,465	295,928	866,636	17,448	
SSECH Factor					1.48%	25.25%	7.59%	41.86%	5.97%	17.50%	0.35%	100%

Oregon General Rate Case - December 2014
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF CHOLLA IV/APS

MONTH	MWH Cholla IV	APS	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Jan-14	236,173	142,560	378,733	14.24%	21.3	375.1	116.6	454.8	63.4	187.6	3.1	
Feb-14	214,225	68,925	283,150	10.65%	14.6	255.2	70.9	335.7	45.7	135.2	2.8	
Mar-14	221,770	-	221,770	8.34%	11.1	188.5	53.9	252.3	34.5	106.7	1.6	
Apr-14	210,961	-	210,961	7.93%	9.6	175.6	44.5	229.3	32.5	96.1	1.8	
May-14	185,607	(77,920)	107,687	4.05%	4.7	75.8	22.3	152.9	21.2	48.3	1.0	
Jun-14	175,540	(137,820)	37,720	1.42%	1.9	28.4	9.4	58.1	8.0	18.1	0.4	
Jul-14	215,643	(142,570)	73,073	2.75%	3.8	63.7	20.2	119.4	14.2	35.5	1.3	
Aug-14	249,468	(142,560)	106,908	4.02%	5.4	94.3	29.1	172.9	16.5	51.1	1.5	
Sep-14	240,283	(68,690)	171,593	6.45%	7.3	132.3	39.8	259.0	27.3	78.2	1.7	
Oct-14	237,815	78,285	316,100	11.89%	12.6	229.5	69.2	425.2	50.7	145.7	3.2	
Nov-14	228,575	137,775	366,350	13.78%	17.4	315.5	95.4	496.2	62.9	183.9	3.4	
Dec-14	242,503	142,680	385,183	14.48%	20.3	352.1	104.1	518.8	68.7	199.2	4.0	
	2,658,564	665	2,659,228	100.00%	130	2,286	676	3,475	446	1,286	26	
SSCCH Factor					1.56%	27.47%	8.12%	41.74%	5.36%	15.45%	0.31%	100%
SSGCH Factor					1.54%	26.91%	7.98%	41.77%	5.51%	15.96%	0.32%	100%

Oregon General Rate Case - December 2014
THIS SECTION OF THE FACTOR INPUT DEALS WITH THE ENERGY OF SEASONAL PURCHASE CONTRACTS

MONTH	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Jan-14	-	0%	-	-	-	-	-	-	-	
Feb-14	-	0%	-	-	-	-	-	-	-	
Mar-14	-	0%	-	-	-	-	-	-	-	
Apr-14	-	0%	-	-	-	-	-	-	-	
May-14	-	0%	-	-	-	-	-	-	-	
Jun-14	-	0%	-	-	-	-	-	-	-	
Jul-14	41,600	34%	28,465	420,558	125,006	817,010	138,428	295,681	7,521	
Aug-14	41,600	34%	26,834	418,121	125,408	809,625	123,904	297,950	7,595	
Sep-14	40,000	32%	22,312	368,325	111,990	673,335	92,015	266,227	5,983	
Oct-14	-	0%	-	-	-	-	-	-	-	
Nov-14	-	0%	-	-	-	-	-	-	-	
Dec-14	-	0%	-	-	-	-	-	-	-	
	123,200	100%	-	-	-	-	-	-	-	
SSEC Factor			1.50%	23.29%	6.99%	44.38%	6.84%	16.59%	0.41%	100%

Oregon General Rate Case - December 2014

THIS SECTION OF THE FACTOR INPUT DEALS WITH THE DEMAND OF SEASONAL PURCHASE CONTRACTS

MONTH	Total	Proportion	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Jan-14	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Feb-14	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Mar-14	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Apr-14	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
May-14	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Jun-14	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Jul-14	41,600	34%	46.8	782.8	248.6	1467.4	174.6	435.8	0.0	
Aug-14	41,600	34%	45.7	792.2	244.6	1452.0	138.5	429.6	0.0	
Sep-14	40,000	32%	36.8	665.9	200.5	1303.3	137.5	393.7	0.0	
Oct-14	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Nov-14	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Dec-14	-	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	123,200	100%	-	-	-	-	-	-	-	
SSCC Factor			1.43%	24.81%	7.68%	46.75%	4.99%	13.94%	0.40%	100%
SSGC Factor			1.45%	24.43%	7.51%	46.16%	5.45%	14.60%	0.40%	100%

Oregon General Rate Case - December 2014
12 Months Ended December 31, 2014
ANNUAL EMBEDDED COSTS
Year End Balance

Revised Protocol ECD

Company Owned Hydro - West

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
535 - 545	Hydro Operation & Maintenance Expense	33,582,849				Page 2.7, West only
403HP	Hydro Depreciation Expense	25,755,587				Page 2.15, West only
404IP / 404HP	Hydro Relicensing Amortization	11,134,225				Page 2.16, West only
	Total West Hydro Operating Expense	**70,472,660**				
330 - 336	Hydro Electric Plant in Service	789,409,821				Page 2.23, West only
302 & 303 &182M	Hydro Relicensing	170,183,089				Page 2.29, West only
108HP	Hydro Accumulated Depreciation Reserve	(232,984,150)				Page 2.36, West only
111IP / 111HP	Hydro Relicensing Accumulated Reserve	(44,162,729)				Page 2.39, West only
154	Materials and Supplies	1,563				Page 2.32, West only
	West Hydro Net Rate Base	**682,447,594**				
	Pre-tax Return	10.79%				
	Rate Base Revenue Requirement	**73,623,599**				
	Annual Embedded Cost					
	West Hydro-Electric Resources	**144,096,260**	3,599,635	40.03	(30,430,908)	MWh from GRID

Mid C Contracts

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Annual Mid-C Contracts Costs	5,503,818	341,005	16.14	(11,029,676)	GRID
	Grant Reasonable Portion	(6,200,845)			(6,200,845)	GRID
		(697,026)			(17,230,521)	

Qualified Facilities

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Utah Annual Qualified Facilities Costs	27,609,061	409,728	67.38	7,743,527	
555	Oregon Annual Qualified Facilities Costs	10,851,778	82,810	131.04	6,836,769	
555	Idaho Annual Qualified Facilities Costs	4,507,943	76,373	59.03	805,036	
555	WYU Annual Qualified Facilities Costs	-	-	-	-	
555	WYP Annual Qualified Facilities Costs	802,689	11,390	70.47	250,429	
555	California Annual Qualified Facilities Costs	4,481,387	33,434	134.04	2,860,341	
555	Washington Annual Qualified Facilities Costs	-	-	-	-	
	Total Qualified Facilities Costs	48,252,858	613,735	78.62	18,496,102	GRID

All Other Generation Resources
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	$/Mwh	Reference
500 - 514	Steam Operation & Maintenance Expense	1,179,365,066			Page 2.5
535 - 545	East Hydro Operation & Maintenance Expense	9,111,468			Page 2.7, East only
546 - 554	Other Generation Operation & Maintenance Expense	399,713,732			Page 2.8
555	Other Purchased Power Contracts	569,368,795			GRID less QF and Mid-C
40910	Production Tax Credit	(109,808,029)			Page 2.20
4118	SO2 Emission Allowances	(206,119)			Page 2.4
	James River Offset	(4,302,805)			James River Adj (Tab 5)
	REC Revenue	0			REC Revenue (Tab 3)
403SP	Steam Depreciation Expense	361,059,042			Page 2.15
403HP	East Hydro Depreciation Expense	6,838,628			Page 2.15, East only
403OP	Other Generation Depreciation Expense	102,062,997			Page 2.15
403MP	Mining Depreciation Expense	0			Page 2.15
404IP / 404HP	East Hydro Relicensing Amortization	362,261			Page 2.16, East only
406	Amortization of Plant Acquisition Costs	4,834,296			Page 2.17
	Total All Other Operating Expenses	**2,518,399,332**			
310 - 316	Steam Electric Plant in Service	6,674,370,926			Page 2.21
330 - 336	East Hydro Electric Plant in Service	162,450,450			Page 2.23, East only
302 & 186M	East Hydro Relicensing	9,612,645			Page 2.29, East only
340 - 346	Other Electric Plant in Service	3,140,073,567			Page 2.24
399	Mining	482,121,148			Page 2.28
108SP	Steam Accumulated Depreciation Reserve	(2,909,360,083)			Page 2.36
108OP	Other Generation Accumulated Depreciation Reserve	(652,870,986)			Page 2.36
108MP	Other Accumulated Depreciation Reserve	(174,787,386)			Page 2.38, East only
108HP	East Hydro Accumulated Depreciation Reserve	(56,811,238)			Page 2.36, East only
111IP / 111HP	East Hydro Relicensing Accumulated Reserve	(5,080,719)			Page 2.39, East only
114	Electric Plant Acquisition Adjustment	159,175,508			Page 2.31
115	Accumulated Provision Acquisition Adjustment	(120,513,028)			Page 2.31
151	Fuel Stock	251,362,310			Page 2.32
253.16 - 253.19	Joint Owner WC Deposit	(6,681,672)			Page 2.32
253.98	SO2 Emission Allowances	(121,735)			Page 2.34
154	Materials & Supplies	93,226,734			Page 2.32
154	East Hydro Materials & Supplies				
	Total Net Rate Base	**7,046,166,441**			
	Pre-tax Return	10.79%			
	Rate Base Revenue Requirement	**760,152,339**			
	Annual Embedded Cost				
	All Other Generation Resources	**3,278,551,671**	67,620,362	48.48	MWh from GRID
	Total Annual Embedded Costs	**3,470,203,762**	**72,174,737**	**48.08**	

Oregon General Rate Case - December 2014
12 Months Ended December 31, 2014
ANNUAL EMBEDDED COSTS
Year End Balance

2010 Protocol ECD

Company Owned Hydro - West

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
535 - 545	Hydro Operation & Maintenance Expense	33,582,849				Page 2.7, West only
403HP	Hydro Depreciation Expense	25,755,587				Page 2.15, West only
404IP / 404HP	Hydro Relicensing Amortization	11,134,225				Page 2.16, West only
	Total West Hydro Operating Expense	**70,472,660**				
330 - 336	Hydro Electric Plant in Service	789,409,821				Page 2.23, West only
302 & 182M	Hydro Relicensing	170,183,089				Page 2.29, West only
108HP	Hydro Accumulated Depreciation Reserve	(232,984,150)				Page 2.36, West only
111IP / 111HP	Hydro Relicensing Accumulated Reserve	(44,162,729)				Page 2.39, West only
154	Materials and Supplies	1,563				Page 2.32, West only
	West Hydro Net Rate Base	**682,447,594**				
	Pre-tax Return	10.79%				
	Rate Base Revenue Requirement	**73,623,599**				
	Annual Embedded Cost					
	West Hydro-Electric Resources	**144,096,260**	3,599,635	40.03	(21,878,231)	MWh from GRID

Mid C Contracts

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Annual Mid-C Contracts Costs	5,503,818	341,005	16.14	(10,219,455)	GRID
	Grant Reasonable Portion	(6,200,845)			(6,200,845)	GRID
		(697,026)			(16,420,299)	

Qualified Facilities

Account	Description	Amount	Mwh	$/Mwh	Differential	Reference
555	Utah Annual Qualified Facilities Costs					
555	Oregon Annual Qualified Facilities Costs					
555	Idaho Annual Qualified Facilities Costs					
555	WYU Annual Qualified Facilities Costs					
555	WYP Annual Qualified Facilities Costs					
555	California Annual Qualified Facilities Costs					
555	Washington Annual Qualified Facilities Costs					
	Total Qualified Facilities Costs	-	-		-	GRID

All Other Generation Resources
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	$/Mwh	Reference
500 - 514	Steam Operation & Maintenance Expense	1,176,885,490			Page 2.5
535 - 545	East Hydro Operation & Maintenance Expense	9,111,468			Page 2.7, East only
546 - 554	Other Generation Operation & Maintenance Expense	71,061,764			Page 2.8
555	Other Purchased Power Contracts	96,435,883			GRID less QF and Mid-C
40910	Production Tax Credits	0			Page 2.20
4118	SO2 Emission Allowances	(206,119)			Page 2.4
	James River	(4,302,805)			James River Adj (Tab 5)
	REC Revenues	0			REC Revenues (Tab 3)
403SP	Steam Depreciation Expense	272,550,907			Page 2.15
403HP	East Hydro Depreciation Expense	6,838,628			Page 2.15, East only
403OP	Other Generation Depreciation Expense	9,919,167			Page 2.15
403MP	Mining Depreciation Expense	0			Page 2.15
404IP / 404 HP	East Hydro Relicensing Amortization	362,261			Page 2.16, East only
406	Amortization of Plant Acquisition Costs	4,834,296			Page 2.17
	Total All Other Operating Expenses	**1,643,490,939**			
310 - 316	Steam Electric Plant in Service	6,670,697,674			Page 2.21
330 - 336	East Hydro Electric Plant in Service	162,450,450			Page 2.23, East only
302 & 186M	East Hydro Relicensing	9,612,645			Page 2.29, East only
340 - 346	Other Electric Plant in Service	293,900,766			Page 2.24
399	Mining	482,121,148			Page 2.28
108SP	Steam Accumulated Depreciation Reserve	(2,796,163,830)			Page 2.36
108OP	Other Generation Accumulated Depreciation Reserve	(111,767,875)			Page 2.36
108MP	Other Accumulated Depreciation Reserve	(174,787,386)			Page 2.38, East only
108HP	East Hydro Accumulated Depreciation Reserve	(56,811,238)			Page 2.36, East only
111IP / 111HP	East Hydro Relicensing Accumulated Reserve	(5,080,719)			Page 2.39, East only
114	Electric Plant Acquisition Adjustment	159,175,508			Page 2.31
115	Accumulated Provision Acquisition Adjustment	(120,513,028)			Page 2.31
151	Fuel Stock	244,812,858			Page 2.32
253.16 - 253.19	Joint Owner WC Deposit	(6,681,672)			Page 2.32
253.98	SO2 Emission Allowances	(121,735)			Page 2.34
154	Materials & Supplies	93,226,734			Page 2.32
154	East Hydro Materials & Supplies	0			
	Total Net Rate Base	**4,844,070,300**			
	Pre-tax Return	10.79%			
	Rate Base Revenue Requirement	**522,586,487**			
	Annual Embedded Cost				
	All Other Generation Resources	**2,166,077,427**	46,977,633	46.11	MWh from GRID
	Total Annual Embedded Costs	**2,309,476,660**	**50,918,273**	**45.36**	

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Operations Revenue (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4118000	GAINS-DISP OF ALLOW	SE	-$2	$0	$0	$0	$0	-$1	$0	$0	$0
4118000 Total			**-$2**	**$0**	**$0**	**$0**	**$0**	**-$1**	**$0**	**$0**	**$0**
4191000	AFUDC - OTHER	SNP	-$54,339	-$1,085	-$14,356	-$3,997	-$7,873	-$23,907	-$2,984	-$135	$0
4191000 Total			**-$54,339**	**-$1,085**	**-$14,356**	**-$3,997**	**-$7,873**	**-$23,907**	**-$2,984**	**-$135**	**$0**
4211000	GAIN DISPOS PROP	SG	-$602	-$9	-$157	-$47	-$94	-$259	-$34	-$2	$0
4211000	GAIN DISPOS PROP	SO	-$184	-$4	-$50	-$14	-$26	-$79	-$10	$0	$0
4211000	GAIN DISPOS PROP	UT	-$18	$0	$0	$0	$0	-$18	$0	$0	$0
4211000 Total			**-$805**	**-$13**	**-$207**	**-$61**	**-$121**	**-$356**	**-$44**	**-$2**	**$0**
4211900	ASST SLS PRCDS-CLEAR	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
4211900 Total			**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
4212000	LOSS DISPOS PROP	OR	$12	$0	$12	$0	$0	$0	$0	$0	$0
4212000	LOSS DISPOS PROP	SO	$28	$1	$8	$2	$4	$12	$2	$0	$0
4212000	LOSS DISPOS PROP	WA	$1	$0	$0	$1	$0	$0	$0	$0	$0
4212000	LOSS DISPOS PROP	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
4212000 Total			**$42**	**$1**	**$20**	**$3**	**$5**	**$12**	**$2**	**$0**	**$0**
4270000	INT ON LNG-TRM DBT	SNP	$314,443	$6,281	$83,075	$23,130	$45,562	$138,344	$17,268	$783	$0
4270000	INT ON LNG-TRM DBT	SNP	$33,824	$676	$8,936	$2,488	$4,901	$14,881	$1,858	$84	$0
4270000	INT ON LNG-TRM DBT	SNP	$6,309	$126	$1,667	$464	$914	$2,776	$346	$16	$0
4270000	INT ON LNG-TRM DBT	SNP	$1,074	$21	$284	$79	$156	$472	$59	$3	$0
4270000	INT ON LNG-TRM DBT	SNP	$3,810	$76	$1,007	$280	$552	$1,676	$209	$9	$0
4270000 Total			**$359,459**	**$7,181**	**$94,968**	**$26,442**	**$52,084**	**$158,149**	**$19,740**	**$895**	**$0**
4280000	AMT DBT DISC & EXP	SNP	$1,016	$20	$269	$75	$147	$447	$56	$3	$0
4280000	AMT DBT DISC & EXP	SNP	$2,906	$58	$768	$214	$421	$1,279	$160	$7	$0
4280000 Total			**$3,923**	**$78**	**$1,036**	**$289**	**$568**	**$1,726**	**$215**	**$10**	**$0**
4281000	AMORTZN OF LOSS	SNP	$1,778	$36	$470	$131	$258	$782	$98	$4	$0
4281000 Total			**$1,778**	**$36**	**$470**	**$131**	**$258**	**$782**	**$98**	**$4**	**$0**
4290000	AMT PREM ON DEBT	SNP	-$5	$0	-$1	$0	-$1	-$2	$0	$0	$0
4290000 Total			**-$5**	**$0**	**-$1**	**$0**	**-$1**	**-$2**	**$0**	**$0**	**$0**
4310000	OTHER INTEREST EXP	SNP	$8,647	$173	$2,285	$636	$1,253	$3,805	$475	$22	$0
4310000 Total			**$8,647**	**$173**	**$2,285**	**$636**	**$1,253**	**$3,805**	**$475**	**$22**	**$0**
4313000	INT EXP ON REG LIAB	SNP	$4,749	$95	$1,255	$349	$688	$2,089	$261	$12	$0
4313000 Total			**$4,749**	**$95**	**$1,255**	**$349**	**$688**	**$2,089**	**$261**	**$12**	**$0**
4320000	AFUDC - BORROWED	SNP	-$28,010	-$560	-$7,400	-$2,060	-$4,058	-$12,323	-$1,538	-$70	$0
4320000	AFUDC - BORROWED	SNP	$0	$0	$0	$0	$0	$0	$0	$0	$0
4320000	AFUDC - BORROWED	SNP	$307	$6	$81	$23	$45	$135	$17	$1	$0
4320000 Total			**-$27,702**	**-$553**	**-$7,319**	**-$2,038**	**-$4,014**	**-$12,188**	**-$1,521**	**-$69**	**$0**
4401000	RESIDENTIAL SALES	CA	-$50,539	-$50,539	$0	$0	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	IDU	-$67,841	$0	$0	$0	$0	$0	-$67,841	$0	$0
4401000	RESIDENTIAL SALES	OR	-$566,949	$0	-$566,949	$0	$0	$0	$0	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Operations Revenue (Actuals)
Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4401000	RESIDENTIAL SALES	UT	-$632,901	$0	$0	$0	$0	-$632,901	$0	$0	$0
4401000	RESIDENTIAL SALES	WA	-$137,771	$0	$0	-$137,771	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	WYP	-$88,444	$0	$0	$0	-$88,444	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	WYU	-$12,603	$0	$0	$0	-$12,603	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	CA	-$230	-$230	$0	$0	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	IDU	-$52	$0	$0	$0	$0	$0	-$52	$0	$0
4401000	RESIDENTIAL SALES	OR	$105	$0	$105	$0	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	UT	-$784	$0	$0	$0	$0	-$784	$0	$0	$0
4401000	RESIDENTIAL SALES	WA	$4,720	$0	$0	$4,720	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	WYP	$273	$0	$0	$0	$273	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	UT	$11,137	$0	$0	$0	$0	$11,137	$0	$0	$0
4401000	RESIDENTIAL SALES	WA	$2,468	$0	$0	$2,468	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	WYP	$1,270	$0	$0	$0	$1,270	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	CA	-$140	-$140	$0	$0	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	IDU	-$503	$0	$0	$0	$0	$0	-$503	$0	$0
4401000	RESIDENTIAL SALES	OR	-$893	$0	-$893	$0	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	UT	-$12,709	$0	$0	$0	$0	-$12,709	$0	$0	$0
4401000	RESIDENTIAL SALES	WA	-$14	$0	$0	-$14	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	WYP	-$1,256	$0	$0	$0	-$1,256	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	WYU	-$13	$0	$0	$0	-$13	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	CA	$2	$2	$0	$0	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	IDU	$17	$0	$0	$0	$0	$0	$17	$0	$0
4401000	RESIDENTIAL SALES	OR	$10	$0	$10	$0	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	UT	$120	$0	$0	$0	$0	$120	$0	$0	$0
4401000	RESIDENTIAL SALES	WA	$1	$0	$0	$1	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	WYP	$26	$0	$0	$0	$26	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	CA	-$472	-$472	$0	$0	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	IDU	-$1,176	$0	$0	$0	$0	$0	-$1,176	$0	$0
4401000	RESIDENTIAL SALES	OR	-$8,053	$0	-$8,053	$0	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	UT	-$7,646	$0	$0	$0	$0	-$7,646	$0	$0	$0
4401000	RESIDENTIAL SALES	WA	-$2,249	$0	$0	-$2,249	$0	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	WYP	-$466	$0	$0	$0	-$466	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	WYP	-$1	$0	$0	$0	-$1	$0	$0	$0	$0
4401000	RESIDENTIAL SALES	OTHER	-$818	$0	$0	$0	$0	$0	$0	$0	-$818
4401000 Total			**-$1,574,376**	**-$51,379**	**-$575,780**	**-$132,846**	**-$101,214**	**-$642,783**	**-$69,556**	**$0**	**-$818**
4403000	BPA REG BAL-RES	IDU	$2,074	$0	$0	$0	$0	$0	$2,074	$0	$0
4403000	BPA REG BAL-RES	OR	$27,427	$0	$27,427	$0	$0	$0	$0	$0	$0
4403000	BPA REG BAL-RES	WA	$6,268	$0	$0	$6,268	$0	$0	$0	$0	$0
4403000 Total			**$35,769**	**$0**	**$27,427**	**$6,268**	**$0**	**$0**	**$2,074**	**$0**	**$0**
4421000	COMMERCIAL SALES	CA	-$33,174	-$33,174	$0	$0	$0	$0	$0	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Operations Revenue (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4421000	COMMERCIAL SALES	IDU	-$35,157	$0	$0	$0	$0	$0	-$35,157	$0	$0
4421000	COMMERCIAL SALES	OR	-$410,390	$0	-$410,390	$0	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	UT	-$600,011	$0	$0	$0	$0	-$600,011	$0	$0	$0
4421000	COMMERCIAL SALES	WA	-$109,184	$0	$0	-$109,184	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	WYP	-$109,114	$0	$0	$0	-$109,114	$0	$0	$0	$0
4421000	COMMERCIAL SALES	WYU	-$14,933	$0	$0	$0	-$14,933	$0	$0	$0	$0
4421000	COMMERCIAL SALES	CA	-$120	-$120	$0	$0	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	IDU	-$29	$0	$0	$0	$0	$0	-$29	$0	$0
4421000	COMMERCIAL SALES	OR	$14	$0	$14	$0	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	UT	-$811	$0	$0	$0	$0	-$811	$0	$0	$0
4421000	COMMERCIAL SALES	WA	$3,659	$0	$0	$3,659	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	WYP	$322	$0	$0	$0	$322	$0	$0	$0	$0
4421000	COMMERCIAL SALES	UT	$11,603	$0	$0	$0	$0	$11,603	$0	$0	$0
4421000	COMMERCIAL SALES	WA	$1,982	$0	$0	$1,982	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	WYP	$1,818	$0	$0	$0	$1,818	$0	$0	$0	$0
4421000	COMMERCIAL SALES	CA	-$613	-$613	$0	$0	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	IDU	-$1,223	$0	$0	$0	$0	$0	-$1,223	$0	$0
4421000	COMMERCIAL SALES	OR	-$1,201	$0	-$1,201	$0	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	UT	-$8,926	$0	$0	$0	$0	-$8,926	$0	$0	$0
4421000	COMMERCIAL SALES	WA	$311	$0	$0	$311	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	WYP	-$1,673	$0	$0	$0	-$1,673	$0	$0	$0	$0
4421000	COMMERCIAL SALES	WYU	-$1,215	$0	$0	$0	-$1,215	$0	$0	$0	$0
4421000	COMMERCIAL SALES	CA	-$300	-$300	$0	$0	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	IDU	-$585	$0	$0	$0	$0	$0	-$585	$0	$0
4421000	COMMERCIAL SALES	OR	-$4,429	$0	-$4,429	$0	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	UT	-$6,466	$0	$0	$0	$0	-$6,466	$0	$0	$0
4421000	COMMERCIAL SALES	WA	-$1,459	$0	$0	-$1,459	$0	$0	$0	$0	$0
4421000	COMMERCIAL SALES	WYP	-$370	$0	$0	$0	-$370	$0	$0	$0	$0
4421000	COMMERCIAL SALES	WYP	-$174	$0	$0	$0	-$174	$0	$0	$0	$0
4421000	COMMERCIAL SALES	OTHER	-$379	$0	$0	$0	$0	$0	$0	$0	-$379
4421000 Total			**-$1,322,228**	**-$34,207**	**-$416,007**	**-$104,691**	**-$125,339**	**-$604,610**	**-$36,995**	**$0**	**-$379**
4421200	BPA REG BAL-INDUST	IDU	$12	$0	$0	$0	$0	$0	$12	$0	$0
4421200	BPA REG BAL-INDUST	OR	$4	$0	$4	$0	$0	$0	$0	$0	$0
4421200	BPA REG BAL-INDUST	WA	$22	$0	$0	$22	$0	$0	$0	$0	$0
4421200 Total			**$37**	**$0**	**$4**	**$22**	**$0**	**$0**	**$12**	**$0**	**$0**
4421400	BPA REG BAL-IRRIG	IDU	$1,051	$0	$0	$0	$0	$0	$1,051	$0	$0
4421400	BPA REG BAL-IRRIG	OR	$670	$0	$670	$0	$0	$0	$0	$0	$0
4421400	BPA REG BAL-IRRIG	WA	$601	$0	$0	$601	$0	$0	$0	$0	$0
4421400 Total			**$2,322**	**$0**	**$670**	**$601**	**$0**	**$0**	**$1,051**	**$0**	**$0**
4421500	BPA REG BAL-COMMRC	IDU	$87	$0	$0	$0	$0	$0	$87	$0	$0

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4421500	BPA REG BAL-COMMRC	OR	$993	$0	$993	$0	$0	$0	$0	$0	$0
4421500	BPA REG BAL-COMMRC	WA	$488	$0	$0	$488	$0	$0	$0	$0	$0
4421500 Total			**$1,569**	**$0**	**$993**	**$488**	**$0**	**$0**	**$87**	**$0**	**$0**
4422000	IND SLS/EXCL IRRIG	CA	-$2,744	-$2,744	$0	$0	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	IDU	-$17,539	$0	$0	$0	$0	$0	-$17,539	$0	$0
4422000	IND SLS/EXCL IRRIG	OR	-$139,610	$0	-$139,610	$0	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	UT	-$320,435	$0	$0	$0	$0	-$320,435	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WA	-$49,431	$0	$0	-$49,431	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WYP	-$295,473	$0	$0	$0	-$295,473	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WYU	-$89,396	$0	$0	$0	-$89,396	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	IDU	-$68,744	$0	$0	$0	$0	$0	-$68,744	$0	$0
4422000	IND SLS/EXCL IRRIG	UT	-$100,863	$0	$0	$0	$0	-$100,863	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	CA	-$96	-$96	$0	$0	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	IDU	-$124	$0	$0	$0	$0	$0	-$124	$0	$0
4422000	IND SLS/EXCL IRRIG	OR	-$13	$0	-$13	$0	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	UT	-$505	$0	$0	$0	$0	-$505	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WA	$1,685	$0	$0	$1,685	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WYP	$842	$0	$0	$0	$842	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	UT	$7,203	$0	$0	$0	$0	$7,203	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WA	$1,042	$0	$0	$1,042	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WYP	$8,521	$0	$0	$0	$8,521	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	CA	$141	$141	$0	$0	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	IDU	-$1,690	$0	$0	$0	$0	$0	-$1,690	$0	$0
4422000	IND SLS/EXCL IRRIG	OR	-$1,153	$0	-$1,153	$0	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	UT	-$2,152	$0	$0	$0	$0	-$2,152	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WA	-$782	$0	$0	-$782	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WYP	-$4,141	$0	$0	$0	-$4,141	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WYU	-$430	$0	$0	$0	-$430	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	CA	-$53	-$53	$0	$0	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	IDU	-$207	$0	$0	$0	$0	$0	-$207	$0	$0
4422000	IND SLS/EXCL IRRIG	OR	-$361	$0	-$361	$0	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	UT	-$3,076	$0	$0	$0	$0	-$3,076	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WA	-$648	$0	$0	-$648	$0	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WYP	-$81	$0	$0	$0	-$81	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	WYP	-$474	$0	$0	$0	-$474	$0	$0	$0	$0
4422000	IND SLS/EXCL IRRIG	OTHER	-$153	$0	$0	$0	$0	$0	$0	$0	-$153
4422000 Total			**-$1,080,937**	**-$2,751**	**-$141,137**	**-$48,133**	**-$380,631**	**-$419,828**	**-$88,303**	**$0**	**-$153**
4423000	INDUST SALES-IRRIG	CA	-$10,834	-$10,834	$0	$0	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	IDU	-$54,565	$0	$0	$0	$0	$0	-$54,565	$0	$0
4423000	INDUST SALES-IRRIG	OR	-$17,801	$0	-$17,801	$0	$0	$0	$0	$0	$0

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4423000	INDUST SALES-IRRIG	UT	-$13,586	$0	$0	$0	$0	-$13,586	$0	$0	$0
4423000	INDUST SALES-IRRIG	WA	-$12,522	$0	$0	-$12,522	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	WYP	-$1,777	$0	$0	$0	-$1,777	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	WYU	-$353	$0	$0	$0	-$353	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	CA	$60	$60	$0	$0	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	OR	$8	$0	$8	$0	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	UT	-$19	$0	$0	$0	$0	-$19	$0	$0	$0
4423000	INDUST SALES-IRRIG	WA	$429	$0	$0	$429	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	WYP	$6	$0	$0	$0	$6	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	CA	-$193	-$193	$0	$0	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	IDU	-$2,375	$0	$0	$0	$0	$0	-$2,375	$0	$0
4423000	INDUST SALES-IRRIG	OR	-$361	$0	-$361	$0	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	UT	-$829	$0	$0	$0	$0	-$829	$0	$0	$0
4423000	INDUST SALES-IRRIG	WA	-$288	$0	$0	-$288	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	WYP	-$82	$0	$0	$0	-$82	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	CA	$19	$19	$0	$0	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	OR	$23	$0	$23	$0	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	WA	-$14	$0	$0	-$14	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	CA	-$104	-$104	$0	$0	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	IDU	-$574	$0	$0	$0	$0	$0	-$574	$0	$0
4423000	INDUST SALES-IRRIG	OR	-$39	$0	-$39	$0	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	UT	$70	$0	$0	$0	$0	$70	$0	$0	$0
4423000	INDUST SALES-IRRIG	WA	-$49	$0	$0	-$49	$0	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	WYP	-$6	$0	$0	$0	-$6	$0	$0	$0	$0
4423000	INDUST SALES-IRRIG	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
4423000 Total			**-$115,756**	**-$11,052**	**-$18,170**	**-$12,443**	**-$2,212**	**-$14,364**	**-$57,514**	**$0**	**$0**
4441000	PUB ST/HWY LIGHT	CA	-$424	-$424	$0	$0	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	IDU	-$489	$0	$0	$0	$0	$0	-$489	$0	$0
4441000	PUB ST/HWY LIGHT	OR	-$6,227	$0	-$6,227	$0	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	UT	-$10,052	$0	$0	$0	$0	-$10,052	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WA	-$1,279	$0	$0	-$1,279	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WYP	-$1,785	$0	$0	$0	-$1,785	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WYU	-$417	$0	$0	$0	-$417	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	OR	$0	$0	$0	$0	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	CA	$2	$2	$0	$0	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	OR	-$91	$0	-$91	$0	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	UT	$20	$0	$0	$0	$0	$20	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WA	$44	$0	$0	$44	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WYU	$8	$0	$0	$0	$8	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	IDU	-$8	$0	$0	$0	$0	$0	-$8	$0	$0

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4441000	PUB ST/HWY LIGHT	OR	-$121	$0	-$121	$0	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	UT	$32	$0	$0	$0	$0	$32	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WA	$104	$0	$0	$104	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WYP	-$12	$0	$0	$0	-$12	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WYU	$9	$0	$0	$0	$9	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	CA	-$6	-$6	$0	$0	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	IDU	-$8	$0	$0	$0	$0	$0	-$8	$0	$0
4441000	PUB ST/HWY LIGHT	OR	-$74	$0	-$74	$0	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	UT	-$136	$0	$0	$0	$0	-$136	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WA	-$12	$0	$0	-$12	$0	$0	$0	$0	$0
4441000	PUB ST/HWY LIGHT	WYP	-$8	$0	$0	$0	-$8	$0	$0	$0	$0
4441000 Total			**-$20,930**	**-$428**	**-$6,513**	**-$1,142**	**-$2,206**	**-$10,135**	**-$505**	**$0**	**$0**
4451000	OTHER SALES PUBLIC	UT	-$17,528	$0	$0	$0	$0	-$17,528	$0	$0	$0
4451000	OTHER SALES PUBLIC	UT	-$59	$0	$0	$0	$0	-$59	$0	$0	$0
4451000	OTHER SALES PUBLIC	UT	$183	$0	$0	$0	$0	$183	$0	$0	$0
4451000	OTHER SALES PUBLIC	UT	-$130	$0	$0	$0	$0	-$130	$0	$0	$0
4451000 Total			**-$17,534**	**$0**	**$0**	**$0**	**$0**	**-$17,534**	**$0**	**$0**	**$0**
4471000	ON-SYS WHOLE-FIRM	OR	-$1,025	$0	-$1,025	$0	$0	$0	$0	$0	$0
4471000	ON-SYS WHOLE-FIRM	FERC	-$4,957	$0	$0	$0	$0	$0	$0	-$4,957	$0
4471000	ON-SYS WHOLE-FIRM	FERC	-$3,936	$0	$0	$0	$0	$0	$0	-$3,936	$0
4471000	ON-SYS WHOLE-FIRM	WYP	-$21	$0	$0	$0	-$21	$0	$0	$0	$0
4471000 Total			**-$9,938**	**$0**	**-$1,025**	**$0**	**-$21**	**$0**	**$0**	**-$8,893**	**$0**
4471300	POST MERGER FIRM	SG	-$113,384	-$1,732	-$29,540	-$8,801	-$17,773	-$48,734	-$6,424	-$380	$0
4471300 Total			**-$113,384**	**-$1,732**	**-$29,540**	**-$8,801**	**-$17,773**	**-$48,734**	**-$6,424**	**-$380**	**$0**
4471400	S/T FIRM WHOLESALE	SG	-$416,104	-$6,356	-$108,408	-$32,299	-$65,226	-$178,846	-$23,575	-$1,395	$0
4471400	S/T FIRM WHOLESALE	SG	-$867	-$13	-$226	-$67	-$136	-$373	-$49	-$3	$0
4471400	S/T FIRM WHOLESALE	SG	$7,686	$117	$2,002	$597	$1,205	$3,303	$435	$26	$0
4471400	S/T FIRM WHOLESALE	SG	$200,410	$3,061	$52,213	$15,556	$31,415	$86,138	$11,354	$672	$0
4471400	S/T FIRM WHOLESALE	SG	-$2,104	-$32	-$548	-$163	-$330	-$904	-$119	-$7	$0
4471400	S/T FIRM WHOLESALE	SG	-$3,939	-$60	-$1,026	-$306	-$617	-$1,693	-$223	-$13	$0
4471400	S/T FIRM WHOLESALE	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
4471400	S/T FIRM WHOLESALE	SG	$190	$3	$49	$15	$30	$81	$11	$1	$0
4471400 Total			**-$214,730**	**-$3,280**	**-$55,944**	**-$16,668**	**-$33,660**	**-$92,293**	**-$12,166**	**-$720**	**$0**
4472000	SLS FOR RESL-SURP	SG	$5,939	$91	$1,547	$461	$931	$2,553	$336	$20	$0
4472000 Total			**$5,939**	**$91**	**$1,547**	**$461**	**$931**	**$2,553**	**$336**	**$20**	**$0**
4475000	OFF-SYS - NON FIRM	SE	-$2	$0	$0	$0	$0	-$1	$0	$0	$0
4475000 Total			**-$2**	**$0**	**$0**	**$0**	**$0**	**-$1**	**$0**	**$0**	**$0**
4476100	BOOKOUTS NETTED-GAIN	SG	-$8,357	-$128	-$2,177	-$649	-$1,310	-$3,592	-$473	-$28	$0
4476100	BOOKOUTS NETTED-GAIN	SG	$1,294	$20	$337	$100	$203	$556	$73	$4	$0
4476100 Total			**-$7,063**	**-$108**	**-$1,840**	**-$548**	**-$1,107**	**-$3,036**	**-$400**	**-$24**	**$0**

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4476200	TRADING NETTED-GAINS	SG	-$301	-$5	-$78	-$23	-$47	-$129	-$17	-$1	$0
4476200 Total			**-$301**	**-$5**	**-$78**	**-$23**	**-$47**	**-$129**	**-$17**	**-$1**	**$0**
4479000	TRANS SRVC	FERC	-$132	$0	$0	$0	$0	$0	$0	-$132	$0
4479000	TRANS SRVC	WYP	-$5	$0	$0	$0	-$5	$0	$0	$0	$0
4479000 Total			**-$136**	**$0**	**$0**	**$0**	**-$5**	**$0**	**$0**	**-$132**	**$0**
4501000	FORF DISC/INT-RES	CA	-$207	-$207	$0	$0	$0	$0	$0	$0	$0
4501000	FORF DISC/INT-RES	IDU	-$215	$0	$0	$0	$0	$0	-$215	$0	$0
4501000	FORF DISC/INT-RES	OR	-$2,946	$0	-$2,946	$0	$0	$0	$0	$0	$0
4501000	FORF DISC/INT-RES	UT	-$2,124	$0	$0	$0	$0	-$2,124	$0	$0	$0
4501000	FORF DISC/INT-RES	WA	-$518	$0	$0	-$518	$0	$0	$0	$0	$0
4501000	FORF DISC/INT-RES	WYP	-$356	$0	$0	$0	-$356	$0	$0	$0	$0
4501000	FORF DISC/INT-RES	WYU	-$49	$0	$0	$0	-$49	$0	$0	$0	$0
4501000 Total			**-$6,416**	**-$207**	**-$2,946**	**-$518**	**-$405**	**-$2,124**	**-$215**	**$0**	**$0**
4502000	FORF DISC/INT-COMM	CA	-$59	-$59	$0	$0	$0	$0	$0	$0	$0
4502000	FORF DISC/INT-COMM	IDU	-$39	$0	$0	$0	$0	$0	-$39	$0	$0
4502000	FORF DISC/INT-COMM	OR	-$631	$0	-$631	$0	$0	$0	$0	$0	$0
4502000	FORF DISC/INT-COMM	UT	-$638	$0	$0	$0	$0	-$638	$0	$0	$0
4502000	FORF DISC/INT-COMM	WA	-$122	$0	$0	-$122	$0	$0	$0	$0	$0
4502000	FORF DISC/INT-COMM	WYP	-$107	$0	$0	$0	-$107	$0	$0	$0	$0
4502000	FORF DISC/INT-COMM	WYU	-$18	$0	$0	$0	-$18	$0	$0	$0	$0
4502000 Total			**-$1,614**	**-$59**	**-$631**	**-$122**	**-$126**	**-$638**	**-$39**	**$0**	**$0**
4503000	FORF DISC/INT-IND	CA	-$18	-$18	$0	$0	$0	$0	$0	$0	$0
4503000	FORF DISC/INT-IND	IDU	-$129	$0	$0	$0	$0	$0	-$129	$0	$0
4503000	FORF DISC/INT-IND	OR	-$132	$0	-$132	$0	$0	$0	$0	$0	$0
4503000	FORF DISC/INT-IND	UT	-$180	$0	$0	$0	$0	-$180	$0	$0	$0
4503000	FORF DISC/INT-IND	WA	-$29	$0	$0	-$29	$0	$0	$0	$0	$0
4503000	FORF DISC/INT-IND	WYP	-$51	$0	$0	$0	-$51	$0	$0	$0	$0
4503000	FORF DISC/INT-IND	WYU	-$22	$0	$0	$0	-$22	$0	$0	$0	$0
4503000 Total			**-$560**	**-$18**	**-$132**	**-$29**	**-$74**	**-$180**	**-$129**	**$0**	**$0**
4504000	GOVT MUNI/ALL OTH	CA	$0	$0	$0	$0	$0	$0	$0	$0	$0
4504000	GOVT MUNI/ALL OTH	IDU	-$4	$0	$0	$0	$0	$0	-$4	$0	$0
4504000	GOVT MUNI/ALL OTH	OR	-$4	$0	-$4	$0	$0	$0	$0	$0	$0
4504000	GOVT MUNI/ALL OTH	UT	-$86	$0	$0	$0	$0	-$86	$0	$0	$0
4504000	GOVT MUNI/ALL OTH	WA	-$9	$0	$0	-$9	$0	$0	$0	$0	$0
4504000	GOVT MUNI/ALL OTH	WYP	-$10	$0	$0	$0	-$10	$0	$0	$0	$0
4504000	GOVT MUNI/ALL OTH	WYU	-$1	$0	$0	$0	-$1	$0	$0	$0	$0
4504000 Total			**-$114**	**$0**	**-$4**	**-$9**	**-$10**	**-$86**	**-$4**	**$0**	**$0**
4511000	ACCOUNT SERV CHG	CA	-$26	-$26	$0	$0	$0	$0	$0	$0	$0
4511000	ACCOUNT SERV CHG	IDU	-$59	$0	$0	$0	$0	$0	-$59	$0	$0
4511000	ACCOUNT SERV CHG	OR	-$469	$0	-$469	$0	$0	$0	$0	$0	$0

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4511000	ACCOUNT SERV CHG	UT	-$2,554	$0	$0	$0	$0	-$2,554	$0	$0	$0
4511000	ACCOUNT SERV CHG	WA	-$101	$0	$0	-$101	$0	$0	$0	$0	$0
4511000	ACCOUNT SERV CHG	WYP	-$124	$0	$0	$0	-$124	$0	$0	$0	$0
4511000	ACCOUNT SERV CHG	WYU	-$16	$0	$0	$0	-$16	$0	$0	$0	$0
4511000	ACCOUNT SERV CHG	CA	-$12	-$12	$0	$0	$0	$0	$0	$0	$0
4511000	ACCOUNT SERV CHG	IDU	-$35	$0	$0	$0	$0	$0	-$35	$0	$0
4511000	ACCOUNT SERV CHG	OR	-$313	$0	-$313	$0	$0	$0	$0	$0	$0
4511000	ACCOUNT SERV CHG	UT	-$491	$0	$0	$0	$0	-$491	$0	$0	$0
4511000	ACCOUNT SERV CHG	WA	-$62	$0	$0	-$62	$0	$0	$0	$0	$0
4511000	ACCOUNT SERV CHG	WYP	-$69	$0	$0	$0	-$69	$0	$0	$0	$0
4511000	ACCOUNT SERV CHG	WYU	-$11	$0	$0	$0	-$11	$0	$0	$0	$0
4511000 Total			**-$4,343**	**-$38**	**-$782**	**-$163**	**-$220**	**-$3,045**	**-$95**	**$0**	**$0**
4512000	TAMPER/RECONNECT	CA	-$1	-$1	$0	$0	$0	$0	$0	$0	$0
4512000	TAMPER/RECONNECT	IDU	-$1	$0	$0	$0	$0	$0	-$1	$0	$0
4512000	TAMPER/RECONNECT	OR	-$19	$0	-$19	$0	$0	$0	$0	$0	$0
4512000	TAMPER/RECONNECT	UT	-$14	$0	$0	$0	$0	-$14	$0	$0	$0
4512000	TAMPER/RECONNECT	WA	-$4	$0	$0	-$4	$0	$0	$0	$0	$0
4512000	TAMPER/RECONNECT	WYP	-$1	$0	$0	$0	-$1	$0	$0	$0	$0
4512000	TAMPER/RECONNECT	WYU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4512000 Total			**-$40**	**-$1**	**-$19**	**-$4**	**-$1**	**-$14**	**-$1**	**$0**	**$0**
4513000	OTHER	CA	-$71	-$71	$0	$0	$0	$0	$0	$0	$0
4513000	OTHER	IDU	-$2	$0	$0	$0	$0	$0	-$2	$0	$0
4513000	OTHER	OR	-$648	$0	-$648	$0	$0	$0	$0	$0	$0
4513000	OTHER	SO	-$4	$0	-$1	$0	-$1	-$2	$0	$0	$0
4513000	OTHER	UT	-$825	$0	$0	$0	$0	-$825	$0	$0	$0
4513000	OTHER	WA	$8	$0	$0	$8	$0	$0	$0	$0	$0
4513000	OTHER	WYP	-$208	$0	$0	$0	-$208	$0	$0	$0	$0
4513000	OTHER	WYU	-$87	$0	$0	$0	-$87	$0	$0	$0	$0
4513000 Total			**-$1,837**	**-$72**	**-$649**	**$8**	**-$296**	**-$827**	**-$2**	**$0**	**$0**
4514100	ENERGY FINANSWER	UT	-$20	$0	$0	$0	$0	-$20	$0	$0	$0
4514100	ENERGY FINANSWER	WA	-$1	$0	$0	-$1	$0	$0	$0	$0	$0
4514100 Total			**-$21**	**$0**	**$0**	**-$1**	**$0**	**-$20**	**$0**	**$0**	**$0**
4514400	ENGY FINANSWER LGHT	CA	-$1	-$1	$0	$0	$0	$0	$0	$0	$0
4514400	ENGY FINANSWER LGHT	WA	-$2	$0	$0	-$2	$0	$0	$0	$0	$0
4514400 Total			**-$3**	**-$1**	**$0**	**-$2**	**$0**	**$0**	**$0**	**$0**	**$0**
4514900	ENGY FINNSWR 12000	WYU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4514900 Total			**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
4530000	SLS WATER & W PWR	SG	-$12	$0	-$3	-$1	-$2	-$5	-$1	$0	$0
4530000 Total			**-$12**	**$0**	**-$3**	**-$1**	**-$2**	**-$5**	**-$1**	**$0**	**$0**
4541000	RENTS - COMMON	CA	-$2	-$2	$0	$0	$0	$0	$0	$0	$0

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4541000	RENTS - COMMON	IDU	-$1	$0	$0	$0	$0	$0	-$1	$0	$0
4541000	RENTS - COMMON	OR	-$655	$0	-$655	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	SO	-$491	-$11	-$134	-$37	-$71	-$210	-$27	-$1	$0
4541000	RENTS - COMMON	UT	-$759	$0	$0	$0	$0	-$759	$0	$0	$0
4541000	RENTS - COMMON	WA	-$32	$0	$0	-$32	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	WYP	-$14	$0	$0	$0	-$14	$0	$0	$0	$0
4541000	RENTS - COMMON	WYU	-$18	$0	$0	$0	-$18	$0	$0	$0	$0
4541000	RENTS - COMMON	CA	-$523	-$523	$0	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	IDU	-$182	$0	$0	$0	$0	$0	-$182	$0	$0
4541000	RENTS - COMMON	OR	-$4,163	$0	-$4,163	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	UT	-$2,034	$0	$0	$0	$0	-$2,034	$0	$0	$0
4541000	RENTS - COMMON	WA	-$968	$0	$0	-$968	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	WYP	-$315	$0	$0	$0	-$315	$0	$0	$0	$0
4541000	RENTS - COMMON	UT	-$2	$0	$0	$0	$0	-$2	$0	$0	$0
4541000	RENTS - COMMON	CA	-$5	-$5	$0	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	OR	-$84	$0	-$84	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	UT	-$37	$0	$0	$0	$0	-$37	$0	$0	$0
4541000	RENTS - COMMON	WA	-$72	$0	$0	-$72	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	WYP	-$5	$0	$0	$0	-$5	$0	$0	$0	$0
4541000	RENTS - COMMON	CA	-$32	-$32	$0	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	OR	-$17	$0	-$17	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	UT	-$1	$0	$0	$0	$0	-$1	$0	$0	$0
4541000	RENTS - COMMON	WA	-$2	$0	$0	-$2	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	WYP	-$16	$0	$0	$0	-$16	$0	$0	$0	$0
4541000	RENTS - COMMON	SG	-$169	-$3	-$44	-$13	-$26	-$73	-$10	-$1	$0
4541000	RENTS - COMMON	SG	-$764	-$12	-$199	-$59	-$120	-$328	-$43	-$3	$0
4541000	RENTS - COMMON	SG	-$1,321	-$20	-$344	-$103	-$207	-$568	-$75	-$4	$0
4541000	RENTS - COMMON	OR	$0	$0	$0	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	SO	-$87	-$2	-$24	-$7	-$12	-$37	-$5	$0	$0
4541000	RENTS - COMMON	UT	-$431	$0	$0	$0	$0	-$431	$0	$0	$0
4541000	RENTS - COMMON	SG	-$20	$0	-$5	-$2	-$3	-$8	-$1	$0	$0
4541000	RENTS - COMMON	SO	-$88	-$2	-$24	-$7	-$13	-$38	-$5	$0	$0
4541000	RENTS - COMMON	UT	-$1	$0	$0	$0	$0	-$1	$0	$0	$0
4541000	RENTS - COMMON	UT	-$51	$0	$0	$0	$0	-$51	$0	$0	$0
4541000	RENTS - COMMON	CA	-$3	-$3	$0	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	OR	-$114	$0	-$114	$0	$0	$0	$0	$0	$0
4541000	RENTS - COMMON	UT	-$143	$0	$0	$0	$0	-$143	$0	$0	$0
4541000	RENTS - COMMON	WA	-$16	$0	$0	-$16	$0	$0	$0	$0	$0

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4541000	RENTS - COMMON	WYP	-$24	$0	$0	$0	-$24	$0	$0	$0	$0
4541000	RENTS - COMMON	SO	-$2,959	-$64	-$810	-$224	-$425	-$1,265	-$164	-$7	$0
4541000	RENTS - COMMON	WYP	-$14	$0	$0	$0	-$14	$0	$0	$0	$0
4541000 Total			**-$16,635**	**-$679**	**-$6,617**	**-$1,541**	**-$1,283**	**-$5,985**	**-$513**	**-$16**	**$0**
4542000	RENTS - NON COMMON	SG	-$11	$0	-$3	-$1	-$2	-$5	-$1	$0	$0
4542000	RENTS - NON COMMON	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
4542000	RENTS - NON COMMON	UT	-$4	$0	$0	$0	$0	-$4	$0	$0	$0
4542000 Total			**-$15**	**$0**	**-$3**	**-$1**	**-$2**	**-$8**	**-$1**	**$0**	**$0**
4543000	MCI FOGWIRE REVENUES	SG	-$3,352	-$51	-$873	-$260	-$525	-$1,441	-$190	-$11	$0
4543000 Total			**-$3,352**	**-$51**	**-$873**	**-$260**	**-$525**	**-$1,441**	**-$190**	**-$11**	**$0**
4561100	Other Wheeling Rev	SG	$27	$0	$7	$2	$4	$12	$2	$0	$0
4561100	Other Wheeling Rev	SG	-$494	-$8	-$129	-$38	-$77	-$212	-$28	-$2	$0
4561100	Other Wheeling Rev	SG	-$203	-$3	-$53	-$16	-$32	-$87	-$11	-$1	$0
4561100	Other Wheeling Rev	SG	-$615	-$9	-$160	-$48	-$96	-$264	-$35	-$2	$0
4561100	Other Wheeling Rev	SG	-$140	-$2	-$36	-$11	-$22	-$60	-$8	$0	$0
4561100	Other Wheeling Rev	SG	-$422	-$6	-$110	-$33	-$66	-$181	-$24	-$1	$0
4561100	Other Wheeling Rev	SG	-$577	-$9	-$150	-$45	-$90	-$248	-$33	-$2	$0
4561100	Other Wheeling Rev	SG	-$247	-$4	-$64	-$19	-$39	-$106	-$14	-$1	$0
4561100	Other Wheeling Rev	SG	-$1,058	-$16	-$276	-$82	-$166	-$455	-$60	-$4	$0
4561100	Other Wheeling Rev	SG	-$354	-$5	-$92	-$27	-$55	-$152	-$20	-$1	$0
4561100	Other Wheeling Rev	SG	-$1,803	-$28	-$470	-$140	-$283	-$775	-$102	-$6	$0
4561100	Other Wheeling Rev	SG	-$355	-$5	-$92	-$28	-$56	-$153	-$20	-$1	$0
4561100	Other Wheeling Rev	SG	-$20,553	-$314	-$5,355	-$1,595	-$3,222	-$8,834	-$1,164	-$69	$0
4561100	Other Wheeling Rev	SG	-$1,821	-$28	-$474	-$141	-$285	-$783	-$103	-$6	$0
4561100	Other Wheeling Rev	SG	-$446	-$7	-$116	-$35	-$70	-$192	-$25	-$1	$0
4561100	Other Wheeling Rev	SG	-$488	-$7	-$127	-$38	-$77	-$210	-$28	-$2	$0
4561100	Other Wheeling Rev	SG	-$112	-$2	-$29	-$9	-$18	-$48	-$6	$0	$0
4561100	Other Wheeling Rev	SG	-$656	-$10	-$171	-$51	-$103	-$282	-$37	-$2	$0
4561100 Total			**-$30,317**	**-$463**	**-$7,898**	**-$2,353**	**-$4,752**	**-$13,031**	**-$1,718**	**-$102**	**$0**
4561910	S/T FIRM WHEEL REV	SG	-$3,147	-$48	-$820	-$244	-$493	-$1,353	-$178	-$11	$0
4561910 Total			**-$3,147**	**-$48**	**-$820**	**-$244**	**-$493**	**-$1,353**	**-$178**	**-$11**	**$0**
4561920	L/T FIRM WHEEL REV	SG	-$1,770	-$27	-$461	-$137	-$278	-$761	-$100	-$6	$0
4561920	L/T FIRM WHEEL REV	SG	-$4,312	-$66	-$1,124	-$335	-$676	-$1,854	-$244	-$14	$0
4561920	L/T FIRM WHEEL REV	SG	-$16,217	-$248	-$4,225	-$1,259	-$2,542	-$6,970	-$919	-$54	$0
4561920	L/T FIRM WHEEL REV	SG	$1,557	$24	$406	$121	$244	$669	$88	$5	$0
4561920	L/T FIRM WHEEL REV	SG	-$1,557	-$24	-$406	-$121	-$244	-$669	-$88	-$5	$0
4561920	L/T FIRM WHEEL REV	SG	-$9,286	-$142	-$2,419	-$721	-$1,456	-$3,991	-$526	-$31	$0
4561920 Total			**-$31,586**	**-$482**	**-$8,229**	**-$2,452**	**-$4,951**	**-$13,576**	**-$1,790**	**-$106**	**$0**
4561930	NON-FIRM WHEEL REV	SE	-$11,357	-$171	-$2,804	-$833	-$1,970	-$4,820	-$719	-$41	$0
4561930 Total			**-$11,357**	**-$171**	**-$2,804**	**-$833**	**-$1,970**	**-$4,820**	**-$719**	**-$41**	**$0**

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4561990	TRANSMN REV REFUND	SG	$1,305	$20	$340	$101	$205	$561	$74	$4	$0
4561990	TRANSMN REV REFUND	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
4561990	TRANSMN REV REFUND	SG	$18	$0	$5	$1	$3	$8	$1	$0	$0
4561990	TRANSMN REV REFUND	SG	$203	$3	$53	$16	$32	$87	$11	$1	$0
4561990	TRANSMN REV REFUND	SG	$216	$3	$56	$17	$34	$93	$12	$1	$0
4561990	TRANSMN REV REFUND	SG	$140	$2	$36	$11	$22	$60	$8	$0	$0
4561990 Total			**$1,881**	**$29**	**$490**	**$146**	**$295**	**$808**	**$107**	**$6**	**$0**
4562100	USE OF FACIL REV	SG	-$19	$0	-$5	-$1	-$3	-$8	-$1	$0	$0
4562100 Total			**-$19**	**$0**	**-$5**	**-$1**	**-$3**	**-$8**	**-$1**	**$0**	**$0**
4562200	DSM REVENUES	OTHER	-$51,527	$0	$0	$0	$0	$0	$0	$0	-$51,527
4562200	DSM REVENUES	OTHER	-$140	$0	$0	$0	$0	$0	$0	$0	-$140
4562200	DSM REVENUES	CA	-$1,274	-$1,274	$0	$0	$0	$0	$0	$0	$0
4562200	DSM REVENUES	UT	-$30,159	$0	$0	$0	$0	-$30,159	$0	$0	$0
4562200	DSM REVENUES	IDU	-$3,199	$0	$0	$0	$0	$0	-$3,199	$0	$0
4562200	DSM REVENUES	WA	-$4,271	$0	$0	-$4,271	$0	$0	$0	$0	$0
4562200	DSM REVENUES	WYP	-$1,174	$0	$0	$0	-$1,174	$0	$0	$0	$0
4562200	DSM REVENUES	WYU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4562200	DSM REVENUES	OR	-$10,205	$0	-$10,205	$0	$0	$0	$0	$0	$0
4562200	DSM REVENUES	WYP	-$493	$0	$0	$0	-$493	$0	$0	$0	$0
4562200	DSM REVENUES	WYU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4562200	DSM REVENUES	WYP	-$752	$0	$0	$0	-$752	$0	$0	$0	$0
4562200	DSM REVENUES	OTHER	$51,527	$0	$0	$0	$0	$0	$0	$0	$51,527
4562200 Total			**-$51,667**	**-$1,274**	**-$10,205**	**-$4,271**	**-$2,420**	**-$30,159**	**-$3,199**	**$0**	**-$140**
4562300	MISC OTHER REV	SG	-$81	-$1	-$21	-$6	-$13	-$35	-$5	$0	$0
4562300	MISC OTHER REV	UT	-$25	$0	$0	$0	$0	-$25	$0	$0	$0
4562300	MISC OTHER REV	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
4562300	MISC OTHER REV	WA	$52	$0	$0	$52	$0	$0	$0	$0	$0
4562300	MISC OTHER REV	SG	-$991	-$15	-$258	-$77	-$155	-$426	-$56	-$3	$0
4562300	MISC OTHER REV	SG	$260	$4	$68	$20	$41	$112	$15	$1	$0
4562300	MISC OTHER REV	SG	-$3,132	-$48	-$816	-$243	-$491	-$1,346	-$177	-$10	$0
4562300	MISC OTHER REV	SG	-$772	-$12	-$201	-$60	-$121	-$332	-$44	-$3	$0
4562300	MISC OTHER REV	SG	-$8,775	-$134	-$2,286	-$681	-$1,376	-$3,772	-$497	-$29	$0
4562300	MISC OTHER REV	WYP	-$245	$0	$0	$0	-$245	$0	$0	$0	$0
4562300	MISC OTHER REV	SG	-$467	-$7	-$122	-$36	-$73	-$201	-$26	-$2	$0
4562300	MISC OTHER REV	SG	-$9,780	-$149	-$2,548	-$759	-$1,533	-$4,204	-$554	-$33	$0
4562300	MISC OTHER REV	SG	-$5,141	-$79	-$1,339	-$399	-$806	-$2,210	-$291	-$17	$0
4562300 Total			**-$29,097**	**-$441**	**-$7,524**	**-$2,189**	**-$4,772**	**-$12,437**	**-$1,636**	**-$97**	**$0**
4562400	M&S INVENTORY SALES	SO	$27	$1	$7	$2	$4	$11	$1	$0	$0
4562400	M&S INVENTORY SALES	UT	-$134	$0	$0	$0	$0	-$134	$0	$0	$0
4562400 Total			**-$108**	**$1**	**$7**	**$2**	**$4**	**-$123**	**$1**	**$0**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Operations Revenue (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4562500	M&S INV COST OF SALE	UT	$89	$0	$0	$0	$0	$89	$0	$0	$0
4562500 Total			**$89**	**$0**	**$0**	**$0**	**$0**	**$89**	**$0**	**$0**	**$0**
4562700	RNW ENRGY CRDT SALES	SG	$52,692	$805	$13,728	$4,090	$8,260	$22,647	$2,985	$177	$0
4562700	RNW ENRGY CRDT SALES	SG	$238	$4	$62	$19	$37	$102	$14	$1	$0
4562700	RNW ENRGY CRDT SALES	SG	-$79,244	-$1,210	-$20,645	-$6,151	-$12,422	-$34,060	-$4,490	-$266	$0
4562700	RNW ENRGY CRDT SALES	OTHER	-$31,656	$0	$0	$0	$0	$0	$0	$0	-$31,656
4562700 Total			**-$57,970**	**-$402**	**-$6,856**	**-$2,043**	**-$4,125**	**-$11,310**	**-$1,491**	**-$88**	**-$31,656**
4569500	BLUE SKY REVENUE	OTHER	-$1,730	$0	$0	$0	$0	$0	$0	$0	-$1,730
4569500 Total			**-$1,730**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$1,730**
Grand Total			**-$4,385,920**	**-$103,318**	**-$1,193,746**	**-$312,583**	**-$646,569**	**-$1,821,077**	**-$263,891**	**-$9,858**	**-$34,877**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5000000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	$18,907	$289	$4,926	$1,468	$2,964	$8,127	$1,071	$63	$0
5000000 Total					**$18,907**	**$289**	**$4,926**	**$1,468**	**$2,964**	**$8,127**	**$1,071**	**$63**	**$0**
5001000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	$1,017	$16	$265	$79	$159	$437	$58	$3	$0
5001000 Total					**$1,017**	**$16**	**$265**	**$79**	**$159**	**$437**	**$58**	**$3**	**$0**
5010000	FUEL CONSUMED	NPCX	Net Power Cost Expense	SE	$263	$4	$65	$19	$46	$111	$17	$1	$0
5010000 Total					**$263**	**$4**	**$65**	**$19**	**$46**	**$111**	**$17**	**$1**	**$0**
5011000	FUEL CONSUMED-COAL	NPCX	Net Power Cost Expense	SE	$684,788	$10,283	$169,052	$50,243	$118,788	$290,619	$43,325	$2,477	$0
5011000 Total					**$684,788**	**$10,283**	**$169,052**	**$50,243**	**$118,788**	**$290,619**	**$43,325**	**$2,477**	**$0**
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	IDU	$178	$0	$0	$0	$0	$0	$178	$0	$0
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	WYP	$481	$0	$0	$0	$481	$0	$0	$0	$0
5011200 Total					**$659**	**$0**	**$0**	**$0**	**$481**	**$0**	**$178**	**$0**	**$0**
5012000	FUEL HAND-COAL	STEX	Steam O&M Expense	SE	$8,947	$134	$2,209	$656	$1,552	$3,797	$566	$32	$0
5012000 Total					**$8,947**	**$134**	**$2,209**	**$656**	**$1,552**	**$3,797**	**$566**	**$32**	**$0**
5013000	START UP FUEL - GAS	NPCX	Net Power Cost Expense	SE	$425	$6	$105	$31	$74	$180	$27	$2	$0
5013000 Total					**$425**	**$6**	**$105**	**$31**	**$74**	**$180**	**$27**	**$2**	**$0**
5013500	FUEL CONSUMED-GAS	NPCX	Net Power Cost Expense	SE	$12,120	$182	$2,992	$889	$2,102	$5,144	$767	$44	$0
5013500 Total					**$12,120**	**$182**	**$2,992**	**$889**	**$2,102**	**$5,144**	**$767**	**$44**	**$0**
5014000	FUEL CONSUMED-DIESEL	NPCX	Net Power Cost Expense	SE	$2	$0	$0	$0	$0	$1	$0	$0	$0
5014000 Total					**$2**	**$0**	**$0**	**$0**	**$0**	**$1**	**$0**	**$0**	**$0**
5014500	START UP FUEL-DIESEL	NPCX	Net Power Cost Expense	SE	$8,698	$131	$2,147	$638	$1,509	$3,691	$550	$31	$0
5014500 Total					**$8,698**	**$131**	**$2,147**	**$638**	**$1,509**	**$3,691**	**$550**	**$31**	**$0**
5015000	FUEL CONS-RES DISP	NPCX	Net Power Cost Expense	SE	$1,045	$16	$258	$77	$181	$443	$66	$4	$0
5015000 Total					**$1,045**	**$16**	**$258**	**$77**	**$181**	**$443**	**$66**	**$4**	**$0**
5015100	ASH & ASH BYPRD SALE	NPCX	Net Power Cost Expense	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
5015100 Total					**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5020000	STEAM EXPENSES	STEX	Steam O&M Expense	SG	$23,193	$354	$6,042	$1,800	$3,636	$9,969	$1,314	$78	$0
5020000 Total					**$23,193**	**$354**	**$6,042**	**$1,800**	**$3,636**	**$9,969**	**$1,314**	**$78**	**$0**
5022000	STM EXP - FLYASH	STEX	Steam O&M Expense	SG	$1,462	$22	$381	$113	$229	$628	$83	$5	$0
5022000 Total					**$1,462**	**$22**	**$381**	**$113**	**$229**	**$628**	**$83**	**$5**	**$0**
5023000	STM EXP BOTTOM ASH	STEX	Steam O&M Expense	SG	$1	$0	$0	$0	$0	$0	$0	$0	$0
5023000 Total					**$1**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5024000	STM EXP SCRUBBER	STEX	Steam O&M Expense	SG	$1,108	$17	$289	$86	$174	$476	$63	$4	$0
5024000 Total					**$1,108**	**$17**	**$289**	**$86**	**$174**	**$476**	**$63**	**$4**	**$0**
5029000	STM EXP - OTHER	STEX	Steam O&M Expense	SG	$12,181	$186	$3,174	$946	$1,909	$5,236	$690	$41	$0
5029000 Total					**$12,181**	**$186**	**$3,174**	**$946**	**$1,909**	**$5,236**	**$690**	**$41**	**$0**
5030000	STEAM FRM OTH SRCS	NPCX	Net Power Cost Expense	SE	$3,976	$60	$981	$292	$690	$1,687	$252	$14	$0
5030000 Total					**$3,976**	**$60**	**$981**	**$292**	**$690**	**$1,687**	**$252**	**$14**	**$0**
5050000	ELECTRIC EXPENSES	STEX	Steam O&M Expense	SG	$4,067	$62	$1,059	$316	$637	$1,748	$230	$14	$0
5050000 Total					**$4,067**	**$62**	**$1,059**	**$316**	**$637**	**$1,748**	**$230**	**$14**	**$0**
5051000	ELEC EXP GENERAL	STEX	Steam O&M Expense	SG	$49	$1	$13	$4	$8	$21	$3	$0	$0
5051000 Total					**$49**	**$1**	**$13**	**$4**	**$8**	**$21**	**$3**	**$0**	**$0**
5060000	MISC STEAM PWR EXP	STEX	Steam O&M Expense	SG	$79,854	$1,220	$20,804	$6,198	$12,517	$34,322	$4,524	$268	$0
5060000 Total					**$79,854**	**$1,220**	**$20,804**	**$6,198**	**$12,517**	**$34,322**	**$4,524**	**$268**	**$0**
5061000	MISC STM EXP - CON	STEX	Steam O&M Expense	SG	$1,139	$17	$297	$88	$178	$489	$65	$4	$0
5061000 Total					**$1,139**	**$17**	**$297**	**$88**	**$178**	**$489**	**$65**	**$4**	**$0**
5061100	MISC STM EXP PLCLU	STEX	Steam O&M Expense	SG	$723	$11	$188	$56	$113	$311	$41	$2	$0
5061100 Total					**$723**	**$11**	**$188**	**$56**	**$113**	**$311**	**$41**	**$2**	**$0**
5061200	MISC STM EXP UNMTG	STEX	Steam O&M Expense	SG	$3	$0	$1	$0	$1	$1	$0	$0	$0
5061200 Total					**$3**	**$0**	**$1**	**$0**	**$1**	**$1**	**$0**	**$0**	**$0**
5061300	MISC STM EXP COMPT	STEX	Steam O&M Expense	SG	$685	$10	$178	$53	$107	$294	$39	$2	$0
5061300 Total					**$685**	**$10**	**$178**	**$53**	**$107**	**$294**	**$39**	**$2**	**$0**
5061400	MISC STM EXP OFFIC	STEX	Steam O&M Expense	SG	$1,728	$26	$450	$134	$271	$743	$98	$6	$0
5061400 Total					**$1,728**	**$26**	**$450**	**$134**	**$271**	**$743**	**$98**	**$6**	**$0**
5061500	MISC STM EXP COMM	STEX	Steam O&M Expense	SG	$148	$2	$39	$11	$23	$64	$8	$0	$0
5061500 Total					**$148**	**$2**	**$39**	**$11**	**$23**	**$64**	**$8**	**$0**	**$0**
5061600	MISC STM EXP FIRE	STEX	Steam O&M Expense	SG	$43	$1	$11	$3	$7	$19	$2	$0	$0
5061600 Total					**$43**	**$1**	**$11**	**$3**	**$7**	**$19**	**$2**	**$0**	**$0**
5062000	MISC STM - ENVRMNT	STEX	Steam O&M Expense	SG	$1,523	$23	$397	$118	$239	$654	$86	$5	$0
5062000 Total					**$1,523**	**$23**	**$397**	**$118**	**$239**	**$654**	**$86**	**$5**	**$0**
5063000	MISC STEAM JVA CR	STEX	Steam O&M Expense	SG	-$33,825	-$517	-$8,812	-$2,626	-$5,302	-$14,538	-$1,916	-$113	$0
5063000 Total					**-$33,825**	**-$517**	**-$8,812**	**-$2,626**	**-$5,302**	**-$14,538**	**-$1,916**	**-$113**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Operations & Maintenance Expense (Actuals)
Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5064000	MISC STM EXP RCRT	STEX	Steam O&M Expense	SG	$18	$0	$5	$1	$3	$8	$1	$0	$0
5064000 Total					**$18**	**$0**	**$5**	**$1**	**$3**	**$8**	**$1**	**$0**	**$0**
5065000	MISC STM EXP - SEC	STEX	Steam O&M Expense	SG	$396	$6	$103	$31	$62	$170	$22	$1	$0
5065000 Total					**$396**	**$6**	**$103**	**$31**	**$62**	**$170**	**$22**	**$1**	**$0**
5066000	MISC STM EXP -SFTY	STEX	Steam O&M Expense	SG	$1,370	$21	$357	$106	$215	$589	$78	$5	$0
5066000 Total					**$1,370**	**$21**	**$357**	**$106**	**$215**	**$589**	**$78**	**$5**	**$0**
5067000	MISC STM EXP TRNNG	STEX	Steam O&M Expense	SG	$2,049	$31	$534	$159	$321	$881	$116	$7	$0
5067000 Total					**$2,049**	**$31**	**$534**	**$159**	**$321**	**$881**	**$116**	**$7**	**$0**
5068000	MISC STM EXP TRAVL	STEX	Steam O&M Expense	SG	$4	$0	$1	$0	$1	$2	$0	$0	$0
5068000 Total					**$4**	**$0**	**$1**	**$0**	**$1**	**$2**	**$0**	**$0**	**$0**
5069000	MISC STM EXP WTSPY	STEX	Steam O&M Expense	SG	$183	$3	$48	$14	$29	$79	$10	$1	$0
5069000 Total					**$183**	**$3**	**$48**	**$14**	**$29**	**$79**	**$10**	**$1**	**$0**
5069900	MISC STM EXP MISC	STEX	Steam O&M Expense	SG	$2,268	$35	$591	$176	$355	$975	$128	$8	$0
5069900 Total					**$2,268**	**$35**	**$591**	**$176**	**$355**	**$975**	**$128**	**$8**	**$0**
5070000	RENTS (STEAM GEN)	STEX	Steam O&M Expense	SG	$334	$5	$87	$26	$52	$143	$19	$1	$0
5070000 Total					**$334**	**$5**	**$87**	**$26**	**$52**	**$143**	**$19**	**$1**	**$0**
5100000	MNT SUPERV & ENG	STEX	Steam O&M Expense	SG	$3,734	$57	$973	$290	$585	$1,605	$212	$13	$0
5100000 Total					**$3,734**	**$57**	**$973**	**$290**	**$585**	**$1,605**	**$212**	**$13**	**$0**
5101000	MNTNCE SUPVSN &ENG	STEX	Steam O&M Expense	SG	$2,568	$39	$669	$199	$403	$1,104	$146	$9	$0
5101000 Total					**$2,568**	**$39**	**$669**	**$199**	**$403**	**$1,104**	**$146**	**$9**	**$0**
5110000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	$3,036	$46	$791	$236	$476	$1,305	$172	$10	$0
5110000 Total					**$3,036**	**$46**	**$791**	**$236**	**$476**	**$1,305**	**$172**	**$10**	**$0**
5111000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	$7,074	$108	$1,843	$549	$1,109	$3,041	$401	$24	$0
5111000 Total					**$7,074**	**$108**	**$1,843**	**$549**	**$1,109**	**$3,041**	**$401**	**$24**	**$0**
5111100	MNT STRCT PMP PLNT	STEX	Steam O&M Expense	SG	$1,204	$18	$314	$93	$189	$517	$68	$4	$0
5111100 Total					**$1,204**	**$18**	**$314**	**$93**	**$189**	**$517**	**$68**	**$4**	**$0**
5111200	MNT STRCT WASTE WT	STEX	Steam O&M Expense	SG	$734	$11	$191	$57	$115	$315	$42	$2	$0
5111200 Total					**$734**	**$11**	**$191**	**$57**	**$115**	**$315**	**$42**	**$2**	**$0**
5112000	STRUCTURAL SYSTEMS	STEX	Steam O&M Expense	SG	$8,239	$126	$2,147	$640	$1,292	$3,541	$467	$28	$0
5112000 Total					**$8,239**	**$126**	**$2,147**	**$640**	**$1,292**	**$3,541**	**$467**	**$28**	**$0**
5114000	MNT OF STRCT CATH	STEX	Steam O&M Expense	SG	$20	$0	$5	$2	$3	$8	$1	$0	$0
5114000 Total					**$20**	**$0**	**$5**	**$2**	**$3**	**$8**	**$1**	**$0**	**$0**
5116000	MNT STRCT DAM RIVR	STEX	Steam O&M Expense	SG	$208	$3	$54	$16	$33	$90	$12	$1	$0
5116000 Total					**$208**	**$3**	**$54**	**$16**	**$33**	**$90**	**$12**	**$1**	**$0**
5117000	MNT STRCT FIRE PRT	STEX	Steam O&M Expense	SG	$970	$15	$253	$75	$152	$417	$55	$3	$0
5117000 Total					**$970**	**$15**	**$253**	**$75**	**$152**	**$417**	**$55**	**$3**	**$0**
5118000	MNT STRCT-GROUNDS	STEX	Steam O&M Expense	SG	$921	$14	$240	$71	$144	$396	$52	$3	$0
5118000 Total					**$921**	**$14**	**$240**	**$71**	**$144**	**$396**	**$52**	**$3**	**$0**
5119000	MNT OF STRCT-HVAC	STEX	Steam O&M Expense	SG	$1,388	$21	$362	$108	$218	$596	$79	$5	$0
5119000 Total					**$1,388**	**$21**	**$362**	**$108**	**$218**	**$596**	**$79**	**$5**	**$0**
5119900	MNT OF STRCT-MISC	STEX	Steam O&M Expense	SG	$229	$3	$60	$18	$36	$98	$13	$1	$0
5119900 Total					**$229**	**$3**	**$60**	**$18**	**$36**	**$98**	**$13**	**$1**	**$0**
5120000	MANT OF BOILR PLNT	STEX	Steam O&M Expense	SG	$16,682	$255	$4,346	$1,295	$2,615	$7,170	$945	$56	$0
5120000 Total					**$16,682**	**$255**	**$4,346**	**$1,295**	**$2,615**	**$7,170**	**$945**	**$56**	**$0**
5121000	MNT BOILR-AIR HTR	STEX	Steam O&M Expense	SG	$20,453	$312	$5,329	$1,588	$3,206	$8,791	$1,159	$69	$0
5121000 Total					**$20,453**	**$312**	**$5,329**	**$1,588**	**$3,206**	**$8,791**	**$1,159**	**$69**	**$0**
5121100	MNT BOILR-CHEM FD	STEX	Steam O&M Expense	SG	$167	$3	$43	$13	$26	$72	$9	$1	$0
5121100 Total					**$167**	**$3**	**$43**	**$13**	**$26**	**$72**	**$9**	**$1**	**$0**
5121200	MNT BOILR-CL HANDL	STEX	Steam O&M Expense	SG	$5,881	$90	$1,532	$456	$922	$2,528	$333	$20	$0
5121200 Total					**$5,881**	**$90**	**$1,532**	**$456**	**$922**	**$2,528**	**$333**	**$20**	**$0**
5121400	MNT BOIL-DEMINERLZ	STEX	Steam O&M Expense	SG	$688	$11	$179	$53	$108	$296	$39	$2	$0
5121400 Total					**$688**	**$11**	**$179**	**$53**	**$108**	**$296**	**$39**	**$2**	**$0**
5121500	MNT BOIL-EXTRC STM	STEX	Steam O&M Expense	SG	$419	$6	$109	$33	$66	$180	$24	$1	$0
5121500 Total					**$419**	**$6**	**$109**	**$33**	**$66**	**$180**	**$24**	**$1**	**$0**
5121600	MNT BOILR-FLYASH	STEX	Steam O&M Expense	SG	$2,681	$41	$698	$208	$420	$1,152	$152	$9	$0
5121600 Total					**$2,681**	**$41**	**$698**	**$208**	**$420**	**$1,152**	**$152**	**$9**	**$0**
5121700	MNT BOIL-FUEL OIL	STEX	Steam O&M Expense	SG	$582	$9	$152	$45	$91	$250	$33	$2	$0
5121700 Total					**$582**	**$9**	**$152**	**$45**	**$91**	**$250**	**$33**	**$2**	**$0**
5121800	MNT BOIL-FEEDWATR	STEX	Steam O&M Expense	SG	$5,675	$87	$1,478	$440	$890	$2,439	$321	$19	$0
5121800 Total					**$5,675**	**$87**	**$1,478**	**$440**	**$890**	**$2,439**	**$321**	**$19**	**$0**
5121900	MNT BOIL-FRZ PRTEC	STEX	Steam O&M Expense	SG	$64	$1	$17	$5	$10	$28	$4	$0	$0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5121900 Total					**$64**	**$1**	**$17**	**$5**	**$10**	**$28**	**$4**	**$0**	**$0**
5122000	MNT BOILR-AUX SYST	STEX	Steam O&M Expense	SG	$2,939	$45	$766	$228	$461	$1,263	$167	$10	$0
5122000 Total					**$2,939**	**$45**	**$766**	**$228**	**$461**	**$1,263**	**$167**	**$10**	**$0**
5122100	MNT BOILR-MAIN STM	STEX	Steam O&M Expense	SG	$3,874	$59	$1,009	$301	$607	$1,665	$219	$13	$0
5122100 Total					**$3,874**	**$59**	**$1,009**	**$301**	**$607**	**$1,665**	**$219**	**$13**	**$0**
5122200	MNT BOIL-PLVRZD CL	STEX	Steam O&M Expense	SG	$10,363	$158	$2,700	$804	$1,624	$4,454	$587	$35	$0
5122200 Total					**$10,363**	**$158**	**$2,700**	**$804**	**$1,624**	**$4,454**	**$587**	**$35**	**$0**
5122300	MNT BOIL-PRECIP/BAG	STEX	Steam O&M Expense	SG	$4,160	$64	$1,084	$323	$652	$1,788	$236	$14	$0
5122300 Total					**$4,160**	**$64**	**$1,084**	**$323**	**$652**	**$1,788**	**$236**	**$14**	**$0**
5122400	MNT BOIL-PRTRT WTR	STEX	Steam O&M Expense	SG	$573	$9	$149	$45	$90	$246	$32	$2	$0
5122400 Total					**$573**	**$9**	**$149**	**$45**	**$90**	**$246**	**$32**	**$2**	**$0**
5122500	MNT BOIL-RV OSMSIS	STEX	Steam O&M Expense	SG	$204	$3	$53	$16	$32	$88	$12	$1	$0
5122500 Total					**$204**	**$3**	**$53**	**$16**	**$32**	**$88**	**$12**	**$1**	**$0**
5122600	MNT BOIL-RHEAT ST	STEX	Steam O&M Expense	SG	$938	$14	$245	$73	$147	$403	$53	$3	$0
5122600 Total					**$938**	**$14**	**$245**	**$73**	**$147**	**$403**	**$53**	**$3**	**$0**
5122800	MNT BOIL-SOOTBLWG	STEX	Steam O&M Expense	SG	$2,499	$38	$651	$194	$392	$1,074	$142	$8	$0
5122800 Total					**$2,499**	**$38**	**$651**	**$194**	**$392**	**$1,074**	**$142**	**$8**	**$0**
5122900	MNT BOILR-SCRUBBER	STEX	Steam O&M Expense	SG	$9,152	$140	$2,384	$710	$1,435	$3,934	$519	$31	$0
5122900 Total					**$9,152**	**$140**	**$2,384**	**$710**	**$1,435**	**$3,934**	**$519**	**$31**	**$0**
5123000	MNT BOILR-BOTM ASH	STEX	Steam O&M Expense	SG	$5,144	$79	$1,340	$399	$806	$2,211	$291	$17	$0
5123000 Total					**$5,144**	**$79**	**$1,340**	**$399**	**$806**	**$2,211**	**$291**	**$17**	**$0**
5123100	MNT BOIL-WTR TRTMT	STEX	Steam O&M Expense	SG	$319	$5	$83	$25	$50	$137	$18	$1	$0
5123100 Total					**$319**	**$5**	**$83**	**$25**	**$50**	**$137**	**$18**	**$1**	**$0**
5123200	MNT BOIL-CNTL SUPT	STEX	Steam O&M Expense	SG	$1,054	$16	$275	$82	$165	$453	$60	$4	$0
5123200 Total					**$1,054**	**$16**	**$275**	**$82**	**$165**	**$453**	**$60**	**$4**	**$0**
5123300	MAINT GEO GATH SYS	STEX	Steam O&M Expense	SG	$139	$2	$36	$11	$22	$60	$8	$0	$0
5123300 Total					**$139**	**$2**	**$36**	**$11**	**$22**	**$60**	**$8**	**$0**	**$0**
5123400	MAINT OF BOILERS	STEX	Steam O&M Expense	SG	$1,917	$29	$499	$149	$301	$824	$109	$6	$0
5123400 Total					**$1,917**	**$29**	**$499**	**$149**	**$301**	**$824**	**$109**	**$6**	**$0**
5124000	MNT BOILR-CONTROLS	STEX	Steam O&M Expense	SG	$1,010	$15	$263	$78	$158	$434	$57	$3	$0
5124000 Total					**$1,010**	**$15**	**$263**	**$78**	**$158**	**$434**	**$57**	**$3**	**$0**
5125000	MNT BOILER-DRAFT	STEX	Steam O&M Expense	SG	$5,121	$78	$1,334	$398	$803	$2,201	$290	$17	$0
5125000 Total					**$5,121**	**$78**	**$1,334**	**$398**	**$803**	**$2,201**	**$290**	**$17**	**$0**
5126000	MNT BOILR-FIRESIDE	STEX	Steam O&M Expense	SG	$1,330	$20	$347	$103	$209	$572	$75	$4	$0
5126000 Total					**$1,330**	**$20**	**$347**	**$103**	**$209**	**$572**	**$75**	**$4**	**$0**
5127000	MNT BLR-BEARNG WTR	STEX	Steam O&M Expense	SG	$256	$4	$67	$20	$40	$110	$15	$1	$0
5127000 Total					**$256**	**$4**	**$67**	**$20**	**$40**	**$110**	**$15**	**$1**	**$0**
5128000	MNT BOILR WTR/STMD	STEX	Steam O&M Expense	SG	$5,130	$78	$1,336	$398	$804	$2,205	$291	$17	$0
5128000 Total					**$5,130**	**$78**	**$1,336**	**$398**	**$804**	**$2,205**	**$291**	**$17**	**$0**
5129000	MNT BOIL-COMP AIR	STEX	Steam O&M Expense	SG	$617	$9	$161	$48	$97	$265	$35	$2	$0
5129000 Total					**$617**	**$9**	**$161**	**$48**	**$97**	**$265**	**$35**	**$2**	**$0**
5129900	MAINT BOILER-MISC	STEX	Steam O&M Expense	SG	$1,312	$20	$342	$102	$206	$564	$74	$4	$0
5129900 Total					**$1,312**	**$20**	**$342**	**$102**	**$206**	**$564**	**$74**	**$4**	**$0**
5130000	MAINT ELEC PLANT	STEX	Steam O&M Expense	SG	$3,233	$49	$842	$251	$507	$1,389	$183	$11	$0
5130000 Total					**$3,233**	**$49**	**$842**	**$251**	**$507**	**$1,389**	**$183**	**$11**	**$0**
5131000	MAINT ELEC AC	STEX	Steam O&M Expense	SG	$21,451	$328	$5,589	$1,665	$3,363	$9,220	$1,215	$72	$0
5131000 Total					**$21,451**	**$328**	**$5,589**	**$1,665**	**$3,363**	**$9,220**	**$1,215**	**$72**	**$0**
5131100	MAINT/LUBE-OIL SYS	STEX	Steam O&M Expense	SG	$708	$11	$185	$55	$111	$304	$40	$2	$0
5131100 Total					**$708**	**$11**	**$185**	**$55**	**$111**	**$304**	**$40**	**$2**	**$0**
5131300	MAINT/PREVENT ROUT	STEX	Steam O&M Expense	SG	$8	$0	$2	$1	$1	$3	$0	$0	$0
5131300 Total					**$8**	**$0**	**$2**	**$1**	**$1**	**$3**	**$0**	**$0**	**$0**
5131400	MAINT/MAIN TURBINE	STEX	Steam O&M Expense	SG	$4,879	$75	$1,271	$379	$765	$2,097	$276	$16	$0
5131400 Total					**$4,879**	**$75**	**$1,271**	**$379**	**$765**	**$2,097**	**$276**	**$16**	**$0**
5132000	MAINT ALARMS/INFO	STEX	Steam O&M Expense	SG	$1,245	$19	$324	$97	$195	$535	$71	$4	$0
5132000 Total					**$1,245**	**$19**	**$324**	**$97**	**$195**	**$535**	**$71**	**$4**	**$0**
5133000	MAINT/AIR-COOL-CON	STEX	Steam O&M Expense	SG	$41	$1	$11	$3	$6	$18	$2	$0	$0
5133000 Total					**$41**	**$1**	**$11**	**$3**	**$6**	**$18**	**$2**	**$0**	**$0**
5134000	MAINT/COMPNT COOL	STEX	Steam O&M Expense	SG	$222	$3	$58	$17	$35	$95	$13	$1	$0
5134000 Total					**$222**	**$3**	**$58**	**$17**	**$35**	**$95**	**$13**	**$1**	**$0**
5135000	MAINT/COMPNT AUXIL	STEX	Steam O&M Expense	SG	$1,717	$26	$447	$133	$269	$738	$97	$6	$0
5135000 Total					**$1,717**	**$26**	**$447**	**$133**	**$269**	**$738**	**$97**	**$6**	**$0**

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A MIDAMERICAN ENERGY HOLDINGS COMPANY

Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5137000	MAINT-COOLING TOWR	STEX	Steam O&M Expense	SG	$2,413	$37	$629	$187	$378	$1,037	$137	$8	$0
5137000 Total					**$2,413**	**$37**	**$629**	**$187**	**$378**	**$1,037**	**$137**	**$8**	**$0**
5138000	MAINT-CIRCUL WATER	STEX	Steam O&M Expense	SG	$1,766	$27	$460	$137	$277	$759	$100	$6	$0
5138000 Total					**$1,766**	**$27**	**$460**	**$137**	**$277**	**$759**	**$100**	**$6**	**$0**
5139000	MAINT-ELECT - DC	STEX	Steam O&M Expense	SG	$354	$5	$92	$28	$56	$152	$20	$1	$0
5139000 Total					**$354**	**$5**	**$92**	**$28**	**$56**	**$152**	**$20**	**$1**	**$0**
5139900	MNT ELEC PLT-MISC	STEX	Steam O&M Expense	SG	$519	$8	$135	$40	$81	$223	$29	$2	$0
5139900 Total					**$519**	**$8**	**$135**	**$40**	**$81**	**$223**	**$29**	**$2**	**$0**
5140000	MAINT MISC STM PLN	STEX	Steam O&M Expense	SG	$5,581	$85	$1,454	$433	$875	$2,399	$316	$19	$0
5140000 Total					**$5,581**	**$85**	**$1,454**	**$433**	**$875**	**$2,399**	**$316**	**$19**	**$0**
5141000	MISC STM-COMP AIR	STEX	Steam O&M Expense	SG	$2,577	$39	$671	$200	$404	$1,108	$146	$9	$0
5141000 Total					**$2,577**	**$39**	**$671**	**$200**	**$404**	**$1,108**	**$146**	**$9**	**$0**
5142000	MISC STM PLT-CONSU	STEX	Steam O&M Expense	SG	$5	$0	$1	$0	$1	$2	$0	$0	$0
5142000 Total					**$5**	**$0**	**$1**	**$0**	**$1**	**$2**	**$0**	**$0**	**$0**
5144000	MISC STM PLNT-LAB	STEX	Steam O&M Expense	SG	$267	$4	$70	$21	$42	$115	$15	$1	$0
5144000 Total					**$267**	**$4**	**$70**	**$21**	**$42**	**$115**	**$15**	**$1**	**$0**
5145000	MAINT MISC-SM TOOL	STEX	Steam O&M Expense	SG	$230	$4	$60	$18	$36	$99	$13	$1	$0
5145000 Total					**$230**	**$4**	**$60**	**$18**	**$36**	**$99**	**$13**	**$1**	**$0**
5146000	MAINT/PAGING SYS	STEX	Steam O&M Expense	SG	$185	$3	$48	$14	$29	$80	$10	$1	$0
5146000 Total					**$185**	**$3**	**$48**	**$14**	**$29**	**$80**	**$10**	**$1**	**$0**
5147000	MAINT/PLANT EQUIP	STEX	Steam O&M Expense	SG	$2,277	$35	$593	$177	$357	$979	$129	$8	$0
5147000 Total					**$2,277**	**$35**	**$593**	**$177**	**$357**	**$979**	**$129**	**$8**	**$0**
5148000	MAINT/PLT-VEHICLES	STEX	Steam O&M Expense	SG	$962	$15	$251	$75	$151	$414	$55	$3	$0
5148000 Total					**$962**	**$15**	**$251**	**$75**	**$151**	**$414**	**$55**	**$3**	**$0**
5149000	MAINT MISC-OTHER	STEX	Steam O&M Expense	SG	$123	$2	$32	$10	$19	$53	$7	$0	$0
5149000 Total					**$123**	**$2**	**$32**	**$10**	**$19**	**$53**	**$7**	**$0**	**$0**
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	$5,037	$77	$1,312	$391	$790	$2,165	$285	$17	$0
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-U	-$846	-$13	-$220	-$66	-$133	-$364	-$48	-$3	$0
5350000 Total					**$4,191**	**$64**	**$1,092**	**$325**	**$657**	**$1,802**	**$237**	**$14**	**$0**
5360000	WATER FOR POWER	HYEX	Hydro O&M Expense	SG-P	$222	$3	$58	$17	$35	$95	$13	$1	$0
5360000 Total					**$222**	**$3**	**$58**	**$17**	**$35**	**$95**	**$13**	**$1**	**$0**
5370000	HYDRAULIC EXPENSES	HYEX	Hydro O&M Expense	SG-P	$2,262	$35	$589	$176	$355	$972	$128	$8	$0
5370000 Total					**$2,262**	**$35**	**$589**	**$176**	**$355**	**$972**	**$128**	**$8**	**$0**
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-P	$32	$0	$8	$2	$5	$14	$2	$0	$0
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-U	$104	$2	$27	$8	$16	$45	$6	$0	$0
5371000 Total					**$135**	**$2**	**$35**	**$11**	**$21**	**$58**	**$8**	**$0**	**$0**
5372000	HYDRO/HATCHERY EXP	HYEX	Hydro O&M Expense	SG-P	$0	$0	$0	$0	$0	$0	$0	$0	$0
5372000 Total					**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	$297	$5	$77	$23	$47	$128	$17	$1	$0
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-U	$16	$0	$4	$1	$3	$7	$1	$0	$0
5374000 Total					**$313**	**$5**	**$82**	**$24**	**$49**	**$135**	**$18**	**$1**	**$0**
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-P	$949	$14	$247	$74	$149	$408	$54	$3	$0
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-U	$182	$3	$47	$14	$29	$78	$10	$1	$0
5379000 Total					**$1,131**	**$17**	**$295**	**$88**	**$177**	**$486**	**$64**	**$4**	**$0**
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-P	$14,673	$224	$3,823	$1,139	$2,300	$6,307	$831	$49	$0
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-U	$6,989	$107	$1,821	$543	$1,096	$3,004	$396	$23	$0
5390000 Total					**$21,662**	**$331**	**$5,644**	**$1,681**	**$3,396**	**$9,311**	**$1,227**	**$73**	**$0**
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-P	-$166	-$3	-$43	-$13	-$26	-$71	-$9	-$1	$0
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-U	$33	$1	$9	$3	$5	$14	$2	$0	$0
5400000 Total					**-$132**	**-$2**	**-$34**	**-$10**	**-$21**	**-$57**	**-$7**	**$0**	**$0**
5410000	MNT SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	$0	$0	$0	$0	$0	$0	$0	$0	$0
5410000 Total					**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-P	$926	$14	$241	$72	$145	$398	$52	$3	$0
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-U	$206	$3	$54	$16	$32	$89	$12	$1	$0
5420000 Total					**$1,132**	**$17**	**$295**	**$88**	**$177**	**$487**	**$64**	**$4**	**$0**
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-P	$1,710	$26	$445	$133	$268	$735	$97	$6	$0
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-U	$569	$9	$148	$44	$89	$244	$32	$2	$0
5430000 Total					**$2,278**	**$35**	**$594**	**$177**	**$357**	**$979**	**$129**	**$8**	**$0**
5440000	MAINT OF ELEC PLNT	HYEX	Hydro O&M Expense	SG-U	$160	$2	$42	$12	$25	$69	$9	$1	$0
5440000 Total					**$160**	**$2**	**$42**	**$12**	**$25**	**$69**	**$9**	**$1**	**$0**
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-P	$1,037	$16	$270	$80	$163	$446	$59	$3	$0

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Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-U	$248	$4	$64	$19	$39	$106	$14	$1	$0
5441000 Total					**$1,284**	**$20**	**$335**	**$100**	**$201**	**$552**	**$73**	**$4**	**$0**
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-P	$977	$15	$254	$76	$153	$420	$55	$3	$0
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-U	$69	$1	$18	$5	$11	$30	$4	$0	$0
5442000 Total					**$1,045**	**$16**	**$272**	**$81**	**$164**	**$449**	**$59**	**$4**	**$0**
5450000	MNT MISC HYDRO PLT	HYEX	Hydro O&M Expense	SG-P	$7	$0	$2	$1	$1	$3	$0	$0	$0
5450000 Total					**$7**	**$0**	**$2**	**$1**	**$1**	**$3**	**$0**	**$0**	**$0**
5451000	MNT-FISH/WILDLIFE	HYEX	Hydro O&M Expense	SG-P	$396	$6	$103	$31	$62	$170	$22	$1	$0
5451000 Total					**$396**	**$6**	**$103**	**$31**	**$62**	**$170**	**$22**	**$1**	**$0**
5454000	MAINT-OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	$9	$0	$2	$1	$1	$4	$1	$0	$0
5454000 Total					**$9**	**$0**	**$2**	**$1**	**$1**	**$4**	**$1**	**$0**	**$0**
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-P	$511	$8	$133	$40	$80	$220	$29	$2	$0
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-U	$425	$6	$111	$33	$67	$183	$24	$1	$0
5455000 Total					**$936**	**$14**	**$244**	**$73**	**$147**	**$402**	**$53**	**$3**	**$0**
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-P	$1,099	$17	$286	$85	$172	$472	$62	$4	$0
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-U	$362	$6	$94	$28	$57	$155	$20	$1	$0
5459000 Total					**$1,460**	**$22**	**$380**	**$113**	**$229**	**$628**	**$83**	**$5**	**$0**
5460000	OPER SUPERV & ENG	OPEX	Other Production O&M Expense	SG	$474	$7	$124	$37	$74	$204	$27	$2	$0
5460000 Total					**$474**	**$7**	**$124**	**$37**	**$74**	**$204**	**$27**	**$2**	**$0**
5471000	NATURAL GAS	NPCX	Net Power Cost Expense	SE	$394,730	$5,928	$97,446	$28,962	$68,473	$167,521	$24,973	$1,428	$0
5471000 Total					**$394,730**	**$5,928**	**$97,446**	**$28,962**	**$68,473**	**$167,521**	**$24,973**	**$1,428**	**$0**
5480000	GENERATION EXP	OPEX	Other Production O&M Expense	SG	$17,744	$271	$4,623	$1,377	$2,781	$7,627	$1,005	$59	$0
5480000 Total					**$17,744**	**$271**	**$4,623**	**$1,377**	**$2,781**	**$7,627**	**$1,005**	**$59**	**$0**
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	SG	$14,405	$220	$3,753	$1,118	$2,258	$6,191	$816	$48	$0
5490000 Total					**$14,405**	**$220**	**$3,753**	**$1,118**	**$2,258**	**$6,191**	**$816**	**$48**	**$0**
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	SG	$4,242	$65	$1,105	$329	$665	$1,823	$240	$14	$0
5500000 Total					**$4,242**	**$65**	**$1,105**	**$329**	**$665**	**$1,823**	**$240**	**$14**	**$0**
5520000	MAINT OF STRUCTURE	OPEX	Other Production O&M Expense	SG	$1,507	$23	$393	$117	$236	$648	$85	$5	$0
5520000 Total					**$1,507**	**$23**	**$393**	**$117**	**$236**	**$648**	**$85**	**$5**	**$0**
5530000	MNT GEN & ELEC PLT	OPEX	Other Production O&M Expense	SG	$14,970	$229	$3,900	$1,162	$2,347	$6,434	$848	$50	$0
5530000 Total					**$14,970**	**$229**	**$3,900**	**$1,162**	**$2,347**	**$6,434**	**$848**	**$50**	**$0**
5540000	MNT MSC OTH PWR GN	OPEX	Other Production O&M Expense	SG	$4,384	$67	$1,142	$340	$687	$1,884	$248	$15	$0
5540000 Total					**$4,384**	**$67**	**$1,142**	**$340**	**$687**	**$1,884**	**$248**	**$15**	**$0**
5546000	MISC PLANT EQUIP	OPEX	Other Production O&M Expense	SG	$1	$0	$0	$0	$0	$0	$0	$0	$0
5546000 Total					**$1**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5550000	PURCHASED POWER	PSEX	Power Supply Expense	SG	$116,222	$1,775	$30,279	$9,021	$18,218	$49,954	$6,585	$390	$0
5550000 Total					**$116,222**	**$1,775**	**$30,279**	**$9,021**	**$18,218**	**$49,954**	**$6,585**	**$390**	**$0**
5551100	REG BILL OR-(PACF)	PSEX	Power Supply Expense	OR	-$29,095	$0	-$29,095	$0	$0	$0	$0	$0	$0
5551100 Total					**-$29,095**	**$0**	**-$29,095**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5551200	REG BILL-WA (PACF)	PSEX	Power Supply Expense	WA	-$7,380	$0	$0	-$7,380	$0	$0	$0	$0	$0
5551200 Total					**-$7,380**	**$0**	**$0**	**-$7,380**	**$0**	**$0**	**$0**	**$0**	**$0**
5551330	REG BILL-ID (UTAH)	PSEX	Power Supply Expense	IDU	-$3,223	$0	$0	$0	$0	$0	-$3,223	$0	$0
5551330 Total					**-$3,223**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$3,223**	**$0**	**$0**
5552500	OTH/INT/REC/DEL	NPCX	Net Power Cost Expense	SE	-$16,365	-$246	-$4,040	-$1,201	-$2,839	-$6,945	-$1,035	-$59	$0
5552500 Total					**-$16,365**	**-$246**	**-$4,040**	**-$1,201**	**-$2,839**	**-$6,945**	**-$1,035**	**-$59**	**$0**
5552600	ELECTRICITY SWAPS	NPCX	Net Power Cost Expense	SG	-$189,888	-$2,900	-$49,472	-$14,739	-$29,766	-$81,616	-$10,758	-$637	$0
5552600 Total					**-$189,888**	**-$2,900**	**-$49,472**	**-$14,739**	**-$29,766**	**-$81,616**	**-$10,758**	**-$637**	**$0**
5555500	IPP ENERGY PURCH	NPCX	Net Power Cost Expense	SG	$26,021	$397	$6,779	$2,020	$4,079	$11,184	$1,474	$87	$0
5555500 Total					**$26,021**	**$397**	**$6,779**	**$2,020**	**$4,079**	**$11,184**	**$1,474**	**$87**	**$0**
5556100	BOOKOUTS NETTED-LOSS	NPCX	Net Power Cost Expense	SG	$3,439	$53	$896	$267	$539	$1,478	$195	$12	$0
5556100 Total					**$3,439**	**$53**	**$896**	**$267**	**$539**	**$1,478**	**$195**	**$12**	**$0**
5556200	TRADING NETTED-LOSS	NPCX	Net Power Cost Expense	SG	$82	$1	$21	$6	$13	$35	$5	$0	$0
5556200 Total					**$82**	**$1**	**$21**	**$6**	**$13**	**$35**	**$5**	**$0**	**$0**
5556300	FIRM ENERGY PURCH	NPCX	Net Power Cost Expense	SG	$699,093	$10,678	$182,135	$54,264	$109,586	$300,478	$39,608	$2,344	$0
5556300 Total					**$699,093**	**$10,678**	**$182,135**	**$54,264**	**$109,586**	**$300,478**	**$39,608**	**$2,344**	**$0**
5556400	FIRM DEMAND PURCH	NPCX	Net Power Cost Expense	SG	$95,315	$1,456	$24,832	$7,398	$14,941	$40,967	$5,400	$320	$0
5556400 Total					**$95,315**	**$1,456**	**$24,832**	**$7,398**	**$14,941**	**$40,967**	**$5,400**	**$320**	**$0**
5556700	POST-MERG FIRM PUR	NPCX	Net Power Cost Expense	SG	-$248,892	-$3,802	-$64,844	-$19,319	-$39,015	-$106,977	-$14,101	-$834	$0
5556700 Total					**-$248,892**	**-$3,802**	**-$64,844**	**-$19,319**	**-$39,015**	**-$106,977**	**-$14,101**	**-$834**	**$0**
5560000	SYS CTRL & LD DISP	PSEX	Power Supply Expense	SG	$1,766	$27	$460	$137	$277	$759	$100	$6	$0
5560000 Total					**$1,766**	**$27**	**$460**	**$137**	**$277**	**$759**	**$100**	**$6**	**$0**

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A MIDAMERICAN ENERGY HOLDINGS COMPANY

Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SE	-$4,414	-$66	-$1,090	-$324	-$766	-$1,873	-$279	-$16	$0
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SG	$62,528	$955	$16,290	$4,853	$9,802	$26,875	$3,543	$210	$0
5570000 Total					**$58,114**	**$889**	**$15,201**	**$4,530**	**$9,036**	**$25,002**	**$3,263**	**$194**	**$0**
5578000	OTH EXP-CHOLLA REG	PSEX	Power Supply Expense	IDU	-$33	$0	$0	$0	$0	$0	-$33	$0	$0
5578000	OTH EXP-CHOLLA REG	PSEX	Power Supply Expense	OR	-$54	$0	-$54	$0	$0	$0	$0	$0	$0
5578000	OTH EXP-CHOLLA REG	PSEX	Power Supply Expense	SGCT	$1,122	$17	$293	$87	$177	$484	$64	$0	$0
5578000	OTH EXP-CHOLLA REG	PSEX	Power Supply Expense	WA	-$97	$0	$0	-$97	$0	$0	$0	$0	$0
5578000 Total					**$939**	**$17**	**$240**	**-$10**	**$177**	**$484**	**$31**	**$0**	**$0**
5600000	OPER SUPERV & ENG	TNEX	Transmission O&M Expense	SG	$4,908	$75	$1,279	$381	$769	$2,110	$278	$16	$0
5600000 Total					**$4,908**	**$75**	**$1,279**	**$381**	**$769**	**$2,110**	**$278**	**$16**	**$0**
5612000	LD - MONITOR & OPER	TNEX	Transmission O&M Expense	SG	$7,338	$112	$1,912	$570	$1,150	$3,154	$416	$25	$0
5612000 Total					**$7,338**	**$112**	**$1,912**	**$570**	**$1,150**	**$3,154**	**$416**	**$25**	**$0**
5614000	SCHED, SYS CTR & DSP	TNEX	Transmission O&M Expense	SG	$118	$2	$31	$9	$18	$51	$7	$0	$0
5614000 Total					**$118**	**$2**	**$31**	**$9**	**$18**	**$51**	**$7**	**$0**	**$0**
5615000	REL PLAN & STDS DEV	TNEX	Transmission O&M Expense	SG	$833	$13	$217	$65	$131	$358	$47	$3	$0
5615000 Total					**$833**	**$13**	**$217**	**$65**	**$131**	**$358**	**$47**	**$3**	**$0**
5616000	TRANS SVC STUDIES	TNEX	Transmission O&M Expense	SG	$203	$3	$53	$16	$32	$87	$11	$1	$0
5616000 Total					**$203**	**$3**	**$53**	**$16**	**$32**	**$87**	**$11**	**$1**	**$0**
5617000	GEN INTERCNCT STUD	TNEX	Transmission O&M Expense	SG	$627	$10	$163	$49	$98	$269	$35	$2	$0
5617000 Total					**$627**	**$10**	**$163**	**$49**	**$98**	**$269**	**$35**	**$2**	**$0**
5620000	STATION EXP(TRANS)	TNEX	Transmission O&M Expense	SG	$2,628	$40	$685	$204	$412	$1,129	$149	$9	$0
5620000 Total					**$2,628**	**$40**	**$685**	**$204**	**$412**	**$1,129**	**$149**	**$9**	**$0**
5630000	OVERHEAD LINE EXP	TNEX	Transmission O&M Expense	SG	$339	$5	$88	$26	$53	$146	$19	$1	$0
5630000 Total					**$339**	**$5**	**$88**	**$26**	**$53**	**$146**	**$19**	**$1**	**$0**
5650000	TRNS ELEC BY OTHRS	NPCX	Net Power Cost Expense	SG	$986	$15	$257	$77	$155	$424	$56	$3	$0
5650000 Total					**$986**	**$15**	**$257**	**$77**	**$155**	**$424**	**$56**	**$3**	**$0**
5651000	S/T FIRM WHEELING	NPCX	Net Power Cost Expense	SG	$1,429	$22	$372	$111	$224	$614	$81	$5	$0
5651000 Total					**$1,429**	**$22**	**$372**	**$111**	**$224**	**$614**	**$81**	**$5**	**$0**
5652500	NON-FIRM WHEEL EXP	NPCX	Net Power Cost Expense	SE	$9,481	$142	$2,341	$696	$1,645	$4,024	$600	$34	$0
5652500 Total					**$9,481**	**$142**	**$2,341**	**$696**	**$1,645**	**$4,024**	**$600**	**$34**	**$0**
5654600	POST-MRG WHEEL EXP	NPCX	Net Power Cost Expense	SG	$129,346	$1,976	$33,699	$10,040	$20,276	$55,595	$7,328	$434	$0
5654600 Total					**$129,346**	**$1,976**	**$33,699**	**$10,040**	**$20,276**	**$55,595**	**$7,328**	**$434**	**$0**
5660000	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	$2,907	$44	$757	$226	$456	$1,250	$165	$10	$0
5660000 Total					**$2,907**	**$44**	**$757**	**$226**	**$456**	**$1,250**	**$165**	**$10**	**$0**
5670000	RENTS-TRANSMISSION	TNEX	Transmission O&M Expense	SG	$2,203	$34	$574	$171	$345	$947	$125	$7	$0
5670000 Total					**$2,203**	**$34**	**$574**	**$171**	**$345**	**$947**	**$125**	**$7**	**$0**
5680000	MNT SUPERV & ENG	TNEX	Transmission O&M Expense	SG	$2,209	$34	$575	$171	$346	$949	$125	$7	$0
5680000 Total					**$2,209**	**$34**	**$575**	**$171**	**$346**	**$949**	**$125**	**$7**	**$0**
5690000	MAINT OF STRUCTURE	TNEX	Transmission O&M Expense	SG	$1	$0	$0	$0	$0	$1	$0	$0	$0
5690000 Total					**$1**	**$0**	**$0**	**$0**	**$0**	**$1**	**$0**	**$0**	**$0**
5691000	MAINT-COMP HW TRANS	TNEX	Transmission O&M Expense	SG	$201	$3	$52	$16	$31	$86	$11	$1	$0
5691000 Total					**$201**	**$3**	**$52**	**$16**	**$31**	**$86**	**$11**	**$1**	**$0**
5692000	MAINT-COMP SW TRANS	TNEX	Transmission O&M Expense	SG	$1,024	$16	$267	$79	$160	$440	$58	$3	$0
5692000 Total					**$1,024**	**$16**	**$267**	**$79**	**$160**	**$440**	**$58**	**$3**	**$0**
5693000	MAINT-COM EQP TRANS	TNEX	Transmission O&M Expense	SG	$3,279	$50	$854	$255	$514	$1,410	$186	$11	$0
5693000 Total					**$3,279**	**$50**	**$854**	**$255**	**$514**	**$1,410**	**$186**	**$11**	**$0**
5700000	MAINT STATION EQIP	TNEX	Transmission O&M Expense	SG	$10,419	$159	$2,715	$809	$1,633	$4,478	$590	$35	$0
5700000 Total					**$10,419**	**$159**	**$2,715**	**$809**	**$1,633**	**$4,478**	**$590**	**$35**	**$0**
5710000	MAINT OVHD LINES	TNEX	Transmission O&M Expense	SG	$23,046	$352	$6,004	$1,789	$3,612	$9,905	$1,306	$77	$0
5710000 Total					**$23,046**	**$352**	**$6,004**	**$1,789**	**$3,612**	**$9,905**	**$1,306**	**$77**	**$0**
5720000	MNT UNDERGRD LINES	TNEX	Transmission O&M Expense	SG	$96	$1	$25	$7	$15	$41	$5	$0	$0
5720000 Total					**$96**	**$1**	**$25**	**$7**	**$15**	**$41**	**$5**	**$0**	**$0**
5730000	MNT MSC TRANS PLNT	TNEX	Transmission O&M Expense	SG	$1,709	$26	$445	$133	$268	$734	$97	$6	$0
5730000 Total					**$1,709**	**$26**	**$445**	**$133**	**$268**	**$734**	**$97**	**$6**	**$0**
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	$33	$33	$0	$0	$0	$0	$0	$0	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	$33	$0	$0	$0	$0	$0	$33	$0	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	$247	$0	$247	$0	$0	$0	$0	$0	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	$13,636	$462	$3,664	$837	$1,454	$6,573	$646	$0	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	$267	$0	$0	$0	$0	$267	$0	$0	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	$87	$0	$0	$87	$0	$0	$0	$0	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	$111	$0	$0	$0	$111	$0	$0	$0	$0

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Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5800000 Total					**$14,415**	**$495**	**$3,911**	**$924**	**$1,565**	**$6,840**	**$679**	**$0**	**$0**
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	$13,181	$447	$3,542	$809	$1,405	$6,353	$624	$0	$0
5810000 Total					**$13,181**	**$447**	**$3,542**	**$809**	**$1,405**	**$6,353**	**$624**	**$0**	**$0**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	$62	$62	$0	$0	$0	$0	$0	$0	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	$254	$0	$0	$0	$0	$0	$254	$0	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	$1,108	$0	$1,108	$0	$0	$0	$0	$0	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	$36	$1	$10	$2	$4	$18	$2	$0	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	$1,665	$0	$0	$0	$0	$1,665	$0	$0	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	$315	$0	$0	$315	$0	$0	$0	$0	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	$603	$0	$0	$0	$603	$0	$0	$0	$0
5820000 Total					**$4,042**	**$63**	**$1,118**	**$317**	**$607**	**$1,682**	**$255**	**$0**	**$0**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	$421	$421	$0	$0	$0	$0	$0	$0	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	$238	$0	$0	$0	$0	$0	$238	$0	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	$2,919	$0	$2,919	$0	$0	$0	$0	$0	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	SNPD	$18	$1	$5	$1	$2	$9	$1	$0	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	$1,887	$0	$0	$0	$0	$1,887	$0	$0	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	$575	$0	$0	$575	$0	$0	$0	$0	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	$235	$0	$0	$0	$235	$0	$0	$0	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	$109	$0	$0	$0	$109	$0	$0	$0	$0
5830000 Total					**$6,401**	**$422**	**$2,924**	**$577**	**$346**	**$1,895**	**$239**	**$0**	**$0**
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	SNPD	$1	$0	$0	$0	$0	$1	$0	$0	$0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	UT	$0	$0	$0	$0	$0	$0	$0	$0	$0
5840000 Total					**$1**	**$0**	**$0**	**$0**	**$0**	**$1**	**$0**	**$0**	**$0**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	$220	$7	$59	$14	$24	$106	$10	$0	$0
5850000 Total					**$220**	**$7**	**$59**	**$14**	**$24**	**$106**	**$10**	**$0**	**$0**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	$235	$235	$0	$0	$0	$0	$0	$0	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	$403	$0	$0	$0	$0	$0	$403	$0	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	$3,146	$0	$3,146	$0	$0	$0	$0	$0	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	SNPD	$1,236	$42	$332	$76	$132	$596	$59	$0	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	$1,461	$0	$0	$0	$0	$1,461	$0	$0	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	$556	$0	$0	$556	$0	$0	$0	$0	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	$688	$0	$0	$0	$688	$0	$0	$0	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	$58	$0	$0	$0	$58	$0	$0	$0	$0
5860000 Total					**$7,783**	**$277**	**$3,478**	**$632**	**$878**	**$2,057**	**$462**	**$0**	**$0**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	$616	$616	$0	$0	$0	$0	$0	$0	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	$424	$0	$0	$0	$0	$0	$424	$0	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	$4,500	$0	$4,500	$0	$0	$0	$0	$0	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	$5,593	$0	$0	$0	$0	$5,593	$0	$0	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	$948	$0	$0	$948	$0	$0	$0	$0	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	$815	$0	$0	$0	$815	$0	$0	$0	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	$75	$0	$0	$0	$75	$0	$0	$0	$0
5870000 Total					**$12,971**	**$616**	**$4,500**	**$948**	**$890**	**$5,593**	**$424**	**$0**	**$0**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	$55	$55	$0	$0	$0	$0	$0	$0	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	$107	$0	$0	$0	$0	$0	$107	$0	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	$84	$0	$84	$0	$0	$0	$0	$0	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	$3,476	$118	$934	$213	$371	$1,676	$165	$0	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	$1,016	$0	$0	$0	$0	$1,016	$0	$0	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	$56	$0	$0	$56	$0	$0	$0	$0	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	$253	$0	$0	$0	$253	$0	$0	$0	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	-$27	$0	$0	$0	-$27	$0	$0	$0	$0
5880000 Total					**$5,021**	**$173**	**$1,018**	**$270**	**$597**	**$2,692**	**$272**	**$0**	**$0**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	$87	$87	$0	$0	$0	$0	$0	$0	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	$21	$0	$0	$0	$0	$0	$21	$0	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	$1,692	$0	$1,692	$0	$0	$0	$0	$0	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	$49	$2	$13	$3	$5	$24	$2	$0	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	$509	$0	$0	$0	$0	$509	$0	$0	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	$116	$0	$0	$116	$0	$0	$0	$0	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	$354	$0	$0	$0	$354	$0	$0	$0	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	$122	$0	$0	$0	$122	$0	$0	$0	$0
5890000 Total					**$2,950**	**$89**	**$1,705**	**$119**	**$481**	**$532**	**$24**	**$0**	**$0**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	$48	$48	$0	$0	$0	$0	$0	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	$27	$0	$0	$0	$0	$0	$27	$0	$0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	$305	$0	$305	$0	$0	$0	$0	$0	$0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	$3,490	$118	$938	$214	$372	$1,682	$165	$0	$0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	$340	$0	$0	$0	$0	$340	$0	$0	$0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	$21	$0	$0	$21	$0	$0	$0	$0	$0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	$86	$0	$0	$0	$86	$0	$0	$0	$0
5900000 Total					**$4,318**	**$166**	**$1,243**	**$236**	**$458**	**$2,022**	**$193**	**$0**	**$0**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	$53	$53	$0	$0	$0	$0	$0	$0	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	$45	$0	$0	$0	$0	$0	$45	$0	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	$922	$0	$922	$0	$0	$0	$0	$0	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	$145	$5	$39	$9	$15	$70	$7	$0	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	$642	$0	$0	$0	$0	$642	$0	$0	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	$200	$0	$0	$200	$0	$0	$0	$0	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	$153	$0	$0	$0	$153	$0	$0	$0	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	$60	$0	$0	$0	$60	$0	$0	$0	$0
5910000 Total					**$2,219**	**$58**	**$961**	**$209**	**$229**	**$712**	**$51**	**$0**	**$0**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	$269	$269	$0	$0	$0	$0	$0	$0	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	$839	$0	$0	$0	$0	$0	$839	$0	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	$3,064	$0	$3,064	$0	$0	$0	$0	$0	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	$1,708	$58	$459	$105	$182	$823	$81	$0	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	$4,158	$0	$0	$0	$0	$4,158	$0	$0	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	$644	$0	$0	$644	$0	$0	$0	$0	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	$1,534	$0	$0	$0	$1,534	$0	$0	$0	$0
5920000 Total					**$12,217**	**$327**	**$3,523**	**$749**	**$1,716**	**$4,981**	**$920**	**$0**	**$0**
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	$6,013	$6,013	$0	$0	$0	$0	$0	$0	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	$6,093	$0	$0	$0	$0	$0	$6,093	$0	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	$28,691	$0	$28,691	$0	$0	$0	$0	$0	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	$1,288	$44	$346	$79	$137	$621	$61	$0	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	$34,308	$0	$0	$0	$0	$34,308	$0	$0	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	$3,874	$0	$0	$3,874	$0	$0	$0	$0	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	$8,082	$0	$0	$0	$8,082	$0	$0	$0	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	$1,410	$0	$0	$0	$1,410	$0	$0	$0	$0
5930000 Total					**$89,758**	**$6,056**	**$29,037**	**$3,953**	**$9,629**	**$34,929**	**$6,154**	**$0**	**$0**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	-$31	-$31	$0	$0	$0	$0	$0	$0	$0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	-$150	$0	$0	$0	$0	$0	-$150	$0	$0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	-$127	$0	-$127	$0	$0	$0	$0	$0	$0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	-$625	$0	$0	$0	$0	-$625	$0	$0	$0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	$92	$0	$0	$92	$0	$0	$0	$0	$0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	-$208	$0	$0	$0	-$208	$0	$0	$0	$0
5931000 Total					**-$1,049**	**-$31**	**-$127**	**$92**	**-$208**	**-$625**	**-$150**	**$0**	**$0**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	$552	$552	$0	$0	$0	$0	$0	$0	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	$686	$0	$0	$0	$0	$0	$686	$0	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	$5,759	$0	$5,759	$0	$0	$0	$0	$0	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	$6	$0	$2	$0	$1	$3	$0	$0	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	$11,300	$0	$0	$0	$0	$11,300	$0	$0	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	$1,028	$0	$0	$1,028	$0	$0	$0	$0	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	$1,587	$0	$0	$0	$1,587	$0	$0	$0	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	$213	$0	$0	$0	$213	$0	$0	$0	$0
5940000 Total					**$21,133**	**$552**	**$5,761**	**$1,029**	**$1,801**	**$11,303**	**$686**	**$0**	**$0**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	$870	$29	$234	$53	$93	$419	$41	$0	$0
5950000 Total					**$870**	**$29**	**$234**	**$53**	**$93**	**$419**	**$41**	**$0**	**$0**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	$101	$101	$0	$0	$0	$0	$0	$0	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	$198	$0	$0	$0	$0	$0	$198	$0	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	$1,185	$0	$1,185	$0	$0	$0	$0	$0	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	$1,810	$0	$0	$0	$0	$1,810	$0	$0	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	$200	$0	$0	$200	$0	$0	$0	$0	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	$356	$0	$0	$0	$356	$0	$0	$0	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	$82	$0	$0	$0	$82	$0	$0	$0	$0
5960000 Total					**$3,934**	**$101**	**$1,185**	**$200**	**$438**	**$1,810**	**$198**	**$0**	**$0**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	$64	$64	$0	$0	$0	$0	$0	$0	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	$364	$0	$0	$0	$0	$0	$364	$0	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	$1,192	$0	$1,192	$0	$0	$0	$0	$0	$0

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Operations & Maintenance Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	$1,180	$40	$317	$72	$126	$569	$56	$0	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	$2,404	$0	$0	$0	$0	$2,404	$0	$0	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	$366	$0	$0	$366	$0	$0	$0	$0	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	$474	$0	$0	$0	$474	$0	$0	$0	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	$118	$0	$0	$0	$118	$0	$0	$0	$0
5970000 Total					**$6,163**	**$104**	**$1,509**	**$438**	**$718**	**$2,972**	**$420**	**$0**	**$0**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	$200	$200	$0	$0	$0	$0	$0	$0	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	$78	$0	$0	$0	$0	$0	$78	$0	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	$482	$0	$482	$0	$0	$0	$0	$0	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	-$563	-$19	-$151	-$35	-$60	-$271	-$27	$0	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	$1,342	$0	$0	$0	$0	$1,342	$0	$0	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	$112	$0	$0	$112	$0	$0	$0	$0	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	$399	$0	$0	$0	$399	$0	$0	$0	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYU	$2	$0	$0	$0	$2	$0	$0	$0	$0
5980000 Total					**$2,053**	**$181**	**$331**	**$78**	**$341**	**$1,071**	**$52**	**$0**	**$0**
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	CN	$2,902	$72	$880	$201	$216	$1,421	$112	$0	$0
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	OR	$0	$0	$0	$0	$0	$0	$0	$0	$0
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
9010000 Total					**$2,902**	**$72**	**$880**	**$201**	**$216**	**$1,421**	**$112**	**$0**	**$0**
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CA	$899	$899	$0	$0	$0	$0	$0	$0	$0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CN	$2,346	$58	$711	$163	$175	$1,148	$90	$0	$0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	IDU	$1,593	$0	$0	$0	$0	$0	$1,593	$0	$0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	OR	$9,516	$0	$9,516	$0	$0	$0	$0	$0	$0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	UT	$4,078	$0	$0	$0	$0	$4,078	$0	$0	$0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WA	$793	$0	$0	$793	$0	$0	$0	$0	$0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYP	$1,341	$0	$0	$0	$1,341	$0	$0	$0	$0
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYU	$217	$0	$0	$0	$217	$0	$0	$0	$0
9020000 Total					**$20,782**	**$957**	**$10,227**	**$956**	**$1,733**	**$5,226**	**$1,683**	**$0**	**$0**
9030000	CUST RCRD/COLL EXP	CAEX	Customer Accounting Expense	CN	$933	$23	$283	$65	$70	$457	$36	$0	$0
9030000 Total					**$933**	**$23**	**$283**	**$65**	**$70**	**$457**	**$36**	**$0**	**$0**
9031000	CUST RCRD/CUST SYS	CAEX	Customer Accounting Expense	CN	$3,906	$96	$1,185	$271	$291	$1,913	$151	$0	$0
9031000 Total					**$3,906**	**$96**	**$1,185**	**$271**	**$291**	**$1,913**	**$151**	**$0**	**$0**
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	CN	$11,516	$284	$3,492	$798	$859	$5,639	$444	$0	$0
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	OR	$2	$0	$2	$0	$0	$0	$0	$0	$0
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	UT	$0	$0	$0	$0	$0	$0	$0	$0	$0
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
9032000 Total					**$11,519**	**$284**	**$3,494**	**$798**	**$859**	**$5,639**	**$445**	**$0**	**$0**
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CA	$211	$211	$0	$0	$0	$0	$0	$0	$0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CN	$11,208	$277	$3,399	$777	$836	$5,488	$432	$0	$0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	IDU	$364	$0	$0	$0	$0	$0	$364	$0	$0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	OR	$2,122	$0	$2,122	$0	$0	$0	$0	$0	$0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	UT	$3,896	$0	$0	$0	$0	$3,896	$0	$0	$0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WA	$762	$0	$0	$762	$0	$0	$0	$0	$0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYP	$545	$0	$0	$0	$545	$0	$0	$0	$0
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYU	$76	$0	$0	$0	$76	$0	$0	$0	$0
9033000 Total					**$19,184**	**$488**	**$5,521**	**$1,539**	**$1,456**	**$9,384**	**$796**	**$0**	**$0**
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	CA	$2	$2	$0	$0	$0	$0	$0	$0	$0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	IDU	$46	$0	$0	$0	$0	$0	$46	$0	$0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	OR	$39	$0	$39	$0	$0	$0	$0	$0	$0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	UT	$38	$0	$0	$0	$0	$38	$0	$0	$0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WA	$0	$0	$0	$0	$0	$0	$0	$0	$0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYP	$3	$0	$0	$0	$3	$0	$0	$0	$0
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYU	$8	$0	$0	$0	$8	$0	$0	$0	$0
9035000 Total					**$135**	**$2**	**$39**	**$0**	**$11**	**$38**	**$46**	**$0**	**$0**
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	CN	$19,619	$485	$5,950	$1,360	$1,463	$9,606	$757	$0	$0
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	OR	$148	$0	$148	$0	$0	$0	$0	$0	$0
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	UT	$19	$0	$0	$0	$0	$19	$0	$0	$0
9036000 Total					**$19,787**	**$485**	**$6,098**	**$1,360**	**$1,463**	**$9,625**	**$757**	**$0**	**$0**
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CA	$490	$490	$0	$0	$0	$0	$0	$0	$0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CN	$270	$7	$82	$19	$20	$132	$10	$0	$0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	IDU	$682	$0	$0	$0	$0	$0	$682	$0	$0

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(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	OR	$7,151	$0	$7,151	$0	$0	$0	$0	$0	$0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	UT	$3,572	$0	$0	$0	$0	$3,572	$0	$0	$0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WA	$2,085	$0	$0	$2,085	$0	$0	$0	$0	$0
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WYP	$802	$0	$0	$0	$802	$0	$0	$0	$0
9040000 Total					**$15,051**	**$496**	**$7,233**	**$2,104**	**$822**	**$3,704**	**$692**	**$0**	**$0**
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	CA	$82	$82	$0	$0	$0	$0	$0	$0	$0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	OR	$149	$0	$149	$0	$0	$0	$0	$0	$0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	UT	$15	$0	$0	$0	$0	$15	$0	$0	$0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WA	$32	$0	$0	$32	$0	$0	$0	$0	$0
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WYP	-$6	$0	$0	$0	-$6	$0	$0	$0	$0
9042000 Total					**$273**	**$82**	**$149**	**$32**	**-$6**	**$15**	**$0**	**$0**	**$0**
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	CN	$177	$4	$54	$12	$13	$87	$7	$0	$0
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	OR	$6	$0	$6	$0	$0	$0	$0	$0	$0
9050000 Total					**$183**	**$4**	**$60**	**$12**	**$13**	**$87**	**$7**	**$0**	**$0**
9051000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	CN	$4	$0	$1	$0	$0	$2	$0	$0	$0
9051000 Total					**$4**	**$0**	**$1**	**$0**	**$0**	**$2**	**$0**	**$0**	**$0**
9070000	SUPRV (CUST SERV)	CSEX	Customer Service Expense	CN	$298	$7	$90	$21	$22	$146	$11	$0	$0
9070000 Total					**$298**	**$7**	**$90**	**$21**	**$22**	**$146**	**$11**	**$0**	**$0**
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CA	$63	$63	$0	$0	$0	$0	$0	$0	$0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CN	$646	$16	$196	$45	$48	$316	$25	$0	$0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	IDU	$15	$0	$0	$0	$0	$0	$15	$0	$0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	OR	$857	$0	$857	$0	$0	$0	$0	$0	$0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	UT	$67	$0	$0	$0	$0	$67	$0	$0	$0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WA	$317	$0	$0	$317	$0	$0	$0	$0	$0
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WYP	$232	$0	$0	$0	$232	$0	$0	$0	$0
9080000 Total					**$2,196**	**$79**	**$1,053**	**$362**	**$280**	**$383**	**$39**	**$0**	**$0**
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	CN	$40	$1	$12	$3	$3	$20	$2	$0	$0
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	UT	$119	$0	$0	$0	$0	$119	$0	$0	$0
9081000 Total					**$159**	**$1**	**$12**	**$3**	**$3**	**$139**	**$2**	**$0**	**$0**
9084000	DSM DIRECT	CSEX	Customer Service Expense	CA	$28	$28	$0	$0	$0	$0	$0	$0	$0
9084000	DSM DIRECT	CSEX	Customer Service Expense	CN	$213	$5	$65	$15	$16	$104	$8	$0	$0
9084000	DSM DIRECT	CSEX	Customer Service Expense	IDU	$44	$0	$0	$0	$0	$0	$44	$0	$0
9084000	DSM DIRECT	CSEX	Customer Service Expense	OTHER	$76	$0	$0	$0	$0	$0	$0	$0	$76
9084000	DSM DIRECT	CSEX	Customer Service Expense	UT	$133	$0	$0	$0	$0	$133	$0	$0	$0
9084000	DSM DIRECT	CSEX	Customer Service Expense	WA	-$43	$0	$0	-$43	$0	$0	$0	$0	$0
9084000	DSM DIRECT	CSEX	Customer Service Expense	WYP	$19	$0	$0	$0	$19	$0	$0	$0	$0
9084000 Total					**$469**	**$33**	**$65**	**-$28**	**$35**	**$237**	**$52**	**$0**	**$76**
9085000	DSM AMORT	CSEX	Customer Service Expense	IDU	$307	$0	$0	$0	$0	$0	$307	$0	$0
9085000	DSM AMORT	CSEX	Customer Service Expense	UT	$65	$0	$0	$0	$0	$65	$0	$0	$0
9085000	DSM AMORT	CSEX	Customer Service Expense	WYP	$38	$0	$0	$0	$38	$0	$0	$0	$0
9085000 Total					**$410**	**$0**	**$0**	**$0**	**$38**	**$65**	**$307**	**$0**	**$0**
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	CA	$2,209	$2,209	$0	$0	$0	$0	$0	$0	$0
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	IDU	$5,750	$0	$0	$0	$0	$0	$5,750	$0	$0
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	OR	$23,161	$0	$23,161	$0	$0	$0	$0	$0	$0
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	UT	$47,543	$0	$0	$0	$0	$47,543	$0	$0	$0
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	WA	$8,687	$0	$0	$8,687	$0	$0	$0	$0	$0
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	WYP	$3,999	$0	$0	$0	$3,999	$0	$0	$0	$0
9085100 Total					**$91,348**	**$2,209**	**$23,161**	**$8,687**	**$3,999**	**$47,543**	**$5,750**	**$0**	**$0**
9086000	CUST SERV	CSEX	Customer Service Expense	CA	$356	$356	$0	$0	$0	$0	$0	$0	$0
9086000	CUST SERV	CSEX	Customer Service Expense	CN	$680	$17	$206	$47	$51	$333	$26	$0	$0
9086000	CUST SERV	CSEX	Customer Service Expense	IDU	$483	$0	$0	$0	$0	$0	$483	$0	$0
9086000	CUST SERV	CSEX	Customer Service Expense	OR	$1,014	$0	$1,014	$0	$0	$0	$0	$0	$0
9086000	CUST SERV	CSEX	Customer Service Expense	UT	$2,576	$0	$0	$0	$0	$2,576	$0	$0	$0
9086000	CUST SERV	CSEX	Customer Service Expense	WA	$147	$0	$0	$147	$0	$0	$0	$0	$0
9086000	CUST SERV	CSEX	Customer Service Expense	WYP	$886	$0	$0	$0	$886	$0	$0	$0	$0
9086000 Total					**$6,142**	**$373**	**$1,220**	**$194**	**$936**	**$2,909**	**$510**	**$0**	**$0**
9089500	BLUE SKY EXPENSE	CSEX	Customer Service Expense	OTHER	$3,081	$0	$0	$0	$0	$0	$0	$0	$3,081
9089500 Total					**$3,081**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$3,081**
9089600	SOLAR FEED-IN EXP	CSEX	Customer Service Expense	OTHER	$947	$0	$0	$0	$0	$0	$0	$0	$947
9089600 Total					**$947**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$947**
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CA	$88	$88	$0	$0	$0	$0	$0	$0	$0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CN	$3,342	$83	$1,013	$232	$249	$1,636	$129	$0	$0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	IDU	$52	$0	$0	$0	$0	$0	$52	$0	$0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	OR	$603	$0	$603	$0	$0	$0	$0	$0	$0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	UT	$344	$0	$0	$0	$0	$344	$0	$0	$0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WA	$87	$0	$0	$87	$0	$0	$0	$0	$0
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WYP	$309	$0	$0	$0	$309	$0	$0	$0	$0
9090000 Total					**$4,825**	**$170**	**$1,616**	**$319**	**$559**	**$1,980**	**$181**	**$0**	**$0**
9100000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	$8	$0	$2	$1	$1	$4	$0	$0	$0
9100000 Total					**$8**	**$0**	**$2**	**$1**	**$1**	**$4**	**$0**	**$0**	**$0**
9101000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	$110	$3	$33	$8	$8	$54	$4	$0	$0
9101000 Total					**$110**	**$3**	**$33**	**$8**	**$8**	**$54**	**$4**	**$0**	**$0**
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	CA	$67	$67	$0	$0	$0	$0	$0	$0	$0
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	OR	$1,088	$0	$1,088	$0	$0	$0	$0	$0	$0
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	SO	$73,784	$1,599	$20,205	$5,578	$10,599	$31,546	$4,078	$178	$0
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	UT	-$2,414	$0	$0	$0	$0	-$2,414	$0	$0	$0
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WA	-$1,018	$0	$0	-$1,018	$0	$0	$0	$0	$0
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WYP	-$678	$0	$0	$0	-$678	$0	$0	$0	$0
9200000 Total					**$70,829**	**$1,666**	**$21,293**	**$4,560**	**$9,921**	**$29,132**	**$4,078**	**$178**	**$0**
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CA	$5	$5	$0	$0	$0	$0	$0	$0	$0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CN	$71	$2	$22	$5	$5	$35	$3	$0	$0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	IDU	$17	$0	$0	$0	$0	$0	$17	$0	$0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	OR	$60	$0	$60	$0	$0	$0	$0	$0	$0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	SO	$8,831	$191	$2,418	$668	$1,269	$3,776	$488	$21	$0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	UT	$109	$0	$0	$0	$0	$109	$0	$0	$0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WA	$14	$0	$0	$14	$0	$0	$0	$0	$0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYP	$39	$0	$0	$0	$39	$0	$0	$0	$0
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYU	$7	$0	$0	$0	$7	$0	$0	$0	$0
9210000 Total					**$9,153**	**$198**	**$2,500**	**$687**	**$1,320**	**$3,920**	**$508**	**$21**	**$0**
9220000	A&G EXP TRANSF-CR	AGEX	Administrative & General Expense	SO	-$25,113	-$544	-$6,877	-$1,899	-$3,607	-$10,737	-$1,388	-$61	$0
9220000 Total					**-$25,113**	**-$544**	**-$6,877**	**-$1,899**	**-$3,607**	**-$10,737**	**-$1,388**	**-$61**	**$0**
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	CA	$156	$156	$0	$0	$0	$0	$0	$0	$0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	OR	$125	$0	$125	$0	$0	$0	$0	$0	$0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	SO	$2,848	$62	$780	$215	$409	$1,218	$157	$7	$0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	UT	$11	$0	$0	$0	$0	$11	$0	$0	$0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WA	$3	$0	$0	$3	$0	$0	$0	$0	$0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYU	$0	$0	$0	$0	$0	$0	$0	$0	$0
9230000 Total					**$3,146**	**$218**	**$905**	**$218**	**$411**	**$1,228**	**$158**	**$7**	**$0**
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	CA	$1	$1	$0	$0	$0	$0	$0	$0	$0
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	OR	$0	$0	$0	$0	$0	$0	$0	$0	$0
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	SO	$4,055	$88	$1,110	$307	$582	$1,734	$224	$10	$0
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	UT	$1	$0	$0	$0	$0	$1	$0	$0	$0
9239990 Total					**$4,057**	**$89**	**$1,111**	**$307**	**$582**	**$1,735**	**$224**	**$10**	**$0**
9240000	PROP INSURANCE - SYS	AGEX	Administrative & General Expense	SO	$659	$14	$180	$50	$95	$282	$36	$2	$0
9240000 Total					**$659**	**$14**	**$180**	**$50**	**$95**	**$282**	**$36**	**$2**	**$0**
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	CA	$66	$66	$0	$0	$0	$0	$0	$0	$0
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	IDU	$109	$0	$0	$0	$0	$0	$109	$0	$0
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	OR	$5,395	$0	$5,395	$0	$0	$0	$0	$0	$0
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	SO	$86	$2	$24	$7	$12	$37	$5	$0	$0
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	UT	$2,152	$0	$0	$0	$0	$2,152	$0	$0	$0
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WYP	$350	$0	$0	$0	$350	$0	$0	$0	$0
9241000 Total					**$8,158**	**$68**	**$5,419**	**$7**	**$362**	**$2,189**	**$114**	**$0**	**$0**
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	OR	-$109	$0	-$109	$0	$0	$0	$0	$0	$0
9242000 Total					**-$109**	**$0**	**-$109**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
9243000	PROP INS - PREMIUMS	AGEX	Administrative & General Expense	SO	$8,069	$175	$2,210	$610	$1,159	$3,450	$446	$19	$0
9243000 Total					**$8,069**	**$175**	**$2,210**	**$610**	**$1,159**	**$3,450**	**$446**	**$19**	**$0**
9250000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	$15,065	$327	$4,126	$1,139	$2,164	$6,441	$833	$36	$0
9250000 Total					**$15,065**	**$327**	**$4,126**	**$1,139**	**$2,164**	**$6,441**	**$833**	**$36**	**$0**
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	CA	$508	$508	$0	$0	$0	$0	$0	$0	$0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	IDU	$597	$0	$0	$0	$0	$0	$597	$0	$0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	OR	$1,739	$0	$1,739	$0	$0	$0	$0	$0	$0

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Primary Account		Secondary Group Code		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	SO	$2,363	$51	$647	$179	$339	$1,010	$131	$6	$0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	UT	$1,977	$0	$0	$0	$0	$1,977	$0	$0	$0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WA	$909	$0	$0	$909	$0	$0	$0	$0	$0
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WYP	$1,634	$0	$0	$0	$1,634	$0	$0	$0	$0
9280000 Total					**$9,728**	**$559**	**$2,387**	**$1,088**	**$1,973**	**$2,987**	**$728**	**$6**	**$0**
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	CA	$4	$4	$0	$0	$0	$0	$0	$0	$0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	IDU	$504	$0	$0	$0	$0	$0	$504	$0	$0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	OR	$2,961	$0	$2,961	$0	$0	$0	$0	$0	$0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	SO	$187	$4	$51	$14	$27	$80	$10	$0	$0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	UT	$4,616	$0	$0	$0	$0	$4,616	$0	$0	$0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WA	$602	$0	$0	$602	$0	$0	$0	$0	$0
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WYP	$1,547	$0	$0	$0	$1,547	$0	$0	$0	$0
9282000 Total					**$10,420**	**$8**	**$3,012**	**$616**	**$1,573**	**$4,696**	**$514**	**$0**	**$0**
9282990	Reg Comms Exp-Affil	AGEX	Administrative & General Expense	SO	$1	$0	$0	$0	$0	$0	$0	$0	$0
9282990	Reg Comms Exp-Affil	AGEX	Administrative & General Expense	UT	$1	$0	$0	$0	$0	$1	$0	$0	$0
9282990	Reg Comms Exp-Affil	AGEX	Administrative & General Expense	WA	$1	$0	$0	$1	$0	$0	$0	$0	$0
9282990	Reg Comms Exp-Affil	AGEX	Administrative & General Expense	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
9282990 Total					**$5**	**$0**	**$0**	**$1**	**$2**	**$1**	**$0**	**$0**	**$0**
9283000	FERC FILING FEE	AGEX	Administrative & General Expense	SG	$3,703	$57	$965	$287	$580	$1,591	$210	$12	$0
9283000 Total					**$3,703**	**$57**	**$965**	**$287**	**$580**	**$1,591**	**$210**	**$12**	**$0**
9290000	DUPLICATE CHRGS-CR	AGEX	Administrative & General Expense	SO	-$6,340	-$137	-$1,736	-$479	-$911	-$2,710	-$350	-$15	$0
9290000 Total					**-$6,340**	**-$137**	**-$1,736**	**-$479**	**-$911**	**-$2,710**	**-$350**	**-$15**	**$0**
9301000	GEN ADVERTISNG EXP	AGEX	Administrative & General Expense	SO	$3	$0	$1	$0	$0	$1	$0	$0	$0
9301000 Total					**$3**	**$0**	**$1**	**$0**	**$0**	**$1**	**$0**	**$0**	**$0**
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	CA	$25	$25	$0	$0	$0	$0	$0	$0	$0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	IDU	$7	$0	$0	$0	$0	$0	$7	$0	$0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	OR	$41	$0	$41	$0	$0	$0	$0	$0	$0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	SG	$1	$0	$0	$0	$0	$1	$0	$0	$0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	SO	$11,352	$246	$3,109	$858	$1,631	$4,853	$627	$27	$0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	UT	-$15	$0	$0	$0	$0	-$15	$0	$0	$0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WA	$2	$0	$0	$2	$0	$0	$0	$0	$0
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WYP	$76	$0	$0	$0	$76	$0	$0	$0	$0
9302000 Total					**$11,489**	**$271**	**$3,150**	**$860**	**$1,707**	**$4,839**	**$635**	**$27**	**$0**
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	CA	$3	$3	$0	$0	$0	$0	$0	$0	$0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	OR	$1,098	$0	$1,098	$0	$0	$0	$0	$0	$0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	SO	$5,580	$121	$1,528	$422	$802	$2,386	$308	$13	$0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	UT	$4	$0	$0	$0	$0	$4	$0	$0	$0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WA	$9	$0	$0	$9	$0	$0	$0	$0	$0
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WYP	$40	$0	$0	$0	$40	$0	$0	$0	$0
9310000 Total					**$6,735**	**$124**	**$2,626**	**$430**	**$841**	**$2,390**	**$309**	**$13**	**$0**
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CA	$7	$7	$0	$0	$0	$0	$0	$0	$0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CN	$21	$1	$6	$1	$2	$10	$1	$0	$0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	IDU	$15	$0	$0	$0	$0	$0	$15	$0	$0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	OR	$142	$0	$142	$0	$0	$0	$0	$0	$0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	SO	$22,522	$488	$6,168	$1,703	$3,235	$9,629	$1,245	$54	$0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	UT	$104	$0	$0	$0	$0	$104	$0	$0	$0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WA	$24	$0	$0	$24	$0	$0	$0	$0	$0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYP	$41	$0	$0	$0	$41	$0	$0	$0	$0
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYU	$13	$0	$0	$0	$13	$0	$0	$0	$0
9350000 Total					**$22,891**	**$496**	**$6,316**	**$1,728**	**$3,291**	**$9,744**	**$1,261**	**$54**	**$0**
Grand Total					**$2,802,214**	**$54,061**	**$724,457**	**$203,230**	**$431,925**	**$1,211,609**	**$164,599**	**$8,230**	**$4,103**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Depreciation Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3102000	LAND RIGHTS	SG	$860	$13	$224	$67	$135	$370	$49	$3	$0
4030000	DEPN EXPENSE-ELECT	3110000	STRUCTURES AND IMPROVEMENTS	SG	$17,767	$271	$4,629	$1,379	$2,796	$7,636	$1,007	$60	$0
4030000	DEPN EXPENSE-ELECT	3120000	BOILER PLANT EQUIPMENT	SG	$86,535	$1,322	$22,545	$6,717	$13,617	$37,194	$4,903	$290	$0
4030000	DEPN EXPENSE-ELECT	3140000	TURBOGENERATOR UNITS	SG	$22,900	$350	$5,966	$1,778	$3,603	$9,843	$1,297	$77	$0
4030000	DEPN EXPENSE-ELECT	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	$7,310	$112	$1,904	$567	$1,150	$3,142	$414	$25	$0
4030000	DEPN EXPENSE-ELECT	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	$1	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	$949	$14	$247	$74	$149	$408	$54	$3	$0
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-P	$89	$1	$23	$7	$14	$38	$5	$0	$0
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-U	$1	$0	$0	$0	$0	$1	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3303000	WATER RIGHTS	SG-U	$2	$0	$0	$0	$0	$1	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-P	$3	$0	$1	$0	$1	$1	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-U	$2	$0	$1	$0	$0	$1	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	$3	$0	$1	$0	$0	$1	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-P	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-U	$182	$3	$47	$14	$29	$78	$10	$1	$0
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	$1,389	$21	$362	$108	$219	$597	$79	$5	$0
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	$100	$2	$26	$8	$16	$43	$6	$0	$0
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	$1,124	$17	$293	$87	$177	$483	$64	$4	$0
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	$10	$0	$3	$1	$2	$4	$1	$0	$0
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	$279	$4	$73	$22	$44	$120	$16	$1	$0
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	$69	$1	$18	$5	$11	$30	$4	$0	$0
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	$75	$1	$19	$6	$12	$32	$4	$0	$0
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	$547	$8	$143	$42	$86	$235	$31	$2	$0
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	$5,823	$89	$1,517	$452	$916	$2,503	$330	$20	$0
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	$1,268	$19	$330	$98	$200	$545	$72	$4	$0
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	$369	$6	$96	$29	$58	$158	$21	$1	$0
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	$15	$0	$4	$1	$2	$7	$1	$0	$0
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	$2	$0	$1	$0	$0	$1	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	$2	$0	$0	$0	$0	$1	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	$2,482	$38	$647	$193	$390	$1,067	$141	$8	$0
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	$1,095	$17	$285	$85	$172	$471	$62	$4	$0
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	$2,293	$35	$598	$178	$361	$986	$130	$8	$0
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	$329	$5	$86	$26	$52	$142	$19	$1	$0
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	$164	$3	$43	$13	$26	$71	$9	$1	$0
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	$1	$0	$0	$0	$0	$1	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3350000	MISC POWER PLANT EQUIP	SG-U	$5	$0	$1	$0	$1	$2	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	$47	$1	$12	$4	$7	$20	$3	$0	$0
4030000	DEPN EXPENSE-ELECT	3353000	MISC POWER PLANT EQUIP - RECREATION	SG-P	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	$425	$6	$111	$33	$67	$183	$24	$1	$0
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	$45	$1	$12	$4	$7	$19	$3	$0	$0
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	SG	$5,025	$77	$1,309	$390	$791	$2,160	$285	$17	$0
4030000	DEPN EXPENSE-ELECT	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	$299	$5	$78	$23	$47	$129	$17	$1	$0
4030000	DEPN EXPENSE-ELECT	3430000	PRIME MOVERS	SG	$91,491	$1,397	$23,836	$7,102	$14,397	$39,324	$5,184	$307	$0
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	SG	$10,202	$156	$2,658	$792	$1,605	$4,385	$578	$34	$0
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	$8,038	$123	$2,094	$624	$1,265	$3,455	$455	$27	$0
4030000	DEPN EXPENSE-ELECT	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	$355	$5	$93	$28	$56	$153	$20	$1	$0
4030000	DEPN EXPENSE-ELECT	3502000	LAND RIGHTS	SG	$1,910	$29	$498	$148	$301	$821	$108	$6	$0
4030000	DEPN EXPENSE-ELECT	3520000	STRUCTURES & IMPROVEMENTS	SG	$1,916	$29	$499	$149	$302	$824	$109	$6	$0
4030000	DEPN EXPENSE-ELECT	3530000	STATION EQUIPMENT	SG	$25,587	$391	$6,666	$1,986	$4,026	$10,997	$1,450	$86	$0
4030000	DEPN EXPENSE-ELECT	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	$2,251	$34	$587	$175	$354	$968	$128	$8	$0
4030000	DEPN EXPENSE-ELECT	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	$692	$11	$180	$54	$109	$297	$39	$2	$0
4030000	DEPN EXPENSE-ELECT	3540000	TOWERS AND FIXTURES	SG	$15,269	$233	$3,978	$1,185	$2,403	$6,563	$865	$51	$0
4030000	DEPN EXPENSE-ELECT	3550000	POLES AND FIXTURES	SG	$16,934	$259	$4,412	$1,314	$2,665	$7,278	$959	$57	$0
4030000	DEPN EXPENSE-ELECT	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	$20,157	$308	$5,251	$1,565	$3,172	$8,664	$1,142	$68	$0
4030000	DEPN EXPENSE-ELECT	3570000	UNDERGROUND CONDUIT	SG	$54	$1	$14	$4	$8	$23	$3	$0	$0
4030000	DEPN EXPENSE-ELECT	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	$123	$2	$32	$10	$19	$53	$7	$0	$0
4030000	DEPN EXPENSE-ELECT	3590000	ROADS AND TRAILS	SG	$161	$2	$42	$12	$25	$69	$9	$1	$0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	CA	$22	$22	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	IDU	$18	$0	$0	$0	$0	$0	$18	$0	$0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	OR	$71	$0	$71	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	UT	$149	$0	$0	$0	$0	$149	$0	$0	$0

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Depreciation Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WA	$5	$0	$0	$5	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYP	$35	$0	$0	$0	$35	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYU	$41	$0	$0	$0	$41	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	CA	$82	$82	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	IDU	$32	$0	$0	$0	$0	$0	$32	$0	$0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	OR	$324	$0	$324	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	UT	$704	$0	$0	$0	$0	$704	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WA	$40	$0	$0	$40	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYP	$172	$0	$0	$0	$172	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYU	$4	$0	$0	$0	$4	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	CA	$517	$517	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	IDU	$622	$0	$0	$0	$0	$0	$622	$0	$0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	OR	$4,205	$0	$4,205	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	UT	$9,187	$0	$0	$0	$0	$9,187	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WA	$946	$0	$0	$946	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYP	$2,297	$0	$0	$0	$2,297	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYU	$249	$0	$0	$0	$249	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	$15	$15	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	$11	$0	$0	$0	$0	$0	$11	$0	$0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	$129	$0	$129	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	$195	$0	$0	$0	$0	$195	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	$39	$0	$0	$39	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	$75	$0	$0	$0	$75	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	$2	$0	$0	$0	$2	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	CA	$2,097	$2,097	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	IDU	$2,323	$0	$0	$0	$0	$0	$2,323	$0	$0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	OR	$12,926	$0	$12,926	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	UT	$11,179	$0	$0	$0	$0	$11,179	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WA	$3,781	$0	$0	$3,781	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYP	$3,264	$0	$0	$0	$3,264	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYU	$684	$0	$0	$0	$684	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	$1,014	$1,014	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	$982	$0	$0	$0	$0	$0	$982	$0	$0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	$7,060	$0	$7,060	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	$6,613	$0	$0	$0	$0	$6,613	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	$1,714	$0	$0	$1,714	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	$2,255	$0	$0	$0	$2,255	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	$308	$0	$0	$0	$308	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	CA	$468	$468	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	IDU	$171	$0	$0	$0	$0	$0	$171	$0	$0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	OR	$2,203	$0	$2,203	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	UT	$3,867	$0	$0	$0	$0	$3,867	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WA	$709	$0	$0	$709	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYP	$556	$0	$0	$0	$556	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYU	$151	$0	$0	$0	$151	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	$413	$413	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	$497	$0	$0	$0	$0	$0	$497	$0	$0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	$3,839	$0	$3,839	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	$10,955	$0	$0	$0	$0	$10,955	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	$654	$0	$0	$654	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	$1,127	$0	$0	$0	$1,127	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	$575	$0	$0	$0	$575	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	CA	$1,211	$1,211	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	IDU	$1,525	$0	$0	$0	$0	$0	$1,525	$0	$0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	OR	$11,312	$0	$11,312	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	UT	$8,964	$0	$0	$0	$0	$8,964	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WA	$2,843	$0	$0	$2,843	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYP	$2,494	$0	$0	$0	$2,494	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYU	$390	$0	$0	$0	$390	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	CA	$153	$153	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	IDU	$131	$0	$0	$0	$0	$0	$131	$0	$0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	OR	$1,403	$0	$1,403	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	UT	$1,304	$0	$0	$0	$0	$1,304	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WA	$420	$0	$0	$420	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYP	$257	$0	$0	$0	$257	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYU	$41	$0	$0	$0	$41	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	CA	$263	$263	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	IDU	$447	$0	$0	$0	$0	$0	$447	$0	$0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	OR	$3,225	$0	$3,225	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	UT	$2,803	$0	$0	$0	$0	$2,803	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WA	$851	$0	$0	$851	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYP	$744	$0	$0	$0	$744	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYU	$236	$0	$0	$0	$236	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	CA	$180	$180	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	IDU	$437	$0	$0	$0	$0	$0	$437	$0	$0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	OR	$2,168	$0	$2,168	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	UT	$2,375	$0	$0	$0	$0	$2,375	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WA	$445	$0	$0	$445	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYP	$410	$0	$0	$0	$410	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYU	$79	$0	$0	$0	$79	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	CA	$13	$13	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	$8	$0	$0	$0	$0	$0	$8	$0	$0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	OR	$119	$0	$119	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	UT	$270	$0	$0	$0	$0	$270	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WA	$19	$0	$0	$19	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	$47	$0	$0	$0	$47	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	$9	$0	$0	$0	$9	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	$20	$20	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	$30	$0	$0	$0	$0	$0	$30	$0	$0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	$676	$0	$676	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	$1,030	$0	$0	$0	$0	$1,030	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	$126	$0	$0	$126	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	$216	$0	$0	$0	$216	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	$62	$0	$0	$0	$62	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	UT	$1	$0	$0	$0	$0	$1	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CA	$47	$47	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CN	$174	$4	$53	$12	$13	$85	$7	$0	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	IDU	$216	$0	$0	$0	$0	$0	$216	$0	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	OR	$616	$0	$616	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SG	$164	$3	$43	$13	$26	$71	$9	$1	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SO	$1,716	$37	$470	$130	$246	$734	$95	$4	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	UT	$856	$0	$0	$0	$0	$856	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WA	$417	$0	$0	$417	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYP	$145	$0	$0	$0	$145	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYU	$94	$0	$0	$0	$94	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CA	$6	$6	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CN	$56	$1	$17	$4	$4	$27	$2	$0	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	OR	$34	$0	$34	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SG	$5	$0	$1	$0	$1	$2	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SO	$784	$17	$215	$59	$112	$335	$43	$2	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	UT	$15	$0	$0	$0	$0	$15	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WA	$1	$0	$0	$1	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYP	$19	$0	$0	$0	$19	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CA	$2	$2	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CN	$101	$2	$31	$7	$8	$50	$4	$0	$0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	IDU	$5	$0	$0	$0	$0	$0	$5	$0	$0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	OR	$105	$0	$105	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SG	$154	$2	$40	$12	$24	$66	$9	$1	$0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SO	$657	$14	$180	$50	$94	$281	$36	$2	$0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	UT	$33	$0	$0	$0	$0	$33	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WA	$38	$0	$0	$38	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYP	$28	$0	$0	$0	$28	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYU	$2	$0	$0	$0	$2	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	$33	$33	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	$1,288	$32	$391	$89	$96	$631	$50	$0	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	$124	$0	$0	$0	$0	$0	$124	$0	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	$385	$0	$385	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	$9	$0	$2	$1	$2	$4	$1	$0	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	$303	$5	$79	$24	$48	$130	$17	$1	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	$8,718	$189	$2,387	$659	$1,249	$3,727	$482	$21	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	$398	$0	$0	$0	$0	$398	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	$166	$0	$0	$166	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	$525	$0	$0	$0	$525	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	$13	$0	$0	$0	$13	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	CN	$1	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	OR	$2	$0	$2	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SG	$61	$1	$16	$5	$10	$26	$3	$0	$0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SO	$30	$1	$8	$2	$4	$13	$2	$0	$0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	UT	$3	$0	$0	$0	$0	$3	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	CA	$6	$6	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	IDU	$18	$0	$0	$0	$0	$0	$18	$0	$0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	OR	$139	$0	$139	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SG	$210	$3	$55	$16	$33	$90	$12	$1	$0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SO	$16	$0	$4	$1	$2	$7	$1	$0	$0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	UT	$152	$0	$0	$0	$0	$152	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WA	$24	$0	$0	$24	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYP	$51	$0	$0	$0	$51	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYU	$3	$0	$0	$0	$3	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	$24	$24	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	$84	$0	$0	$0	$0	$0	$84	$0	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	$463	$0	$463	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	$1,195	$18	$311	$93	$188	$514	$68	$4	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	$187	$4	$51	$14	$27	$80	$10	$0	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	$581	$0	$0	$0	$0	$581	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	$99	$0	$0	$99	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	$185	$0	$0	$0	$185	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	$23	$0	$0	$0	$23	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	CA	$18	$18	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	IDU	$71	$0	$0	$0	$0	$0	$71	$0	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	OR	$584	$0	$584	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SE	$1	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SG	$354	$5	$92	$28	$56	$152	$20	$1	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SO	$299	$6	$82	$23	$43	$128	$17	$1	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	UT	$385	$0	$0	$0	$0	$385	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WA	$97	$0	$0	$97	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYP	$158	$0	$0	$0	$158	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYU	$39	$0	$0	$0	$39	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CA	$126	$126	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CN	$116	$3	$35	$8	$9	$57	$4	$0	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	IDU	$245	$0	$0	$0	$0	$0	$245	$0	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	OR	$1,633	$0	$1,633	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SE	$5	$0	$1	$0	$1	$2	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SG	$4,615	$70	$1,202	$358	$726	$1,984	$261	$15	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SO	$2,327	$50	$637	$176	$333	$995	$129	$6	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	UT	$1,444	$0	$0	$0	$0	$1,444	$0	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Depreciation Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WA	$563	$0	$0	$563	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYP	$1,007	$0	$0	$0	$1,007	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYU	$187	$0	$0	$0	$187	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	CA	$3	$3	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	IDU	$18	$0	$0	$0	$0	$0	$18	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	OR	$67	$0	$67	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SG	$46	$1	$12	$4	$7	$20	$3	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SO	$38	$1	$10	$3	$5	$16	$2	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	UT	$168	$0	$0	$0	$0	$168	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WA	$30	$0	$0	$30	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYP	$38	$0	$0	$0	$38	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYU	$10	$0	$0	$0	$10	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CA	$2	$2	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CN	$12	$0	$4	$1	$1	$6	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	IDU	$3	$0	$0	$0	$0	$0	$3	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	OR	$48	$0	$48	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SG	$104	$2	$27	$8	$16	$45	$6	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SO	$173	$4	$48	$13	$25	$74	$10	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	UT	$24	$0	$0	$0	$0	$24	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WA	$9	$0	$0	$9	$0	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYP	$8	$0	$0	$0	$8	$0	$0	$0	$0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYU	$1	$0	$0	$0	$1	$0	$0	$0	$0
4030000 Total					**$544,448**	**$12,870**	**$153,700**	**$44,320**	**$78,591**	**$224,403**	**$29,196**	**$1,367**	**$0**
4032000	DEPR - STEAM	565131	DEPR - PROD STEAM NOT CLASSIFIED	SG	$186	$3	$49	$14	$29	$80	$11	$1	$0
4032000 Total					**$186**	**$3**	**$49**	**$15**	**$29**	**$79**	**$10**	**$1**	**$0**
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-P	$2,234	$34	$582	$173	$352	$960	$127	$7	$0
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-U	$1,351	$21	$352	$105	$213	$581	$77	$5	$0
4033000 Total					**$3,585**	**$57**	**$943**	**$287**	**$564**	**$1,520**	**$201**	**$13**	**$0**
4034000	DEPR - OTHER	565134	DEPR - PROD OTHER NOT CLASSIFIED	SG	$24	$0	$6	$2	$4	$10	$1	$0	$0
4034000 Total					**$24**	**$0**	**$6**	**$2**	**$4**	**$10**	**$1**	**$0**	**$0**
4035000	DEPR-TRANSMISSION	565141	DEPR - TRANS ASSETS NOT CLASSIFIED	SG	$416	$6	$108	$32	$65	$179	$24	$1	$0
4035000 Total					**$416**	**$7**	**$110**	**$33**	**$65**	**$176**	**$23**	**$2**	**$0**
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	CA	$25	$25	$0	$0	$0	$0	$0	$0	$0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	IDU	$35	$0	$0	$0	$0	$0	$35	$0	$0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	OR	$188	$0	$188	$0	$0	$0	$0	$0	$0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	UT	$280	$0	$0	$0	$0	$280	$0	$0	$0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WA	$48	$0	$0	$48	$0	$0	$0	$0	$0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WYP	$150	$0	$0	$0	$150	$0	$0	$0	$0
4036000 Total					**$727**	**$25**	**$188**	**$48**	**$150**	**$280**	**$35**	**$0**	**$0**
4037000	DEPR - GENERAL	565201	DEPR - GEN ASSETS NOT CLASSIFIED	SG	$315	$5	$82	$24	$50	$135	$18	$1	$0
4037000 Total					**$315**	**$5**	**$83**	**$25**	**$50**	**$134**	**$18**	**$1**	**$0**
4039999	DEPR EXP-ELEC, OTH	565970	DEPRECIATION-JOINT OWNER BILLED-CREDIT	SG	-$199	-$3	-$52	-$15	-$31	-$85	-$11	-$1	$0
4039999 Total					**-$199**	**-$3**	**-$52**	**-$16**	**-$31**	**-$84**	**-$11**	**-$1**	**$0**
Grand Total					**$549,503**	**$12,964**	**$155,027**	**$44,714**	**$79,422**	**$226,518**	**$29,473**	**$1,383**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Amortization Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	IDU	$20	$0	$0	$0	$0	$0	$20	$0	$0
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG	$572	$9	$149	$44	$90	$246	$32	$2	$0
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-P	$10,888	$166	$2,837	$845	$1,707	$4,680	$617	$37	$0
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-U	$324	$5	$84	$25	$51	$139	$18	$1	$0
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	OR	$12	$0	$12	$0	$0	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	SG	$818	$12	$213	$63	$128	$351	$46	$3	$0
4040000	AMOR LTD TRM PLNT	3031050	RWT - RCMS WORK TRACKING	SO	$43	$1	$12	$3	$6	$18	$2	$0	$0
4040000	AMOR LTD TRM PLNT	3031080	FMS - FUEL MANAGEMENT SYSTEM	SO	$10	$0	$3	$1	$1	$4	$1	$0	$0
4040000	AMOR LTD TRM PLNT	3031680	DISTRIBUTION AUTOMATION PILOT	SO	$435	$9	$119	$33	$62	$186	$24	$1	$0
4040000	AMOR LTD TRM PLNT	3031760	RECORD CENTER MGMT SOFTWARE	SO	$2	$0	$1	$0	$0	$1	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3031830	CUSTOMER SERVICE SYSTEM	CN	$4,742	$117	$1,438	$329	$354	$2,322	$183	$0	$0
4040000	AMOR LTD TRM PLNT	3032040	SAP	SO	$5,531	$120	$1,515	$418	$794	$2,365	$306	$13	$0
4040000	AMOR LTD TRM PLNT	3032270	ENTERPRISE DATA WAREHOUSE	SO	$315	$7	$86	$24	$45	$135	$17	$1	$0
4040000	AMOR LTD TRM PLNT	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	$73	$2	$20	$6	$10	$31	$4	$0	$0
4040000	AMOR LTD TRM PLNT	3032360	2002 GRID NET POWER COST MODELING	SO	$144	$3	$39	$11	$21	$61	$8	$0	$0
4040000	AMOR LTD TRM PLNT	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	$2	$0	$1	$0	$0	$1	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3032510	OPERATIONS MAPPING SYSTEM	SO	$8	$0	$2	$1	$1	$4	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	$58	$1	$16	$4	$8	$25	$3	$0	$0
4040000	AMOR LTD TRM PLNT	3032600	SINGLE PERSON SCHEDULING	SO	$318	$7	$87	$24	$46	$136	$18	$1	$0
4040000	AMOR LTD TRM PLNT	3032640	TIBCO SOFTWARE	SO	$81	$2	$22	$6	$12	$35	$4	$0	$0
4040000	AMOR LTD TRM PLNT	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	$6	$0	$2	$0	$1	$3	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3032730	IMPROVEMENTS TO PLANT OWNED BY JAMES RIV	SG	$707	$11	$184	$55	$111	$304	$40	$2	$0
4040000	AMOR LTD TRM PLNT	3032760	SWIFT 2 IMPROVEMENTS	SG	$432	$7	$112	$34	$68	$186	$24	$1	$0
4040000	AMOR LTD TRM PLNT	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	$15	$0	$4	$1	$2	$6	$1	$0	$0
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	$5	$0	$1	$0	$1	$2	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	$1	$0	$0	$0	$0	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3032860	WEB SOFTWARE	SO	$536	$12	$147	$41	$77	$229	$30	$1	$0
4040000	AMOR LTD TRM PLNT	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	$255	$4	$66	$20	$40	$109	$14	$1	$0
4040000	AMOR LTD TRM PLNT	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	$376	$8	$103	$28	$54	$161	$21	$1	$0
4040000	AMOR LTD TRM PLNT	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	$2,296	$35	$598	$178	$360	$987	$130	$8	$0
4040000	AMOR LTD TRM PLNT	3033120	RANGER EMS/SCADA SYSTEM	SG	$22	$0	$6	$2	$3	$9	$1	$0	$0
4040000	AMOR LTD TRM PLNT	3033120	RANGER EMS/SCADA SYSTEM	SO	$3,886	$84	$1,064	$294	$558	$1,661	$215	$9	$0
4040000	AMOR LTD TRM PLNT	3033120	RANGER EMS/SCADA SYSTEM	WYP	$72	$0	$0	$0	$72	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3033170	GTX VERSION 7 SOFTWARE	CN	$471	$12	$143	$33	$35	$231	$18	$0	$0
4040000	AMOR LTD TRM PLNT	3033180	HPOV - HP Openview Software	SO	$524	$11	$143	$40	$75	$224	$29	$1	$0
4040000	AMOR LTD TRM PLNT	3033190	ITRON METER READING SOFTWARE	CN	$574	$14	$174	$40	$43	$281	$22	$0	$0
4040000	AMOR LTD TRM PLNT	3033300	SECID - CUST SECURE WEB LOGIN	CN	$218	$5	$66	$15	$16	$107	$8	$0	$0
4040000	AMOR LTD TRM PLNT	3033310	C&T - ENERGY TRADING SYSTEM	SO	$1,524	$33	$417	$115	$219	$652	$84	$4	$0
4040000	AMOR LTD TRM PLNT	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SO	$967	$21	$265	$73	$139	$413	$53	$2	$0
4040000	AMOR LTD TRM PLNT	3033360	DSM REPORTING & TRACKING SOFTWARE	SO	$248	$5	$68	$19	$36	$106	$14	$1	$0
4040000	AMOR LTD TRM PLNT	3033370	DISTRIBUTION INTANGIBLES	WYP	$3	$0	$0	$0	$3	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CN	$10	$0	$3	$1	$1	$5	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	OR	$2	$0	$2	$0	$0	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SE	$56	$1	$14	$4	$10	$24	$4	$0	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SG	$5,356	$82	$1,395	$416	$840	$2,302	$303	$18	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SG-P	$0	$0	$0	$0	$0	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SO	$388	$8	$106	$29	$56	$166	$21	$1	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	UT	$13	$0	$0	$0	$0	$13	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WA	$0	$0	$0	$0	$0	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WYP	$68	$0	$0	$0	$68	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	$233	$4	$61	$18	$37	$100	$13	$1	$0
4040000	AMOR LTD TRM PLNT	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-U	$18	$0	$5	$1	$3	$8	$1	$0	$0
4040000	AMOR LTD TRM PLNT	3326000	RESERVOIR, DAMS, WATERWAYS, LEASE HOLDS	SG-U	$28	$0	$7	$2	$4	$12	$2	$0	$0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	$143	$143	$0	$0	$0	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CN	$273	$7	$83	$19	$20	$134	$11	$0	$0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	$446	$0	$446	$0	$0	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	$1,270	$28	$348	$96	$182	$543	$70	$3	$0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	$1	$0	$0	$0	$0	$1	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	$203	$0	$0	$203	$0	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	$540	$0	$0	$0	$540	$0	$0	$0	$0
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYU	$5	$0	$0	$0	$5	$0	$0	$0	$0
4040000 Total					**$46,586**	**$998**	**$12,689**	**$3,615**	**$7,016**	**$19,718**	**$2,437**	**$114**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Amortization Expense (Actuals)
Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4049000	AMR LTD TRM PLNT-OTH	566970	AMORTIZATION JO BILL CREDIT	SG	-$243	-$4	-$63	-$19	-$38	-$104	-$14	-$1	$0
4049000 Total					**-$243**	**-$4**	**-$63**	**-$19**	**-$38**	**-$104**	**-$14**	**-$1**	**$0**
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	SG	$5,524	$84	$1,439	$429	$866	$2,374	$313	$19	$0
4061000 Total					**$5,524**	**$84**	**$1,439**	**$429**	**$866**	**$2,374**	**$313**	**$19**	**$0**
4073000	REGULATORY DEBITS	367553	Other Rev Adj - Commercial - Deferral	OTHER	$659	$0	$0	$0	$0	$0	$0	$0	$659
4073000	REGULATORY DEBITS	367653	Other Rev Adj - Commercial - Deferral	OTHER	$581	$0	$0	$0	$0	$0	$0	$0	$581
4073000	REGULATORY DEBITS	367753	Other Rev Adj - Industrial - Deferral	OTHER	$130	$0	$0	$0	$0	$0	$0	$0	$130
4073000	REGULATORY DEBITS	367853	Other Rev Adj - Irrigation - Deferral	OTHER	$129	$0	$0	$0	$0	$0	$0	$0	$129
4073000	REGULATORY DEBITS	367953	Other Rev Adj - St/Hwy Light - Deferral	OTHER	$7	$0	$0	$0	$0	$0	$0	$0	$7
4073000 Total					**$1,506**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,506**
4074000	REGULATORY CREDITS	367554	Other Rev Adj - Residential - Realized	OTHER	-$523	$0	$0	$0	$0	$0	$0	$0	-$523
4074000	REGULATORY CREDITS	367654	Other Rev Adj - Commercial - Realized	OTHER	-$454	$0	$0	$0	$0	$0	$0	$0	-$454
4074000	REGULATORY CREDITS	367754	Other Rev Adj - Industrial - Realized	OTHER	-$188	$0	$0	$0	$0	$0	$0	$0	-$188
4074000	REGULATORY CREDITS	367854	Other Rev Adj - Irrigation - Realized	OTHER	-$104	$0	$0	$0	$0	$0	$0	$0	-$104
4074000	REGULATORY CREDITS	367954	Other Rev Adj - St/Hwy Light - Realized	OTHER	$322	$0	$0	$0	$0	$0	$0	$0	$322
4074000 Total					**-$947**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$947**
Grand Total					**$52,427**	**$1,078**	**$14,065**	**$4,025**	**$7,843**	**$21,988**	**$2,736**	**$132**	**$560**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Taxes Other Than Income (Actuals)
Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4081000	TAX OTH INC-U OP I	583451	Extraction Tax - Mines	SO	$3,543	$77	$970	$268	$509	$1,515	$196	$9	$0
4081000	TAX OTH INC-U OP I	583501	Federal Reclamation Tax - Mines	SO	$438	$9	$120	$33	$63	$187	$24	$1	$0
4081000	TAX OTH INC-U OP I	584101	Government Royalties - Mines	SO	$10,180	$221	$2,788	$770	$1,462	$4,352	$563	$25	$0
4081000	TAX OTH INC-U OP I	584201	Other Royalties - Mines	SO	$10	$0	$3	$1	$1	$4	$1	$0	$0
4081000	TAX OTH INC-U OP I	584960	Taxes Other Non-Income - Credit	SO	-$16,262	-$352	-$4,453	-$1,229	-$2,336	-$6,953	-$899	-$39	$0
4081000 Total					**-$2,091**	**-$45**	**-$573**	**-$158**	**-$300**	**-$894**	**-$116**	**-$5**	**$0**
4081500	PROPERTY TAXES	579000	PROPERTY TAX	GPS	$115,859	$2,511	$31,727	$8,759	$16,642	$49,535	$6,404	$280	$0
4081500	PROPERTY TAXES	579001	SAPERROR	GPS	$870	$19	$238	$66	$125	$372	$48	$2	$0
4081500 Total					**$116,729**	**$2,530**	**$31,965**	**$8,825**	**$16,767**	**$49,907**	**$6,452**	**$282**	**$0**
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	CA	$1,345	$1,345	$0	$0	$0	$0	$0	$0	$0
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	OR	$26,427	$0	$26,427	$0	$0	$0	$0	$0	$0
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	UT	$218	$0	$0	$0	$0	$218	$0	$0	$0
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WA	$1	$0	$0	$1	$0	$0	$0	$0	$0
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WYP	$1,763	$0	$0	$0	$1,763	$0	$0	$0	$0
4081800 Total					**$29,753**	**$1,345**	**$26,427**	**$1**	**$1,763**	**$218**	**$0**	**$0**	**$0**
4081990	MISC TAXES - OTHER	583260	PUBLIC UTILITY TAX	SO	$10,940	$237	$2,996	$827	$1,571	$4,677	$605	$26	$0
4081990	MISC TAXES - OTHER	583261	OREGON ENERGY RESOURCE SUPPLIER TAX	OR	$849	$0	$849	$0	$0	$0	$0	$0	$0
4081990	MISC TAXES - OTHER	583262	NAVAJO BUSINESS ACTIVITY TAX	UT	$7	$0	$0	$0	$0	$7	$0	$0	$0
4081990	MISC TAXES - OTHER	583263	MONTANA ENERGY TAX	SE	$221	$3	$55	$16	$38	$94	$14	$1	$0
4081990	MISC TAXES - OTHER	583265	WASHINGTON GROSS REVENUE TAX - SERVICES	WA	$37	$0	$0	$37	$0	$0	$0	$0	$0
4081990	MISC TAXES - OTHER	583266	IDAHO KILOWATT HOUR TAX	SE	$39	$1	$10	$3	$7	$17	$2	$0	$0
4081990	MISC TAXES - OTHER	583267	WYOMING ANNUAL CORPORATION FEE (TAX)	WYP	$57	$0	$0	$0	$57	$0	$0	$0	$0
4081990	MISC TAXES - OTHER	583269	MONTANA WHOLESALE ENERGY TAX	SE	$157	$2	$39	$12	$27	$67	$10	$1	$0
4081990	MISC TAXES - OTHER	583273	Wyoming Wind Generation Tax	SG	$679	$10	$177	$53	$106	$292	$38	$2	$0
4081990	MISC TAXES - OTHER	584100	GOVERNMENT ROYALTIES	SE	$402	$6	$99	$30	$70	$171	$25	$1	$0
4081990 Total					**$13,388**	**$260**	**$4,224**	**$977**	**$1,876**	**$5,324**	**$695**	**$32**	**$0**
Grand Total					**$157,779**	**$4,090**	**$62,044**	**$9,644**	**$20,106**	**$54,555**	**$7,032**	**$308**	**$0**

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Schedule M (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC	FERC Secondary A		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMAP	105105	30% Capitalized labor costs for PowerTax	SO	-$236	-$5	-$65	-$18	-$34	-$101	-$13	-$1	$0
SCHMAP	130100	Non - Deductible Expenses	SO	$1,125	$24	$308	$85	$162	$481	$62	$3	$0
SCHMAP	130400	PMINondeductible Exp	SE	$6	$0	$2	$0	$1	$3	$0	$0	$0
SCHMAP	130550	MEHC Insurance Services-Premium	SO	$861	$19	$236	$65	$124	$368	$48	$2	$0
SCHMAP	130700	Mining Rescue Training Credit Addback	SE	$50	$1	$12	$4	$9	$21	$3	$0	$0
SCHMAP	505505	Income Tax Interest	SO	$2,339	$51	$640	$177	$336	$1,000	$129	$6	$0
SCHMAP	610106	PMIFuel Tax Cr	SE	$14	$0	$3	$1	$2	$6	$1	$0	$0
SCHMAP	610107	PMI Dividend Gross Up for Foreign Tax Cr	OTHER	-$7	$0	$0	$0	$0	$0	$0	$0	-$7
SCHMAP	7201051	Contra Medicare Subsidy	SO	$3,441	$75	$942	$260	$494	$1,471	$190	$8	$0
SCHMAP	920145	PMI Mining Rescue Training Credit Addbac	SE	$13	$0	$3	$1	$2	$5	$1	$0	$0
SCHMAP Total				**$7,604**	**$164**	**$2,082**	**$575**	**$1,096**	**$3,254**	**$421**	**$18**	**-$7**
SCHMAT	105100	Capitalized Labor Costs	SO	$10,464	$227	$2,866	$791	$1,503	$4,474	$578	$25	$0
SCHMAT	105120	Book Depreciation	SCHMDEXP	$626,056	$12,880	$169,669	$48,650	$93,506	$265,652	$34,059	$1,640	$0
SCHMAT	105121	PMIBook Depreciation	SE	$17,806	$267	$4,396	$1,306	$3,089	$7,557	$1,127	$64	$0
SCHMAT	105123	Sec. 481a Adj - Repair Deduction	SG	-$2,318	-$35	-$604	-$180	-$363	-$996	-$131	-$8	$0
SCHMAT	105130	CIAC	CIAC	$41,148	$1,394	$11,057	$2,526	$4,387	$19,834	$1,949	$0	$0
SCHMAT	105140	Highway relocation	SNPD	$9,256	$314	$2,487	$568	$987	$4,462	$438	$0	$0
SCHMAT	105142	Avoided Costs	SNP	$51,429	$1,027	$13,587	$3,783	$7,452	$22,627	$2,824	$128	$0
SCHMAT	110100	Book Cost Depletion	SE	$1,637	$25	$404	$120	$284	$695	$104	$6	$0
SCHMAT	205100	Coal Pile Inventory Adjustment	SE	$4,081	$61	$1,008	$299	$708	$1,732	$258	$15	$0
SCHMAT	210200	Prepaid Taxes-property taxes	GPS	$4,582	$99	$1,255	$346	$658	$1,959	$253	$11	$0
SCHMAT	220100	Bad Debts Allowance - Cash Basis	BADDEBT	$4,403	$169	$2,087	$623	$238	$1,084	$202	$0	$0
SCHMAT	415301	Environmental Costs WA	WA	$100	$0	$0	$100	$0	$0	$0	$0	$0
SCHMAT	415500	Cholla Plt Transact Costs-APS Amort	SGCT	$1,122	$17	$293	$87	$177	$484	$64	$0	$0
SCHMAT	415510	WA Disallowed Colstrip #3 Write-off	WA	$52	$0	$0	$52	$0	$0	$0	$0	$0
SCHMAT	415702	Reg Asset - Lake Side Liq.	WYP	$28	$0	$0	$0	$28	$0	$0	$0	$0
SCHMAT	415703	Goodnoe Hills Liquidation Damages - WY	WYP	$21	$0	$0	$0	$21	$0	$0	$0	$0
SCHMAT	415704	Reg Liability - Tax Revenue Adjustment -	UT	$12	$0	$0	$0	$0	$12	$0	$0	$0
SCHMAT	415705	Reg Liability - Tax Revenue Adjustment -	WYP	$29	$0	$0	$0	$29	$0	$0	$0	$0
SCHMAT	415803	WA RTO Grid West N/R w/o	WA	$23	$0	$0	$23	$0	$0	$0	$0	$0
SCHMAT	415804	RTO Grid West Notes Receivable-OR	OR	$383	$0	$383	$0	$0	$0	$0	$0	$0
SCHMAT	415806	ID RTO Grid West N/R	IDU	$27	$0	$0	$0	$0	$0	$27	$0	$0
SCHMAT	415822	Reg Asset _ Pension MMT -UT	UT	$283	$0	$0	$0	$0	$283	$0	$0	$0
SCHMAT	415828	Regulatory Asset - Post -Ret MMT -WY	WYP	$309	$0	$0	$0	$309	$0	$0	$0	$0
SCHMAT	415829	Reg Asset - Post - Ret MMT -UT	UT	$279	$0	$0	$0	$0	$279	$0	$0	$0
SCHMAT	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	$731	$0	$0	$0	$0	$0	$0	$0	$731
SCHMAT	415852	Powerdale Decommissioning Reg Asset - ID	IDU	$92	$0	$0	$0	$0	$0	$92	$0	$0
SCHMAT	415853	Powerdale Decommissioning Reg Asset - OR	OR	$493	$0	$493	$0	$0	$0	$0	$0	$0
SCHMAT	415854	Powerdale Decommissioning Reg Asset - WA	WA	$213	$0	$0	$213	$0	$0	$0	$0	$0
SCHMAT	415855	CA - January 2010 Storm Costs	OTHER	$1,164	$0	$0	$0	$0	$0	$0	$0	$1,164
SCHMAT	415856	Powerdale Decommissioning Reg Asset - WY	WYP	$34	$0	$0	$0	$34	$0	$0	$0	$0
SCHMAT	415857	ID - Deferred Overburden Costs	OTHER	$73	$0	$0	$0	$0	$0	$0	$0	$73
SCHMAT	415858	WY - Deferred Overburden Costs	WYP	$178	$0	$0	$0	$178	$0	$0	$0	$0
SCHMAT	415859	WY - Deferred Advertising Costs	WYP	$52	$0	$0	$0	$52	$0	$0	$0	$0
SCHMAT	415865	Reg Asset - UT MPA	OTHER	$15,725	$0	$0	$0	$0	$0	$0	$0	$15,725
SCHMAT	415867	Reg Asset - CA Solar Feed-in Tariff	OTHER	$246	$0	$0	$0	$0	$0	$0	$0	$246
SCHMAT	415873	Deferred Excess Net Power Costs - WA Hyd	WA	$1,853	$0	$0	$1,853	$0	$0	$0	$0	$0
SCHMAT	415876	Deferred Excess Net PowerCosts - OR	OTHER	$3,588	$0	$0	$0	$0	$0	$0	$0	$3,588
SCHMAT	415881	Deferral of Renewable Energy Credit - UT	OTHER	$17	$0	$0	$0	$0	$0	$0	$0	$17
SCHMAT	415883	Deferral of Renewable Energy Credit - WY	OTHER	$517	$0	$0	$0	$0	$0	$0	$0	$517
SCHMAT	415893	OR - MEHC Transition Service Costs	OTHER	$2,057	$0	$0	$0	$0	$0	$0	$0	$2,057
SCHMAT	415895	OR RCAC Sept-Dec 07 deferred	OR	$639	$0	$639	$0	$0	$0	$0	$0	$0
SCHMAT	415896	WA - Chehalis Plant Revenue Requirement	WA	$3,000	$0	$0	$3,000	$0	$0	$0	$0	$0
SCHMAT	415897	Reg Asset MEHC Transition Service Costs	CA	$178	$178	$0	$0	$0	$0	$0	$0	$0
SCHMAT	415898	Deferred Coal Costs - Naughton Contract	SE	$1,376	$21	$340	$101	$239	$584	$87	$5	$0
SCHMAT	425125	Deferred Coal Cost - Arch	SE	$63	$1	$16	$5	$11	$27	$4	$0	$0
SCHMAT	425215	Unearned Joint Use Pole Contact Revenu	SNPD	$302	$10	$81	$19	$32	$145	$14	$0	$0
SCHMAT	425250	TGS Buyout-SG	SG	$15	$0	$4	$1	$2	$7	$1	$0	$0

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Allocation Method - Factor 2010 Protocol
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FERC	FERC Secondary A		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMAT	425280	Joseph Settlement-SG	SG	$137	$2	$36	$11	$22	$59	$8	$0	$0
SCHMAT	425360	Hermiston Swap	SG	$172	$3	$45	$13	$27	$74	$10	$1	$0
SCHMAT	425380	Idaho Customer Balancing Account	OTHER	$1,390	$0	$0	$0	$0	$0	$0	$0	$1,390
SCHMAT	430100	Customer Service / Weatherization	SO	$9,655	$209	$2,644	$730	$1,387	$4,128	$534	$23	$0
SCHMAT	505125	PMI Accrued Royalties	SE	$213	$3	$53	$16	$37	$91	$13	$1	$0
SCHMAT	505400	Bonus Liability	SO	$203	$4	$56	$15	$29	$87	$11	$0	$0
SCHMAT	505600	Sick Leave Vacation & Personal Time	SO	$881	$19	$241	$67	$126	$376	$49	$2	$0
SCHMAT	605100	Trojan Decomissioning Costs	TROJD	$13	$0	$3	$1	$2	$6	$1	$0	$0
SCHMAT	605710	Reverse Accrued Final Reclamation	SE	$281	$4	$69	$21	$49	$119	$18	$1	$0
SCHMAT	610000	Coal Mine Development-PMI	SE	$236	$4	$58	$17	$41	$100	$15	$1	$0
SCHMAT	610143	Reg Liability - WA Low Energy Program	WA	$261	$0	$0	$261	$0	$0	$0	$0	$0
SCHMAT	610145	Reg Liab-OR Balance Consol	OR	$388	$0	$388	$0	$0	$0	$0	$0	$0
SCHMAT	610148	Reg Liability - Def NPC Balance Reclass	OTHER	$595	$0	$0	$0	$0	$0	$0	$0	$595
SCHMAT	705240	CA Alternative Rate for Energy Program(C	CA	$492	$492	$0	$0	$0	$0	$0	$0	$0
SCHMAT	705263	Reg Liability - Sale of REC's-WA	OTHER	$17,313	$0	$0	$0	$0	$0	$0	$0	$17,313
SCHMAT	705301	Reg Liability - OR 2010 Protocol Def	OR	$2,432	$0	$2,432	$0	$0	$0	$0	$0	$0
SCHMAT	705336	Reg Liability - Sale of Renewable Energy	OTHER	$23,986	$0	$0	$0	$0	$0	$0	$0	$23,986
SCHMAT	705400	Reg Liability - OR Injuries & Damages Re	OR	$186	$0	$186	$0	$0	$0	$0	$0	$0
SCHMAT	705451	Reg Liability - OR Property Insurance Re	OR	$2,972	$0	$2,972	$0	$0	$0	$0	$0	$0
SCHMAT	705453	Reg Liability - ID Property Insurance Re	IDU	$88	$0	$0	$0	$0	$0	$88	$0	$0
SCHMAT	705455	Reg Liability - WY Property Insurance Re	WYP	$272	$0	$0	$0	$272	$0	$0	$0	$0
SCHMAT	705500	Reg Liability - Powerdale Decommissionin	UT	$541	$0	$0	$0	$0	$541	$0	$0	$0
SCHMAT	715105	MCI FOG Wire Lease	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCHMAT	715720	NW Power Act-WA	OTHER	$253	$0	$0	$0	$0	$0	$0	$0	$253
SCHMAT	720300	Pension / Retirement (Accrued / Prepaid)	SO	$20	$0	$5	$1	$3	$8	$1	$0	$0
SCHMAT	740100	Post Merger Loss-Reacquired Debt	SNP	$1,770	$35	$468	$130	$256	$779	$97	$4	$0
SCHMAT	910905	Bridger Coal Company Underground Mine Co	SE	$44	$1	$11	$3	$8	$19	$3	$0	$0
SCHMAT	920110	PMIWY Extraction Tax	SE	$294	$4	$73	$22	$51	$125	$19	$1	$0
SCHMAT Total				**$868,907**	**$17,436**	**$220,198**	**$65,596**	**$115,870**	**$337,411**	**$42,816**	**$1,923**	**$67,655**
SCHMDP	105127	Book Depreciation Allocated to Medicare	SCHMDEXP	$257	$5	$70	$20	$38	$109	$14	$1	$0
SCHMDP	1102051	TAX PERCENTAGE DEPLETION - DEDUCTION	SE	$452	$7	$112	$33	$78	$192	$29	$2	$0
SCHMDP	120100	Preferred Dividend - PPL	SNP	$383	$8	$101	$28	$55	$168	$21	$1	$0
SCHMDP	130560	MEHC Insurance Services-Receivable	SO	$8,817	$191	$2,414	$667	$1,267	$3,770	$487	$21	$0
SCHMDP	720105	MEDICARE SUBSIDY	SO	$2,679	$58	$734	$203	$385	$1,145	$148	$6	$0
SCHMDP	910918	PMI Overriding Royalty	SE	$11	$0	$3	$1	$2	$5	$1	$0	$0
SCHMDP	920105	PMI Tax Exempt Interest Income	SE	$12	$0	$3	$1	$2	$5	$1	$0	$0
SCHMDP Total				**$12,611**	**$269**	**$3,436**	**$952**	**$1,828**	**$5,394**	**$700**	**$31**	**$0**
SCHMDT	105122	Repair Deduction	SG	$198,206	$3,027	$51,639	$15,385	$31,070	$85,191	$11,230	$665	$0
SCHMDT	105125	Tax Depreciation	TAXDEPR	$1,309,115	$26,045	$345,576	$59,238	$189,474	$575,615	$71,226	$3,352	$0
SCHMDT	105126	PMITax Depreciation	SE	$24,305	$365	$6,000	$1,783	$4,216	$10,315	$1,538	$88	$0
SCHMDT	105137	Capitalized Depreciation	SO	$5,121	$111	$1,402	$387	$736	$2,189	$283	$12	$0
SCHMDT	105141	AFUDC	SNP	$26,529	$530	$7,009	$1,951	$3,844	$11,672	$1,457	$66	$0
SCHMDT	1051411	AFUDC - Equity	SNP	$52,284	$1,044	$13,813	$3,846	$7,576	$23,003	$2,871	$130	$0
SCHMDT	105143	Basis Intangible Difference	SO	$2,401	$52	$658	$182	$345	$1,027	$133	$6	$0
SCHMDT	105148	Mine Safety Sec. 179E Election - PPW	SE	$34	$1	$8	$2	$6	$14	$2	$0	$0
SCHMDT	105149	Mine Safety Sec. 179E Election - PMI	SE	$68	$1	$17	$5	$12	$29	$4	$0	$0
SCHMDT	105152	Gain/(Loss) on Prop Dispositions	GPS	$21,776	$472	$5,963	$1,646	$3,128	$9,310	$1,204	$53	$0
SCHMDT	105165	Coal Mine Development	SE	$181	$3	$45	$13	$31	$77	$11	$1	$0
SCHMDT	105170	Coal Mine Receding Face (Extension)	SE	$2,878	$43	$710	$211	$499	$1,221	$182	$10	$0
SCHMDT	105171	PMI Coal Mine Receding Face (Extension)	SE	$1,550	$23	$383	$114	$269	$658	$98	$6	$0
SCHMDT	105175	Removal Cost (net of salvage)	GPS	$82,780	$1,794	$22,669	$6,258	$11,891	$35,392	$4,576	$200	$0
SCHMDT	1052203	Cholla SHL-NOPA (Lease Amortization)	SG	$98	$1	$25	$8	$15	$42	$6	$0	$0
SCHMDT	105470	Book Gain/Loss on Land Sales	GPS	$665	$14	$182	$50	$96	$284	$37	$2	$0
SCHMDT	110200	Depletion - Tax Percentage Deduction	SE	$399	$6	$99	$29	$69	$169	$25	$1	$0
SCHMDT	1102051	Tax Percentage Depletion - Deduction	SE	$163	$2	$40	$12	$28	$69	$10	$1	$0
SCHMDT	120105	Willow Wind Account Receivable	WA	$98	$0	$0	$98	$0	$0	$0	$0	$0
SCHMDT	145030	Distribution O&M Amort of Writeoff	SNPD	$2,601	$88	$699	$160	$277	$1,254	$123	$0	$0

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FERC	FERC Secondary A		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMDT	205025	PMI - Fuel Cost Adjustment	SE	$601	$9	$148	$44	$104	$255	$38	$2	$0
SCHMDT	205200	Coal M&S Inventory Write-Off	SE	$126	$2	$31	$9	$22	$54	$8	$0	$0
SCHMDT	205411	PMISEC 263A Adjustment	SE	$89	$1	$22	$7	$15	$38	$6	$0	$0
SCHMDT	210100	Prepaid Taxes-OR PUC	OR	$275	$0	$275	$0	$0	$0	$0	$0	$0
SCHMDT	210120	Prepaid Taxes-UT PUC	UT	$628	$0	$0	$0	$0	$628	$0	$0	$0
SCHMDT	210130	Prepaid Taxes-ID PUC	IDU	$47	$0	$0	$0	$0	$0	$47	$0	$0
SCHMDT	210180	OTHER PREPAIDS	SO	$283	$6	$78	$21	$41	$121	$16	$1	$0
SCHMDT	287396	Regulatory Liabilities - Interim Provisi	OTHER	$10,144	$0	$0	$0	$0	$0	$0	$0	$10,144
SCHMDT	287616	Regulatory Assets - Interim Provisions	OTHER	-$34,987	$0	$0	$0	$0	$0	$0	$0	-$34,987
SCHMDT	320210	Research & Exper. Sec. 174 Amort.	SO	$1,044	$23	$286	$79	$150	$446	$58	$3	$0
SCHMDT	320290	LT Prepaid IBEW 57 Pension Contribution	OTHER	$5,652	$0	$0	$0	$0	$0	$0	$0	$5,652
SCHMDT	415110	Def Reg Asset-Transmission Srvc Deposit	SG	$844	$13	$220	$66	$132	$363	$48	$3	$0
SCHMDT	415120	DEFERRED REG ASSET - FOOTE CREEK CONTRAC	SG	$138	$2	$36	$11	$22	$59	$8	$0	$0
SCHMDT	415300	Hazardous Waste Clean-up Costs	SO	$4,556	$99	$1,248	$344	$655	$1,948	$252	$11	$0
SCHMDT	415406	Reg Asset Utah ECAM	OTHER	$67,787	$0	$0	$0	$0	$0	$0	$0	$67,787
SCHMDT	415501	Cholla Plt Transact Costs- APS Amort - I	IDU	$33	$0	$0	$0	$0	$0	$33	$0	$0
SCHMDT	415502	Cholla Plt Transact Costs- APS Amort - O	OR	$54	$0	$54	$0	$0	$0	$0	$0	$0
SCHMDT	415503	Cholla Plt Transact Costs- APS Amort - W	WA	$97	$0	$0	$97	$0	$0	$0	$0	$0
SCHMDT	415680	Deferred Intervenor Funding Grants-OR	OR	$309	$0	$309	$0	$0	$0	$0	$0	$0
SCHMDT	415700	Reg Liability BPA balancing accounts-OR	OTHER	$477	$0	$0	$0	$0	$0	$0	$0	$477
SCHMDT	415701	CA Deferred Intervenor Funding	CA	$33	$33	$0	$0	$0	$0	$0	$0	$0
SCHMDT	415821	Contra Pension Reg Asset MMT & CTG _WY	WYP	$1,664	$0	$0	$0	$1,664	$0	$0	$0	$0
SCHMDT	415850	Unrecovered Plant Powerdale	SG	$279	$4	$73	$22	$44	$120	$16	$1	$0
SCHMDT	415851	Powerdale Hydro Decom Reg Asset - CA	CA	$33	$33	$0	$0	$0	$0	$0	$0	$0
SCHMDT	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	$1,044	$0	$0	$0	$0	$0	$0	$0	$1,044
SCHMDT	415870	CA Def Excess NPC	CA	$197	$197	$0	$0	$0	$0	$0	$0	$0
SCHMDT	415874	Deferred Excess Net Power Costs - WY 08	OTHER	$19,603	$0	$0	$0	$0	$0	$0	$0	$19,603
SCHMDT	415880	UT Def Independent Evaluation Fee	UT	$92	$0	$0	$0	$0	$92	$0	$0	$0
SCHMDT	415882	Deferral of Renewable Energy Credit - WA	OTHER	$681	$0	$0	$0	$0	$0	$0	$0	$681
SCHMDT	415892	Deferred Excess Net Power Costs - ID 09	OTHER	$10,304	$0	$0	$0	$0	$0	$0	$0	$10,304
SCHMDT	415900	OR SB 408 Recovery	OTHER	$5,812	$0	$0	$0	$0	$0	$0	$0	$5,812
SCHMDT	425100	Deferred Regulatory Expense-IDU	IDU	$15	$0	$0	$0	$0	$0	$15	$0	$0
SCHMDT	425110	Tenant Lease Allow-PSU Call Cntr	CN	$48	$1	$15	$3	$4	$24	$2	$0	$0
SCHMDT	425225	Duke/Hermiston Contract Renegotiation	SG	$409	$6	$107	$32	$64	$176	$23	$1	$0
SCHMDT	425295	BPA Conservation Rate Credit	SG	$692	$11	$180	$54	$108	$297	$39	$2	$0
SCHMDT	430110	Reg Asset balance reclass	SO	$388	$8	$106	$29	$56	$166	$21	$1	$0
SCHMDT	430112	Reg Asset - Other - Balance Reclass	OTHER	$1,163	$0	$0	$0	$0	$0	$0	$0	$1,163
SCHMDT	430113	Reg Asset - Def NPC Balance Reclass	OTHER	$595	$0	$0	$0	$0	$0	$0	$0	$595
SCHMDT	505100	Energy West Accrued Liabilities	SE	$559	$8	$138	$41	$97	$237	$35	$2	$0
SCHMDT	505150	Misc Current & Accrued Liability-SO	SO	$1,902	$41	$521	$144	$273	$813	$105	$5	$0
SCHMDT	505510	Vacation Accrual - PMI	SE	$49	$1	$12	$4	$9	$21	$3	$0	$0
SCHMDT	605101	Trojan Decommissioning Costs - WA	WA	$23	$0	$0	$23	$0	$0	$0	$0	$0
SCHMDT	605102	Trojan Decommissioning Costs - OR	OR	$6	$0	$6	$0	$0	$0	$0	$0	$0
SCHMDT	610100	PMIDEVT COST AMORT	SE	$1,439	$22	$355	$106	$250	$611	$91	$5	$0
SCHMDT	6101001	AMORT NOPAS 99-00 RAR	SO	$58	$1	$16	$4	$8	$25	$3	$0	$0
SCHMDT	610111	Bridger Coal Company Gain/Loss on Assets	SE	$463	$7	$114	$34	$80	$196	$29	$2	$0
SCHMDT	610114	PMI EITF Pre Stripping Costs	SE	$699	$10	$172	$51	$121	$297	$44	$3	$0
SCHMDT	610142	Reg. Liability - UT Home Energy Lifeline	UT	$143	$0	$0	$0	$0	$143	$0	$0	$0
SCHMDT	610146	OR Reg Asset/Liability Consolidation	OR	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCHMDT	705200	Oregon Gain on Sale of Halsey-OR	OTHER	$33	$0	$0	$0	$0	$0	$0	$0	$33
SCHMDT	705261	Reg Liability - Sale of Renewable Energy	OTHER	$1,378	$0	$0	$0	$0	$0	$0	$0	$1,378
SCHMDT	705265	Reg Liab - OR Energy Conservation Charge	OR	$15	$0	$15	$0	$0	$0	$0	$0	$0
SCHMDT	705300	Reg. Liability - Deferred Benefit_Arch S	SE	$44	$1	$11	$3	$8	$19	$3	$0	$0
SCHMDT	705305	Reg Liability-CA Gain on Sale of Asset	CA	$4	$4	$0	$0	$0	$0	$0	$0	$0
SCHMDT	705337	Reg Liability - Sale of Renewable Energy	OTHER	$3,594	$0	$0	$0	$0	$0	$0	$0	$3,594
SCHMDT	705454	Reg Liability - UT Property Insurance Re	UT	$683	$0	$0	$0	$0	$683	$0	$0	$0
SCHMDT	715800	Redding Renegotiated Contract	SG	$550	$8	$143	$43	$86	$236	$31	$2	$0
SCHMDT	720200	Deferred Comp Plan Benefits-PPL	SO	$437	$9	$120	$33	$63	$187	$24	$1	$0

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Schedule M (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC	FERC Secondary A		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMDT	720500	Severance Accrual	SO	$18	$0	$5	$1	$3	$8	$1	$0	$0
SCHMDT	910530	Injuries and Damages Reserve	SO	$3,031	$66	$830	$229	$435	$1,296	$168	$7	$0
SCHMDT	910560	283SMUD REVENUE IMPUTATION-UT REG LIAB	OTHER	$2,292	$0	$0	$0	$0	$0	$0	$0	$2,292
SCHMDT	910580	Wasach workers comp reserve	SO	$138	$3	$38	$10	$20	$59	$8	$0	$0
SCHMDT Total				**$1,850,059**	**$34,256**	**$462,618**	**$92,924**	**$258,114**	**$767,150**	**$96,190**	**$4,645**	**$95,573**
Grand Total				**$2,739,180**	**$52,126**	**$688,335**	**$160,047**	**$376,907**	**$1,113,209**	**$140,128**	**$6,618**	**$163,221**

			Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
Total Schedule M Additions			**$876,510**	**$17,601**	**$222,280**	**$66,171**	**$116,966**	**$340,665**	**$43,238**	**$1,941**	**$67,648**
Total Schedule M Deductions			**$1,862,670**	**$34,525**	**$466,054**	**$93,876**	**$259,942**	**$772,544**	**$96,891**	**$4,676**	**$95,573**
Total Schedule M			**-$986,159**	**-$16,924**	**-$243,774**	**-$27,705**	**-$142,976**	**-$431,879**	**-$53,653**		

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Interest Expense & Renewable Energy Tax Credits

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4091000	310310	Renewable Electricity Production Tax Cre	SG	-$70,557	-$1,078	-$18,382	-$5,477	-$11,060	-$30,326	-$3,998	-$237	$0
4091000	310311	Research & Experimentation Credit	SG	-$75	-$1	-$20	-$6	-$12	-$32	-$4	$0	$0
4091000	310312	Mining Rescue Training Credit ~ Energy W	SE	-$50	-$1	-$12	-$4	-$9	-$21	-$3	$0	$0
4091000	310313	Mining Rescue Training Credit ~ PMI	SE	-$13	$0	-$3	-$1	-$2	-$5	-$1	$0	$0
4091000	310314	HR Hiring Retention Tax Credit	SO	-$36	-$1	-$10	-$3	-$5	-$15	-$2	$0	$0
4091000	600600	Fuel Tax Credit	SE	-$14	$0	-$3	-$1	-$2	-$6	-$1	$0	$0
4091000	900900	Foreign Tax Credit	SO	$7	$0	$2	$1	$1	$3	$0	$0	$0
4091100	311311	Utah Renewable Energy Production Tax Cre	SG	-$167	-$3	-$44	-$13	-$26	-$72	-$9	-$1	$0
4191000	0	AFUDC - EQUITY	SNP	-$54,339	-$1,085	-$14,356	-$3,997	-$7,873	-$23,907	-$2,984	-$135	$0
4270000	585001	INTEREST EXPENSE - LONG-TERM DEBT - FMBS	SNP	$314,443	$6,281	$83,075	$23,130	$45,562	$138,344	$17,268	$783	$0
4270000	585002	INTEREST EXPENSE - LONG-TERM DEBT - MTNS	SNP	$33,824	$676	$8,936	$2,488	$4,901	$14,881	$1,858	$84	$0
4270000	585003	INTEREST EXPENSE - LT DEBT - PCRBS FIXED	SNP	$6,309	$126	$1,667	$464	$914	$2,776	$346	$16	$0
4270000	585004	INTEREST EXPENSE - LT DEBT - PCRBS VARIA	SNP	$1,074	$21	$284	$79	$156	$472	$59	$3	$0
4270000	585005	INTEREST EXPENSE - LT DEBT - PCRB FEES &	SNP	$3,810	$76	$1,007	$280	$552	$1,676	$209	$9	$0
4280000	586160	AMORTIZATION - DEBT DISCOUNT	SNP	$1,016	$20	$269	$75	$147	$447	$56	$3	$0
4280000	586170	AMORTIZATION - DEBT ISSUANCE EXP	SNP	$2,906	$58	$768	$214	$421	$1,279	$160	$7	$0
4281000	586190	AMORTIZATION - LOSS ON REQACQUIRED DEBT	SNP	$1,778	$36	$470	$131	$258	$782	$98	$4	$0
4290000	586180	AMORTIZATION - DEBT PREMIUM/GAIN	SNP	-$5	$0	-$1	$0	-$1	-$2	$0	$0	$0
4310000	0		SNP	$8,647	$173	$2,285	$636	$1,253	$3,805	$475	$22	$0
4313000	0	INTEREST EXPENSE ON REG LIABILITIES	SNP	$4,749	$95	$1,255	$349	$688	$2,089	$261	$12	$0
4320000	585800	INTEREST CAPITALIZED (SEE OTH INCOME)	SNP	-$28,010	-$560	-$7,400	-$2,060	-$4,058	-$12,323	-$1,538	-$70	$0
4320000	585851	Int Exp - AFUDC Calc	SNP	$0	$0	$0	$0	$0	$0	$0	$0	$0
4320000	585860	INTEREST EXPENSE - AFUDC MANUAL ADJ	SNP	$307	$6	$81	$23	$45	$135	$17	$1	$0

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A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Income Tax Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4101000	100105	190FAS 109 DEF TAX LIAB WA-NUTIL	WA		$0	$0	$0	$0	$0	$0	$0	$0
4101000	105110	282DIT Adjustment	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	105121	282PMI Book Depreciation	SE		$0	$0	$0	$0	$0	$0	$0	$0
4101000	105122	Repair Deduction	SG	$75,221	$1,149	$19,597	$5,839	$11,791	$32,331	$4,262	$252	$0
4101000	105125	Tax Depreciation	TAXDEPR	$496,822	$9,884	$131,149	$22,482	$71,907	$218,452	$27,031	$1,272	$0
4101000	1051252	282DIT ACRS Property-FERC	FERC		$0	$0	$0	$0	$0	$0	$0	$0
4101000	105126	282DIT PMIDepreciation-Tax	SE	$9,137	$137	$2,256	$670	$1,585	$3,877	$578	$33	$0
4101000	105128	Accelerated Pollution Control Facilities	SG		$0	$0	$0	$0	$0	$0	$0	$0
4101000	105130	CIAC	CIAC		$0	$0	$0	$0	$0	$0	$0	$0
4101000	105137	Capitalized Depreciation	SO	$1,943	$42	$532	$147	$279	$831	$107	$5	$0
4101000	105141	AFUDC Debt	SNP	$10,068	$201	$2,660	$741	$1,459	$4,430	$553	$25	$0
4101000	1051411	AFUDC Equity	SNP	$19,842	$396	$5,242	$1,460	$2,875	$8,730	$1,090	$49	$0
4101000	105143	282Basis Intangible Difference	SO	$911	$20	$250	$69	$131	$390	$50	$2	$0
4101000	105147	Sec 1031 Like Kind Exchange	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	105148	Mine Safety Sec. 179E Election - PPW	SE	$13	$0	$3	$1	$2	$5	$1	$0	$0
4101000	105149	Mine Safety Sec. 179E Election - PMI	SE	$26	$0	$6	$2	$5	$11	$2	$0	$0
4101000	105152	Gain / (Loss) on Prop. Disposition	GPS	$8,264	$179	$2,263	$625	$1,187	$3,533	$457	$20	$0
4101000	105165	Coal Mine Development	SE	$69	$1	$17	$5	$12	$29	$4	$0	$0
4101000	105170	Coal Mine Extension	SE	$1,092	$16	$270	$80	$189	$464	$69	$4	$0
4101000	105171	PMI Coal Mine Extension Costs	SE	$588	$9	$145	$43	$102	$250	$37	$2	$0
4101000	105175	Cost of Removal	GPS	$31,416	$681	$8,603	$2,375	$4,513	$13,432	$1,736	$76	$0
4101000	1052203	Cholla SHL NOPA (Lease Amortization)	SG	$37	$1	$10	$3	$6	$16	$2	$0	$0
4101000	105470	282Book Gain/Loss on Land Sales	GPS	$252	$5	$69	$19	$36	$108	$14	$1	$0
4101000	110200	IGC Tax Percentage Depletion Deduct	SE	$151	$2	$37	$11	$26	$64	$10	$1	$0
4101000	110205	SRC Tax Percentage Depletion Deduct	SG		$0	$0	$0	$0	$0	$0	$0	$0
4101000	1102051	Tax Percentage Depletion - Deduction (BI	SE	$62	$1	$15	$5	$11	$26	$4	$0	$0
4101000	120105	Willow Wind Account Receivable	WA	$37	$0	$0	$37	$0	$0	$0	$0	$0
4101000	145030	190Distribution O&M	SNPD	$987	$33	$265	$61	$105	$476	$47	$0	$0
4101000	205025	PMI-Fuel Cost Adjustment	SE	$228	$3	$56	$17	$40	$97	$14	$1	$0
4101000	205200	M&S INVENTORY WRITE-OFF	SE	$48	$1	$12	$4	$8	$20	$3	$0	$0
4101000	205411	190PMISec263A	SE	$14	$0	$3	$1	$2	$6	$1	$0	$0
4101000	210100	283OR PUC Prepaid Taxes	OR	$104	$0	$104	$0	$0	$0	$0	$0	$0
4101000	210105	Self Insured Health Benefits	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	210120	283UT PUC Prepaid Taxes	UT	$238	$0	$0	$0	$0	$238	$0	$0	$0
4101000	210130	283ID PUC Prepaid Taxes	IDU	$18	$0	$0	$0	$0	$0	$18	$0	$0
4101000	210180	283Prepaid Membership Fees-EEI WSCC	SO	$107	$2	$29	$8	$15	$46	$6	$0	$0
4101000	210200	283Prepaid Taxes-Property Taxes	GPS		$0	$0	$0	$0	$0	$0	$0	$0
4101000	220100	190Bad Debt Allowance	BADDEBT		$0	$0	$0	$0	$0	$0	$0	$0
4101000	287270	Valuation Allowance for DTA	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	287396	Regulatory Liabilities - Interim Provisi	OTHER	$3,850	$0	$0	$0	$0	$0	$0	$0	$3,850
4101000	287449	NOL (State) Carryforward (Federal Detrim	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	287616	Regulatory Assets - Interim Provisions	OTHER	-$13,278	$0	$0	$0	$0	$0	$0	$0	-$13,278
4101000	287944	Reg Asset Federal Interst Expense	UT		$0	$0	$0	$0	$0	$0	$0	$0
4101000	287961	Reg Asset Fed Int Exp - WY	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	320115	283INTERIM PROVISION_TOTAL REG ASSETS_LI	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	320210	190R&E Expense Sec174 Deduction	SO	$396	$9	$108	$30	$57	$169	$22	$1	$0
4101000	320290	LT Prepaid IBEW 57 Pension Contribution	OTHER	$2,145	$0	$0	$0	$0	$0	$0	$0	$2,145
4101000	415110	190DEF REG ASSET-TRANSM SVC DEPOSIT	SG	$320	$5	$83	$25	$50	$138	$18	$1	$0
4101000	415120	190DEF REG ASSET-FOOTE CREEK CONTRACT	SG	$52	$1	$14	$4	$8	$22	$3	$0	$0
4101000	415300	283Hazardous Waste/Environmental Cleanup	SO	$1,729	$37	$474	$131	$248	$739	$96	$4	$0
4101000	415406	Reg Asset Utah ECAM	OTHER	$25,726	$0	$0	$0	$0	$0	$0	$0	$25,726
4101000	415500	283Cholla Plt Trans-APS Amort	SGCT		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415501	Cholla Plt Transact Costs- APS Amort - I	IDU	$13	$0	$0	$0	$0	$0	$13	$0	$0
4101000	415502	Cholla Plt Transact Costs- APS Amort - O	OR	$20	$0	$20	$0	$0	$0	$0	$0	$0
4101000	415503	Cholla Plt Transact Costs- APS Amort - W	WA	$37	$0	$0	$37	$0	$0	$0	$0	$0
4101000	415680	190Def Intervenor Funding Grants-OR	OR	$117	$0	$117	$0	$0	$0	$0	$0	$0
4101000	415700	190Reg Liabs BPA balancing accounts-OR	OTHER	$181	$0	$0	$0	$0	$0	$0	$0	$181
4101000	415701	CA Deferred Intervenor Funding	CA	$12	$12	$0	$0	$0	$0	$0	$0	$0
4101000	415703	Goodnoe Hills Liquidation Damages - WY	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415705	Reg Liability - Tax Revenue Adjustment -	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415801	190CONTRA RTO GRID WEST N/R ALLOWANCE	SG		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415804	RTO Gridwest NR Writeoff OR	OR		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415821	Contra Pension Reg Asset MMT & CTG WY	WYP	$631	$0	$0	$0	$631	$0	$0	$0	$0
4101000	415850	Unrecovered Plant Powerdale	SG	$106	$2	$28	$8	$17	$46	$6	$0	$0

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Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4101000	415851	Powerdale Hydro Decom Reg Asset - CA	CA	$13	$13	$0	$0	$0	$0	$0	$0	$0
4101000	415852	Powerdale Decommissioning Reg Asset - ID	IDU		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415853	Powerdale Decommissioning Reg Asset - OR	OR		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415854	Powerdale Decommissioning Reg Asset - WA	WA		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415855	Ca - January 2010 Storm Costs	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415856	Powerdale Decommissioning Reg Asset - WY	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415857	ID - Deferred Overburden Costs	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415858	WY - Deferred Overburden Costs	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415859	WY - Deferred Advertising Costs	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415865	Reg Asset - Utah MPA	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	$396	$0	$0	$0	$0	$0	$0	$0	$396
4101000	415870	Deferred Excess Net Power Costs CA	CA	$75	$75	$0	$0	$0	$0	$0	$0	$0
4101000	415874	Deferred Excess Net Power Costs - WY 09	OTHER	$7,439	$0	$0	$0	$0	$0	$0	$0	$7,439
4101000	415876	Deferred Excess Net Power Costs - OR	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415880	Deferred UT Independent Evaluation Fee	UT	$35	$0	$0	$0	$0	$35	$0	$0	$0
4101000	415882	Deferral of Renewable Energy Credit - WA	OTHER	$259	$0	$0	$0	$0	$0	$0	$0	$259
4101000	415892	Deferred Excess Net Power Costs - ID 09	OTHER	$3,911	$0	$0	$0	$0	$0	$0	$0	$3,911
4101000	415893	OR - MEHC Transition Service Costs	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415896	WA - Chehalis Plant Revenue Requirement	WA		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415897	Reg Asset MEHC Transition Service Costs	CA		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415898	Deferred Coal Costs - Naughton Contract	SE		$0	$0	$0	$0	$0	$0	$0	$0
4101000	415900	OR SB 408 Recovery	OTHER	$2,206	$0	$0	$0	$0	$0	$0	$0	$2,206
4101000	425100	190Deferred Regulatory Expense-IDU	IDU	$6	$0	$0	$0	$0	$0	$6	$0	$0
4101000	425110	190Tenant Lease Allow-PSU Call Cntr	CN	$18	$0	$6	$1	$1	$9	$1	$0	$0
4101000	425125	Deferred Coal Cost - Arch	SE		$0	$0	$0	$0	$0	$0	$0	$0
4101000	425215	283Unearned Joint Use Pole Contact Revnu	SNPD		$0	$0	$0	$0	$0	$0	$0	$0
4101000	425225	Duke/Hermiston Contract Renegotiation	SG	$155	$2	$40	$12	$24	$67	$9	$1	$0
4101000	425295	BPA Conservation Rate Credit	SG	$263	$4	$68	$20	$41	$113	$15	$1	$0
4101000	425380	190Idaho Customer Bal Acct	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	430100	283Weatherization	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	430110	Reg Asset Balance Reclass	SO	$147	$3	$40	$11	$21	$63	$8	$0	$0
4101000	430111	Reg Assets - SB 1149 Balance Reclass	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	430112	Reg Asset - Other - Balance Reclass	OTHER	$441	$0	$0	$0	$0	$0	$0	$0	$441
4101000	430113	Reg Asset - Def NPC Balance Reclass	OTHER	$226	$0	$0	$0	$0	$0	$0	$0	$226
4101000	505100	190Energy West Accrued Liabilities	SE	$212	$3	$52	$16	$37	$90	$13	$1	$0
4101000	505125	190Accrued Royalties	SE		$0	$0	$0	$0	$0	$0	$0	$0
4101000	505150	190Misc Current and Accrued Liability-SO	SO	$722	$16	$198	$55	$104	$309	$40	$2	$0
4101000	505400	190Bonus Liability	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	505510	190PMI Vacation/Bonus	SE	$5	$0	$1	$0	$1	$2	$0	$0	$0
4101000	505600	190Vacation Sickleave & PT Accrual	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	605100	190Trojan Decommissioning Amort	TROJD		$0	$0	$0	$0	$0	$0	$0	$0
4101000	605101	Trojan Decommissioning Costs - WA	WA	$9	$0	$0	$9	$0	$0	$0	$0	$0
4101000	605102	Trojan Decommissioning Costs - OR	OR	$2	$0	$2	$0	$0	$0	$0	$0	$0
4101000	605710	190Reverse Accrued Final Reclamation	SE		$0	$0	$0	$0	$0	$0	$0	$0
4101000	610000	283PMI Development Costs	SE		$0	$0	$0	$0	$0	$0	$0	$0
4101000	610100	283PMI AMORT DEVELOPMENT	SE	$546	$8	$135	$40	$95	$232	$35	$2	$0
4101000	6101001	190NOPA 103-99-00 RAR	SO	$22	$0	$6	$2	$3	$9	$1	$0	$0
4101000	610111	283PMI SALE OF ASSETS	SE	$370	$6	$91	$27	$64	$157	$23	$1	$0
4101000	610114	PMI EITF Pre stripping Cost	SE	$265	$4	$66	$19	$46	$113	$17	$1	$0
4101000	610130	283781 Shopping Incentive-OR	OR		$0	$0	$0	$0	$0	$0	$0	$0
4101000	610140	190 OR Rate Refunds	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	610141	190WA Rate Refunds	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	610142	283Reg Liability-UT Home Energy Lifeline	UT	$54	$0	$0	$0	$0	$54	$0	$0	$0
4101000	610143	283Reg Liability-WA Low Energy Program	WA		$0	$0	$0	$0	$0	$0	$0	$0
4101000	610146	190OR Reg Asset/Liability Consol	OR	$0	$0	$0	$0	$0	$0	$0	$0	$0
4101000	610148	Reg Liability - Def NPC Balance Reclass	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	610149	Reg Liability - SB 1149 Balance Reclass	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705200	190OR Gain on Sale of Halsey-OR	OTHER	$13	$0	$0	$0	$0	$0	$0	$0	$13
4101000	705210	190Property Insurance	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705232	WEST VALLEY LEASE REDUCTION - CA	CA		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705233	West Valley Lease Reduction - ID	IDU		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705234	West Valley Lease Reduction - WY	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705252	A&G CREDIT - CA	CA		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705253	A&G Credit - ID	IDU		$0	$0	$0	$0	$0	$0	$0	$0

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(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4101000	705254	A&G Credit - WY	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705261	Reg Liability - Sale of Renewable Energy	OTHER	$523	$0	$0	$0	$0	$0	$0	$0	$523
4101000	705265	Reg Liab - OR Energy Conservation Charge	OR	$6	$0	$6	$0	$0	$0	$0	$0	$0
4101000	705300	Reg. Liability - Deferred Benefit_Arch S	SE	$17	$0	$4	$1	$3	$7	$1	$0	$0
4101000	705305	Reg Liability-CA Gain on Sale of Asset	CA	$1	$1	$0	$0	$0	$0	$0	$0	$0
4101000	705310	Reg Liab - UT Gain on Sale of Asset	UT		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705320	Reg Liab - ID Gain on Sale of Asset	IDU		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705330	Reg Liab - WY Gain on Sale of Asset	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4101000	705337	Reg Liability - Sale of Renewable Energy	OTHER	$1,364	$0	$0	$0	$0	$0	$0	$0	$1,364
4101000	705454	Reg Liability - UT Property Insurance Re	UT	$259	$0	$0	$0	$0	$259	$0	$0	$0
4101000	7151001	MCI Fogwire	SG		$0	$0	$0	$0	$0	$0	$0	$0
4101000	715800	190Redding Contract	SG	$209	$3	$54	$16	$33	$90	$12	$1	$0
4101000	7201051	Contra Medicare Subsidy	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	720200	190Deferred Compensation Payout	SO	$166	$4	$45	$13	$24	$71	$9	$0	$0
4101000	720300	190Pension/Retirement (Accrued/Prepaid)	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	720500	190Severance	SO	$7	$0	$2	$1	$1	$3	$0	$0	$0
4101000	720550	190Accrued CIC Severence	SO		$0	$0	$0	$0	$0	$0	$0	$0
4101000	720844	Reg Asset RA Tax Adj on PR Benefit UT	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	910530	190Injuries & Damages	SO	$1,150	$25	$315	$87	$165	$492	$64	$3	$0
4101000	910560	283SMUD Revenue Imputation-UT Reg Liab	OTHER	$870	$0	$0	$0	$0	$0	$0	$0	$870
4101000	910580	190Wasatch workers comp reserve	SO	$52	$1	$14	$4	$8	$22	$3	$0	$0
4101000	910905	283PMI BCC Underground Mine Cost Deplet	SE		$0	$0	$0	$0	$0	$0	$0	$0
4101000	920110	BRIDGER COAL COMPANY EXTRACTION TAXES PA	SE		$0	$0	$0	$0	$0	$0	$0	$0
4101000	930100	190OR BETC Credit	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4101000	9301001	Oregon BETC Credit	SG		$0	$0	$0	$0	$0	$0	$0	$0
4101000 Total				**$702,189**	**$13,001**	**$175,586**	**$35,271**	**$97,969**	**$291,172**	**$36,510**	**$1,763**	**$36,271**
4111000	100105	283FAS 109 Def Tax Liab WA-NUTIL	WA	-$500	$0	$0	-$500	$0	$0	$0	$0	$0
4111000	105100	190CAPITALIZED LABOR COSTS	SO	-$3,971	-$86	-$1,088	-$300	-$570	-$1,698	-$220	-$10	$0
4111000	1051151	Depreciation Flow-Through - CA	CA	-$290	-$290	$0	$0	$0	$0	$0	$0	$0
4111000	1051152	Depreciation Flow-Through - FERC	FERC	$12	$0	$0	$0	$0	$0	$0	$12	$0
4111000	1051153	Depreciation Flow-Through - ID	IDU	-$771	$0	$0	$0	$0	$0	-$771	$0	$0
4111000	1051154	Depreciation Flow-Through - OR	OR	$1,918	$0	$1,918	$0	$0	$0	$0	$0	$0
4111000	1051155	Depreciation Flow-Through - OTHER	OTHER	-$11	$0	$0	$0	$0	$0	$0	$0	-$11
4111000	1051156	Depreciation Flow-Through - UT	UT	-$5,870	$0	$0	$0	$0	-$5,870	$0	$0	$0
4111000	1051157	Depreciation Flow-Through - WA	WA	$2,260	$0	$0	$2,260	$0	$0	$0	$0	$0
4111000	1051158	Depreciation Flow-Through - WYP	WYP	$964	$0	$0	$0	$964	$0	$0	$0	$0
4111000	1051159	Depreciation Flow-Through - WYU	WYU	$52	$0	$0	$0	$52	$0	$0	$0	$0
4111000	105120	Book Depreciation	SCHMDEXP	-$237,594	-$4,888	-$64,391	-$18,463	-$35,486	-$100,818	-$12,926	-$623	$0
4111000	105121	282DIT PMIDepreciation-Book	SE	-$6,757	-$101	-$1,668	-$496	-$1,172	-$2,868	-$428	-$24	$0
4111000	105122	Repair Deduction	SG		$0	$0	$0	$0	$0	$0	$0	$0
4111000	105123	Sec 481a Adj- Repair Deduction	SG	$880	$13	$229	$68	$138	$378	$50	$3	$0
4111000	105128	Accel Pollution Control Facilities Depr	SG		$0	$0	$0	$0	$0	$0	$0	$0
4111000	105130	CIAC	CIAC	-$15,616	-$529	-$4,196	-$959	-$1,665	-$7,527	-$740	$0	$0
4111000	105140	Highway Relocation	SNPD	-$3,513	-$119	-$944	-$216	-$375	-$1,693	-$166	$0	$0
4111000	105141	AFUDC Equity	SNP		$0	$0	$0	$0	$0	$0	$0	$0
4111000	105142	Avoided Costs	SNP	-$19,518	-$390	-$5,157	-$1,436	-$2,828	-$8,587	-$1,072	-$49	$0
4111000	105143	282Basis Intangible Difference	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	105146	Capitalization of Test Energy	SG		$0	$0	$0	$0	$0	$0	$0	$0
4111000	105165	Coal Mine Development	SE		$0	$0	$0	$0	$0	$0	$0	$0
4111000	105170	Coal Mine Extension	SE		$0	$0	$0	$0	$0	$0	$0	$0
4111000	105220	282CHOLLA TAX LEASE	SG	-$541	-$8	-$141	-$42	-$85	-$232	-$31	-$2	$0
4111000	110100	283BOOK COST DEPLETION ADDBACK	SE	-$621	-$9	-$153	-$46	-$108	-$264	-$39	-$2	$0
4111000	120105	Willow Wind Account Receivable	WA		$0	$0	$0	$0	$0	$0	$0	$0
4111000	145030	190Distribution O&M	SNPD		$0	$0	$0	$0	$0	$0	$0	$0
4111000	205025	PMI - Fuel Cost Adjustment	SE		$0	$0	$0	$0	$0	$0	$0	$0
4111000	205100	190COAL PILE INVENTORY	SE	-$1,549	-$23	-$382	-$114	-$269	-$657	-$98	-$6	$0
4111000	205411	190PMI Sec263A	SE		$0	$0	$0	$0	$0	$0	$0	$0
4111000	210100	283OR PUC Prepaid Taxes	OR		$0	$0	$0	$0	$0	$0	$0	$0
4111000	210120	283UT PUC Prepaid Taxes	UT		$0	$0	$0	$0	$0	$0	$0	$0
4111000	210130	283ID PUC Prepaid Taxes	IDU		$0	$0	$0	$0	$0	$0	$0	$0
4111000	210180	190 Other - Pension(Prepaid)	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	210200	283Prepaid Taxes-Property Taxes	GPS	-$1,739	-$38	-$476	-$131	-$250	-$744	-$96	-$4	$0
4111000	220100	190Bad Debt Allowance	BADDEBT	-$1,671	-$64	-$792	-$236	-$90	-$412	-$77	$0	$0
4111000	287281	CA AMT Credit	OTHER		$0	$0	$0	$0	$0	$0	$0	$0

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FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	287449	NOL (State) Carryforward (Federal Detrim	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	287492	190Production Tax Credit Carryforward	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	2874941	190Idaho ITC Credits	SO	-$324	-$7	-$89	-$25	-$47	-$139	-$18	-$1	$0
4111000	287944	Fin 48 - Reg Asset Fed Int Exp - UT	UT		$0	$0	$0	$0	$0	$0	$0	$0
4111000	320115	283INTERIM PROVISION_TOTAL REG ASSET_LIA	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	320140	283May 2000 Transition Plan Costs-OR	OR		$0	$0	$0	$0	$0	$0	$0	$0
4111000	320220	283GLENROCK EXCLUDING RECLAMATION-UT	UT		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415110	283Def Reg Asset-Transm Svc Deposit	SG		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415300	283Hazardous Waste/Envir. Cleanup	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415301	190Hazardous Waste/Environmental-WA	WA	-$38	$0	$0	-$38	$0	$0	$0	$0	$0
4111000	415500	283Cholla Plt Trans-APS Amort	SGCT	-$426	-$7	-$111	-$33	-$67	-$184	-$24	$0	$0
4111000	415510	283WA DISALLOWED COLSTRIP #3 WRITE-OFF	WA	-$20	$0	$0	-$20	$0	$0	$0	$0	$0
4111000	415700	190Reg Assets BPA balancing accounts-OR	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415701	CA Deferred Intervenor Funding	CA		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415702	REG ASSET - LAKE SIDE LIQ - WY	WYP	-$11	$0	$0	$0	-$11	$0	$0	$0	$0
4111000	415703	Goodnoe Hills Liquidation Damages - WY	WYP	-$8	$0	$0	$0	-$8	$0	$0	$0	$0
4111000	415704	Reg Liability - Tax Revenue Adjustment -	UT	-$5	$0	$0	$0	$0	-$5	$0	$0	$0
4111000	415705	Reg Liability - Tax Revenue Adjustment -	WYP	-$11	$0	$0	$0	-$11	$0	$0	$0	$0
4111000	415800	RTO Grid West N/R Allowance	SG		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415803	RTO Grid West N/R Writeoff WA	WA	-$9	$0	$0	-$9	$0	$0	$0	$0	$0
4111000	415804	RTO Grid West Notes Receivable-OR	OR	-$145	$0	-$145	$0	$0	$0	$0	$0	$0
4111000	415805	RTO Grid West Notes Receivable - WY	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415806	RTO Grid West N/R Writeoff ID	IDU	-$10	$0	$0	$0	$0	$0	-$10	$0	$0
4111000	415822	Reg Asset _ Pension MMT -UT	UT	-$107	$0	$0	$0	$0	-$107	$0	$0	$0
4111000	415828	Reg Asset Post Retirement MMT - WY	WYP	-$117	$0	$0	$0	-$117	$0	$0	$0	$0
4111000	415829	Reg Asset - Post - Ret MMT -UT	UT	-$106	$0	$0	$0	$0	-$106	$0	$0	$0
4111000	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	-$278	$0	$0	$0	$0	$0	$0	$0	-$278
4111000	415850	Unrecovered Plant-Powerdale	SG		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415852	Powerdale Decommissioning Reg Asset - ID	IDU	-$35	$0	$0	$0	$0	$0	-$35	$0	$0
4111000	415853	Powerdale Decommissioning Reg Asset - OR	OR	-$187	$0	-$187	$0	$0	$0	$0	$0	$0
4111000	415854	Powerdale Decommissioning Reg Asset - WA	WA	-$81	$0	$0	-$81	$0	$0	$0	$0	$0
4111000	415855	CA - January 2010 Storm Costs	OTHER	-$442	$0	$0	$0	$0	$0	$0	$0	-$442
4111000	415856	Powerdale Decommissioning Reg Asset - WY	WYP	-$13	$0	$0	$0	-$13	$0	$0	$0	$0
4111000	415857	ID - Deferred Overburden Costs	OTHER	-$28	$0	$0	$0	$0	$0	$0	$0	-$28
4111000	415858	WY - Deferred Overburden Costs	WYP	-$68	$0	$0	$0	-$68	$0	$0	$0	$0
4111000	415859	WY - Deferred Advertising Costs	WYP	-$20	$0	$0	$0	-$20	$0	$0	$0	$0
4111000	415865	Reg Asset - UT MPA	OTHER	-$5,968	$0	$0	$0	$0	$0	$0	$0	-$5,968
4111000	415867	Reg Asset - CA Solar Feed-in Tariff	OTHER	-$93	$0	$0	$0	$0	$0	$0	$0	-$93
4111000	415870	Deferred Excess Net Power Costs-CA	CA		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415871	Deferred Excess Net Power Costs-WY	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415872	Deferred Excess Net Power Costs - WY 08	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415873	Deferred Excess Net Power Costs - WA Hyd	WA	-$703	$0	$0	-$703	$0	$0	$0	$0	$0
4111000	415876	Deferred Excess Net PowerCosts - OR	OTHER	-$1,361	$0	$0	$0	$0	$0	$0	$0	-$1,361
4111000	415880	Deferred UT Independent Evaluation Fee	UT		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415881	Deferral of Renewable Energy Credit - UT	OTHER	-$6	$0	$0	$0	$0	$0	$0	$0	-$6
4111000	415883	Deferral of Renewable Energy Credit - WY	OTHER	-$196	$0	$0	$0	$0	$0	$0	$0	-$196
4111000	415890	ID MEHC 2006 Transition Costs	IDU		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415891	WY - 2006 Transition Severance Costs	WYP		$0	$0	$0	$0	$0	$0	$0	$0
4111000	415893	OR - MEHC Transition Service Costs	OTHER	-$781	$0	$0	$0	$0	$0	$0	$0	-$781
4111000	415895	OR_RCAC SEP-DEC 07 DEFERRED	OR	-$242	$0	-$242	$0	$0	$0	$0	$0	$0
4111000	415896	WA - Chehalis Plant Revenue Requirement	WA	-$1,139	$0	$0	-$1,139	$0	$0	$0	$0	$0
4111000	415897	Reg Asset MEHC Transition Service Costs	CA	-$68	-$68	$0	$0	$0	$0	$0	$0	$0
4111000	415898	Deferred Coal Costs - Naughton Contract	SE	-$522	-$8	-$129	-$38	-$91	-$222	-$33	-$2	$0
4111000	415900	OR SB 409 Recovery	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	425100	Deferred Regulatory Expense	IDU		$0	$0	$0	$0	$0	$0	$0	$0
4111000	425125	Deferred Coal Cost - Arch	SE	-$24	$0	-$6	-$2	-$4	-$10	-$2	$0	$0
4111000	425215	283Unearned Joint Use Pole Contact Revnu	SNPD	-$114	-$4	-$31	-$7	-$12	-$55	-$5	$0	$0
4111000	425250	283TGS BUYOUT-SG	SG	-$6	$0	-$2	$0	-$1	-$3	$0	$0	$0
4111000	425260	283LAKEVIEW BUYOUT-SG	SG		$0	$0	$0	$0	$0	$0	$0	$0
4111000	425280	283JOSEPH SETTLEMENT-SG	SG	-$52	-$1	-$14	-$4	-$8	-$22	-$3	$0	$0
4111000	425360	190Hermiston Swap	SG	-$65	-$1	-$17	-$5	-$10	-$28	-$4	$0	$0
4111000	425380	190Idaho Customer Bal Acct	OTHER	-$528	$0	$0	$0	$0	$0	$0	$0	-$528
4111000	430100	283Weatherization	SO	-$3,664	-$79	-$1,003	-$277	-$526	-$1,567	-$203	-$9	$0
4111000	430111	Reg Asset - SB 1149 Balance Reclass	OTHER		$0	$0	$0	$0	$0	$0	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Income Tax Expense (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	430112	Reg Asset - Other - Balance Reclass	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	430113	Reg Asset - Def NPC Balance Reclass	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	505125	190Accrued Royalties	SE	-$81	-$1	-$20	-$6	-$14	-$34	-$5	$0	$0
4111000	505400	190Bonus Liability	SO	-$77	-$2	-$21	-$6	-$11	-$33	-$4	$0	$0
4111000	505510	190PMIVacation Bonus	SE		$0	$0	$0	$0	$0	$0	$0	$0
4111000	505600	190Vacation Sickleave & PT Accrual	SO	-$334	-$7	-$92	-$25	-$48	-$143	-$18	-$1	$0
4111000	5058002	State Tax Deduction Fed TR - RTP	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	605100	283TROJAN DECOMMISSIONING AMORT	TROJD	-$5	$0	-$1	$0	-$1	-$2	$0	$0	$0
4111000	605710	REVERSE ACCRUED FINAL RECLAMATION	SE	-$107	-$2	-$26	-$8	-$18	-$45	-$7	$0	$0
4111000	610000	283PMI Development Costs	SE	-$90	-$1	-$22	-$7	-$16	-$38	-$6	$0	$0
4111000	610005	283Sec 174 94-98 & 99-00 RAR	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	610111	282PMI Sale of Assets	SE		$0	$0	$0	$0	$0	$0	$0	$0
4111000	610114	PMI EITF04-06 Pre-Stripping Cost	SE		$0	$0	$0	$0	$0	$0	$0	$0
4111000	610130	283781 Shopping Incentive-OR	OR		$0	$0	$0	$0	$0	$0	$0	$0
4111000	610135	283 SB1149Costs-OROTHER	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	610141	190WA Rate Refunds	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	610142	283Reg Liability-UT Home Energy Lifeline	UT		$0	$0	$0	$0	$0	$0	$0	$0
4111000	610143	283Reg Liability-WA Low Energy Program	WA	-$99	$0	$0	-$99	$0	$0	$0	$0	$0
4111000	610145	190Reg Liab_OR Balance Consol	OR	-$147	$0	-$147	$0	$0	$0	$0	$0	$0
4111000	610146	OR Reg Asset/Liability Consolidation	OR		$0	$0	$0	$0	$0	$0	$0	$0
4111000	610148	Reg Liability - Def NPC Balance Reclass	OTHER	-$226	$0	$0	$0	$0	$0	$0	$0	-$226
4111000	610149	Reg Liability - SB 1149 Balance Reclass	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	705210	190Property Insurance	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	705240	283CA Alternative Rate for Energy Progra	CA	-$187	-$187	$0	$0	$0	$0	$0	$0	$0
4111000	705260	MEHC Transition Costs-WA	WA		$0	$0	$0	$0	$0	$0	$0	$0
4111000	705261	Reg Liability - Sale of renewable Energy	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	705263	Reg Liability - Sale of REC's-WA	OTHER	-$6,571	$0	$0	$0	$0	$0	$0	$0	-$6,571
4111000	705265	Reg Liability - OR Energy Conservation C	OR		$0	$0	$0	$0	$0	$0	$0	$0
4111000	705300	Reg. Liability - Deferred Benefit_Arch S	SE		$0	$0	$0	$0	$0	$0	$0	$0
4111000	705301	Reg Liability - OR 2010 Protocol Def	OR	-$923	$0	-$923	$0	$0	$0	$0	$0	$0
4111000	705336	Reg Liability - Sale of Renewable Energy	OTHER	-$9,103	$0	$0	$0	$0	$0	$0	$0	-$9,103
4111000	705337	Regulatory Liability - Sale of Renewable	OTHER		$0	$0	$0	$0	$0	$0	$0	$0
4111000	705400	Reg Liability - OR Injuries & Damages Re	OR	-$71	$0	-$71	$0	$0	$0	$0	$0	$0
4111000	705451	Reg Liability - OR Property Insurance Re	OR	-$1,128	$0	-$1,128	$0	$0	$0	$0	$0	$0
4111000	705453	Reg Liability - ID Property Insurance Re	IDU	-$33	$0	$0	$0	$0	$0	-$33	$0	$0
4111000	705455	Reg Liability - WY Property Insurance Re	WYP	-$103	$0	$0	$0	-$103	$0	$0	$0	$0
4111000	705500	Reg Liability - Powerdale Decommissionin	UT	-$205	$0	$0	$0	$0	-$205	$0	$0	$0
4111000	715105	MCI FOG Wire Lease	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
4111000	715720	190NW Power Act(BPA Regional Crs)-WA	OTHER	-$96	$0	$0	$0	$0	$0	$0	$0	-$96
4111000	7201051	Contra Medicare Subsidy	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	720200	190Deferred Compensation Payout	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	720300	190Pension/Retirement (Accrued/Prepaid)	SO	-$7	$0	-$2	-$1	-$1	-$3	$0	$0	$0
4111000	720400	190SERP - Cash Basis	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	720840	Reg Asset Medicare Subsidy	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	740100	283Post Merger Debt Loss	SNP	-$672	-$13	-$177	-$49	-$97	-$296	-$37	-$2	$0
4111000	910530	190Injuries & Damages	SO		$0	$0	$0	$0	$0	$0	$0	$0
4111000	910905	283PMI BCC Underground Mine Cost Deplet	SE	-$10	$0	-$2	-$1	-$2	-$4	-$1	$0	$0
4111000	910910	190PMISec 471 Adjustment	SE		$0	$0	$0	$0	$0	$0	$0	$0
4111000	920110	190PMIWYExtractionTax	SE	-$112	-$2	-$28	-$8	-$19	-$47	-$7	$0	$0
4111000	930100	190OR BETC Credit	OTHER	-$15	$0	$0	$0	$0	$0	$0	$0	-$15
4111000	9301001	190OR BETC Credit	SG	-$606	-$9	-$158	-$47	-$95	-$261	-$34	-$2	$0
4111000 Total				**-$333,474**	**-$6,932**	**-$82,036**	**-$23,248**	**-$43,183**	**-$134,549**	**-$17,102**	**-$723**	**-$25,702**
Grand Total				**$368,715**	**$6,070**	**$93,550**	**$12,023**	**$54,787**	**$156,622**	**$19,407**	**$1,041**	**$10,569**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Investment Tax Credit Amortization (Actuals)

Twelve Months Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4114000	DEF ITC-EL-FED-CR	0	DEF ITC CREDIT FED	DGU	-$1,863	$0	$0	$0	-$115	-$1,534	-$202	-$12	$0
4114000 Total					**-$1,863**	**$0**	**$0**	**$0**	**-$115**	**-$1,534**	**-$202**	**-$12**	**$0**
Grand Total					**-$1,863**	**$0**	**$0**	**$0**	**-$115**	**-$1,534**	**-$202**	**-$12**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Plant in Service with Unclassified Plant (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	3020000	FRANCHISES AND CONSENTS	IDU	$1,000	$0	$0	$0	$0	$0	$1,000	$0	$0
1010000	3020000	FRANCHISES AND CONSENTS	SG	$10,419	$159	$2,715	$809	$1,633	$4,478	$590	$35	$0
1010000	3020000	FRANCHISES AND CONSENTS	SG-P	$173,622	$2,652	$45,234	$13,477	$27,216	$74,625	$9,837	$582	$0
1010000	3020000	FRANCHISES AND CONSENTS	SG-U	$9,790	$150	$2,551	$760	$1,535	$4,208	$555	$33	$0
1010000	3031040	TRANSMISSION INTANGIBLE ASSETS	OR	$531	$0	$531	$0	$0	$0	$0	$0	$0
1010000	3031040	TRANSMISSION INTANGIBLE ASSETS	SG	$35,215	$538	$9,175	$2,733	$5,520	$15,136	$1,995	$118	$0
1010000	3031050	RCMS - REGION CONSTRUCTION MGMT SYSTEM	SO	$10,936	$237	$2,995	$827	$1,571	$4,676	$604	$26	$0
1010000	3031080	FUEL MANAGEMENT SYSTEM	SO	$3,293	$71	$902	$249	$473	$1,408	$182	$8	$0
1010000	3031230	AUTOMATE POLE CARD SYSTEM	SO	$4,410	$96	$1,208	$333	$633	$1,885	$244	$11	$0
1010000	3031470	RILDA CANYON ROAD IMPROVEMENTS	SE	$3,381	$51	$835	$248	$587	$1,435	$214	$12	$0
1010000	3031680	DISTRIBUTION AUTOMATION PILOT PROJECT	SO	$13,072	$283	$3,580	$988	$1,878	$5,589	$723	$32	$0
1010000	3031760	RECORD CENTER MANAGEMENT SOFTWARE	SO	$291	$6	$80	$22	$42	$124	$16	$1	$0
1010000	3031780	OUTAGE REPORTING SYSTEM	SO	$3,498	$76	$958	$264	$502	$1,496	$193	$8	$0
1010000	3031830	CUSTOMER SERVICE SYSTEM (CSS)	CN	$113,205	$2,796	$34,330	$7,845	$8,441	$55,428	$4,366	$0	$0
1010000	3032040	S A P	SO	$172,227	$3,733	$47,163	$13,021	$24,739	$73,635	$9,520	$416	$0
1010000	3032090	ENERGY COMMODITY SYSTEM SOFTWARE	SO	$9,974	$216	$2,731	$754	$1,433	$4,264	$551	$24	$0
1010000	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	$1,660	$36	$455	$126	$238	$710	$92	$4	$0
1010000	3032260	DWHS - DATA WAREHOUSE	SO	$1,158	$25	$317	$88	$166	$495	$64	$3	$0
1010000	3032270	ENTERPRISE DATA WAREHOUSE	SO	$5,877	$127	$1,609	$444	$844	$2,513	$325	$14	$0
1010000	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	$2,908	$63	$796	$220	$418	$1,243	$161	$7	$0
1010000	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	$1,905	$41	$522	$144	$274	$814	$105	$5	$0
1010000	3032360	2002 GRID NET POWER COST MODELING	SO	$8,933	$194	$2,446	$675	$1,283	$3,819	$494	$22	$0
1010000	3032400	INCEDENT MANAGEMENT ANALYSIS PROGRAM	SO	$5,286	$115	$1,448	$400	$759	$2,260	$292	$13	$0
1010000	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	$12,508	$271	$3,425	$946	$1,797	$5,348	$691	$30	$0
1010000	3032480	OUTAGE CALL HANDLING INTEGRATION	CN	$1,981	$49	$601	$137	$148	$970	$76	$0	$0
1010000	3032510	OPERATIONS MAPPING SYSTEM	SO	$10,386	$225	$2,844	$785	$1,492	$4,441	$574	$25	$0
1010000	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	$1,892	$41	$518	$143	$272	$809	$105	$5	$0
1010000	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	$2,355	$51	$645	$178	$338	$1,007	$130	$6	$0
1010000	3032600	SINGLE PERSON SCHEDULING	SO	$9,035	$196	$2,474	$683	$1,298	$3,863	$499	$22	$0
1010000	3032640	TIBCO SOFTWARE	SO	$4,134	$90	$1,132	$313	$594	$1,768	$229	$10	$0
1010000	3032670	C&T OFFICIAL RECORD INFO SYSTEM	SO	$1,586	$34	$434	$120	$228	$678	$88	$4	$0
1010000	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	$1,581	$24	$412	$123	$248	$680	$90	$5	$0
1010000	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	$196	$3	$51	$15	$31	$84	$11	$1	$0
1010000	3032730	IMPROVEMENTS TO PLANT OWNED BY JAMES RIV	SG	$13,873	$212	$3,614	$1,077	$2,175	$5,963	$786	$47	$0
1010000	3032760	SWIFT 2 IMPROVEMENTS	SG	$23,200	$354	$6,044	$1,801	$3,637	$9,972	$1,314	$78	$0
1010000	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	$434	$7	$113	$34	$68	$187	$25	$1	$0
1010000	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	$117	$2	$31	$9	$18	$50	$7	$0	$0
1010000	3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE -	SO	$2,179	$47	$597	$165	$313	$931	$120	$5	$0
1010000	3032860	WEB SOFTWARE	SO	$2,680	$58	$734	$203	$385	$1,146	$148	$6	$0
1010000	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	$6,360	$97	$1,657	$494	$997	$2,734	$360	$21	$0
1010000	3032910	WYOMING VHF (VPC) SPECTRUM	WYP	$545	$0	$0	$0	$545	$0	$0	$0	$0
1010000	3032920	IDAHO VHF (VPC) SPECTRUM	IDU	$427	$0	$0	$0	$0	$0	$427	$0	$0
1010000	3032930	UTAH VHF (VPC) SPECTRUM	UT	$2,937	$0	$0	$0	$0	$2,937	$0	$0	$0
1010000	3032990	P8DM - FILENET P8	SO	$4,641	$101	$1,271	$351	$667	$1,984	$257	$11	$0
1010000	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	$49,778	$760	$12,969	$3,864	$7,803	$21,395	$2,820	$167	$0
1010000	3033120	RANGER EMS/SCADA SYSTEM	SG	$141	$2	$37	$11	$22	$61	$8	$0	$0
1010000	3033120	RANGER EMS/SCADA SYSTEM	SO	$37,422	$811	$10,248	$2,829	$5,375	$15,999	$2,068	$90	$0
1010000	3033120	RANGER EMS/SCADA SYSTEM	WYP	$463	$0	$0	$0	$463	$0	$0	$0	$0
1010000	3033140	ETAGM - Electronic Tagging Sys-Merchant	SO	$1,417	$31	$388	$107	$204	$606	$78	$3	$0
1010000	3033170	GTX VERSION 7 SOFTWARE	CN	$3,800	$94	$1,152	$263	$283	$1,860	$147	$0	$0
1010000	3033180	HPOV - HP Open Software	SO	$2,154	$47	$590	$163	$309	$921	$119	$5	$0
1010000	3033190	ITRON METER READING SOFTWARE	CN	$2,665	$66	$808	$185	$199	$1,305	$103	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Electric Plant in Service with Unclassified Plant (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	3033300	SECID - CUST SECURE WEB LOGIN	CN	$1,085	$27	$329	$75	$81	$531	$42	$0	$0
1010000	3033310	C&T - Energy Trading System	SO	$14,101	$306	$3,862	$1,066	$2,026	$6,029	$779	$34	$0
1010000	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	$4,694	$72	$1,223	$364	$736	$2,018	$266	$16	$0
1010000	3033330	OR VHF (VPC) SPECTRUM	OR	$3,456	$0	$3,456	$0	$0	$0	$0	$0	$0
1010000	3033340	WA VHF (VPC) SPECTRUM	WA	$1,465	$0	$0	$1,465	$0	$0	$0	$0	$0
1010000	3033350	CA VHF (VPC) SPECTRUM	CA	$354	$354	$0	$0	$0	$0	$0	$0	$0
1010000	3033360	DSM REPORTING & TRACKING SOFTWARE	SO	$1,224	$27	$335	$93	$176	$523	$68	$3	$0
1010000	3033370	DISTRIBUTION INTANGIBLES	WYP	$158	$0	$0	$0	$158	$0	$0	$0	$0
1010000	3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG	$1,601	$24	$417	$124	$251	$688	$91	$5	$0
1010000	3034900	MISC - MISCELLANEOUS	CN	$52	$1	$16	$4	$4	$25	$2	$0	$0
1010000	3034900	MISC - MISCELLANEOUS	IDU	$5	$0	$0	$0	$0	$0	$5	$0	$0
1010000	3034900	MISC - MISCELLANEOUS	OR	$8	$0	$8	$0	$0	$0	$0	$0	$0
1010000	3034900	MISC - MISCELLANEOUS	SE	$285	$4	$70	$21	$49	$121	$18	$1	$0
1010000	3034900	MISC - MISCELLANEOUS	SG	$1,395	$21	$363	$108	$219	$599	$79	$5	$0
1010000	3034900	MISC - MISCELLANEOUS	SO	$30,190	$654	$8,267	$2,282	$4,337	$12,907	$1,669	$73	$0
1010000	3034900	MISC - MISCELLANEOUS	UT	$67	$0	$0	$0	$0	$67	$0	$0	$0
1010000	3034900	MISC - MISCELLANEOUS	WYP	$342	$0	$0	$0	$342	$0	$0	$0	$0
1010000	3100000	LAND & LAND RIGHTS	SG	$1,306	$20	$340	$101	$205	$562	$74	$4	$0
1010000	3101000	LAND OWNED IN FEE	SG	$12,170	$186	$3,171	$945	$1,908	$5,231	$690	$41	$0
1010000	3102000	LAND RIGHTS	SG	$42,991	$657	$11,200	$3,337	$6,739	$18,478	$2,436	$144	$0
1010000	3103000	WATER RIGHTS	SG	$36,504	$558	$9,510	$2,833	$5,722	$15,690	$2,068	$122	$0
1010000	3108000	FEE LAND - LEASED	SG	$37	$1	$10	$3	$6	$16	$2	$0	$0
1010000	3110000	STRUCTURES AND IMPROVEMENTS	SG	$969,439	$14,808	$252,568	$75,249	$151,964	$416,676	$54,925	$3,250	$0
1010000	3120000	BOILER PLANT EQUIPMENT	SG	$4,157,483	$63,504	$1,083,149	$322,709	$651,703	$1,786,933	$235,547	$13,939	$0
1010000	3140000	TURBOGENERATOR UNITS	SG	$968,134	$14,788	$252,228	$75,148	$151,759	$416,115	$54,851	$3,246	$0
1010000	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	$453,267	$6,923	$118,090	$35,183	$71,051	$194,819	$25,680	$1,520	$0
1010000	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	$63	$1	$16	$5	$10	$27	$4	$0	$0
1010000	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	$33,557	$513	$8,743	$2,605	$5,260	$14,423	$1,901	$113	$0
1010000	3300000	LAND AND LAND RIGHTS	SG-U	$118	$2	$31	$9	$19	$51	$7	$0	$0
1010000	3301000	LAND OWNED IN FEE	SG-P	$16,986	$259	$4,425	$1,318	$2,663	$7,301	$962	$57	$0
1010000	3301000	LAND OWNED IN FEE	SG-U	$5,526	$84	$1,440	$429	$866	$2,375	$313	$19	$0
1010000	3302000	LAND RIGHTS	SG-P	$8,035	$123	$2,093	$624	$1,260	$3,454	$455	$27	$0
1010000	3302000	LAND RIGHTS	SG-U	$65	$1	$17	$5	$10	$28	$4	$0	$0
1010000	3303000	WATER RIGHTS	SG-U	$140	$2	$36	$11	$22	$60	$8	$0	$0
1010000	3304000	FLOOD RIGHTS	SG-P	$260	$4	$68	$20	$41	$112	$15	$1	$0
1010000	3304000	FLOOD RIGHTS	SG-U	$91	$1	$24	$7	$14	$39	$5	$0	$0
1010000	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	$310	$5	$81	$24	$49	$133	$18	$1	$0
1010000	3310000	STRUCTURES AND IMPROVE	SG-P	$7	$0	$2	$1	$1	$3	$0	$0	$0
1010000	3310000	STRUCTURES AND IMPROVE	SG-U	$7,395	$113	$1,927	$574	$1,159	$3,178	$419	$25	$0
1010000	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	$50,657	$774	$13,198	$3,932	$7,941	$21,773	$2,870	$170	$0
1010000	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	$4,130	$63	$1,076	$321	$647	$1,775	$234	$14	$0
1010000	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	$50,271	$768	$13,097	$3,902	$7,880	$21,607	$2,848	$169	$0
1010000	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	$364	$6	$95	$28	$57	$156	$21	$1	$0
1010000	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	$14,447	$221	$3,764	$1,121	$2,265	$6,210	$819	$48	$0
1010000	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	$1,998	$31	$521	$155	$313	$859	$113	$7	$0
1010000	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	$12,681	$194	$3,304	$984	$1,988	$5,450	$718	$43	$0
1010000	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-U	$185	$3	$48	$14	$29	$79	$10	$1	$0
1010000	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	$6,306	$96	$1,643	$489	$988	$2,710	$357	$21	$0
1010000	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	$23,174	$354	$6,038	$1,799	$3,633	$9,960	$1,313	$78	$0
1010000	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	$270,013	$4,124	$70,347	$20,959	$42,326	$116,055	$15,298	$905	$0
1010000	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	$48,980	$748	$12,761	$3,802	$7,678	$21,052	$2,775	$164	$0
1010000	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	$9,188	$140	$2,394	$713	$1,440	$3,949	$521	$31	$0

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1010000	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	$546	$8	$142	$42	$86	$235	$31	$2	$0
1010000	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	$217	$3	$57	$17	$34	$93	$12	$1	$0
1010000	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	$63	$1	$17	$5	$10	$27	$4	$0	$0
1010000	3326000	RESERVOIR, DAMS, WATERWAYS, LEASE HOLDS	SG-U	$529	$8	$138	$41	$83	$227	$30	$2	$0
1010000	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	$80,137	$1,224	$20,878	$6,220	$12,562	$34,444	$4,540	$269	$0
1010000	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	$38,848	$593	$10,121	$3,015	$6,090	$16,697	$2,201	$130	$0
1010000	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	$52,277	$799	$13,620	$4,058	$8,195	$22,469	$2,962	$175	$0
1010000	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	$10,940	$167	$2,850	$849	$1,715	$4,702	$620	$37	$0
1010000	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	$3,163	$48	$824	$246	$496	$1,360	$179	$11	$0
1010000	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	$46	$1	$12	$4	$7	$20	$3	$0	$0
1010000	3350000	MISC POWER PLANT EQUIP	SG-U	$170	$3	$44	$13	$27	$73	$10	$1	$0
1010000	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	$2,179	$33	$568	$169	$342	$937	$123	$7	$0
1010000	3353000	MISC POWER PLANT EQUIP - RECREATION	SG-P	$9	$0	$2	$1	$1	$4	$1	$0	$0
1010000	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	$15,312	$234	$3,989	$1,189	$2,400	$6,581	$868	$51	$0
1010000	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	$1,549	$24	$404	$120	$243	$666	$88	$5	$0
1010000	3401000	LAND OWNED IN FEE	SG	$11,474	$175	$2,989	$891	$1,799	$4,932	$650	$38	$0
1010000	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	$17,420	$266	$4,538	$1,352	$2,731	$7,487	$987	$58	$0
1010000	3410000	STRUCTURES & IMPROVEMENTS	SG	$163,984	$2,505	$42,723	$12,729	$25,705	$70,482	$9,291	$550	$0
1010000	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	$10,887	$166	$2,836	$845	$1,707	$4,679	$617	$36	$0
1010000	3430000	PRIME MOVERS	SG	$2,496,588	$38,134	$650,436	$193,788	$391,351	$1,073,062	$141,447	$8,370	$0
1010000	3440000	GENERATORS	SG	$352,167	$5,379	$91,750	$27,336	$55,204	$151,365	$19,952	$1,181	$0
1010000	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	$249,246	$3,807	$64,936	$19,347	$39,070	$107,129	$14,121	$836	$0
1010000	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	$12,487	$191	$3,253	$969	$1,957	$5,367	$707	$42	$0
1010000	3500000	LAND AND LAND RIGHTS	SG	$841	$13	$219	$65	$132	$362	$48	$3	$0
1010000	3501000	LAND OWNED IN FEE	SG	$49,672	$759	$12,941	$3,856	$7,786	$21,350	$2,814	$167	$0
1010000	3502000	LAND RIGHTS	SG	$144,271	$2,204	$37,587	$11,198	$22,615	$62,009	$8,174	$484	$0
1010000	3520000	STRUCTURES & IMPROVEMENTS	SG	$155,217	$2,371	$40,439	$12,048	$24,331	$66,714	$8,794	$520	$0
1010000	3530000	STATION EQUIPMENT	SG	$1,512,443	$23,102	$394,037	$117,398	$237,082	$650,065	$85,689	$5,071	$0
1010000	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	$131,750	$2,012	$34,325	$10,227	$20,652	$56,628	$7,464	$442	$0
1010000	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	$17,841	$273	$4,648	$1,385	$2,797	$7,668	$1,011	$60	$0
1010000	3540000	TOWERS AND FIXTURES	SG	$984,286	$15,034	$256,436	$76,401	$154,291	$423,057	$55,766	$3,300	$0
1010000	3550000	POLES AND FIXTURES	SG	$656,145	$10,022	$170,945	$50,931	$102,853	$282,018	$37,175	$2,200	$0
1010000	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	$902,945	$13,792	$235,244	$70,088	$141,540	$388,096	$51,157	$3,027	$0
1010000	3570000	UNDERGROUND CONDUIT	SG	$3,269	$50	$852	$254	$512	$1,405	$185	$11	$0
1010000	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	$7,477	$114	$1,948	$580	$1,172	$3,214	$424	$25	$0
1010000	3590000	ROADS AND TRAILS	SG	$11,587	$177	$3,019	$899	$1,816	$4,980	$656	$39	$0
1010000	3600000	LAND AND LAND RIGHTS	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1010000	3600000	LAND AND LAND RIGHTS	OR	$8	$0	$8	$0	$0	$0	$0	$0	$0
1010000	3600000	LAND AND LAND RIGHTS	UT	$168	$0	$0	$0	$0	$168	$0	$0	$0
1010000	3600000	LAND AND LAND RIGHTS	WA	$0	$0	$0	$0	$0	$0	$0	$0	$0
1010000	3600000	LAND AND LAND RIGHTS	WYP	$4	$0	$0	$0	$4	$0	$0	$0	$0
1010000	3600000	LAND AND LAND RIGHTS	WYU	$2	$0	$0	$0	$2	$0	$0	$0	$0
1010000	3601000	LAND OWNED IN FEE	CA	$1,412	$1,412	$0	$0	$0	$0	$0	$0	$0
1010000	3601000	LAND OWNED IN FEE	IDU	$297	$0	$0	$0	$0	$0	$297	$0	$0
1010000	3601000	LAND OWNED IN FEE	OR	$8,844	$0	$8,844	$0	$0	$0	$0	$0	$0
1010000	3601000	LAND OWNED IN FEE	UT	$25,002	$0	$0	$0	$0	$25,002	$0	$0	$0
1010000	3601000	LAND OWNED IN FEE	WA	$1,258	$0	$0	$1,258	$0	$0	$0	$0	$0
1010000	3601000	LAND OWNED IN FEE	WYP	$591	$0	$0	$0	$591	$0	$0	$0	$0
1010000	3601000	LAND OWNED IN FEE	WYU	$48	$0	$0	$0	$48	$0	$0	$0	$0
1010000	3602000	LAND RIGHTS	CA	$967	$967	$0	$0	$0	$0	$0	$0	$0
1010000	3602000	LAND RIGHTS	IDU	$1,085	$0	$0	$0	$0	$0	$1,085	$0	$0
1010000	3602000	LAND RIGHTS	OR	$4,312	$0	$4,312	$0	$0	$0	$0	$0	$0

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1010000	3602000	LAND RIGHTS	UT	$10,722	$0	$0	$0	$0	$10,722	$0	$0	$0
1010000	3602000	LAND RIGHTS	WA	$252	$0	$0	$252	$0	$0	$0	$0	$0
1010000	3602000	LAND RIGHTS	WYP	$1,969	$0	$0	$0	$1,969	$0	$0	$0	$0
1010000	3602000	LAND RIGHTS	WYU	$2,738	$0	$0	$0	$2,738	$0	$0	$0	$0
1010000	3610000	STRUCTURES & IMPROVEMENTS	CA	$4,170	$4,170	$0	$0	$0	$0	$0	$0	$0
1010000	3610000	STRUCTURES & IMPROVEMENTS	IDU	$2,171	$0	$0	$0	$0	$0	$2,171	$0	$0
1010000	3610000	STRUCTURES & IMPROVEMENTS	OR	$22,196	$0	$22,196	$0	$0	$0	$0	$0	$0
1010000	3610000	STRUCTURES & IMPROVEMENTS	UT	$44,691	$0	$0	$0	$0	$44,691	$0	$0	$0
1010000	3610000	STRUCTURES & IMPROVEMENTS	WA	$2,441	$0	$0	$2,441	$0	$0	$0	$0	$0
1010000	3610000	STRUCTURES & IMPROVEMENTS	WYP	$9,856	$0	$0	$0	$9,856	$0	$0	$0	$0
1010000	3610000	STRUCTURES & IMPROVEMENTS	WYU	$192	$0	$0	$0	$192	$0	$0	$0	$0
1010000	3620000	STATION EQUIPMENT	CA	$21,824	$21,824	$0	$0	$0	$0	$0	$0	$0
1010000	3620000	STATION EQUIPMENT	IDU	$28,634	$0	$0	$0	$0	$0	$28,634	$0	$0
1010000	3620000	STATION EQUIPMENT	OR	$209,545	$0	$209,545	$0	$0	$0	$0	$0	$0
1010000	3620000	STATION EQUIPMENT	UT	$429,348	$0	$0	$0	$0	$429,348	$0	$0	$0
1010000	3620000	STATION EQUIPMENT	WA	$46,673	$0	$0	$46,673	$0	$0	$0	$0	$0
1010000	3620000	STATION EQUIPMENT	WYP	$109,629	$0	$0	$0	$109,629	$0	$0	$0	$0
1010000	3620000	STATION EQUIPMENT	WYU	$11,807	$0	$0	$0	$11,807	$0	$0	$0	$0
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	$217	$217	$0	$0	$0	$0	$0	$0	$0
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	$389	$0	$0	$0	$0	$0	$389	$0	$0
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	$3,394	$0	$3,394	$0	$0	$0	$0	$0	$0
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	$5,599	$0	$0	$0	$0	$5,599	$0	$0	$0
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	$919	$0	$0	$919	$0	$0	$0	$0	$0
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	$1,951	$0	$0	$0	$1,951	$0	$0	$0	$0
1010000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	$61	$0	$0	$0	$61	$0	$0	$0	$0
1010000	3640000	"POLES, TOWERS AND FIXTURES"	CA	$56,466	$56,466	$0	$0	$0	$0	$0	$0	$0
1010000	3640000	"POLES, TOWERS AND FIXTURES"	IDU	$70,819	$0	$0	$0	$0	$0	$70,819	$0	$0
1010000	3640000	"POLES, TOWERS AND FIXTURES"	OR	$332,415	$0	$332,415	$0	$0	$0	$0	$0	$0
1010000	3640000	"POLES, TOWERS AND FIXTURES"	UT	$324,187	$0	$0	$0	$0	$324,187	$0	$0	$0
1010000	3640000	"POLES, TOWERS AND FIXTURES"	WA	$92,644	$0	$0	$92,644	$0	$0	$0	$0	$0
1010000	3640000	"POLES, TOWERS AND FIXTURES"	WYP	$102,417	$0	$0	$0	$102,417	$0	$0	$0	$0
1010000	3640000	"POLES, TOWERS AND FIXTURES"	WYU	$21,184	$0	$0	$0	$21,184	$0	$0	$0	$0
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	$32,835	$32,835	$0	$0	$0	$0	$0	$0	$0
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	$34,797	$0	$0	$0	$0	$0	$34,797	$0	$0
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	$237,217	$0	$237,217	$0	$0	$0	$0	$0	$0
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	$212,921	$0	$0	$0	$0	$212,921	$0	$0	$0
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	$58,634	$0	$0	$58,634	$0	$0	$0	$0	$0
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	$84,511	$0	$0	$0	$84,511	$0	$0	$0	$0
1010000	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	$11,574	$0	$0	$0	$11,574	$0	$0	$0	$0
1010000	3660000	UNDERGROUND CONDUIT	CA	$15,989	$15,989	$0	$0	$0	$0	$0	$0	$0
1010000	3660000	UNDERGROUND CONDUIT	IDU	$7,946	$0	$0	$0	$0	$0	$7,946	$0	$0
1010000	3660000	UNDERGROUND CONDUIT	OR	$85,676	$0	$85,676	$0	$0	$0	$0	$0	$0
1010000	3660000	UNDERGROUND CONDUIT	UT	$171,847	$0	$0	$0	$0	$171,847	$0	$0	$0
1010000	3660000	UNDERGROUND CONDUIT	WA	$16,365	$0	$0	$16,365	$0	$0	$0	$0	$0
1010000	3660000	UNDERGROUND CONDUIT	WYP	$15,218	$0	$0	$0	$15,218	$0	$0	$0	$0
1010000	3660000	UNDERGROUND CONDUIT	WYU	$3,987	$0	$0	$0	$3,987	$0	$0	$0	$0
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	$17,151	$17,151	$0	$0	$0	$0	$0	$0	$0
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	$24,717	$0	$0	$0	$0	$0	$24,717	$0	$0
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	$159,274	$0	$159,274	$0	$0	$0	$0	$0	$0
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	$472,354	$0	$0	$0	$0	$472,354	$0	$0	$0
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	$22,765	$0	$0	$22,765	$0	$0	$0	$0	$0
1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	$33,243	$0	$0	$0	$33,243	$0	$0	$0	$0

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1010000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	$16,640	$0	$0	$0	$16,640	$0	$0	$0	$0
1010000	3680000	LINE TRANSFORMERS	CA	$48,525	$48,525	$0	$0	$0	$0	$0	$0	$0
1010000	3680000	LINE TRANSFORMERS	IDU	$70,426	$0	$0	$0	$0	$0	$70,426	$0	$0
1010000	3680000	LINE TRANSFORMERS	OR	$396,579	$0	$396,579	$0	$0	$0	$0	$0	$0
1010000	3680000	LINE TRANSFORMERS	UT	$432,366	$0	$0	$0	$0	$432,366	$0	$0	$0
1010000	3680000	LINE TRANSFORMERS	WA	$98,871	$0	$0	$98,871	$0	$0	$0	$0	$0
1010000	3680000	LINE TRANSFORMERS	WYP	$85,152	$0	$0	$0	$85,152	$0	$0	$0	$0
1010000	3680000	LINE TRANSFORMERS	WYU	$13,153	$0	$0	$0	$13,153	$0	$0	$0	$0
1010000	3691000	SERVICES - OVERHEAD	CA	$8,675	$8,675	$0	$0	$0	$0	$0	$0	$0
1010000	3691000	SERVICES - OVERHEAD	IDU	$7,068	$0	$0	$0	$0	$0	$7,068	$0	$0
1010000	3691000	SERVICES - OVERHEAD	OR	$76,003	$0	$76,003	$0	$0	$0	$0	$0	$0
1010000	3691000	SERVICES - OVERHEAD	UT	$72,615	$0	$0	$0	$0	$72,615	$0	$0	$0
1010000	3691000	SERVICES - OVERHEAD	WA	$19,119	$0	$0	$19,119	$0	$0	$0	$0	$0
1010000	3691000	SERVICES - OVERHEAD	WYP	$14,272	$0	$0	$0	$14,272	$0	$0	$0	$0
1010000	3691000	SERVICES - OVERHEAD	WYU	$2,234	$0	$0	$0	$2,234	$0	$0	$0	$0
1010000	3692000	SERVICES - UNDERGROUND	CA	$14,679	$14,679	$0	$0	$0	$0	$0	$0	$0
1010000	3692000	SERVICES - UNDERGROUND	IDU	$23,962	$0	$0	$0	$0	$0	$23,962	$0	$0
1010000	3692000	SERVICES - UNDERGROUND	OR	$152,909	$0	$152,909	$0	$0	$0	$0	$0	$0
1010000	3692000	SERVICES - UNDERGROUND	UT	$157,548	$0	$0	$0	$0	$157,548	$0	$0	$0
1010000	3692000	SERVICES - UNDERGROUND	WA	$33,116	$0	$0	$33,116	$0	$0	$0	$0	$0
1010000	3692000	SERVICES - UNDERGROUND	WYP	$26,053	$0	$0	$0	$26,053	$0	$0	$0	$0
1010000	3692000	SERVICES - UNDERGROUND	WYU	$8,288	$0	$0	$0	$8,288	$0	$0	$0	$0
1010000	3700000	METERS	CA	$3,945	$3,945	$0	$0	$0	$0	$0	$0	$0
1010000	3700000	METERS	IDU	$13,485	$0	$0	$0	$0	$0	$13,485	$0	$0
1010000	3700000	METERS	OR	$59,644	$0	$59,644	$0	$0	$0	$0	$0	$0
1010000	3700000	METERS	UT	$73,545	$0	$0	$0	$0	$73,545	$0	$0	$0
1010000	3700000	METERS	WA	$11,452	$0	$0	$11,452	$0	$0	$0	$0	$0
1010000	3700000	METERS	WYP	$11,907	$0	$0	$0	$11,907	$0	$0	$0	$0
1010000	3700000	METERS	WYU	$2,205	$0	$0	$0	$2,205	$0	$0	$0	$0
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	CA	$271	$271	$0	$0	$0	$0	$0	$0	$0
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	$169	$0	$0	$0	$0	$0	$169	$0	$0
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	OR	$2,506	$0	$2,506	$0	$0	$0	$0	$0	$0
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	UT	$4,419	$0	$0	$0	$0	$4,419	$0	$0	$0
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	WA	$518	$0	$0	$518	$0	$0	$0	$0	$0
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	$787	$0	$0	$0	$787	$0	$0	$0	$0
1010000	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	$152	$0	$0	$0	$152	$0	$0	$0	$0
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	$671	$671	$0	$0	$0	$0	$0	$0	$0
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	$617	$0	$0	$0	$0	$0	$617	$0	$0
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	$22,303	$0	$22,303	$0	$0	$0	$0	$0	$0
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	$23,914	$0	$0	$0	$0	$23,914	$0	$0	$0
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	$4,037	$0	$0	$4,037	$0	$0	$0	$0	$0
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	$7,757	$0	$0	$0	$7,757	$0	$0	$0	$0
1010000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	$2,233	$0	$0	$0	$2,233	$0	$0	$0	$0
1010000	3890000	LAND AND LAND RIGHTS	IDU	$93	$0	$0	$0	$0	$0	$93	$0	$0
1010000	3890000	LAND AND LAND RIGHTS	OR	$228	$0	$228	$0	$0	$0	$0	$0	$0
1010000	3890000	LAND AND LAND RIGHTS	UT	$1,441	$0	$0	$0	$0	$1,441	$0	$0	$0
1010000	3890000	LAND AND LAND RIGHTS	WYU	$434	$0	$0	$0	$434	$0	$0	$0	$0
1010000	3891000	LAND OWNED IN FEE	CA	$636	$636	$0	$0	$0	$0	$0	$0	$0
1010000	3891000	LAND OWNED IN FEE	CN	$1,129	$28	$342	$78	$84	$553	$44	$0	$0
1010000	3891000	LAND OWNED IN FEE	IDU	$100	$0	$0	$0	$0	$0	$100	$0	$0
1010000	3891000	LAND OWNED IN FEE	OR	$4,373	$0	$4,373	$0	$0	$0	$0	$0	$0
1010000	3891000	LAND OWNED IN FEE	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0

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1010000	3891000	LAND OWNED IN FEE	SO	$5,597	$121	$1,533	$423	$804	$2,393	$309	$14	$0
1010000	3891000	LAND OWNED IN FEE	UT	$2,543	$0	$0	$0	$0	$2,543	$0	$0	$0
1010000	3891000	LAND OWNED IN FEE	WA	$1,099	$0	$0	$1,099	$0	$0	$0	$0	$0
1010000	3891000	LAND OWNED IN FEE	WYP	$1,417	$0	$0	$0	$1,417	$0	$0	$0	$0
1010000	3891000	LAND OWNED IN FEE	WYU	$221	$0	$0	$0	$221	$0	$0	$0	$0
1010000	3892000	LAND RIGHTS	IDU	$5	$0	$0	$0	$0	$0	$5	$0	$0
1010000	3892000	LAND RIGHTS	SG	$1	$0	$0	$0	$0	$1	$0	$0	$0
1010000	3892000	LAND RIGHTS	UT	$84	$0	$0	$0	$0	$84	$0	$0	$0
1010000	3892000	LAND RIGHTS	WYP	$52	$0	$0	$0	$52	$0	$0	$0	$0
1010000	3892000	LAND RIGHTS	WYU	$22	$0	$0	$0	$22	$0	$0	$0	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	CA	$1,821	$1,821	$0	$0	$0	$0	$0	$0	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	CN	$7,979	$197	$2,420	$553	$595	$3,907	$308	$0	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	IDU	$10,204	$0	$0	$0	$0	$0	$10,204	$0	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	OR	$28,420	$0	$28,420	$0	$0	$0	$0	$0	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	SG	$7,264	$111	$1,892	$564	$1,139	$3,122	$412	$24	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	SO	$76,432	$1,657	$20,930	$5,779	$10,979	$32,678	$4,225	$185	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	UT	$40,113	$0	$0	$0	$0	$40,113	$0	$0	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	WA	$10,994	$0	$0	$10,994	$0	$0	$0	$0	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	WYP	$5,947	$0	$0	$0	$5,947	$0	$0	$0	$0
1010000	3900000	STRUCTURES AND IMPROVEMENTS	WYU	$3,222	$0	$0	$0	$3,222	$0	$0	$0	$0
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	$352	$352	$0	$0	$0	$0	$0	$0	$0
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CN	$3,401	$84	$1,031	$236	$254	$1,665	$131	$0	$0
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	$4,784	$0	$4,784	$0	$0	$0	$0	$0	$0
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	$16,196	$351	$4,435	$1,224	$2,326	$6,924	$895	$39	$0
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	$23	$0	$0	$0	$0	$23	$0	$0	$0
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	$2,896	$0	$0	$2,896	$0	$0	$0	$0	$0
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	$4,703	$0	$0	$0	$4,703	$0	$0	$0	$0
1010000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYU	$56	$0	$0	$0	$56	$0	$0	$0	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CA	$84	$84	$0	$0	$0	$0	$0	$0	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CN	$938	$23	$284	$65	$70	$459	$36	$0	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	IDU	$13	$0	$0	$0	$0	$0	$13	$0	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	OR	$530	$0	$530	$0	$0	$0	$0	$0	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SG	$79	$1	$21	$6	$12	$34	$4	$0	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SO	$10,482	$227	$2,870	$792	$1,506	$4,481	$579	$25	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	UT	$188	$0	$0	$0	$0	$188	$0	$0	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WA	$23	$0	$0	$23	$0	$0	$0	$0	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYP	$316	$0	$0	$0	$316	$0	$0	$0	$0
1010000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYU	$7	$0	$0	$0	$7	$0	$0	$0	$0
1010000	3910000	OFFICE FURNITURE	CA	$74	$74	$0	$0	$0	$0	$0	$0	$0
1010000	3910000	OFFICE FURNITURE	CN	$2,002	$49	$607	$139	$149	$980	$77	$0	$0
1010000	3910000	OFFICE FURNITURE	IDU	$88	$0	$0	$0	$0	$0	$88	$0	$0
1010000	3910000	OFFICE FURNITURE	OR	$1,653	$0	$1,653	$0	$0	$0	$0	$0	$0
1010000	3910000	OFFICE FURNITURE	SG	$2,715	$41	$707	$211	$426	$1,167	$154	$9	$0
1010000	3910000	OFFICE FURNITURE	SO	$11,464	$249	$3,139	$867	$1,647	$4,901	$634	$28	$0
1010000	3910000	OFFICE FURNITURE	UT	$536	$0	$0	$0	$0	$536	$0	$0	$0
1010000	3910000	OFFICE FURNITURE	WA	$539	$0	$0	$539	$0	$0	$0	$0	$0
1010000	3910000	OFFICE FURNITURE	WYP	$451	$0	$0	$0	$451	$0	$0	$0	$0
1010000	3910000	OFFICE FURNITURE	WYU	$31	$0	$0	$0	$31	$0	$0	$0	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	$169	$169	$0	$0	$0	$0	$0	$0	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	$6,629	$164	$2,010	$459	$494	$3,246	$256	$0	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	$633	$0	$0	$0	$0	$0	$633	$0	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	$1,545	$0	$1,545	$0	$0	$0	$0	$0	$0

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1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	$34	$1	$8	$2	$6	$14	$2	$0	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	$1,509	$23	$393	$117	$236	$648	$85	$5	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	$43,534	$944	$11,922	$3,291	$6,253	$18,613	$2,406	$105	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	$2,084	$0	$0	$0	$0	$2,084	$0	$0	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	$823	$0	$0	$823	$0	$0	$0	$0	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	$2,460	$0	$0	$0	$2,460	$0	$0	$0	$0
1010000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	$95	$0	$0	$0	$95	$0	$0	$0	$0
1010000	3913000	OFFICE EQUIPMENT	CN	$6	$0	$2	$0	$0	$3	$0	$0	$0
1010000	3913000	OFFICE EQUIPMENT	OR	$19	$0	$19	$0	$0	$0	$0	$0	$0
1010000	3913000	OFFICE EQUIPMENT	SG	$439	$7	$114	$34	$69	$188	$25	$1	$0
1010000	3913000	OFFICE EQUIPMENT	SO	$300	$7	$82	$23	$43	$128	$17	$1	$0
1010000	3913000	OFFICE EQUIPMENT	UT	$25	$0	$0	$0	$0	$25	$0	$0	$0
1010000	3913000	OFFICE EQUIPMENT	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	$95	$95	$0	$0	$0	$0	$0	$0	$0
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	$399	$0	$0	$0	$0	$0	$399	$0	$0
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	$2,275	$0	$2,275	$0	$0	$0	$0	$0	$0
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	$452	$7	$118	$35	$71	$194	$26	$2	$0
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	$1,179	$26	$323	$89	$169	$504	$65	$3	$0
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	$2,488	$0	$0	$0	$0	$2,488	$0	$0	$0
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	$365	$0	$0	$365	$0	$0	$0	$0	$0
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	$512	$0	$0	$0	$512	$0	$0	$0	$0
1010000	3920100	1/4 TON MINI-PICKUPS AND VANS	WYU	$47	$0	$0	$0	$47	$0	$0	$0	$0
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	IDU	$14	$0	$0	$0	$0	$0	$14	$0	$0
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	OR	$335	$0	$335	$0	$0	$0	$0	$0	$0
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	SG	$54	$1	$14	$4	$8	$23	$3	$0	$0
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	SO	$234	$5	$64	$18	$34	$100	$13	$1	$0
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	UT	$368	$0	$0	$0	$0	$368	$0	$0	$0
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	WA	$43	$0	$0	$43	$0	$0	$0	$0	$0
1010000	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	$78	$0	$0	$0	$78	$0	$0	$0	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	$635	$635	$0	$0	$0	$0	$0	$0	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	$1,398	$0	$0	$0	$0	$0	$1,398	$0	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	$7,180	$0	$7,180	$0	$0	$0	$0	$0	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	$191	$3	$47	$14	$33	$81	$12	$1	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	$6,591	$101	$1,717	$512	$1,033	$2,833	$373	$22	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	$1,313	$28	$359	$99	$189	$561	$73	$3	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	$7,557	$0	$0	$0	$0	$7,557	$0	$0	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	$1,155	$0	$0	$1,155	$0	$0	$0	$0	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	$1,763	$0	$0	$0	$1,763	$0	$0	$0	$0
1010000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	$454	$0	$0	$0	$454	$0	$0	$0	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	$954	$954	$0	$0	$0	$0	$0	$0	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	$2,524	$0	$0	$0	$0	$0	$2,524	$0	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	$10,182	$0	$10,182	$0	$0	$0	$0	$0	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	$206	$3	$51	$15	$36	$87	$13	$1	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	$5,691	$87	$1,483	$442	$892	$2,446	$322	$19	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	$576	$12	$158	$44	$83	$246	$32	$1	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	$15,363	$0	$0	$0	$0	$15,363	$0	$0	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	$2,664	$0	$0	$2,664	$0	$0	$0	$0	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	$3,221	$0	$0	$0	$3,221	$0	$0	$0	$0
1010000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	$802	$0	$0	$0	$802	$0	$0	$0	$0
1010000	3920600	DUMP TRUCKS	OR	$76	$0	$76	$0	$0	$0	$0	$0	$0
1010000	3920600	DUMP TRUCKS	SE	$4	$0	$1	$0	$1	$1	$0	$0	$0
1010000	3920600	DUMP TRUCKS	SG	$3,504	$54	$913	$272	$549	$1,506	$199	$12	$0

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1010000	3920600	DUMP TRUCKS	SO	$55	$1	$15	$4	$8	$24	$3	$0	$0
1010000	3920600	DUMP TRUCKS	UT	$125	$0	$0	$0	$0	$125	$0	$0	$0
1010000	3920900	TRAILERS	CA	$496	$496	$0	$0	$0	$0	$0	$0	$0
1010000	3920900	TRAILERS	IDU	$927	$0	$0	$0	$0	$0	$927	$0	$0
1010000	3920900	TRAILERS	OR	$3,313	$0	$3,313	$0	$0	$0	$0	$0	$0
1010000	3920900	TRAILERS	SE	$49	$1	$12	$4	$8	$21	$3	$0	$0
1010000	3920900	TRAILERS	SG	$2,204	$34	$574	$171	$345	$947	$125	$7	$0
1010000	3920900	TRAILERS	SO	$545	$12	$149	$41	$78	$233	$30	$1	$0
1010000	3920900	TRAILERS	UT	$5,235	$0	$0	$0	$0	$5,235	$0	$0	$0
1010000	3920900	TRAILERS	WA	$714	$0	$0	$714	$0	$0	$0	$0	$0
1010000	3920900	TRAILERS	WYP	$2,071	$0	$0	$0	$2,071	$0	$0	$0	$0
1010000	3920900	TRAILERS	WYU	$330	$0	$0	$0	$330	$0	$0	$0	$0
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	$66	$66	$0	$0	$0	$0	$0	$0	$0
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	$70	$0	$0	$0	$0	$0	$70	$0	$0
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	$315	$0	$315	$0	$0	$0	$0	$0	$0
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	$234	$4	$61	$18	$37	$101	$13	$1	$0
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	$20	$0	$5	$1	$3	$8	$1	$0	$0
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	$188	$0	$0	$0	$0	$188	$0	$0	$0
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	$47	$0	$0	$47	$0	$0	$0	$0	$0
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	$103	$0	$0	$0	$103	$0	$0	$0	$0
1010000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	$16	$0	$0	$0	$16	$0	$0	$0	$0
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	$170	$0	$170	$0	$0	$0	$0	$0	$0
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	$373	$6	$97	$29	$59	$160	$21	$1	$0
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	$381	$8	$104	$29	$55	$163	$21	$1	$0
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	$860	$0	$0	$0	$0	$860	$0	$0	$0
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	$170	$0	$0	$170	$0	$0	$0	$0	$0
1010000	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	$86	$0	$0	$0	$86	$0	$0	$0	$0
1010000	3923000	TRANSPORTATION EQUIPMENT	SO	$3,076	$67	$842	$233	$442	$1,315	$170	$7	$0
1010000	3930000	STORES EQUIPMENT	CA	$199	$199	$0	$0	$0	$0	$0	$0	$0
1010000	3930000	STORES EQUIPMENT	IDU	$426	$0	$0	$0	$0	$0	$426	$0	$0
1010000	3930000	STORES EQUIPMENT	OR	$2,816	$0	$2,816	$0	$0	$0	$0	$0	$0
1010000	3930000	STORES EQUIPMENT	SG	$5,156	$79	$1,343	$400	$808	$2,216	$292	$17	$0
1010000	3930000	STORES EQUIPMENT	SO	$319	$7	$87	$24	$46	$136	$18	$1	$0
1010000	3930000	STORES EQUIPMENT	UT	$3,412	$0	$0	$0	$0	$3,412	$0	$0	$0
1010000	3930000	STORES EQUIPMENT	WA	$598	$0	$0	$598	$0	$0	$0	$0	$0
1010000	3930000	STORES EQUIPMENT	WYP	$1,056	$0	$0	$0	$1,056	$0	$0	$0	$0
1010000	3930000	STORES EQUIPMENT	WYU	$45	$0	$0	$0	$45	$0	$0	$0	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	$753	$753	$0	$0	$0	$0	$0	$0	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	$1,887	$0	$0	$0	$0	$0	$1,887	$0	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	$10,862	$0	$10,862	$0	$0	$0	$0	$0	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	$6	$0	$1	$0	$1	$2	$0	$0	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	$25,178	$385	$6,560	$1,954	$3,947	$10,822	$1,426	$84	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	$3,775	$82	$1,034	$285	$542	$1,614	$209	$9	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	$12,832	$0	$0	$0	$0	$12,832	$0	$0	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	$2,904	$0	$0	$2,904	$0	$0	$0	$0	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	$3,848	$0	$0	$0	$3,848	$0	$0	$0	$0
1010000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	$505	$0	$0	$0	$505	$0	$0	$0	$0
1010000	3950000	LABORATORY EQUIPMENT	CA	$484	$484	$0	$0	$0	$0	$0	$0	$0
1010000	3950000	LABORATORY EQUIPMENT	IDU	$1,388	$0	$0	$0	$0	$0	$1,388	$0	$0
1010000	3950000	LABORATORY EQUIPMENT	OR	$9,673	$0	$9,673	$0	$0	$0	$0	$0	$0
1010000	3950000	LABORATORY EQUIPMENT	SE	$8	$0	$2	$1	$1	$3	$0	$0	$0
1010000	3950000	LABORATORY EQUIPMENT	SG	$6,721	$103	$1,751	$522	$1,054	$2,889	$381	$23	$0

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1010000	3950000	LABORATORY EQUIPMENT	SO	$5,281	$114	$1,446	$399	$759	$2,258	$292	$13	$0
1010000	3950000	LABORATORY EQUIPMENT	UT	$7,661	$0	$0	$0	$0	$7,661	$0	$0	$0
1010000	3950000	LABORATORY EQUIPMENT	WA	$1,919	$0	$0	$1,919	$0	$0	$0	$0	$0
1010000	3950000	LABORATORY EQUIPMENT	WYP	$2,764	$0	$0	$0	$2,764	$0	$0	$0	$0
1010000	3950000	LABORATORY EQUIPMENT	WYU	$614	$0	$0	$0	$614	$0	$0	$0	$0
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	CA	$1,197	$1,197	$0	$0	$0	$0	$0	$0	$0
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	IDU	$1,914	$0	$0	$0	$0	$0	$1,914	$0	$0
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	OR	$7,884	$0	$7,884	$0	$0	$0	$0	$0	$0
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SG	$384	$6	$100	$30	$60	$165	$22	$1	$0
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SO	$169	$4	$46	$13	$24	$72	$9	$0	$0
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	UT	$6,149	$0	$0	$0	$0	$6,149	$0	$0	$0
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WA	$1,768	$0	$0	$1,768	$0	$0	$0	$0	$0
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYP	$3,005	$0	$0	$0	$3,005	$0	$0	$0	$0
1010000	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYU	$489	$0	$0	$0	$489	$0	$0	$0	$0
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	$173	$173	$0	$0	$0	$0	$0	$0	$0
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	$171	$0	$0	$0	$0	$0	$171	$0	$0
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	$833	$0	$833	$0	$0	$0	$0	$0	$0
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	$124	$2	$32	$10	$19	$53	$7	$0	$0
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	$1,740	$0	$0	$0	$0	$1,740	$0	$0	$0
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	$205	$0	$0	$0	$205	$0	$0	$0	$0
1010000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	$210	$0	$0	$0	$210	$0	$0	$0	$0
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	$1,576	$1,576	$0	$0	$0	$0	$0	$0	$0
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	$2,930	$0	$0	$0	$0	$0	$2,930	$0	$0
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	$13,034	$0	$13,034	$0	$0	$0	$0	$0	$0
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	$1,244	$19	$324	$97	$195	$535	$71	$4	$0
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	$377	$8	$103	$28	$54	$161	$21	$1	$0
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	$16,616	$0	$0	$0	$0	$16,616	$0	$0	$0
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	$3,440	$0	$0	$3,440	$0	$0	$0	$0	$0
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	$4,283	$0	$0	$0	$4,283	$0	$0	$0	$0
1010000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	$1,099	$0	$0	$0	$1,099	$0	$0	$0	$0
1010000	3961000	CRANES	OR	$413	$0	$413	$0	$0	$0	$0	$0	$0
1010000	3961000	CRANES	SG	$3,650	$56	$951	$283	$572	$1,569	$207	$12	$0
1010000	3961000	CRANES	SO	$43	$1	$12	$3	$6	$19	$2	$0	$0
1010000	3961000	CRANES	UT	$3	$0	$0	$0	$0	$3	$0	$0	$0
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	$928	$0	$928	$0	$0	$0	$0	$0	$0
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SE	$35	$1	$9	$3	$6	$15	$2	$0	$0
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	$26,764	$409	$6,973	$2,077	$4,195	$11,504	$1,516	$90	$0
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	$895	$19	$245	$68	$129	$383	$49	$2	$0
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	$1,824	$0	$0	$0	$0	$1,824	$0	$0	$0
1010000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	$164	$0	$0	$0	$164	$0	$0	$0	$0
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	$932	$932	$0	$0	$0	$0	$0	$0	$0
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	$1,957	$0	$0	$0	$0	$0	$1,957	$0	$0
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	$9,520	$0	$9,520	$0	$0	$0	$0	$0	$0
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	$154	$2	$40	$12	$24	$66	$9	$1	$0
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	$287	$6	$79	$22	$41	$123	$16	$1	$0
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	$13,855	$0	$0	$0	$0	$13,855	$0	$0	$0
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	$1,908	$0	$0	$1,908	$0	$0	$0	$0	$0
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	$3,736	$0	$0	$0	$3,736	$0	$0	$0	$0
1010000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	$824	$0	$0	$0	$824	$0	$0	$0	$0
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	$486	$486	$0	$0	$0	$0	$0	$0	$0
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	$1,062	$0	$0	$0	$0	$0	$1,062	$0	$0
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	$1,719	$0	$1,719	$0	$0	$0	$0	$0	$0

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1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	$10	$0	$2	$1	$2	$4	$1	$0	$0
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	$5,287	$81	$1,378	$410	$829	$2,273	$300	$18	$0
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	$149	$3	$41	$11	$21	$63	$8	$0	$0
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	$4,030	$0	$0	$0	$0	$4,030	$0	$0	$0
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	$977	$0	$0	$977	$0	$0	$0	$0	$0
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	$1,069	$0	$0	$0	$1,069	$0	$0	$0	$0
1010000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	$648	$0	$0	$0	$648	$0	$0	$0	$0
1010000	3970000	COMMUNICATION EQUIPMENT	CA	$3,316	$3,316	$0	$0	$0	$0	$0	$0	$0
1010000	3970000	COMMUNICATION EQUIPMENT	CN	$2,855	$71	$866	$198	$213	$1,398	$110	$0	$0
1010000	3970000	COMMUNICATION EQUIPMENT	IDU	$6,720	$0	$0	$0	$0	$0	$6,720	$0	$0
1010000	3970000	COMMUNICATION EQUIPMENT	OR	$44,183	$0	$44,183	$0	$0	$0	$0	$0	$0
1010000	3970000	COMMUNICATION EQUIPMENT	SE	$163	$2	$40	$12	$28	$69	$10	$1	$0
1010000	3970000	COMMUNICATION EQUIPMENT	SG	$112,918	$1,725	$29,419	$8,765	$17,700	$48,533	$6,398	$379	$0
1010000	3970000	COMMUNICATION EQUIPMENT	SO	$57,844	$1,254	$15,840	$4,373	$8,309	$24,731	$3,197	$140	$0
1010000	3970000	COMMUNICATION EQUIPMENT	UT	$37,022	$0	$0	$0	$0	$37,022	$0	$0	$0
1010000	3970000	COMMUNICATION EQUIPMENT	WA	$11,484	$0	$0	$11,484	$0	$0	$0	$0	$0
1010000	3970000	COMMUNICATION EQUIPMENT	WYP	$20,798	$0	$0	$0	$20,798	$0	$0	$0	$0
1010000	3970000	COMMUNICATION EQUIPMENT	WYU	$3,858	$0	$0	$0	$3,858	$0	$0	$0	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	CA	$29	$29	$0	$0	$0	$0	$0	$0	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	IDU	$279	$0	$0	$0	$0	$0	$279	$0	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	OR	$897	$0	$897	$0	$0	$0	$0	$0	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	SE	$70	$1	$17	$5	$12	$30	$4	$0	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	SG	$1,199	$18	$312	$93	$188	$515	$68	$4	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	SO	$415	$9	$114	$31	$60	$177	$23	$1	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	UT	$2,387	$0	$0	$0	$0	$2,387	$0	$0	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	WA	$398	$0	$0	$398	$0	$0	$0	$0	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	WYP	$450	$0	$0	$0	$450	$0	$0	$0	$0
1010000	3972000	MOBILE RADIO EQUIPMENT	WYU	$158	$0	$0	$0	$158	$0	$0	$0	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	CA	$51	$51	$0	$0	$0	$0	$0	$0	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	CN	$216	$5	$65	$15	$16	$106	$8	$0	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	IDU	$64	$0	$0	$0	$0	$0	$64	$0	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	OR	$1,083	$0	$1,083	$0	$0	$0	$0	$0	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	SE	$2	$0	$0	$0	$0	$1	$0	$0	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	SG	$2,070	$32	$539	$161	$324	$890	$117	$7	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	SO	$2,961	$64	$811	$224	$425	$1,266	$164	$7	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	UT	$528	$0	$0	$0	$0	$528	$0	$0	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	WA	$204	$0	$0	$204	$0	$0	$0	$0	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	WYP	$181	$0	$0	$0	$181	$0	$0	$0	$0
1010000	3980000	MISCELLANEOUS EQUIPMENT	WYU	$10	$0	$0	$0	$10	$0	$0	$0	$0
1010000	3992100	LAND OWNED IN FEE	SE	$2,635	$40	$650	$193	$457	$1,118	$167	$10	$0
1010000	3992200	LAND RIGHTS	SE	$52,551	$789	$12,973	$3,856	$9,116	$22,302	$3,325	$190	$0
1010000	3993000	"ENGINEERING SUPP-OFF WORK(SECY,MAP,DRAF	SE	$40,289	$605	$9,946	$2,956	$6,989	$17,099	$2,549	$146	$0
1010000	3994100	SURFACE - PLANT EQUIPMENT	SE	$12,685	$190	$3,131	$931	$2,200	$5,383	$803	$46	$0
1010000	3994400	SURFACE - ELECTRIC POWER FACILITIES	SE	$3,425	$51	$845	$251	$594	$1,453	$217	$12	$0
1010000	3994500	UNDERGROUND - COAL MINE EQUIPMENT	SE	$72,946	$1,095	$18,008	$5,352	$12,654	$30,958	$4,615	$264	$0
1010000	3994600	LONGWALL SHIELDS	SE	$24,487	$368	$6,045	$1,797	$4,248	$10,392	$1,549	$89	$0
1010000	3994700	LONGWALL EQUIPMENT	SE	$9,116	$137	$2,250	$669	$1,581	$3,869	$577	$33	$0
1010000	3994800	MAINLINE EXTENSION	SE	$18,944	$284	$4,677	$1,390	$3,286	$8,040	$1,199	$69	$0
1010000	3994900	SECTION EXTENSION	SE	$6,945	$104	$1,715	$510	$1,205	$2,947	$439	$25	$0
1010000	3995100	VEHICLES	SE	$1,236	$19	$305	$91	$214	$524	$78	$4	$0
1010000	3995200	HEAVY CONSTRUCTION EQUIPMENT	SE	$6,158	$92	$1,520	$452	$1,068	$2,614	$390	$22	$0
1010000	3996000	MISCELLANEOUS GENERAL EQUIPMENT	SE	$2,331	$35	$575	$171	$404	$989	$147	$8	$0

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1010000	3996100	COMPUTERS - MAINFRAME	SE	$402	$6	$99	$29	$70	$171	$25	$1	$0
1010000	3997000	MINE DEVELOPMENT AND ROAD EXTENSION	SE	$38,415	$577	$9,483	$2,819	$6,664	$16,303	$2,430	$139	$0
1010000 Total				**$23,234,344**	**$506,672**	**$6,367,663**	**$1,768,089**	**$3,320,820**	**$9,934,405**	**$1,280,936**	**$55,758**	**$0**
1019000	140139	PRODUCTION PLANT-NON-RECONCILED	SG	-$25,188	-$385	-$6,562	-$1,955	-$3,948	-$10,826	-$1,427	-$84	$0
1019000	140149	TRANS PLANT NON-RECONCILED	SG	-$5,623	-$86	-$1,465	-$436	-$881	-$2,417	-$319	-$19	$0
1019000	140169	DISTRIBN- NON-RECONCILED	CA	-$11	-$11	$0	$0	$0	$0	$0	$0	$0
1019000	140169	DISTRIBN- NON-RECONCILED	IDU	$34	$0	$0	$0	$0	$0	$34	$0	$0
1019000	140169	DISTRIBN- NON-RECONCILED	OR	-$818	$0	-$818	$0	$0	$0	$0	$0	$0
1019000	140169	DISTRIBN- NON-RECONCILED	SNPD	$0	$0	$0	$0	$0	$0	$0	$0	$0
1019000	140169	DISTRIBN- NON-RECONCILED	UT	-$695	$0	$0	$0	$0	-$695	$0	$0	$0
1019000	140169	DISTRIBN- NON-RECONCILED	WA	-$100	$0	$0	-$100	$0	$0	$0	$0	$0
1019000	140169	DISTRIBN- NON-RECONCILED	WYU	-$152	$0	$0	$0	-$152	$0	$0	$0	$0
1019000	140189	MOTOR VEH/MOBILE PLANT - IN SERVICE-NON-	SO	-$3,460	-$75	-$948	-$262	-$497	-$1,479	-$191	-$8	$0
1019000	3601000	LAND OWNED IN FEE	CA	-$682	-$682	$0	$0	$0	$0	$0	$0	$0
1019000 Total				**-$36,696**	**-$1,239**	**-$9,792**	**-$2,754**	**-$5,478**	**-$15,417**	**-$1,903**	**-$112**	**$0**
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	CA	$348	$348	$0	$0	$0	$0	$0	$0	$0
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	IDU	$1,123	$0	$0	$0	$0	$0	$1,123	$0	$0
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	OR	$6,802	$0	$6,802	$0	$0	$0	$0	$0	$0
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	UT	$19,028	$0	$0	$0	$0	$19,028	$0	$0	$0
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WA	$983	$0	$0	$983	$0	$0	$0	$0	$0
1061000	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WYU	$2,404	$0	$0	$0	$2,404	$0	$0	$0	$0
1061000 Total				**$30,687**	**$348**	**$6,802**	**$983**	**$2,404**	**$19,028**	**$1,123**	**$0**	**$0**
1062000	0	TRANSM COMPLETED CONSTRUCTN NOT CLASSIFI	SG	$11,957	$183	$3,115	$928	$1,874	$5,139	$677	$40	$0
1062000 Total				**$11,957**	**$183**	**$3,115**	**$928**	**$1,874**	**$5,139**	**$677**	**$40**	**$0**
1063000	0	PROD COMPLETED CONSTRUCTN NOT CLASSIFIED	SG	$2,451	$37	$639	$190	$384	$1,054	$139	$8	$0
1063000 Total				**$2,451**	**$37**	**$639**	**$190**	**$384**	**$1,054**	**$139**	**$8**	**$0**
1064000	0	GENERAL COMPLETED CONSTRUCTN NOT CLASSIF	SO	$10,862	$235	$2,974	$821	$1,560	$4,644	$600	$26	$0
1064000 Total				**$10,862**	**$235**	**$2,974**	**$821**	**$1,560**	**$4,644**	**$600**	**$26**	**$0**
Grand Total				**$23,253,606**	**$506,237**	**$6,371,401**	**$1,768,259**	**$3,321,565**	**$9,948,852**	**$1,281,572**	**$55,721**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Capital Lease (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1011000	3908000	CAPITAL LEASE COMMON	OR	$5,882	$0	$5,882	$0	$0	$0	$0	$0	$0
1011000	3908000	CAPITAL LEASE COMMON	SG	$33,745	$515	$8,792	$2,619	$5,290	$14,504	$1,912	$113	$0
1011000	3908000	CAPITAL LEASE COMMON	SO	$12,664	$275	$3,468	$957	$1,819	$5,414	$700	$31	$0
1011000	3908000	CAPITAL LEASE COMMON	UT	$11,714	$0	$0	$0	$0	$11,714	$0	$0	$0
1011000	3908000	CAPITAL LEASE COMMON	WYP	$1,388	$0	$0	$0	$1,388	$0	$0	$0	$0
1011000 Total				**$65,393**	**$790**	**$18,142**	**$3,577**	**$8,497**	**$31,633**	**$2,612**	**$144**	**$0**
1110000	3908000	CAPITAL LEASE COMMON	OR	-$2,469	$0	-$2,469	$0	$0	$0	$0	$0	$0
1110000	3908000	CAPITAL LEASE COMMON	SG	-$5,217	-$80	-$1,359	-$405	-$818	-$2,242	-$296	-$17	$0
1110000	3908000	CAPITAL LEASE COMMON	SO	$429	$9	$117	$32	$62	$183	$24	$1	$0
1110000	3908000	CAPITAL LEASE COMMON	UT	-$1,873	$0	$0	$0	$0	-$1,873	$0	$0	$0
1110000	3908000	CAPITAL LEASE COMMON	WYP	-$984	$0	$0	$0	-$984	$0	$0	$0	$0
1110000 Total				**-$10,114**	**-$70**	**-$3,711**	**-$373**	**-$1,740**	**-$3,932**	**-$272**	**-$16**	**$0**
Grand Total				**$55,279**	**$720**	**$14,431**	**$3,204**	**$6,757**	**$27,701**	**$2,340**	**$127**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Plant Held for Future Use (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1050000	3401000	LAND OWNED IN FEE	SG	$8,923	$136	$2,325	$693	$1,399	$3,835	$506	$30	$0
1050000	3501000	LAND OWNED IN FEE	SG	$2,841	$43	$740	$220	$445	$1,221	$161	$10	$0
1050000	3502000	LAND RIGHTS	SG	$156	$2	$41	$12	$24	$67	$9	$1	$0
1050000	3601000	LAND OWNED IN FEE	OR	$746	$0	$746	$0	$0	$0	$0	$0	$0
1050000	3601000	LAND OWNED IN FEE	UT	$3,009	$0	$0	$0	$0	$3,009	$0	$0	$0
1050000	3891000	LAND OWNED IN FEE	OR	$3,508	$0	$3,508	$0	$0	$0	$0	$0	$0
1050000	3992200	LAND RIGHTS	SE	$953	$14	$235	$70	$165	$404	$60	$3	$0
1050000 Total				**$20,136**	**$196**	**$7,595**	**$995**	**$2,034**	**$8,537**	**$736**	**$43**	**$0**
1059000	0	ELECTRIC PLANT HELD FOR FUTURE USE-OTHER	SE	$25,360	$381	$6,261	$1,861	$4,399	$10,763	$1,604	$92	$0
1059000	3601000	ELECTRIC PLANT HELD FOR FUTURE USE-OTHER	CA	$682	$682	$0	$0	$0	$0	$0	$0	$0
1059000 Total				**$26,042**	**$1,063**	**$6,261**	**$1,861**	**$4,399**	**$10,763**	**$1,604**	**$92**	**$0**
Grand Total				**$46,179**	**$1,259**	**$13,855**	**$2,856**	**$6,433**	**$19,300**	**$2,340**	**$135**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Debits (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1861000	185016	EMISSION REDUCTION CREDITS PURCHASED	SE	$2,631	$40	$650	$193	$456	$1,117	$166	$10	$0
1861000 Total				**$2,631**	**$40**	**$650**	**$193**	**$456**	**$1,117**	**$166**	**$10**	**$0**
1861200	185025	FINANCING COST DEFERRED	SO	$20	$0	$5	$1	$3	$8	$1	$0	$0
1861200	185026	DEFERRED - S-3 SHELF REGISTRATION COSTS	SO		$0	$0	$0	$0	$0	$0	$0	$0
1861200	185027	UNAMORTIZED CREDIT AGREEMENT COSTS	OTHER	$2,242	$0	$0	$0	$0	$0	$0	$0	$2,242
1861200	185028	UNAMORTIZED PCRB LOC/SBBPA COSTS	OTHER	$202	$0	$0	$0	$0	$0	$0	$0	$202
1861200	185029	UNAMORTIZED PCRB MADE CONVERSION COSTS	OTHER	$200	$0	$0	$0	$0	$0	$0	$0	$200
1861200	185030	UNAMORTIZED '94 SERIES RESTRUCTURING COS	OTHER	$813	$0	$0	$0	$0	$0	$0	$0	$813
1861200 Total				**$3,476**	**$0**	**$5**	**$1**	**$3**	**$8**	**$1**	**$0**	**$3,457**
1865000	134200	Deferred Longwall Costs	SE	$1,258	$19	$311	$92	$218	$534	$80	$5	$0
1865000	184414	DEFERRED COAL COSTS - WYODAK SETTLEMENT	SE	$3,519	$53	$869	$258	$610	$1,494	$223	$13	$0
1865000	184416	Deferred Coal Costs - Naughton Contract	SE	$6,193	$93	$1,529	$454	$1,074	$2,628	$392	$22	$0
1865000 Total				**$10,971**	**$165**	**$2,708**	**$805**	**$1,903**	**$4,656**	**$694**	**$40**	**$0**
1867000	134300	DEFERRED CHARGES	SE	$39	$1	$10	$3	$7	$17	$2	$0	$0
1867000 Total				**$39**	**$1**	**$10**	**$3**	**$7**	**$17**	**$2**	**$0**	**$0**
1868000	134360	LAKE SIDE MAINT. PREPAYMENT - CURRENT	SG	$4,909	$75	$1,279	$381	$769	$2,110	$278	$16	$0
1868000	134361	PREPAID OUTAGE MAINTENANCE	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1868000	134362	Currant Creek Maint Prepayment - Current	SG	$14,633	$224	$3,812	$1,136	$2,294	$6,290	$829	$49	$0
1868000	185306	TGS BUYOUT	SG	$117	$2	$31	$9	$18	$50	$7	$0	$0
1868000	185309	LAKEVIEW BUYOUT	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1868000	185310	BUFFALO SETTLEMENT	SG		$0	$0	$0	$0	$0	$0	$0	$0
1868000	185311	JOSEPH SETTLEMENT	SG	$767	$12	$200	$60	$120	$330	$43	$3	$0
1868000	185313	MEAD-PHOENIX-AVAILABILITY & TRANS CHARGE	SG	$13,190	$201	$3,436	$1,024	$2,068	$5,669	$747	$44	$0
1868000	185335	LACOMB IRRIGATION	SG	$438	$7	$114	$34	$69	$188	$25	$1	$0
1868000	185336	BOGUS CREEK	SG	$1,139	$17	$297	$88	$178	$489	$65	$4	$0
1868000	185337	POINT-TO-POINT TRANS RESERVATIONS	SG	$3,271	$50	$852	$254	$513	$1,406	$185	$11	$0
1868000	185342	JIM BOYD HYDRO BUYOUT	SG	$131	$2	$34	$10	$21	$56	$7	$0	$0
1868000	185349	LGIA LT Transmission Prepaid	OTHER	$643	$0	$0	$0	$0	$0	$0	$0	$643
1868000	185351	BPA LT TRANSMISSION PREPAID	OTHER	$8,302	$0	$0	$0	$0	$0	$0	$0	$8,302
1868000	185360	LT LAKE SIDE MAINT PREPAYMENT	SG	$9,652	$147	$2,515	$749	$1,513	$4,149	$547	$32	$0
1868000	185361	LT CHEHALIS CSA MAINT. PREPAYMENT	SG	$8,484	$130	$2,210	$659	$1,330	$3,646	$481	$28	$0
1868000	185362	LT Currant Creek CSA Maint Prepayment	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1868000 Total				**$65,676**	**$867**	**$14,780**	**$4,404**	**$8,893**	**$24,384**	**$3,214**	**$190**	**$8,945**
1868200	184441	DEFERRED MONTANA COLSTRIP PLANT COSTS	SG	$1,075	$16	$280	$83	$169	$462	$61	$4	$0
1868200 Total				**$1,075**	**$16**	**$280**	**$83**	**$169**	**$462**	**$61**	**$4**	**$0**
1869000	185327	FIRTH COGENERATION BUYOUT	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1869000	185334	HERMISTON SWAP	SG	$4,135	$63	$1,077	$321	$648	$1,777	$234	$14	$0
1869000	185380	LT Prepaid IBEW 57 Pension Contribution	OTHER	$5,791	$0	$0	$0	$0	$0	$0	$0	$5,791
1869000 Total				**$9,926**	**$63**	**$1,077**	**$321**	**$648**	**$1,777**	**$234**	**$14**	**$5,791**
Grand Total				**$93,794**	**$1,151**	**$19,510**	**$5,810**	**$12,079**	**$32,421**	**$4,373**	**$257**	**$18,193**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Material & Supplies (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1511100	0	COAL INVENTORY - CARBON	SE	$2,128	$32	$525	$156	$369	$903	$135	$8	$0
1511100 Total				**$2,128**	**$32**	**$525**	**$156**	**$369**	**$903**	**$135**	**$8**	**$0**
1511120	0	COAL INVENTORY - HUNTER	SE	$75,700	$1,137	$18,688	$5,554	$13,132	$32,127	$4,789	$274	$0
1511120 Total				**$75,700**	**$1,137**	**$18,688**	**$5,554**	**$13,132**	**$32,127**	**$4,789**	**$274**	**$0**
1511130	0	COAL INVENTORY - HUNTINGTON	SE	$23,726	$356	$5,857	$1,741	$4,116	$10,069	$1,501	$86	$0
1511130 Total				**$23,726**	**$356**	**$5,857**	**$1,741**	**$4,116**	**$10,069**	**$1,501**	**$86**	**$0**
1511140	0	COAL INVENTORY - JIM BRIDGER	SE	$25,432	$382	$6,278	$1,866	$4,412	$10,793	$1,609	$92	$0
1511140 Total				**$25,432**	**$382**	**$6,278**	**$1,866**	**$4,412**	**$10,793**	**$1,609**	**$92**	**$0**
1511160	0	COAL INVENTORY - NAUGHTON	SE	$10,435	$157	$2,576	$766	$1,810	$4,428	$660	$38	$0
1511160 Total				**$10,435**	**$157**	**$2,576**	**$766**	**$1,810**	**$4,428**	**$660**	**$38**	**$0**
1511170	0	COAL INVENTORY - COAL PREP PLANT	SE	$59,276	$890	$14,633	$4,349	$10,282	$25,157	$3,750	$214	$0
1511170 Total				**$59,276**	**$890**	**$14,633**	**$4,349**	**$10,282**	**$25,157**	**$3,750**	**$214**	**$0**
1511180	0	COAL INVENTORY - WYODAK	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1511180 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1511200	0	COAL INVENTORY - CHOLLA	SE	$10,115	$152	$2,497	$742	$1,755	$4,293	$640	$37	$0
1511200 Total				**$10,115**	**$152**	**$2,497**	**$742**	**$1,755**	**$4,293**	**$640**	**$37**	**$0**
1511300	0	COAL INVENTORY - COLSTIP	SE	$1,357	$20	$335	$100	$235	$576	$86	$5	$0
1511300 Total				**$1,357**	**$20**	**$335**	**$100**	**$235**	**$576**	**$86**	**$5**	**$0**
1511400	0	COAL INVENTORY - CRAIG	SE	$7,839	$118	$1,935	$575	$1,360	$3,327	$496	$28	$0
1511400 Total				**$7,839**	**$118**	**$1,935**	**$575**	**$1,360**	**$3,327**	**$496**	**$28**	**$0**
1511500	0	COAL INVENTORY - DEER CREEK	SE	$52	$1	$13	$4	$9	$22	$3	$0	$0
1511500 Total				**$52**	**$1**	**$13**	**$4**	**$9**	**$22**	**$3**	**$0**	**$0**
1511600	0	COAL INVENTORY - DAVE JOHNSTON	SE	$8,121	$122	$2,005	$596	$1,409	$3,446	$514	$29	$0
1511600 Total				**$8,121**	**$122**	**$2,005**	**$596**	**$1,409**	**$3,446**	**$514**	**$29**	**$0**
1511700	0	COAL INVENTORY ROCK GARDEN PILE	SE	$34,434	$517	$8,501	$2,526	$5,973	$14,614	$2,179	$125	$0
1511700 Total				**$34,434**	**$517**	**$8,501**	**$2,526**	**$5,973**	**$14,614**	**$2,179**	**$125**	**$0**
1511800	0	COAL INVENTORY	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1511800 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1511900	0	COAL INVENTORY - HAYDEN	SE	$3,504	$53	$865	$257	$608	$1,487	$222	$13	$0
1511900 Total				**$3,504**	**$53**	**$865**	**$257**	**$608**	**$1,487**	**$222**	**$13**	**$0**
1512000	0	NATURAL GAS	SE		$0	$0	$0	$0	$0	$0	$0	$0
1512000 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1512110	0	NATURAL GAS - HERMISTON	SE		$0	$0	$0	$0	$0	$0	$0	$0
1512110 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1512150	0	NATURAL GAS - LITTLE MOUNTAIN	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1512150 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1512170	0	NATURAL GAS - WEST VALLEY	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1512170 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1512180	0	NATURAL GAS - CLAY BASIN	SE	$3,275	$49	$808	$240	$568	$1,390	$207	$12	$0
1512180 Total				**$3,275**	**$49**	**$808**	**$240**	**$568**	**$1,390**	**$207**	**$12**	**$0**
1512190	0	NATURAL GAS - CHEHALIS	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1512190 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1512800	0	OIL INVENTORY - BLACK HILLS POWER & LIGH	SE	$413	$6	$102	$30	$72	$175	$26	$1	$0
1512800 Total				**$413**	**$6**	**$102**	**$30**	**$72**	**$175**	**$26**	**$1**	**$0**
1514000	0	FUEL STOCK COAL MINE	SE	$3,761	$56	$928	$276	$652	$1,596	$238	$14	$0
1514000 Total				**$3,761**	**$56**	**$928**	**$276**	**$652**	**$1,596**	**$238**	**$14**	**$0**
1514300	0	OIL INVENTORY - COLSTRIP	SE	$156	$2	$39	$11	$27	$66	$10	$1	$0
1514300 Total				**$156**	**$2**	**$39**	**$11**	**$27**	**$66**	**$10**	**$1**	**$0**
1514400	0	OIL INVENTORY - CRAIG	SE	$79	$1	$20	$6	$14	$34	$5	$0	$0
1514400 Total				**$79**	**$1**	**$20**	**$6**	**$14**	**$34**	**$5**	**$0**	**$0**
1514800	0	OIL INVENTORY - OTHER	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1514800 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Material & Supplies (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1514900	0	OIL INVENTORY - HAYDEN	SE	$74	$1	$18	$5	$13	$31	$5	$0	$0
1514900 Total				**$74**	**$1**	**$18**	**$5**	**$13**	**$31**	**$5**	**$0**	**$0**
1541000	0	MATERIAL CONTROL ADJUST	SO	-$148	-$3	-$41	-$11	-$21	-$63	-$8	$0	$0
1541000	1510	JIM BRIDGER STORE ROOM	SG	$19,611	$300	$5,109	$1,522	$3,074	$8,429	$1,111	$66	$0
1541000	1515	DAVE JOHNSTON STORE ROOM	SG	$9,690	$148	$2,525	$752	$1,519	$4,165	$549	$32	$0
1541000	1520	WYODAK STORE ROOM	SG	$4,909	$75	$1,279	$381	$770	$2,110	$278	$16	$0
1541000	1525	GADSBY STORE ROOM	SG	$4,268	$65	$1,112	$331	$669	$1,834	$242	$14	$0
1541000	1530	CARBON STORE ROOM	SG	$3,806	$58	$992	$295	$597	$1,636	$216	$13	$0
1541000	1535	NAUGHTON STORE ROOM	SG	$12,204	$186	$3,180	$947	$1,913	$5,246	$691	$41	$0
1541000	1540	HUNTINGTON STORE ROOM	SG	$14,273	$218	$3,719	$1,108	$2,237	$6,135	$809	$48	$0
1541000	1545	HUNTER STORE ROOM	SG	$21,234	$324	$5,532	$1,648	$3,328	$9,127	$1,203	$71	$0
1541000	1550	BLUNDELL STORE ROOM	SG	$1,030	$16	$268	$80	$162	$443	$58	$3	$0
1541000	1560	WEST VALLEY GAS PLANT	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1541000	1565	CURRANT CREEK PLANT	SG	$3,014	$46	$785	$234	$472	$1,295	$171	$10	$0
1541000	1570	LAKESIDE PLANT	SG	$2,940	$45	$766	$228	$461	$1,264	$167	$10	$0
1541000	1580	CHEHALIS PLANT	SG	$2,700	$41	$703	$210	$423	$1,161	$153	$9	$0
1541000	1650	HYDRO SOUTH - KLAMATH RIVER - CA	SG		$0	$0	$0	$0	$0	$0	$0	$0
1541000	1675	HYDRO EAST - UTAH	SG	$2	$0	$1	$0	$0	$1	$0	$0	$0
1541000	1680	HYDRO EAST - IDAHO	SG	$1	$0	$0	$0	$0	$1	$0	$0	$0
1541000	1700	LEANING JUNIPER STOREROOM	SG	$662	$10	$172	$51	$104	$284	$37	$2	$0
1541000	1705	GOODNOE HILLS WIND	SG	$581	$9	$151	$45	$91	$250	$33	$2	$0
1541000	1715	MARENGO WIND	SG	$427	$7	$111	$33	$67	$183	$24	$1	$0
1541000	1725	Glenrock/Rolling Hills	SG	$1,126	$17	$293	$87	$177	$484	$64	$4	$0
1541000	1730	Seven Mile Hill	SG	$769	$12	$200	$60	$121	$330	$44	$3	$0
1541000	1740	High Plains/McFadden	SG	$408	$6	$106	$32	$64	$175	$23	$1	$0
1541000	1745	Dunlap Wind Project	SG	$226	$3	$59	$18	$35	$97	$13	$1	$0
1541000	1799	WIND OFFICE	SG	$1	$0	$0	$0	$0	$0	$0	$0	$0
1541000	2005	CASPER STORE ROOM	WYP	$515	$0	$0	$0	$515	$0	$0	$0	$0
1541000	2010	BUFFALO STORE ROOM	WYP	$145	$0	$0	$0	$145	$0	$0	$0	$0
1541000	2015	DOUGLAS STORE ROOM	WYP	$299	$0	$0	$0	$299	$0	$0	$0	$0
1541000	2020	CODY STORE ROOM	WYP	$740	$0	$0	$0	$740	$0	$0	$0	$0
1541000	2030	WORLAND STORE ROOM	WYP	$791	$0	$0	$0	$791	$0	$0	$0	$0
1541000	2035	RIVERTON STORE ROOM	WYP	$358	$0	$0	$0	$358	$0	$0	$0	$0
1541000	2040	EVANSTON STORE ROOM	WYU	$763	$0	$0	$0	$763	$0	$0	$0	$0
1541000	2045	KEMMERER STORE ROOM	WYU	$11	$0	$0	$0	$11	$0	$0	$0	$0
1541000	2050	PINEDALE STORE ROOM	WYU	$587	$0	$0	$0	$587	$0	$0	$0	$0
1541000	2060	ROCK SPRINGS STORE ROOM	WYP	$1,461	$0	$0	$0	$1,461	$0	$0	$0	$0
1541000	2065	RAWLINS STORE ROOM	WYP	$601	$0	$0	$0	$601	$0	$0	$0	$0
1541000	2070	LARAMIE STORE ROOM	WYP	$335	$0	$0	$0	$335	$0	$0	$0	$0
1541000	2075	REXBERG STORE ROOM	IDU	$1,272	$0	$0	$0	$0	$0	$1,272	$0	$0
1541000	2085	SHELLY STORE ROOM	IDU	$850	$0	$0	$0	$0	$0	$850	$0	$0
1541000	2090	PRESTON STORE ROOM	IDU	$111	$0	$0	$0	$0	$0	$111	$0	$0
1541000	2095	LAVA HOT SPRINGS STORE ROOM	IDU	$159	$0	$0	$0	$0	$0	$159	$0	$0
1541000	2100	MONTPELIER STORE ROOM	IDU	$225	$0	$0	$0	$0	$0	$225	$0	$0
1541000	2110	BRIDGERLAND STORE ROOM	UT	$601	$0	$0	$0	$0	$601	$0	$0	$0
1541000	2205	TREMONTON STORE ROOM	UT	$231	$0	$0	$0	$0	$231	$0	$0	$0
1541000	2210	OGDEN STORE ROOM	UT	$1,323	$0	$0	$0	$0	$1,323	$0	$0	$0
1541000	2215	LAYTON STORE ROOM	UT	$549	$0	$0	$0	$0	$549	$0	$0	$0
1541000	2220	SALT LAKE METRO STORE ROOM	UT	$8,803	$0	$0	$0	$0	$8,803	$0	$0	$0
1541000	2225	SALT LAKE TOOL ROOM	UT	$178	$0	$0	$0	$0	$178	$0	$0	$0
1541000	2230	JORDAN VALLEY STORE ROOM	UT	$1,270	$0	$0	$0	$0	$1,270	$0	$0	$0
1541000	2235	PARK CITY STORE ROOM	UT	$672	$0	$0	$0	$0	$672	$0	$0	$0
1541000	2240	TOOELE STORE ROOM	UT	$482	$0	$0	$0	$0	$482	$0	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Material & Supplies (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1541000	2245	WASATCH RESTORATION CENTER	UT	$506	$0	$0	$0	$0	$506	$0	$0	$0
1541000	2405	AMERICAN FORK STORE ROOM	UT	$1,292	$0	$0	$0	$0	$1,292	$0	$0	$0
1541000	2410	SANTAQUIN STORE ROOM	UT	$390	$0	$0	$0	$0	$390	$0	$0	$0
1541000	2415	DELTA STORE ROOM	UT	$326	$0	$0	$0	$0	$326	$0	$0	$0
1541000	2420	VERNAL STORE ROOM	UT	$607	$0	$0	$0	$0	$607	$0	$0	$0
1541000	2425	PRICE STORE ROOM	UT	$689	$0	$0	$0	$0	$689	$0	$0	$0
1541000	2430	MOAB STORE ROOM	UT	$654	$0	$0	$0	$0	$654	$0	$0	$0
1541000	2435	BLANDING STORE ROOM	UT	$157	$0	$0	$0	$0	$157	$0	$0	$0
1541000	2445	RICHFIELD STORE ROOM	UT	$102	$0	$0	$0	$0	$102	$0	$0	$0
1541000	2450	CEDAR CITY STORE ROOM	UT	$982	$0	$0	$0	$0	$982	$0	$0	$0
1541000	2455	MILFORD STORE ROOM	UT	$257	$0	$0	$0	$0	$257	$0	$0	$0
1541000	2460	WASHINGTON STORE ROOM	UT	$419	$0	$0	$0	$0	$419	$0	$0	$0
1541000	2620	WALLA WALLA STORE ROOM	WA	$1,251	$0	$0	$1,251	$0	$0	$0	$0	$0
1541000	2630	YAKIMA STORE ROOM	WA	$324	$0	$0	$324	$0	$0	$0	$0	$0
1541000	2635	ENTERPRISE STORE ROOM	OR	$226	$0	$226	$0	$0	$0	$0	$0	$0
1541000	2640	PENDLETON STORE ROOM	OR	$616	$0	$616	$0	$0	$0	$0	$0	$0
1541000	2650	HOOD RIVER STORE ROOM	OR	$182	$0	$182	$0	$0	$0	$0	$0	$0
1541000	2655	PORTLAND METRO - STORE ROOM	OR	$7,678	$0	$7,678	$0	$0	$0	$0	$0	$0
1541000	2660	ASTORIA STORE ROOM	OR	$1,186	$0	$1,186	$0	$0	$0	$0	$0	$0
1541000	2665	MADRAS STORE ROOM	OR	$651	$0	$651	$0	$0	$0	$0	$0	$0
1541000	2675	BEND STORE ROOM	OR	$1,004	$0	$1,004	$0	$0	$0	$0	$0	$0
1541000	2805	ALBANY STORE ROOM	OR	$260	$0	$260	$0	$0	$0	$0	$0	$0
1541000	2810	LINCOLN CITY STORE ROOM	OR	$209	$0	$209	$0	$0	$0	$0	$0	$0
1541000	2830	ROSEBURG STORE ROOM	OR	$2,391	$0	$2,391	$0	$0	$0	$0	$0	$0
1541000	2835	COOS BAY STORE ROOM	OR	$732	$0	$732	$0	$0	$0	$0	$0	$0
1541000	2840	GRANTS PASS STORE ROOM	OR	$810	$0	$810	$0	$0	$0	$0	$0	$0
1541000	2845	MEDFORD STORE ROOM	OR	$885	$0	$885	$0	$0	$0	$0	$0	$0
1541000	2850	KLAMATH FALLS STORE ROOM	OR	$2,144	$0	$2,144	$0	$0	$0	$0	$0	$0
1541000	2855	LAKEVIEW STORE ROOM	OR	$121	$0	$121	$0	$0	$0	$0	$0	$0
1541000	2860	ALTURAS STORE ROOM	CA	$71	$71	$0	$0	$0	$0	$0	$0	$0
1541000	2865	MT SHASTA STORE ROOM	CA	$206	$206	$0	$0	$0	$0	$0	$0	$0
1541000	2870	YREKA STORE ROOM	CA	$697	$697	$0	$0	$0	$0	$0	$0	$0
1541000	2875	CRESENT CITY STORE ROOM	CA	$375	$375	$0	$0	$0	$0	$0	$0	$0
1541000	5005	TREMONTON STORE ROOM	SO	$144	$3	$39	$11	$21	$62	$8	$0	$0
1541000	5110	MATERIAL PACKAGING CENTER - WEST	OR	$0	$0	$0	$0	$0	$0	$0	$0	$0
1541000	5115	DEMC - SLC	SNPD	$132	$4	$36	$8	$14	$64	$6	$0	$0
1541000	5120	DEMC - MEDFORD	OR	$227	$0	$227	$0	$0	$0	$0	$0	$0
1541000	5125	DEMC - OREGON	OR	$6,038	$0	$6,038	$0	$0	$0	$0	$0	$0
1541000	5130	MEDFORD HUB	OR	$4,938	$0	$4,938	$0	$0	$0	$0	$0	$0
1541000	5135	YAKIMA HUB	WA	$4,342	$0	$0	$4,342	$0	$0	$0	$0	$0
1541000	5140	PRESTON HUB	IDU	$2,521	$0	$0	$0	$0	$0	$2,521	$0	$0
1541000	5150	RICHFIELD HUB	UT	$3,217	$0	$0	$0	$0	$3,217	$0	$0	$0
1541000	5155	CASPER HUB	WYP	$4,553	$0	$0	$0	$4,553	$0	$0	$0	$0
1541000	5160	SALT LAKE METRO HUB	UT	$13,862	$0	$0	$0	$0	$13,862	$0	$0	$0
1541000	5200	UTAH TRANSPORTATION BUILDING	SNPD	$129	$4	$35	$8	$14	$62	$6	$0	$0
1541000	5300	METER TEST WAREHOUSE	UT	$10	$0	$0	$0	$0	$10	$0	$0	$0
1541000 Total				**$195,576**	**$2,944**	**$57,431**	**$13,996**	**$27,470**	**$82,350**	**$11,036**	**$348**	**$0**
1541500	0	M&S GLENROCK COAL MINE	SE	$198	$3	$49	$14	$34	$84	$13	$1	$0
1541500	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SE	-$198	-$3	-$49	-$14	-$34	-$84	-$13	-$1	$0
1541500	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1541500	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SO	$248	$5	$68	$19	$36	$106	$14	$1	$0
1541500 Total				**$248**	**$5**	**$68**	**$19**	**$36**	**$106**	**$14**	**$1**	**$0**
1541900	0	PLANT M&S - GENERATION JV CUTBACK	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Material & Supplies (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1541900	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SG	$2,171	$33	$566	$168	$340	$933	$123	$7	$0
1541900 Total				**$2,171**	**$33**	**$566**	**$168**	**$340**	**$933**	**$123**	**$7**	**$0**
1544200	0	M&S - OPER SUPPLIES-DEER CREEK MINE	SE	$5,974	$90	$1,475	$438	$1,036	$2,535	$378	$22	$0
1544200 Total				**$5,974**	**$90**	**$1,475**	**$438**	**$1,036**	**$2,535**	**$378**	**$22**	**$0**
1545000	0	CREDIT OFFSET CENTRALIA - WWP	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1545000 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1549900	102930	SB Asset # 120930	SO	-$27	-$1	-$8	-$2	-$4	-$12	-$2	$0	$0
1549900	120930	INVENTORY RESERVE POWER SUPPLY	SG	-$742	-$11	-$193	-$58	-$116	-$319	-$42	-$2	$0
1549900	120930	INVENTORY RESERVE POWER SUPPLY	SO	-$12	$0	-$3	-$1	-$2	-$5	-$1	$0	$0
1549900	120931	INVENTORY RESERVE POWER DELIVERY	SNPD	-$2,541	-$86	-$683	-$156	-$271	-$1,225	-$120	$0	$0
1549900 Total				**-$3,323**	**-$98**	**-$887**	**-$217**	**-$393**	**-$1,561**	**-$165**	**-$3**	**$0**
2531600	289920	WORKING CAPITAL DEPOSIT - UAMPS	SE	-$3,235	-$49	-$799	-$237	-$561	-$1,373	-$205	-$12	$0
2531600 Total				**-$3,235**	**-$49**	**-$799**	**-$237**	**-$561**	**-$1,373**	**-$205**	**-$12**	**$0**
2531700	289921	OTH DEF CR - WORKING CAPITAL DEPOS-DG&T	SE	-$2,490	-$37	-$615	-$183	-$432	-$1,057	-$158	-$9	$0
2531700 Total				**-$2,490**	**-$37**	**-$615**	**-$183**	**-$432**	**-$1,057**	**-$158**	**-$9**	**$0**
2531800	289922	OTH DEF CR - WCD - PROVO - PLANT M&S	SG	-$273	-$4	-$71	-$21	-$43	-$117	-$15	-$1	$0
2531800 Total				**-$273**	**-$4**	**-$71**	**-$21**	**-$43**	**-$117**	**-$15**	**-$1**	**$0**
Grand Total				**$464,523**	**$6,936**	**$123,791**	**$33,765**	**$74,268**	**$196,350**	**$28,082**	**$1,330**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Cash Working Capital (Actuals)
Twelve Month Average Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1430000	OTHER ACCTS REC	0	OTHER ACCOUNTS RECEIVABLE	SO	$3	$0	$1	$0	$0	$1	$0	$0	$0
1430000 Total					**$3**	**$0**	**$1**	**$0**	**$0**	**$1**	**$0**	**$0**	**$0**
1431000	EMP ACCOUNTS REC	0	EMPLOYEE RECEIVABLES	SO	$4,636	$101	$1,270	$351	$666	$1,982	$256	$11	$0
1431000 Total					**$4,636**	**$101**	**$1,270**	**$351**	**$666**	**$1,982**	**$256**	**$11**	**$0**
1431200	MISC OTHER LOANS-CSS	0	MISC OTHER LOANS	SO		$0	$0	$0	$0	$0	$0	$0	$0
1431200 Total					**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1433000	JOINT OWNER REC	0	JOINT OWNER RECEIVABLE	SO	$17,571	$381	$4,812	$1,328	$2,524	$7,512	$971	$42	$0
1433000 Total					**$17,571**	**$381**	**$4,812**	**$1,328**	**$2,524**	**$7,512**	**$971**	**$42**	**$0**
1436000	OTH ACCT REC	0	OTHER ACCOUNTS RECEIVABLE	SO	$33,519	$727	$9,179	$2,534	$4,815	$14,331	$1,853	$81	$0
1436000 Total					**$33,519**	**$727**	**$9,179**	**$2,534**	**$4,815**	**$14,331**	**$1,853**	**$81**	**$0**
1437000	CSS OAR BILLINGS	0	CSS OAR BILLINGS	SO	$2,773	$60	$759	$210	$398	$1,186	$153	$7	$0
1437000 Total					**$2,773**	**$60**	**$759**	**$210**	**$398**	**$1,186**	**$153**	**$7**	**$0**
1437100	CSS OAR BILLINGS-WOR	0	OTHER ACCT REC CCS	SO	-$646	-$14	-$177	-$49	-$93	-$276	-$36	-$2	$0
1437100 Total					**-$646**	**-$14**	**-$177**	**-$49**	**-$93**	**-$276**	**-$36**	**-$2**	**$0**
2300000	ASSET RETIREMENT OBL	284915	ARO LIAB - DEER CREEK MINE RECLAMATION	SE	-$2,628	-$39	-$649	-$193	-$456	-$1,115	-$166	-$10	$0
2300000	ASSET RETIREMENT OBL	284980	ARO Liab - Cottonwood Mine	SE	-$221	-$3	-$55	-$16	-$38	-$94	-$14	-$1	$0
2300000 Total					**-$2,850**	**-$43**	**-$704**	**-$209**	**-$494**	**-$1,209**	**-$180**	**-$10**	**$0**
2320000	ACCOUNTS PAYABLE	210412	Marengo Wind Proj Accrual	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	210460	JOINT OWNER RECEIVABLES - CREDIT	SE	-$2,101	-$32	-$519	-$154	-$365	-$892	-$133	-$8	$0
2320000	ACCOUNTS PAYABLE	210470	Minority Plant Accrual-Idaho Power (T&D)	SG	-$86	-$1	-$23	-$7	-$14	-$37	-$5	$0	$0
2320000	ACCOUNTS PAYABLE	210643	Mountain Fuel Supply Co	SE		$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	210648	Spring Creek Coal - Centralia Purchases	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	210651	Genwal Coal Co Inc	SE		$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	210656	Foidel Creek/Cypress Coal Purchase	SE		$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	210674	America West Resources - Coal Purchases	SE	-$103	-$2	-$25	-$8	-$18	-$44	-$6	$0	$0
2320000	ACCOUNTS PAYABLE	211108	UNION DUES/CONTRIBUTIONS WITHHOLDING	SO	$1	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	211109	MET PAY HOME & AUTO WITHHOLDINGS	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	211110	CREDIT UNION WITHHOLDINGS	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	211111	SAVINGS BONDS WITHHOLDINGS	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	211116	DEPENDENT SUPPORT/LEVY WITHHOLDINGS	SO	-$7	$0	-$2	-$1	-$1	-$3	$0	$0	$0
2320000	ACCOUNTS PAYABLE	211149	OTHER PAYROLL LIABILITY	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215077	K-PLUS EMPLOYER CONTRIBUTIONS - ENHANCED	SO	-$507	-$11	-$139	-$38	-$73	-$217	-$28	-$1	$0
2320000	ACCOUNTS PAYABLE	215078	K-Plus Employer Contributions - Fixed	SO	-$1,276	-$28	-$349	-$96	-$183	-$546	-$71	-$3	$0
2320000	ACCOUNTS PAYABLE	215080	METLIFE MEDICAL INSURANCE	SO	-$3,022	-$66	-$828	-$229	-$434	-$1,292	-$167	-$7	$0
2320000	ACCOUNTS PAYABLE	215081	OTHER EMPLOYEE BENEFITS	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215082	METLIFE DENTAL INSURANCE	SO	-$65	-$1	-$18	-$5	-$9	-$28	-$4	$0	$0
2320000	ACCOUNTS PAYABLE	215084	METLIFE VISION INSURANCE	SO	-$63	-$1	-$17	-$5	-$9	-$27	-$3	$0	$0
2320000	ACCOUNTS PAYABLE	215085	Western Utilities Dental Payable	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215086	Western Utilities Vision Payable	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215090	LUMENOS HEALTH PLAN	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215095	HMO HEALTH PLAN	SO	$1	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215096	DELTA DENTAL	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215112	Minnesota Life Insurance	SO	-$110	-$2	-$30	-$8	-$16	-$47	-$6	$0	$0
2320000	ACCOUNTS PAYABLE	215116	IBEW 57 MEDICAL INSURANCE	SO	-$45	-$1	-$12	-$3	-$6	-$19	-$2	$0	$0
2320000	ACCOUNTS PAYABLE	215136	ESOP ACCRUAL	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215198	WEST VALLEY CITY STORM DRAINS FEE	SO	-$113	-$2	-$31	-$9	-$16	-$48	-$6	$0	$0
2320000	ACCOUNTS PAYABLE	215211	DRAPER CITY STORM DRAIN	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215350	"IBEW 57 HEALTH REIMBURSEMENT, CURRENT Y	SO	$14	$0	$4	$1	$2	$6	$1	$0	$0
2320000	ACCOUNTS PAYABLE	215351	"IBEW 57 DEPENDENT CARE REIMBURSEMENT, C	SO	$7	$0	$2	$1	$1	$3	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215356	"HEALTH REIMBURSEMENT, CURRENT YEAR"	SO	-$16	$0	-$4	-$1	-$2	-$7	-$1	$0	$0
2320000	ACCOUNTS PAYABLE	215357	"DEPENDENT CARE REIMBURSEMENT, CURRENT Y	SO	$16	$0	$4	$1	$2	$7	$1	$0	$0
2320000	ACCOUNTS PAYABLE	215425	OR DOE Cool School Program	OTHER	-$6	$0	$0	$0	$0	$0	$0	$0	-$6
2320000	ACCOUNTS PAYABLE	215725	Medicare Subsidies Payable to FAS 106 Tr	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	215901	FLATHEAD ELECTRIC CO-OP LIABILITY	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	235195	Miscellaneous Payroll	SO		$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	235502	Payroll Reconciliation	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	235504	Sales Incentive Accrual	SO		$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	235511	Incentive Plan - Power Supply	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	235513	Incentive Plan - Wt&T	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	235529	Met Pay	SO		$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	235554	Continuation Pay	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2320000	ACCOUNTS PAYABLE	235561	International Assign Adj	SO		$0	$0	$0	$0	$0	$0	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Cash Working Capital (Actuals)

Twelve Month Average Ending - June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2320000	ACCOUNTS PAYABLE	240330	PROVISION FOR WORKERS' COMPENSATION	SO	-$88	-$2	-$24	-$7	-$13	-$38	-$5	$0	$0
2320000	ACCOUNTS PAYABLE	249995	Accrued Severance - Reclass to Long-Term	SO	$10	$0	$3	$1	$1	$4	$1	$0	$0
2320000 Total					**-$7,563**	**-$149**	**-$2,009**	**-$567**	**-$1,152**	**-$3,224**	**-$435**	**-$21**	**-$6**
2533000	O DEF CR-MISC PPL	288307	TRAIL MTN MINE RECLAMATION	SE	-$995	-$15	-$246	-$73	-$173	-$422	-$63	-$4	$0
2533000	O DEF CR-MISC PPL	289511	DESERET MINE RECLAMATION	SE	-$524	-$8	-$129	-$38	-$91	-$222	-$33	-$2	$0
2533000	O DEF CR-MISC PPL	289514	FINAL & INTERIM RECLAMATION - DJ MINE	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2533000	O DEF CR-MISC PPL	289515	FINAL RECLAMATION COSTS - CENTRALIA	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2533000	O DEF CR-MISC PPL	289517	TRAPPER MINE FINAL RECLAMATION	SE	-$5,016	-$75	-$1,238	-$368	-$870	-$2,129	-$317	-$18	$0
2533000 Total					**-$6,535**	**-$98**	**-$1,613**	**-$479**	**-$1,134**	**-$2,773**	**-$413**	**-$24**	**$0**
2541050	FAS143 ARO REG LIAB	00111920	REG LIAB-ARO/REGDIFF DEER CREEK MINE REC	SE	-$20	$0	-$5	-$1	-$3	-$8	-$1	$0	$0
2541050	FAS143 ARO REG LIAB	111920	REG LIAB-ARO/REGDIFF DEER CREEK MINE REC	SE	$20	$0	$5	$1	$3	$8	$1	$0	$0
2541050	FAS143 ARO REG LIAB	288503	ARO/REG DIFF - DEER CREEK MINE RECLAMA	SE	-$977	-$15	-$241	-$72	-$169	-$415	-$62	-$4	$0
2541050 Total					**-$977**	**-$15**	**-$241**	**-$72**	**-$169**	**-$415**	**-$62**	**-$4**	**$0**
Grand Total					**$39,931**	**$950**	**$11,277**	**$3,047**	**$5,361**	**$17,115**	**$2,107**	**$81**	**-$6**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Miscellaneous Rate Base (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Id-PPL	Mont	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
1140000	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	SG	$159,176	$2,431	$41,470	$12,355			$19,822	$24,951	$68,415	$9,018	$5,129	$534	$0
1140000 Total				**$159,176**	**$2,431**	**$41,470**	**$12,355**	**$0**	**$0**	**$19,822**	**$24,951**	**$68,415**	**$9,018**	**$5,129**	**$534**	**$0**
1150000	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	SG	-$110,131	-$1,682	-$28,692	-$8,549			-$13,715	-$17,264	-$47,336	-$6,240	-$3,549	-$369	$0
1150000 Total				**-$110,131**	**-$1,682**	**-$28,692**	**-$8,549**	**$0**	**$0**	**-$13,715**	**-$17,264**	**-$47,336**	**-$6,240**	**-$3,549**	**-$369**	**$0**
1651000	132000	PREPAID INSURANCE	SE	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132001	PREPAID INSURANCE - SPECIAL COVERAGE	SO		$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132002	PREPAID INSURANCE - BURGLARY & ROBBERY	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132004	PREPAID INSURANCE - FOREIGN LIABILITY	SO		$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132005	PREPAID INSURANCE - JIM BRIDGER OPERATIO	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132006	PREPAID INSURANCE - LEASEBACK LIABILITY	SO		$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132007	PREPAID INSURANCE - WYODAK OPERATIONS	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132008	PREPAID INSURANCE - PUBLIC LIABILITY & P	SO	$440	$10	$120	$33			$51	$63	$188	$24	$12	$1	$0
1651000	132009	PREPAID INSURANCE - JOINT VENTURE HUNTER	SO		$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132010	PREPAID INSURANCE - JOINT VENTURE HUNTER	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132012	PREPAID INSURANCE - ALLPURPOSE INSURANCE	SO	$1,754	$38	$480	$133			$203	$252	$750	$97	$49	$4	$0
1651000	132013	PREPAID INSURANCE - D&O LIABILITY	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132015	PREPAID INSURANCE - FOOTE CREEK	SG	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132016	PREPAID INS-MINORITY OWNED PLANTS	SO	$510	$11	$140	$39			$59	$73	$218	$28	$14	$1	$0
1651000	132045	PREPAID WORKERS COMPENSATION	SO	$678	$15	$186	$51			$78	$97	$290	$37	$19	$2	$0
1651000	132050	PREPAID IBEW 57 MEDICAL	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000	132055	PREPAID EMPLOYEE BENEFIT COSTS	SO	$30	$1	$8	$2			$3	$4	$13	$2	$1	$0	$0
1651000	132723	I/C PRPD CAP LIAB IN	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1651000 Total				**$3,411**	**$74**	**$934**	**$258**	**$0**	**$0**	**$394**	**$490**	**$1,458**	**$189**	**$96**	**$8**	**$0**
1652000	132101	PREPAID PROPERTY TAX	GPS	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652000	132102	CA - PREPAID PROPERTY TAX	GPS	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652000	132103	UT - PREPAID PROPERTY TAX	GPS	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652000	132109	UTE-PREPAID POSSESSORY INTEREST	GPS	$16	$0	$4	$1			$2	$2	$7	$1	$0	$0	$0
1652000	132110	SHO-BAN-PREPAID POSSESSORY INTEREST	GPS	$98	$2	$27	$7			$11	$14	$42	$5	$3	$0	$0
1652000	132111	Goshute - Prepaid Possessory Interest	GPS	$11	$0	$3	$1			$1	$2	$5	$1	$0	$0	$0
1652000	132200	"Prepaid Taxes (Federal, State, Local)"	SO	$15	$0	$4	$1			$2	$2	$6	$1	$0	$0	$0
1652000	132910	PREPAYMENT OF HARDWARE & SOFTWARE	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652000 Total				**$140**	**$3**	**$38**	**$11**	**$0**	**$0**	**$16**	**$20**	**$60**	**$8**	**$4**	**$0**	**$0**
1652100	132095	PREPAID EMISSIONS PERMIT FEES (UT)	SG	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652100	132310	PREPAID RATING AGNCY	SO	$172	$4	$47	$13			$20	$25	$74	$10	$5	$0	$0
1652100	132603	OTH PREPAY - ASHTON PLANT LAND	SG	$6	$0	$1	$0			$1	$1	$2	$0	$0	$0	$0
1652100	132606	OTHER PREPAY - LEASE COMMISSIONS	SO	$8	$0	$2	$1			$1	$1	$4	$0	$0	$0	$0
1652100	132607	OTHER PREP-FERC LAND	SG	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652100	132608	Prepaid - Records Management Costs	SG	$112	$2	$29	$9			$14	$17	$48	$6	$4	$0	$0
1652100	132620	PREPAYMENTS - WATER RIGHTS LEASE	SG	$611	$9	$159	$47			$76	$96	$263	$35	$20	$2	$0
1652100	132621	Prepayments - Water Rights (Ferron Canal	SG	$89	$1	$23	$7			$11	$14	$38	$5	$3	$0	$0
1652100	132622	Prepayments - Water Rights (Hntgtn-Clev)	SG	$104	$2	$27	$8			$13	$16	$45	$6	$3	$0	$0
1652100	132625	PREPAYMENTS-CES/WAY/SEMPRA-DSM ENERGY S	SG	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652100	132630	PREPAID OR RENEWAL & HABITAT RESTORATION	OTHER	$596	$0	$0	$0			$0	$0	$0	$0	$0	$0	$596
1652100	132650	PREPAID DUES	SE	$2,290	$34	$565	$168			$312	$397	$972	$145	$85	$8	$0
1652100	132700	PREPAID RENT	GPS	$91	$2	$25	$7			$11	$13	$39	$5	$3	$0	$0
1652100	132701	INTERCO PREPAID RENT	GPS	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652100	132705	Prepaid Pole Contact	SG	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652100	132740	PREPAID O&M WIND	SG	$148	$2	$39	$11			$18	$23	$64	$8	$5	$0	$0
1652100	132825	Prepaid LGIA Transmission	SG	$1,464	$22	$381	$114			$182	$230	$629	$83	$47	$5	$0
1652100	132831	PREPAID BPA TRANSM - WINE COUNTRY	SG	$863	$13	$225	$67			$108	$135	$371	$49	$28	$3	$0
1652100	132900	PREPAYMENTS - OTHER	SE	$72	$1	$18	$5			$10	$13	$31	$5	$3	$0	$0
1652100	132900	PREPAYMENTS - OTHER	SO	$590	$13	$162	$45			$68	$85	$252	$33	$17	$1	$0
1652100	132901	PRE FEES - OREGON PUB UTIL COMMISSION	OR	$2,425	$0	$2,425	$0			$0	$0	$0	$0	$0	$0	$0
1652100	132903	PREP FEES-UTAH PUBLIC SERVICE COMMISSION	UT	$4,456	$0	$0	$0			$0	$0	$4,456	$0	$0	$0	$0
1652100	132904	PREP FEES-IDAHO PUB UTIL COMMISSION	IDU	$269	$0	$0	$0			$0	$0	$0	$269	$0	$0	$0
1652100	132908	Prepaid OR Low Income Customer Assist	OTHER	$668	$0	$0	$0			$0	$0	$0	$0	$0	$0	$668
1652100	132909	Prepaid Licensing Fees	SO	$339	$7	$93	$26			$39	$49	$145	$19	$9	$1	$0
1652100	132910	Prepayments - Hardware & Software	SO	$6,564	$142	$1,798	$496			$759	$943	$2,807	$363	$184	$16	$0
1652100	132926	PREPAID ROYALTIES	SE	$833	$13	$206	$61			$114	$144	$354	$53	$31	$3	$0
1652100	132999	PREPAY - RECLASS TO LT	SO	-$1,369	-$30	-$375	-$104			-$158	-$197	-$585	-$76	-$38	-$3	$0
1652100	134000	L/T PREPAY RECLASS	SO	$1,369	$30	$375	$104			$158	$197	$585	$76	$38	$3	$0
1652100	182600	PREPAYMENT-OTHER	SE	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1652100 Total				**$22,772**	**$268**	**$6,225**	**$1,085**	**$0**	**$0**	**$1,757**	**$2,202**	**$10,592**	**$1,093**	**$445**	**$42**	**$1,265**
1655000	132400	PREPAID - TAXES	SE		$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
1655000 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2281100	280301	ACC. PROV. PROP INS. - THERMAL	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2281100 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2281200	280290	STORM REIMBURSEMENTS	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2281200	280302	ACC. PROV. PROP INS. - T&D LINES	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2281200	280307	Accum Prov For Prop Ins - Pac Power T&D	SO		$0	$0	$0			$0	$0	$0	$0	$0	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Miscellaneous Rate Base (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Id-PPL	Mont	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
2281200	280308	Accum Prov For Prop Ins - RMP T&D	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2281200	280311		SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2281200 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2282100	280311	ACC. PROV. I & D - EXCL. AUTO	SO	-$12,639	-$274	-$3,461	-$956			-$1,461	-$1,816	-$5,404	-$699	-$354	-$31	$0
2282100 Total				**-$12,639**	**-$274**	**-$3,461**	**-$956**	**$0**	**$0**	**-$1,461**	**-$1,816**	**-$5,404**	**-$699**	**-$354**	**-$31**	**$0**
2282200	280312	ACC. PROV. I & D - AUTO	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2282200 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2282300	280313	ACC. PROV. I&D - CONST.	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2282300 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2283000	187240	CONTRA REG ASSET - TRANSITION PLAN SEVER	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2283000	280319	ACCRUAL-TRANSITION PLAN SEVERANCE PAYMEN	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2283000	280349	SUPPL. PENSION BENEFITS (RETIRE ALLOW)	SO	-$2,335	-$51	-$639	-$177			-$270	-$335	-$998	-$129	-$65	-$6	$0
2283000 Total				**-$2,335**	**-$51**	**-$639**	**-$177**	**$0**	**$0**	**-$270**	**-$335**	**-$998**	**-$129**	**-$65**	**-$6**	**$0**
2283400	280321	FAS 106 - PACIFICORP EXCL. COAL MINES	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2283400 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2283500	280340	PENSION	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2283500	280350	Pension - Local 57	SO	-$722	-$16	-$198	-$55			-$83	-$104	-$309	-$40	-$20	-$2	$0
2283500 Total				**-$722**	**-$16**	**-$198**	**-$55**	**$0**	**$0**	**-$83**	**-$104**	**-$309**	**-$40**	**-$20**	**-$2**	**$0**
2284100	284901	BLACK LUNG RESERVE	SE	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2284100	289320	CHEHALIS WA EFSEC C02 MITIGATION OBLIG	SG	-$1,480	-$23	-$385	-$115			-$184	-$232	-$636	-$84	-$48	-$5	$0
2284100 Total				**-$1,480**	**-$23**	**-$385**	**-$115**	**$0**	**$0**	**-$184**	**-$232**	**-$636**	**-$84**	**-$48**	**-$5**	**$0**
2284200	284910	DECOMMISSIONING LIABILITY	TROJD		$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2284200	284912	TROJAN WORKING FUNDS BALANCES - NET	TROJD	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2284200 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	CA	-$55	-$55	$0	$0			$0	$0	$0	$0	$0	$0	$0
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	IDU	-$11	$0	$0	$0			$0	$0	$0	-$11	$0	$0	$0
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	OR	-$297	$0	-$297	$0			$0	$0	$0	$0	$0	$0	$0
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	UT	-$264	$0	$0	$0			$0	$0	-$264	$0	$0	$0	$0
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WA	-$75	$0	$0	-$75			$0	$0	$0	$0	$0	$0	$0
2530000	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WYP	-$30	$0	$0	$0			-$30	-$30	$0	$0	$0	$0	$0
2530000	289009	OREGON DSM LOANS NPV UNEARNED INCOME	OTHER	-$63	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$63
2530000 Total				**-$796**	**-$55**	**-$297**	**-$75**	**$0**	**$0**	**-$30**	**-$30**	**-$264**	**-$11**	**$0**	**$0**	**-$63**
2532500	289301	PARIBAS FUTURES 5310	SE	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2532500 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2539900	0	Fossil Rock Fuels Entries	SE	-$5,006	-$75	-$1,236	-$367			-$683	-$868	-$2,125	-$317	-$185	-$18	$0
2539900	230155	EMPLOYEE HOUSING SECURITY DEPOSITS	CA	-$13	-$13	$0	$0			$0	$0	$0	$0	$0	$0	$0
2539900	230155	EMPLOYEE HOUSING SECURITY DEPOSITS	SG	-$1	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2539900	289025	DEF REV-DUKE/HERMISTON GAS SALE NOVATION	SE	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2539900	289523	Govt Coal Lease Bonus Payment Liability	SE	$5,006	$75	$1,236	$367			$683	$868	$2,125	$317	$185	$18	$0
2539900	289907	FIRTH COGENERATION BUYOUT	SG	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2539900	289909	REDDING CONTRACT	SG	-$1,925	-$29	-$502	-$149			-$240	-$302	-$827	-$109	-$62	-$6	$0
2539900	289913	MCI - F.O.G. WIRE LEASE	SG	-$2,233	-$34	-$582	-$173			-$278	-$350	-$960	-$127	-$72	-$7	$0
2539900	289914	AMERICAN ELECTRIC POWER CRP	SG	-$1,154	-$18	-$301	-$90			-$144	-$181	-$496	-$65	-$37	-$4	$0
2539900	289915	FOOTCREEK CONTRACT	SG	-$361	-$6	-$94	-$28			-$45	-$57	-$155	-$20	-$12	-$1	$0
2539900	289917	West Valley Contract Term	SG	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2539900	289925	TRANSM CONST SECURITY DEPOSITS	SG	-$4,015	-$61	-$1,046	-$312			-$500	-$629	-$1,725	-$227	-$129	-$13	$0
2539900 Total				**-$9,702**	**-$161**	**-$2,524**	**-$752**	**$0**	**$0**	**-$1,207**	**-$1,519**	**-$4,164**	**-$549**	**-$312**	**-$32**	**$0**
2540000	231010	Reg Liab Current - Blue Sky	OTHER	-$4,864	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$4,864
2540000	231020	Reg Liab Current - DSM	OTHER	-$11,811	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$11,811
2540000	231060	Reg Liab Current - BPA Balancing Accts	OTHER	-$4,100	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$4,100
2540000	231070	Reg Liab Current - Asset Sale Givebacks	OTHER	-$121	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$121
2540000	231080	Reg Liab Current - REC Sales	OTHER	-$23,234	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$23,234
2540000	231100	Reg Liab Current - Other	OTHER	-$5,785	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$5,785
2540000	288115	REG LIABILITY PROP INS RESERVE	SO	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2540000	288124	Reg Liability - OR 2010 Protocol Def	OR	-$1,386	$0	-$1,386	$0			$0	$0	$0	$0	$0	$0	$0
2540000	288125	Powerdale Decom Costs Giveback - UT	UT	-$361	$0	$0	$0			$0	$0	-$361	$0	$0	$0	$0
2540000	288140	Reg Liability - WA A&G Credit	WA	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2540000	288159	RegL - Blue Sky - Recl to Curr	OTHER	$4,864	$0	$0	$0			$0	$0	$0	$0	$0	$0	$4,864
2540000	288165	Reg Liab - OR Enrgy	OTHER	-$1,977	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$1,977
2540000	288175	RegL - Asset Sale Givebacks - Recl to Cu	OTHER	$121	$0	$0	$0			$0	$0	$0	$0	$0	$0	$121
2540000	288176	Reg Liability - RECs - UT - Amortz	OTHER	-$4,396	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$4,396
2540000	288177	Reg Liability # WA REC Deferral	OTHER	-$17,313	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$17,313
2540000	288180	Reg Liability - Sale of REC's - OR	OTHER	-$1,525	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$1,525
2540000	288195	RegL - REC Sales - Recl to Curr	OTHER	$23,234	$0	$0	$0			$0	$0	$0	$0	$0	$0	$23,234
2540000	288250	Reg Liability -Tax Rev Req Adj - UT	UT	-$62	$0	$0	$0			$0	$0	-$62	$0	$0	$0	$0
2540000	288295	RegL - BPA Balancing Accts - Recl to Cur	OTHER	$4,100	$0	$0	$0			$0	$0	$0	$0	$0	$0	$4,100
2540000	288415	REGULATORY LIABILITY - DEF. BENEFIT- ARC	SE	$0	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0
2540000	288435	RegL - DSM - Recl to Curr	OTHER	$11,811	$0	$0	$0			$0	$0	$0	$0	$0	$0	$11,811
2540000	288479	Reg Liability - Def NPC Balance Reclass	OTHER	-$5,640	$0	$0	$0			$0	$0	$0	$0	$0	$0	-$5,640

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Miscellaneous Rate Base (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Id-PPL	Mont	Wy-PPL	Wyoming	Utah	Idaho	Wy-UPL	FERC	Other
2540000	288700	REG LIAB - OR INJURIES & DAMAGES RESERVE	OR	$724	$0	$724	$0			$0	$0	$0	$0	$0	$0	$0
2540000	288712	REG LIAB - OR PROPERTY INSURANCE RESERVE	OR	$960	$0	$960	$0			$0	$0	$0	$0	$0	$0	$0
2540000	288714	Reg Liab - ID Property Insurance Reserve	IDU	-$145	$0	$0	$0			$0	$0	$0	-$145	$0	$0	$0
2540000	288715	Reg Liab - UT Property Insurance Reserve	UT	-$82	$0	$0	$0			$0	$0	-$82	$0	$0	$0	$0
2540000	288716	Reg Liab - WY Property Insurance Reserve	WYP	-$447	$0	$0	$0			-$447	-$447	$0	$0	$0	$0	$0
2540000	288995	RegL - Other - Recl to Curr	OTHER	$5,785	$0	$0	$0			$0	$0	$0	$0	$0	$0	$5,785
2540000 Total				**-$31,648**	**$0**	**$298**	**$0**	**$0**	**$0**	**-$447**	**-$447**	**-$505**	**-$145**	**$0**	**$0**	**-$30,850**
2541050	288506	ARO/REG DIFF - TROJAN NUCLEAR PLANT	TROJP	-$3,236	-$49	-$836	-$249			-$409	-$516	-$1,388	-$187	-$107	-$11	$0
2541050 Total				**-$3,236**	**-$49**	**-$836**	**-$249**	**$0**	**$0**	**-$409**	**-$516**	**-$1,388**	**-$187**	**-$107**	**-$11**	**$0**
Grand Total				**$12,809**	**$465**	**$11,932**	**$2,783**	**$0**	**$0**	**$4,183**	**$5,402**	**$19,522**	**$2,225**	**$1,219**	**$128**	**-$29,648**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Regulatory Assests (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1242000	0	INT FREE-PPL	OTHER	$1,589	$0	$0	$0	$0	$0	$0	$0	$1,589
1242000	0	INT FREE-PPL	WA	$8	$0	$0	$8	$0	$0	$0	$0	$0
1242000 Total				**$1,597**	**$0**	**$0**	**$8**	**$0**	**$0**	**$0**	**$0**	**$1,589**
1243200	0	INT BEARING VAR%-PPL	OR	$0	$0	$0	$0	$0	$0	$0	$0	$0
1243200	0	INT BEARING VAR%-PPL	WA	$0	$0	$0	$0	$0	$0	$0	$0	$0
1243200 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1244100	0	ENERGY FINANSWER	OTHER	$66	$0	$0	$0	$0	$0	$0	$0	$66
1244100	0	ENERGY FINANSWER	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1244100	0	ENERGY FINANSWER	UT	$184	$0	$0	$0	$0	$184	$0	$0	$0
1244100	0	ENERGY FINANSWER	WA	$1	$0	$0	$1	$0	$0	$0	$0	$0
1244100 Total				**$250**	**$0**	**$0**	**$1**	**$0**	**$184**	**$0**	**$0**	**$66**
1244500	0	HOME COMFORT	CA	$10	$10	$0	$0	$0	$0	$0	$0	$0
1244500	0	HOME COMFORT	OTHER	$6	$0	$0	$0	$0	$0	$0	$0	$6
1244500	0	HOME COMFORT	SO	-$4	$0	-$1	$0	-$1	-$2	$0	$0	$0
1244500	0	HOME COMFORT	WA	$25	$0	$0	$25	$0	$0	$0	$0	$0
1244500 Total				**$37**	**$10**	**-$1**	**$25**	**-$1**	**-$2**	**$0**	**$0**	**$6**
1244900	0	"FINANSWER 12,000"	OTHER	$10	$0	$0	$0	$0	$0	$0	$0	$10
1244900	0	"FINANSWER 12,000"	UT	$1	$0	$0	$0	$0	$1	$0	$0	$0
1244900	0	"FINANSWER 12,000"	WYU	$2	$0	$0	$0	$2	$0	$0	$0	$0
1244900 Total				**$13**	**$0**	**$0**	**$0**	**$2**	**$1**	**$0**	**$0**	**$10**
1245300	0	IRRIGATION FINANSWER	CA	$20	$20	$0	$0	$0	$0	$0	$0	$0
1245300	0	IRRIGATION FINANSWER	OTHER	-$20	$0	$0	$0	$0	$0	$0	$0	-$20
1245300 Total				**$0**	**$20**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$20**
1245400	0	RETRO ENERGY FINANS	OTHER	$4	$0	$0	$0	$0	$0	$0	$0	$4
1245400	0	RETRO ENERGY FINANS	UT	-$4	$0	$0	$0	$0	-$4	$0	$0	$0
1245400 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**-$4**	**$0**	**$0**	**$4**
1247000	0	ELI/GAWL SYSTEM	CA	$362	$362	$0	$0	$0	$0	$0	$0	$0
1247000	0	ELI/GAWL SYSTEM	IDU	$17	$0	$0	$0	$0	$0	$17	$0	$0
1247000	0	ELI/GAWL SYSTEM	OTHER	-$6,999	$0	$0	$0	$0	$0	$0	$0	-$6,999
1247000	0	ELI/GAWL SYSTEM	UT	$4,629	$0	$0	$0	$0	$4,629	$0	$0	$0
1247000	0	ELI/GAWL SYSTEM	WA	$1,912	$0	$0	$1,912	$0	$0	$0	$0	$0
1247000	0	ELI/GAWL SYSTEM	WYP	$117	$0	$0	$0	$117	$0	$0	$0	$0
1247000	0	ELI/GAWL SYSTEM	WYU	$5	$0	$0	$0	$5	$0	$0	$0	$0
1247000 Total				**$42**	**$362**	**$0**	**$1,912**	**$122**	**$4,629**	**$17**	**$0**	**-$6,999**
1247100	0	CSS/ELI SYSTEM	OTHER	-$38	$0	$0	$0	$0	$0	$0	$0	-$38
1247100 Total				**-$38**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$38**
1249000	0	ESC - RESERVE	CA	$0	$0	$0	$0	$0	$0	$0	$0	$0
1249000	0	ESC - RESERVE	OTHER	-$82	$0	$0	$0	$0	$0	$0	$0	-$82
1249000	0	ESC - RESERVE	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1249000	0	ESC - RESERVE	UT	-$107	$0	$0	$0	$0	-$107	$0	$0	$0
1249000	0	ESC - RESERVE	WA	-$1	$0	$0	-$1	$0	$0	$0	$0	$0
1249000	0	ESC - RESERVE	WYU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1249000 Total				**-$191**	**$0**	**$0**	**-$1**	**$0**	**-$107**	**$0**	**$0**	**-$82**
1822200	185801	UNRECOVD PLANT - TROJAN-DR	TROJP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1822200	185802	UNRECOVD PLANT - TROJAN-CR-DEP'N	TROJP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1822200	185803	UNRECOVD PLANT - TROJAN-DECOM-DR	TROJD	$0	$0	$0	$0	$0	$0	$0	$0	$0
1822200	185804	UNRECOVD PLANT - TROJAN-DECOM-CR	TROJD	$0	$0	$0	$0	$0	$0	$0	$0	$0
1822200 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1822600	187058	Trail Mountain Mine Closure Costs	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1822600	187059	TRAIL MTN MINE UNRECOVERED INVEST	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1822600 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1822700	185821	UNRECOVERED PLANT - POWERDALE HYDRO PLAN	SG-P	$0	$0	$0	$0	$0	$0	$0	$0	$0
1822700 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1823910	102191	ASTORIA YOUNGS BAY CLEANUP	SO	$28	$1	$8	$2	$4	$12	$2	$0	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Regulatory Assests (Actuals)
Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823910	102324	DSM RETAIL MINOR SITES	SO	$17	$0	$5	$1	$2	$7	$1	$0	$0
1823910	102325	ASTORIA YOUNG'S BAY CLEANUP	SO	$3	$0	$1	$0	$1	$1	$0	$0	$0
1823910	102326	UTAH METALS CLEANUP	SO	$2	$0	$1	$0	$0	$1	$0	$0	$0
1823910	102463	D-SM RETAIL MINOR SITES	SO	$38	$1	$11	$3	$6	$16	$2	$0	$0
1823910	102464	ASTORIA YOUNGS BAY CLEANUP	SO	$1	$0	$0	$0	$0	$0	$0	$0	$0
1823910	102467	THIRD WEST SUBSTATION CLEANUP	SO	$815	$18	$223	$62	$117	$348	$45	$2	$0
1823910	102477	SALT LAKE CITY AUTO	SO	$6	$0	$2	$0	$1	$3	$0	$0	$0
1823910	102570	D-SM RETAIL MINOR SITES	SO	$6,541	$142	$1,791	$495	$940	$2,797	$362	$16	$0
1823910	102571	SALT LAKE CITY AUTO	SO	$2	$0	$1	$0	$0	$1	$0	$0	$0
1823910	102584	WASHINGTON NON-DEFERRED COSTS	WA	-$772	$0	$0	-$772	$0	$0	$0	$0	$0
1823910	102661	ASTORIA YOUNG BAY CLEANUP	SO	$1,242	$27	$340	$94	$178	$531	$69	$3	$0
1823910	102771	ENVIRONMENTAL COST UNDER AMORTIZATION	SO	$1,332	$29	$365	$101	$191	$569	$74	$3	$0
1823910 Total				**$9,257**	**$217**	**$2,746**	**-$14**	**$1,441**	**$4,288**	**$554**	**$24**	**$0**
1823920	102030	ENERGY FINANSWER - WASHINGTON	OTHER	$4,613	$0	$0	$0	$0	$0	$0	$0	$4,613
1823920	102032	INDUSTRIAL FINANSWER - WASHINGTON	OTHER	$23,446	$0	$0	$0	$0	$0	$0	$0	$23,446
1823920	102033	LOW INCOME - WASHINGTON	OTHER	$7,495	$0	$0	$0	$0	$0	$0	$0	$7,495
1823920	102034	SELF AUDIT - WASHINGTON	OTHER	$14	$0	$0	$0	$0	$0	$0	$0	$14
1823920	102036	COMMERCIAL SMALL RETROFIT - WASHINGTON	OTHER	$788	$0	$0	$0	$0	$0	$0	$0	$788
1823920	102037	INDUSTRIAL SMALL RETROFIT - WASHINGTON	OTHER	$13	$0	$0	$0	$0	$0	$0	$0	$13
1823920	102038	COMMERCIAL RETROFIT LIGHTING - WASHINGTO	OTHER	$624	$0	$0	$0	$0	$0	$0	$0	$624
1823920	102039	INDUSTRIAL RETROFIT LIGHTING-WA	OTHER	$88	$0	$0	$0	$0	$0	$0	$0	$88
1823920	102040	NEEA - WASHINGTON	OTHER	$6,633	$0	$0	$0	$0	$0	$0	$0	$6,633
1823920	102043	ENERGY CODE DEVELOPMENT	OTHER	$2	$0	$0	$0	$0	$0	$0	$0	$2
1823920	102044	HOME COMFORT - WASHINGTON	OTHER	$162	$0	$0	$0	$0	$0	$0	$0	$162
1823920	102045	WEATHERIZATION - WASHINGTON	OTHER	$22	$0	$0	$0	$0	$0	$0	$0	$22
1823920	102046	HASSLE FREE	OTHER	$41	$0	$0	$0	$0	$0	$0	$0	$41
1823920	102072	COMPACT FLUORESCENT LAMPS - WASHINGTON	OTHER	$1,183	$0	$0	$0	$0	$0	$0	$0	$1,183
1823920	102127	RESIDENTIAL PROGRAM RESEARCH - WA	OTHER	$24	$0	$0	$0	$0	$0	$0	$0	$24
1823920	102128	WA REVENUE RECOVERY - SBC OFFSET	OTHER	-$67,074	$0	$0	$0	$0	$0	$0	$0	-$67,074
1823920	102131	ENERGY FINANSWER - UTAH 2001/2002	OTHER	$1,280	$0	$0	$0	$0	$0	$0	$0	$1,280
1823920	102133	INDUSTRIAL FINANSWER - UTAH 2001/2002	OTHER	$1,353	$0	$0	$0	$0	$0	$0	$0	$1,353
1823920	102138	COMPACT FLUOR LAMPS (CFL) UT 2001/2002	OTHER	$4,202	$0	$0	$0	$0	$0	$0	$0	$4,202
1823920	102147	COMMERCIAL SMALL RETROFIT - UT 2001/2002	OTHER	$848	$0	$0	$0	$0	$0	$0	$0	$848
1823920	102148	INDUSTRIAL SMALL RETROFIT - UT 2002	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102149	COMMERCIAL RETROFIT LIGHTING - UT 2001/2	OTHER	$498	$0	$0	$0	$0	$0	$0	$0	$498
1823920	102150	INDUSTRIAL RETROFIT LIGHTING - UT 2001/2	OTHER	$82	$0	$0	$0	$0	$0	$0	$0	$82
1823920	102158	ENERGY FINANSWER - WYP - 2002	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
1823920	102159	INDUSTRIAL FINANSWER - WYP - 2002	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102160	SELF AUDIT - WYP - 2002	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102161	SELF AUDIT - WYU - 2002	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102185	WEB AUDIT PILOT - WA	OTHER	$527	$0	$0	$0	$0	$0	$0	$0	$527
1823920	102186	APPLIANCE REBATE - WA	OTHER	$18	$0	$0	$0	$0	$0	$0	$0	$18
1823920	102195	INDUSTRIAL RETROFIT LIGHTING - UT 2002	OTHER	$71	$0	$0	$0	$0	$0	$0	$0	$71
1823920	102196	POWER FORWARD UT 2002	OTHER	$115	$0	$0	$0	$0	$0	$0	$0	$115
1823920	102205	A/C LOAD CONTROL PGM - RESIDENTIAL - UT	OTHER	$28	$0	$0	$0	$0	$0	$0	$0	$28
1823920	102206	SCHOOL ENERGY EDUCATION - WA	OTHER	$3,456	$0	$0	$0	$0	$0	$0	$0	$3,456
1823920	102208	COMPACT FLUORESCENT LAMPS (CFL) - WYP 20	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102209	AIR CONDITIONING - UT 2002	OTHER	$24	$0	$0	$0	$0	$0	$0	$0	$24
1823920	102210	HASSELFREE EFFICIENCY - IDU 2003	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1823920	102213	REFRIGERATOR RECYCLING PGM - UT 2003	OTHER	$1,509	$0	$0	$0	$0	$0	$0	$0	$1,509
1823920	102214	REFRIGERATOR RECYCLING PGM - WA	OTHER	$2,990	$0	$0	$0	$0	$0	$0	$0	$2,990
1823920	102215	REFRIGERATOR RECYCLING - WYP 2003	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
1823920	102223	A/C LOAD CONTROL - RESIDENTIAL UT 2003	OTHER	$460	$0	$0	$0	$0	$0	$0	$0	$460
1823920	102225	AIR CONDITIONING - UT 2003	OTHER	$2,564	$0	$0	$0	$0	$0	$0	$0	$2,564

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1823920	102226	COMMERCIAL RETROFIT LIGHTING - UT 2003	OTHER	$1,187	$0	$0	$0	$0	$0	$0	$0	$1,187
1823920	102227	COMMERCIAL SMALL RETROFIT - UT 2003	OTHER	$895	$0	$0	$0	$0	$0	$0	$0	$895
1823920	102228	COMPACT FLOURESCENT LAMP (CFL) - UT 2002	OTHER	$13	$0	$0	$0	$0	$0	$0	$0	$13
1823920	102229	ENERGY FINANSWER - UT 2003	OTHER	$1,542	$0	$0	$0	$0	$0	$0	$0	$1,542
1823920	102230	INDUSTRIAL FINANSWER - UT 2003	OTHER	$1,658	$0	$0	$0	$0	$0	$0	$0	$1,658
1823920	102231	INDUSTRIAL RETROFIT LIGHTING - UT 2003	OTHER	$191	$0	$0	$0	$0	$0	$0	$0	$191
1823920	102232	INDUSTRIAL SMALL RETROFIT - UTAH - 2003	OTHER	$14	$0	$0	$0	$0	$0	$0	$0	$14
1823920	102233	POWER FORWARD - UT 2003	OTHER	-$27	$0	$0	$0	$0	$0	$0	$0	-$27
1823920	102236	COMPACT FLUORESCENT LAMPS - WYP 2003	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102237	ENERGY FINANSWER - WYP 2003	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102238	INDUSTRIAL FINANSWER - WYP 2003	WYP	$6	$0	$0	$0	$6	$0	$0	$0	$0
1823920	102239	SELF AUDIT - WYOMING - PPL 2003	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102245	CA REVENUE RECOVERY - BALANCING ACCT	OTHER	-$2,105	$0	$0	$0	$0	$0	$0	$0	-$2,105
1823920	102327	COMMERCIAL SELF-DIRECT UT 2003	OTHER	$4	$0	$0	$0	$0	$0	$0	$0	$4
1823920	102328	INDUSTRIAL SELF-DIRECT UT 2003	OTHER	$7	$0	$0	$0	$0	$0	$0	$0	$7
1823920	102336	LOW INCOME - UTAH - 2004	OTHER	$22	$0	$0	$0	$0	$0	$0	$0	$22
1823920	102337	REFRIGERATOR RECYCLING PGM - UT 2004	OTHER	$3,581	$0	$0	$0	$0	$0	$0	$0	$3,581
1823920	102338	AC LOAD CONTROL - RESIDENTIAL UT 2004	OTHER	$2,910	$0	$0	$0	$0	$0	$0	$0	$2,910
1823920	102339	AIR CONDITIONING - UT 2004	OTHER	$3,026	$0	$0	$0	$0	$0	$0	$0	$3,026
1823920	102340	COMMERCIAL RETROFIT LIGHTING - UT 2004	OTHER	$1,547	$0	$0	$0	$0	$0	$0	$0	$1,547
1823920	102341	COMMERCIAL SMALL RETROFIT - UT 2004	OTHER	$285	$0	$0	$0	$0	$0	$0	$0	$285
1823920	102342	COMPACT FLOURESCENT LAMPS (CFL) UT 2004	OTHER	-$1	$0	$0	$0	$0	$0	$0	$0	-$1
1823920	102343	ENERGY FINANSWER - UT 2004	OTHER	$1,227	$0	$0	$0	$0	$0	$0	$0	$1,227
1823920	102344	INDUSTRIAL FINANSWER - UT 2004	OTHER	$2,562	$0	$0	$0	$0	$0	$0	$0	$2,562
1823920	102345	INDUSTRIAL RETROFIT - UT 2004	OTHER	$230	$0	$0	$0	$0	$0	$0	$0	$230
1823920	102346	INDUSTRIAL SMALL RETROFIT - UT 2004	OTHER	$51	$0	$0	$0	$0	$0	$0	$0	$51
1823920	102347	POWER FORWARD - UT 2004	OTHER	$54	$0	$0	$0	$0	$0	$0	$0	$54
1823920	102348	COMMERCIAL SELF-DIRECT - UT 2004	OTHER	$89	$0	$0	$0	$0	$0	$0	$0	$89
1823920	102349	INDUSTRIAL SELF-DIRECT - UT 2004	OTHER	$129	$0	$0	$0	$0	$0	$0	$0	$129
1823920	102351	ENERGY FINANSWER - ID/UT 2004	IDU	$3	$0	$0	$0	$0	$0	$3	$0	$0
1823920	102360	REFRIGERATOR RECYCLING PGM - WYP 2004	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102362	ENERGY FINANSWER - WYP 2004	WYP	$4	$0	$0	$0	$4	$0	$0	$0	$0
1823920	102363	INDUSTRIAL FINANSWER - WYP 2004	WYP	$11	$0	$0	$0	$11	$0	$0	$0	$0
1823920	102364	SELF AUDIT - WYOMING - PPL 2004	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102443	ESIDENTIAL NEW CONSTRUCTION - WASHINGTON	OTHER	$561	$0	$0	$0	$0	$0	$0	$0	$561
1823920	102444	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$76	$0	$0	$0	$0	$0	$0	$0	$76
1823920	102458	COMMERCIAL FINANSWER EXPRESS - WASHINGTO	OTHER	$6,010	$0	$0	$0	$0	$0	$0	$0	$6,010
1823920	102459	INDUSTRIAL FINANSWER EXPRESS - WASHINGTO	OTHER	$2,197	$0	$0	$0	$0	$0	$0	$0	$2,197
1823920	102460	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$446	$0	$0	$0	$0	$0	$0	$0	$446
1823920	102461	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$146	$0	$0	$0	$0	$0	$0	$0	$146
1823920	102462	UTAH REVENUE RECOVERY - SBC OFFSET	OTHER	-$319,916	$0	$0	$0	$0	$0	$0	$0	-$319,916
1823920	102502	RETROFIT COMMISSIONING PROGRAM - UTAH	OTHER	$2	$0	$0	$0	$0	$0	$0	$0	$2
1823920	102503	C&I LIGHTING LOAD CONTROL - UTAH - 2004	OTHER	$23	$0	$0	$0	$0	$0	$0	$0	$23
1823920	102504	REFRIGERATOR RECYCLING PGM - IDAHO - 200	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1823920	102506	COMMERCIAL FINANSWER EXPRESS - IDAHO - 2	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
1823920	102507	INDUSTRIAL FINANSWER EXPRESS - IDAHO - 2	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
1823920	102508	IRRIGATION EFFICIENCY PROGRAM - IDAHO -	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
1823920	102518	ENERGY FINANSWER - ID/UT 2005	IDU	$8	$0	$0	$0	$0	$0	$8	$0	$0
1823920	102525	REFRIGERATOR RECYCLING PGM - IDAHO - 200	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
1823920	102528	COMMERCIAL FINANSWER EXPRESS - IDAHO - 2	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
1823920	102529	INDUSTRIAL FINANSWER EXPRESS - IDAHO - 2	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1823920	102530	IRRIGATION EFFICIENCY PROGRAM - IDAHO -	IDU	$18	$0	$0	$0	$0	$0	$18	$0	$0
1823920	102532	LOW INCOME - UTAH - 2005	OTHER	$48	$0	$0	$0	$0	$0	$0	$0	$48
1823920	102533	REFRIGERATOR RECYCLING PGM- UTAH - 2005	OTHER	$3,306	$0	$0	$0	$0	$0	$0	$0	$3,306

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1823920	102534	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$3,060	$0	$0	$0	$0	$0	$0	$0	$3,060
1823920	102535	AIR CONDITIONING - UTAH - 2005	OTHER	$2,347	$0	$0	$0	$0	$0	$0	$0	$2,347
1823920	102536	COMMERCIAL RETROFIT LIGHTING - UTAH - 20	OTHER	$65	$0	$0	$0	$0	$0	$0	$0	$65
1823920	102537	COMMERCIAL SMALL RETROFIT - UTAH - 2005	OTHER	$223	$0	$0	$0	$0	$0	$0	$0	$223
1823920	102539	ENERGY FINANSWER - UTAH - 2005	OTHER	$1,476	$0	$0	$0	$0	$0	$0	$0	$1,476
1823920	102540	INDUSTRIAL FINANSWER - UTAH - 2005	OTHER	$3,485	$0	$0	$0	$0	$0	$0	$0	$3,485
1823920	102541	INDUSTRIAL RETROFIT LIGHTING - UTAH - 20	OTHER	$60	$0	$0	$0	$0	$0	$0	$0	$60
1823920	102543	POWER FORWARD - UTAH - 2005	OTHER	$50	$0	$0	$0	$0	$0	$0	$0	$50
1823920	102544	COMMERCIAL SELF-DIRECT - UTAH - 2005	OTHER	$67	$0	$0	$0	$0	$0	$0	$0	$67
1823920	102545	INDUSTRIAL SELF-DIRECT - UTAH - 2005	OTHER	$103	$0	$0	$0	$0	$0	$0	$0	$103
1823920	102546	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$944	$0	$0	$0	$0	$0	$0	$0	$944
1823920	102547	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$1,967	$0	$0	$0	$0	$0	$0	$0	$1,967
1823920	102548	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$421	$0	$0	$0	$0	$0	$0	$0	$421
1823920	102549	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$105	$0	$0	$0	$0	$0	$0	$0	$105
1823920	102550	C&I LIGHTING LOAD CONTROL - UTAH - 2005	OTHER	$36	$0	$0	$0	$0	$0	$0	$0	$36
1823920	102552	ENERGY FINANSWER - WYOMING PPL - 2005	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102553	INDUSTRIAL FINANSWER-WYOMING - PPL 2005	WYP	$9	$0	$0	$0	$9	$0	$0	$0	$0
1823920	102554	SELF AUDIT - WYOMING - PPL 2005	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102555	REFRIGERATOR RECYCLING - PPL WYOMING - 2	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102556	1823920/102556	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102562	APPLIANCE INCENTIVE - WASHWISE - WASHING	OTHER	$53	$0	$0	$0	$0	$0	$0	$0	$53
1823920	102586	IRRIGATION LOAD CONTROL - UTAH - 2005	OTHER	$3	$0	$0	$0	$0	$0	$0	$0	$3
1823920	102702	ENERGY FINANSWER - WYOMING PPL - 2006	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
1823920	102703	INDUSTRIAL FINANSWER-WYOMING-PPL 2006	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102706	LOW INCOME-UTAH-2006	OTHER	$119	$0	$0	$0	$0	$0	$0	$0	$119
1823920	102707	REFRIGERATOR RECYCLING PGM-UTAH-2006	OTHER	$3,752	$0	$0	$0	$0	$0	$0	$0	$3,752
1823920	102708	A/C LOAD CONTROL-RESIDENTIAL/UTAH-2006	OTHER	$8,624	$0	$0	$0	$0	$0	$0	$0	$8,624
1823920	102709	AIR CONDITIONING-UTAH-2006	OTHER	$1,499	$0	$0	$0	$0	$0	$0	$0	$1,499
1823920	102712	ENERGY FINANSWER-UTAH-2006	OTHER	$2,187	$0	$0	$0	$0	$0	$0	$0	$2,187
1823920	102713	INDUSTRIAL FINANSWER-WYOMING-UTAH-2006	OTHER	$2,748	$0	$0	$0	$0	$0	$0	$0	$2,748
1823920	102717	COMMERCIAL SELF-DIRECT-UTAH-2006	OTHER	$65	$0	$0	$0	$0	$0	$0	$0	$65
1823920	102718	INDUSTRIAL SELF-DIRECT-UTAH-2006	OTHER	$122	$0	$0	$0	$0	$0	$0	$0	$122
1823920	102719	RESIDENTIAL NEW CONSTRUCTION-UTAH-2006	OTHER	$1,848	$0	$0	$0	$0	$0	$0	$0	$1,848
1823920	102720	COMMERCIAL FINANSWER EXPRESS-UTAH-2006	OTHER	$2,469	$0	$0	$0	$0	$0	$0	$0	$2,469
1823920	102721	INDUSTRIAL FINANSWER-UTAH-2006	OTHER	$536	$0	$0	$0	$0	$0	$0	$0	$536
1823920	102722	RETROFIT COMMISSIONING PROGRAM -UTAH-200	OTHER	$211	$0	$0	$0	$0	$0	$0	$0	$211
1823920	102723	C&I LIGHTING LOAD CONTROL -UTAH-2006	OTHER	$8	$0	$0	$0	$0	$0	$0	$0	$8
1823920	102725	CALIFORNIA DSM EXPENSE-2006	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102759	HOME ENERGY EFF INCENTIVE PROG-UTAH-2006	OTHER	$241	$0	$0	$0	$0	$0	$0	$0	$241
1823920	102760	HOME ENERGY EFF INCENTIVE PROG-WA-2006	OTHER	$6,265	$0	$0	$0	$0	$0	$0	$0	$6,265
1823920	102761	HOME ENERGY EFF INCENTIVE PROG-PPL WYOMI	WYP	$6	$0	$0	$0	$6	$0	$0	$0	$0
1823920	102767	DSR COSTS BEING AMORTIZED	OTHER	-$26,568	$0	$0	$0	$0	$0	$0	$0	-$26,568
1823920	102788	DSR COSTS BEING AMORTIZED	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102789	DSR COSTS BEING AMORTIZED	WYP	$3	$0	$0	$0	$3	$0	$0	$0	$0
1823920	102790	DSR COSTS BEING AMORTIZED	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102791	DSR COSTS BEING AMORTIZED	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102792	DSR COSTS BEING AMORTIZED	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102796	DSR COSTS BEING AMORTIZED	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102798	ENERGY FINANSWER - WYOMING PPL - 2007	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
1823920	102799	MAJOR CUSTOMER 99	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102802	HOME ENERGY EFF INCENTIVE PRO - PPL WYOM	WYP	$5	$0	$0	$0	$5	$0	$0	$0	$0
1823920	102803	LOW-INCOME WEATHERIZATION - WYOMING PPL-	WYP	$3	$0	$0	$0	$3	$0	$0	$0	$0
1823920	102804	COMMERCIAL FINANSWER EXPRESS - WY - 2007	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102805	INDUSTRIAL FINANSWER EXPRESS - WY - 2007	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0

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1823920	102806	SELF DIRECT - COMMERCIAL - WY - 2007	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102807	SELF DIRECT - INDUSTRIAL - WY - 2007	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102819	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$5,982	$0	$0	$0	$0	$0	$0	$0	$5,982
1823920	102820	AIR CONDITIONING - UTAH - 2007	OTHER	$883	$0	$0	$0	$0	$0	$0	$0	$883
1823920	102821	ENERGY FINANSWER - UTAH - 2007	OTHER	$1,952	$0	$0	$0	$0	$0	$0	$0	$1,952
1823920	102822	INDUSTRIAL FINANSWER - UTAH - 2007	OTHER	$3,369	$0	$0	$0	$0	$0	$0	$0	$3,369
1823920	102823	LOW INCOME - UTAH - 2007	OTHER	$117	$0	$0	$0	$0	$0	$0	$0	$117
1823920	102824	POWER FORWARD - UTAH - 2007	OTHER	$50	$0	$0	$0	$0	$0	$0	$0	$50
1823920	102825	REFRIGERATOR RECYCLING PGM- UTAH - 2007	OTHER	$3,399	$0	$0	$0	$0	$0	$0	$0	$3,399
1823920	102826	COMMERCIAL SELF-DIRECT - UTAH - 2007	OTHER	$61	$0	$0	$0	$0	$0	$0	$0	$61
1823920	102827	INDUSTRIAL SELF-DIRECT - UTAH - 2007	OTHER	$108	$0	$0	$0	$0	$0	$0	$0	$108
1823920	102828	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$1,936	$0	$0	$0	$0	$0	$0	$0	$1,936
1823920	102829	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$3,277	$0	$0	$0	$0	$0	$0	$0	$3,277
1823920	102830	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$968	$0	$0	$0	$0	$0	$0	$0	$968
1823920	102831	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$187	$0	$0	$0	$0	$0	$0	$0	$187
1823920	102833	IRRIGATION LOAD CONTROL - UTAH - 2007	OTHER	$277	$0	$0	$0	$0	$0	$0	$0	$277
1823920	102834	HOME ENERGY EFF INCENTIVE PROG - UT 2007	OTHER	$3,034	$0	$0	$0	$0	$0	$0	$0	$3,034
1823920	102883	CALIFORNIA DSM EXPENSE - 2008	CA	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102885	ENERGY FINANSWER - WYOMING PPL - 2008	WYP	$3	$0	$0	$0	$3	$0	$0	$0	$0
1823920	102886	INDUSTRIAL FINANSWER - WYOMING PPL - 200	WYP	$4	$0	$0	$0	$4	$0	$0	$0	$0
1823920	102888	REFRIGERATOR RECYCLING - WYOMING 2008	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
1823920	102889	HOME ENERGY EFF INCENTIVE PROGRAM - WYOM	WYP	$4	$0	$0	$0	$4	$0	$0	$0	$0
1823920	102890	LOW INCOME WEATHERIZATION - WYOMING 2008	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
1823920	102891	COMMERCIAL FINANSWER EXPRESS - WYOMING 2	WYP	$1	$0	$0	$0	$1	$0	$0	$0	$0
1823920	102892	INDUSTRIAL FINANSWER EXPRESS - WY - 2008	WYP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102893	SELF DIRECT COMMERCIAL - WYOMING 2008	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102894	SELF DIRECT INDUSTRIAL - WYOMING 2008	WYP	$2	$0	$0	$0	$2	$0	$0	$0	$0
1823920	102906	AC LOAD CONTROL - RESIDENTIAL - UTAH 200	OTHER	$7,175	$0	$0	$0	$0	$0	$0	$0	$7,175
1823920	102907	AIR CONDITIONING - UTAH 2008	OTHER	$526	$0	$0	$0	$0	$0	$0	$0	$526
1823920	102908	ENERGY FINANSWER - UTAH - 2008	OTHER	$3,466	$0	$0	$0	$0	$0	$0	$0	$3,466
1823920	102909	INDUSTRIAL FINANSWER - UTAH - 2008	OTHER	$4,289	$0	$0	$0	$0	$0	$0	$0	$4,289
1823920	102910	LOW INCOME - UTAH 2008	OTHER	$127	$0	$0	$0	$0	$0	$0	$0	$127
1823920	102911	POWER FORWARD - UTAH - 2008	OTHER	$50	$0	$0	$0	$0	$0	$0	$0	$50
1823920	102912	REFRIGERATOR RECYCLING - UTAH - 2008	OTHER	$2,570	$0	$0	$0	$0	$0	$0	$0	$2,570
1823920	102913	COMMERCIAL SELF DIRECT - UTAH - 2008	OTHER	$83	$0	$0	$0	$0	$0	$0	$0	$83
1823920	102914	INDUSTRIAL SELF DIRECT - UTAH - 2008	OTHER	$126	$0	$0	$0	$0	$0	$0	$0	$126
1823920	102915	RESIDENTIAL NEW CONSTRUCTION - UTAH 2008	OTHER	$1,664	$0	$0	$0	$0	$0	$0	$0	$1,664
1823920	102916	COMMERCIAL FINANSWER EXPRESS - UTAH 2008	OTHER	$3,791	$0	$0	$0	$0	$0	$0	$0	$3,791
1823920	102917	INDUSTRIAL FINANSWER EXPRESS - UTAH 2008	OTHER	$1,133	$0	$0	$0	$0	$0	$0	$0	$1,133
1823920	102918	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$1,053	$0	$0	$0	$0	$0	$0	$0	$1,053
1823920	102919	C&I LIGHTING LOAD CONTROL - UTAH - 2008	OTHER	$4	$0	$0	$0	$0	$0	$0	$0	$4
1823920	102920	IRRIGATION LOAD CONTROL - UTAH	OTHER	$762	$0	$0	$0	$0	$0	$0	$0	$762
1823920	102921	HOME ENERGY EFF INCENTIVE PROGRAM - UTAH	OTHER	$7,817	$0	$0	$0	$0	$0	$0	$0	$7,817
1823920	102964	CALIFORNIA DSM EXPENSE - 2009	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	102976	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$9,817	$0	$0	$0	$0	$0	$0	$0	$9,817
1823920	102977	AIR CONDITIONING - UTAH - 2009	OTHER	$500	$0	$0	$0	$0	$0	$0	$0	$500
1823920	102978	ENERGY FINANSWER - UTAH - 2009	OTHER	$2,532	$0	$0	$0	$0	$0	$0	$0	$2,532
1823920	102979	INDUSTRIAL FINANSWER - UTAH - 2009	OTHER	$5,215	$0	$0	$0	$0	$0	$0	$0	$5,215
1823920	102980	LOW INCOME - UTAH - 2009	OTHER	$162	$0	$0	$0	$0	$0	$0	$0	$162
1823920	102981	POWER FORWARD - UTAH - 2009	OTHER	$50	$0	$0	$0	$0	$0	$0	$0	$50
1823920	102982	REFRIGERATOR RECYCLING PGM- UTAH - 2009	OTHER	$2,339	$0	$0	$0	$0	$0	$0	$0	$2,339
1823920	102983	COMMERCIAL SELF-DIRECT - UTAH - 2009	OTHER	$53	$0	$0	$0	$0	$0	$0	$0	$53
1823920	102984	INDUSTRIAL SELF-DIRECT - UTAH - 2009	OTHER	$72	$0	$0	$0	$0	$0	$0	$0	$72
1823920	102985	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$1,446	$0	$0	$0	$0	$0	$0	$0	$1,446

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1823920	102986	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$3,258	$0	$0	$0	$0	$0	$0	$0	$3,258
1823920	102987	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$776	$0	$0	$0	$0	$0	$0	$0	$776
1823920	102988	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$947	$0	$0	$0	$0	$0	$0	$0	$947
1823920	102990	IRRIGATION LOAD CONTROL - UTAH - 2009	OTHER	$2,732	$0	$0	$0	$0	$0	$0	$0	$2,732
1823920	102991	HOME ENERGY EFF INCENTIVE PROG - UT 2009	OTHER	$25,439	$0	$0	$0	$0	$0	$0	$0	$25,439
1823920	102992	ENERGY FINANSWER - WYOMING PPL - 2009	OTHER	$21	$0	$0	$0	$0	$0	$0	$0	$21
1823920	102993	INDUSTRIAL FINANSWER-WYOMING - PPL 2009	OTHER	$96	$0	$0	$0	$0	$0	$0	$0	$96
1823920	102995	REFRIGERATOR RECYCLING - PPL WYOMING - 2	OTHER	$140	$0	$0	$0	$0	$0	$0	$0	$140
1823920	102996	HOME ENERGY EFF INCENTIVE PRO - PPL WYOM	OTHER	$439	$0	$0	$0	$0	$0	$0	$0	$439
1823920	102997	LOW-INCOME WEATHERIZATION - WYOMING PPL	OTHER	$86	$0	$0	$0	$0	$0	$0	$0	$86
1823920	102998	COMMERCIAL FINANSWER EXPRESS - WY - 2009	OTHER	$139	$0	$0	$0	$0	$0	$0	$0	$139
1823920	102999	INDUSTRIAL FINANSWER EXPRESS - WY - 2009	OTHER	$59	$0	$0	$0	$0	$0	$0	$0	$59
1823920	103000	SELF DIRECT - COMMERCIAL - WY - 2009	OTHER	$5	$0	$0	$0	$0	$0	$0	$0	$5
1823920	103001	SELF DIRECT - INDUSTRIAL - WY - 2009	OTHER	$12	$0	$0	$0	$0	$0	$0	$0	$12
1823920	103003	MAIN CHECK DISB-WIRES/ACH IN CLEAR ACCT	OTHER	$2	$0	$0	$0	$0	$0	$0	$0	$2
1823920	103004	MAIN CHECK DISB-WIRES/ACH OUT CLEAR ACCT	OTHER	$2	$0	$0	$0	$0	$0	$0	$0	$2
1823920	103005	COMMERCIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	$236	$0	$0	$0	$0	$0	$0	$0	$236
1823920	103006	INDUSTRIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	$34	$0	$0	$0	$0	$0	$0	$0	$34
1823920	103007	ENERGY FINANSWER Cat 2 - WY 2009	OTHER	$40	$0	$0	$0	$0	$0	$0	$0	$40
1823920	103008	INDUSTRIAL FINANSWER Cat 2 -WY 2009	OTHER	$34	$0	$0	$0	$0	$0	$0	$0	$34
1823920	103012	WYOMING REV RECOVERY - SBC OFFSET CAT 1	OTHER	-$3,852	$0	$0	$0	$0	$0	$0	$0	-$3,852
1823920	103013	WYOMING REV RECOVERY - SBC OFFSET CAT 2	OTHER	-$2,648	$0	$0	$0	$0	$0	$0	$0	-$2,648
1823920	103014	WYOMING REV RECOVERY - SBC OFFSET CAT 3	OTHER	-$3,061	$0	$0	$0	$0	$0	$0	$0	-$3,061
1823920	103031	OUTREACH and COMMUNICATIONS - UT 2009	OTHER	$571	$0	$0	$0	$0	$0	$0	$0	$571
1823920	103059	CALIFORNIA DSM EXPENSE - 2010	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	103071	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$4,836	$0	$0	$0	$0	$0	$0	$0	$4,836
1823920	103072	AIR CONDITIONING - UTAH - 2010	OTHER	$1,490	$0	$0	$0	$0	$0	$0	$0	$1,490
1823920	103073	ENERGY FINANSWER - UTAH - 2010	OTHER	$3,246	$0	$0	$0	$0	$0	$0	$0	$3,246
1823920	103074	INDUSTRIAL FINANSWER - UTAH - 2010	OTHER	$4,524	$0	$0	$0	$0	$0	$0	$0	$4,524
1823920	103075	LOW INCOME - UTAH - 2010	OTHER	$258	$0	$0	$0	$0	$0	$0	$0	$258
1823920	103076	POWER FORWARD - UTAH # 2010	OTHER	$50	$0	$0	$0	$0	$0	$0	$0	$50
1823920	103077	REFRIGERATOR RECYCLING PGM- UTAH - 2010	OTHER	$2,370	$0	$0	$0	$0	$0	$0	$0	$2,370
1823920	103078	COMMERCIAL SELF-DIRECT - UTAH - 2010	OTHER	$187	$0	$0	$0	$0	$0	$0	$0	$187
1823920	103079	INDUSTRIAL SELF-DIRECT - UTAH - 2010	OTHER	$330	$0	$0	$0	$0	$0	$0	$0	$330
1823920	103080	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$2,605	$0	$0	$0	$0	$0	$0	$0	$2,605
1823920	103081	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$4,107	$0	$0	$0	$0	$0	$0	$0	$4,107
1823920	103082	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$1,019	$0	$0	$0	$0	$0	$0	$0	$1,019
1823920	103083	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$986	$0	$0	$0	$0	$0	$0	$0	$986
1823920	103085	IRRIGATION LOAD CONTROL - UTAH - 2010	OTHER	$2,513	$0	$0	$0	$0	$0	$0	$0	$2,513
1823920	103086	HOME ENERGY EFF INCENTIVE PROG - UT 2010	OTHER	$16,876	$0	$0	$0	$0	$0	$0	$0	$16,876
1823920	103087	OUTREACH and COMMUNICATIONS - UT 2010	OTHER	$1,485	$0	$0	$0	$0	$0	$0	$0	$1,485
1823920	103089	ENERGY FINANSWER-WY-2010 CAT3	OTHER	$11	$0	$0	$0	$0	$0	$0	$0	$11
1823920	103090	INDUSTRIAL FINANSWER-WY-2010 CAT3	OTHER	$669	$0	$0	$0	$0	$0	$0	$0	$669
1823920	103092	REFRIGERATOR RECYCLING-WY -2010 CAT1	OTHER	$176	$0	$0	$0	$0	$0	$0	$0	$176
1823920	103093	HOME ENERGY EFF INCENT PROG Y-2010 CAT1	OTHER	$740	$0	$0	$0	$0	$0	$0	$0	$740
1823920	103094	LOW-INCOME WEATHERZTN - WY 2010 CAT1	OTHER	$49	$0	$0	$0	$0	$0	$0	$0	$49
1823920	103095	COMMERCIAL FINANSWER EXP WY-2010 CAT3	OTHER	$65	$0	$0	$0	$0	$0	$0	$0	$65
1823920	103096	INDUSTRIAL FINANSWER EXP WY-2010 CAT3	OTHER	$127	$0	$0	$0	$0	$0	$0	$0	$127
1823920	103097	SELF DIRECT - COMMERCIAL -WY-2010 CAT3	OTHER	$3	$0	$0	$0	$0	$0	$0	$0	$3
1823920	103098	SELF DIRECT -INDUSTRIAL -WY-2010 CAT3	OTHER	$12	$0	$0	$0	$0	$0	$0	$0	$12
1823920	103099	COMMERCIAL FINANSWER EXP- WY-2010 CAT2	OTHER	$587	$0	$0	$0	$0	$0	$0	$0	$587
1823920	103100	INDUSTRIAL FINAN EXPRESS WY-2010 CAT2	OTHER	$55	$0	$0	$0	$0	$0	$0	$0	$55
1823920	103101	ENERGY FINANSWER -WY 2010 CAT2	OTHER	$186	$0	$0	$0	$0	$0	$0	$0	$186
1823920	103102	INDUSTRIAL FINANSWER -WY 2010 CAT2	OTHER	$125	$0	$0	$0	$0	$0	$0	$0	$125

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1823920	103103	Check Disb-Wires/ACH In Clearing - BT	OTHER	$1	$0	$0	$0	$0	$0	$0	$0	$1
1823920	103104	Check Disb-Wires/ACH Out Clearing - BT	OTHER	$3	$0	$0	$0	$0	$0	$0	$0	$3
1823920	103137	Company Initiatives DEI Study- Washingto	OTHER	$595	$0	$0	$0	$0	$0	$0	$0	$595
1823920	103163	Commercial Direct Install - Utah - 2011	OTHER	$3	$0	$0	$0	$0	$0	$0	$0	$3
1823920	103164	Commercial Curtailment - Utah - 2011	OTHER	$30	$0	$0	$0	$0	$0	$0	$0	$30
1823920	103165	Commercial Direct Install - Washington	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	103166	Commercial Curtailment - Washington	OTHER	$5	$0	$0	$0	$0	$0	$0	$0	$5
1823920	103168	CALIFORNIA DSM EXPENSE - 2011	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	103169	Commercial Curtailment - Oregon	OTHER	$27	$0	$0	$0	$0	$0	$0	$0	$27
1823920	103181	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$6,498	$0	$0	$0	$0	$0	$0	$0	$6,498
1823920	103182	AIR CONDITIONING - UTAH - 2011	OTHER	$1,305	$0	$0	$0	$0	$0	$0	$0	$1,305
1823920	103183	ENERGY FINANSWER - UTAH - 2011	OTHER	$3,647	$0	$0	$0	$0	$0	$0	$0	$3,647
1823920	103184	INDUSTRIAL FINANSWER - UTAH - 2011	OTHER	$5,016	$0	$0	$0	$0	$0	$0	$0	$5,016
1823920	103185	LOW INCOME - UTAH - 2011	OTHER	$255	$0	$0	$0	$0	$0	$0	$0	$255
1823920	103186	Power Forward - Utah - 2011	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	103187	REFRIGERATOR RECYCLING PGM- UTAH - 2011	OTHER	$1,880	$0	$0	$0	$0	$0	$0	$0	$1,880
1823920	103188	COMMERCIAL SELF-DIRECT - UTAH - 2011	OTHER	$126	$0	$0	$0	$0	$0	$0	$0	$126
1823920	103189	INDUSTRIAL SELF-DIRECT - UTAH - 2011	OTHER	$240	$0	$0	$0	$0	$0	$0	$0	$240
1823920	103190	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$3,071	$0	$0	$0	$0	$0	$0	$0	$3,071
1823920	103191	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$4,607	$0	$0	$0	$0	$0	$0	$0	$4,607
1823920	103192	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$1,233	$0	$0	$0	$0	$0	$0	$0	$1,233
1823920	103193	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$411	$0	$0	$0	$0	$0	$0	$0	$411
1823920	103195	IRRIGATION LOAD CONTROL - UTAH - 2011	OTHER	$2,513	$0	$0	$0	$0	$0	$0	$0	$2,513
1823920	103196	HOME ENERGY EFF INCENTIVE PROG - UT 2011	OTHER	$11,360	$0	$0	$0	$0	$0	$0	$0	$11,360
1823920	103197	OUTREACH and COMMUNICATIONS - UT 2011	OTHER	$1,437	$0	$0	$0	$0	$0	$0	$0	$1,437
1823920	103199	ENERGY FINANSWER-WY-2011 CAT3	OTHER	$30	$0	$0	$0	$0	$0	$0	$0	$30
1823920	103200	INDUSTRIAL FINANSWER-WY-2011 CAT3	OTHER	$433	$0	$0	$0	$0	$0	$0	$0	$433
1823920	103202	REFRIGERATOR RECYCLING-WY -2011 CAT1	OTHER	$183	$0	$0	$0	$0	$0	$0	$0	$183
1823920	103203	HOME ENERGY EFF INCENT PROG Y-2011 CAT1	OTHER	$1,070	$0	$0	$0	$0	$0	$0	$0	$1,070
1823920	103204	Low-Income Weatherztn - Wy 2011 CAT1	OTHER	$42	$0	$0	$0	$0	$0	$0	$0	$42
1823920	103205	COMMERCIAL FINANSWER EXP WY-2011 CAT3	OTHER	$102	$0	$0	$0	$0	$0	$0	$0	$102
1823920	103206	INDUSTRIAL FINANSWER EXP WY-2011 CAT3	OTHER	$168	$0	$0	$0	$0	$0	$0	$0	$168
1823920	103207	Self Direct - Commercial -Wy-2011 CAT3	OTHER	$6	$0	$0	$0	$0	$0	$0	$0	$6
1823920	103208	Self Direct -Industrial -Wy-2011 CAT3	OTHER	$268	$0	$0	$0	$0	$0	$0	$0	$268
1823920	103209	COMMERCIAL FINANSWER EXP- WY-2011 CAT2	OTHER	$894	$0	$0	$0	$0	$0	$0	$0	$894
1823920	103210	INDUSTRIAL FINAN EXPRESS WY-2011 CAT2	OTHER	$55	$0	$0	$0	$0	$0	$0	$0	$55
1823920	103211	ENERGY FINANSWER -WY 2011 CAT2	OTHER	$51	$0	$0	$0	$0	$0	$0	$0	$51
1823920	103212	INDUSTRIAL FINANSWER -WY 2011 CAT2	OTHER	$98	$0	$0	$0	$0	$0	$0	$0	$98
1823920	103213	Self Direct - Commercial Wy-2011 CAT2	OTHER	$3	$0	$0	$0	$0	$0	$0	$0	$3
1823920	103214	Self Direct- Industrial Wy-2011 CAT2	OTHER	$11	$0	$0	$0	$0	$0	$0	$0	$11
1823920	103277	OUTREACH & COMM- WATTSMART - EVALUATION	OTHER	$422	$0	$0	$0	$0	$0	$0	$0	$422
1823920	103280	COMPANY INITIATIVES -PRODUCTION EFFICIEN	OTHER	$209	$0	$0	$0	$0	$0	$0	$0	$209
1823920	103291	Portfolio -WY-2011 Cat4	OTHER	$266	$0	$0	$0	$0	$0	$0	$0	$266
1823920	103292	Portfolio - Washington	OTHER	$345	$0	$0	$0	$0	$0	$0	$0	$345
1823920	103293	Energy Storage Demonstration Project -UT	OTHER	$7	$0	$0	$0	$0	$0	$0	$0	$7
1823920	103295	Outreach And Communication-WY-2011	OTHER	$1	$0	$0	$0	$0	$0	$0	$0	$1
1823920	103299	AGRICULURAL FINANSWER EXPRESS - UTAH - 2	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	103300	AGRICULTURAL FINANSWER EXPRESS - WASHING	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	103301	PORTFOLIO -WY-2011 CAT2	OTHER	$74	$0	$0	$0	$0	$0	$0	$0	$74
1823920	103302	PORTFOLIO -WY-2011 CAT3	OTHER	$110	$0	$0	$0	$0	$0	$0	$0	$110
1823920	103308	Home Energy Reporting -OPower -WA 2011	OTHER	$31	$0	$0	$0	$0	$0	$0	$0	$31
1823920	103309	Industrial Curtailment -WA 2011	OTHER	$13	$0	$0	$0	$0	$0	$0	$0	$13
1823920	103311	CALIFORNIA DSM EXPENSE - 2012	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	103324	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	$2,425	$0	$0	$0	$0	$0	$0	$0	$2,425

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1823920	103325	AIR CONDITIONING - UTAH - 2012	OTHER	$403	$0	$0	$0	$0	$0	$0	$0	$403
1823920	103326	ENERGY FINANSWER - UTAH - 2012	OTHER	$1,370	$0	$0	$0	$0	$0	$0	$0	$1,370
1823920	103327	INDUSTRIAL FINANSWER - UTAH - 2012	OTHER	$1,263	$0	$0	$0	$0	$0	$0	$0	$1,263
1823920	103328	LOW INCOME - UTAH - 2012	OTHER	$96	$0	$0	$0	$0	$0	$0	$0	$96
1823920	103330	REFRIGERATOR RECYCLING PGM- UTAH - 2012	OTHER	$636	$0	$0	$0	$0	$0	$0	$0	$636
1823920	103331	COMMERCIAL SELF-DIRECT - UTAH - 2012	OTHER	$93	$0	$0	$0	$0	$0	$0	$0	$93
1823920	103332	INDUSTRIAL SELF-DIRECT - UTAH - 2012	OTHER	$156	$0	$0	$0	$0	$0	$0	$0	$156
1823920	103333	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	$1,055	$0	$0	$0	$0	$0	$0	$0	$1,055
1823920	103334	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$2,235	$0	$0	$0	$0	$0	$0	$0	$2,235
1823920	103335	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	$560	$0	$0	$0	$0	$0	$0	$0	$560
1823920	103336	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	$240	$0	$0	$0	$0	$0	$0	$0	$240
1823920	103337	IRRIGATION LOAD CONTROL - UTAH - 2012	OTHER	$384	$0	$0	$0	$0	$0	$0	$0	$384
1823920	103338	HOME ENERGY EFF INCENTIVE PROG - UT 2012	OTHER	$5,276	$0	$0	$0	$0	$0	$0	$0	$5,276
1823920	103339	OUTREACH and COMMUNICATIONS - UT 2012	OTHER	$1,006	$0	$0	$0	$0	$0	$0	$0	$1,006
1823920	103340	COMMERCIAL DIRECT INSTALL - UT 2012	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	103341	COMMERCIAL CURTAILMENT - UT 2012	OTHER	$20	$0	$0	$0	$0	$0	$0	$0	$20
1823920	103342	ENERGY STORAGE DEMO PROJECT - UT 2012	OTHER	$5	$0	$0	$0	$0	$0	$0	$0	$5
1823920	103343	AGRICULTURAL FINANSWER EXPRESS - UTAH -	OTHER	$1	$0	$0	$0	$0	$0	$0	$0	$1
1823920	103346	HOME ENERGY REPORTING - UT 2012	OTHER	$215	$0	$0	$0	$0	$0	$0	$0	$215
1823920	103347	ENERGY FINANSWER-WY-2012 CAT3	OTHER	$3	$0	$0	$0	$0	$0	$0	$0	$3
1823920	103348	INDUSTRIAL FINANSWER-WY-2012 CAT3	OTHER	$493	$0	$0	$0	$0	$0	$0	$0	$493
1823920	103349	REFRIGERATOR RECYCLING-WY -2012 CAT1	OTHER	$68	$0	$0	$0	$0	$0	$0	$0	$68
1823920	103350	HOME ENERGY EFF INCENT PROG Y-2012 CAT1	OTHER	$422	$0	$0	$0	$0	$0	$0	$0	$422
1823920	103351	LOW-INCOME WEATHERZTN - WY 2012 CAT1	OTHER	$15	$0	$0	$0	$0	$0	$0	$0	$15
1823920	103352	COMMERCIAL FINANSWER EXP WY-2012 CAT3	OTHER	$40	$0	$0	$0	$0	$0	$0	$0	$40
1823920	103353	INDUSTRIAL FINANSWER EXP WY-2012 CAT3	OTHER	$86	$0	$0	$0	$0	$0	$0	$0	$86
1823920	103354	SELF DIRECT - COMMERCIAL -WY-2012 CAT3	OTHER	$2	$0	$0	$0	$0	$0	$0	$0	$2
1823920	103355	SELF DIRECT -INDUSTRIAL -WY-2012 CAT3	OTHER	$55	$0	$0	$0	$0	$0	$0	$0	$55
1823920	103356	COMMERCIAL FINANSWER EXP- WY-2012 CAT2	OTHER	$435	$0	$0	$0	$0	$0	$0	$0	$435
1823920	103357	INDUSTRIAL FINAN EXPRESS WY-2012 CAT2	OTHER	$28	$0	$0	$0	$0	$0	$0	$0	$28
1823920	103358	ENERGY FINANSWER -WY 2012 CAT2	OTHER	$44	$0	$0	$0	$0	$0	$0	$0	$44
1823920	103359	INDUSTRIAL FINANSWER -WY 2012 CAT2	OTHER	$21	$0	$0	$0	$0	$0	$0	$0	$21
1823920	103360	SELF DIRECT - COMMERCIAL WY-2012 CAT2	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823920	103361	SELF DIRECT- INDUSTRIAL WY-2012 CAT2	OTHER	$1	$0	$0	$0	$0	$0	$0	$0	$1
1823920	103363	PORTFOLIO WY-2012 CAT1	OTHER	$17	$0	$0	$0	$0	$0	$0	$0	$17
1823920	103364	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	$90	$0	$0	$0	$0	$0	$0	$0	$90
1823920	103367	PORTFOLIO WY-2012 CAT2	OTHER	$30	$0	$0	$0	$0	$0	$0	$0	$30
1823920	103368	PORTFOLIO WY-2012 CAT3	OTHER	$27	$0	$0	$0	$0	$0	$0	$0	$27
1823920	103369	COMMERCIAL CURTAILMENT - OR 2012	OTHER	$20	$0	$0	$0	$0	$0	$0	$0	$20
1823920 Total				**-$45,090**	**$0**	**$0**	**$0**	**$89**	**$0**	**$41**	**$0**	**-$45,220**
1823930	101881	HASSEL FREE EFFICIENCY IDAHO-UT 1999	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	101887	INDUSTRIAL FINANSWER - IDAHO UP&L - 199	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	101926	ENERGY FINANSWER - IDAHO-UT 2000	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1823930	101927	HASSLEFREE EFFICIENCY - IDAHO-UT 2000	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	101928	INDUSTRIAL FINANSWER - IDAHO-UT 2000	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	101929	LOW INCOME WZ - IDAHO-UT 2000	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1823930	101930	SELF AUDIT - IDAHO-UT 2000	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	101950	"LOW INCOME BID WZ, ID 2000"	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	101955	NEEA - IDAHO-UT 2000	IDU	$13	$0	$0	$0	$0	$0	$13	$0	$0
1823930	102062	ENERGY FINANSWER - ID-UT 2001	IDU	$5	$0	$0	$0	$0	$0	$5	$0	$0
1823930	102063	HASSLEFREE EFFICIENCY - ID-UT 2001	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1823930	102064	INDUSTRIAL FINANSWER - ID-UT 2001	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
1823930	102065	LOW INCOME WZ - ID-UT 2001	IDU	$7	$0	$0	$0	$0	$0	$7	$0	$0
1823930	102066	SELF AUDIT - ID-UT 2001	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823930	102079	NEEA - IDAHO - UTAH 2001	IDU	$34	$0	$0	$0	$0	$0	$34	$0	$0
1823930	102180	HASSLEFREE EFFICIENCY - IDU - 2002	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102181	INDUSTRIAL FINANSWER - IDU - 2002	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102182	LOW INCOME WZ - IDU - 2002	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1823930	102183	SELF AUDIT - IDU - 2002	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102184	NEEA - IDU - 2002 ACTUALS	IDU	$53	$0	$0	$0	$0	$0	$53	$0	$0
1823930	102204	COMPACT FLUORESCENT - UT 2002	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1823930	102216	WEATHERIZATION LOANS - RES UT 2003	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
1823930	102217	COMPACT FLOURESCENT - IDU 2002	IDU	$4	$0	$0	$0	$0	$0	$4	$0	$0
1823930	102218	ENERGY FINANSWER - IDU 2003	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102219	INDUSTRIAL FINANSWER - IDU 2003	IDU	$56	$0	$0	$0	$0	$0	$56	$0	$0
1823930	102220	LOAN INCOME WZ - IDU 2003	IDU	$4	$0	$0	$0	$0	$0	$4	$0	$0
1823930	102221	NEEA - IDU 2003	IDU	$124	$0	$0	$0	$0	$0	$124	$0	$0
1823930	102222	SELF AUDIT - IDAHO-UT 2003	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102263	IRRIGATION INTERRUPTIBLE IDAHO - UT 2003	IDU	$84	$0	$0	$0	$0	$0	$84	$0	$0
1823930	102352	INDUSTRIAL FINANSWER - IDU 2004	IDU	$38	$0	$0	$0	$0	$0	$38	$0	$0
1823930	102353	LOW INCOME WZ - IDU 2004	IDU	$17	$0	$0	$0	$0	$0	$17	$0	$0
1823930	102354	NEEA - IDU 2004	IDU	$78	$0	$0	$0	$0	$0	$78	$0	$0
1823930	102355	SELF AUDIT - IDAHO-UT 2004	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102356	IRRIGATION INTERRUPTIBLE - IDU 2004	IDU	$111	$0	$0	$0	$0	$0	$111	$0	$0
1823930	102358	WEATHERIZATION LOANS - RESIDENTIAL UT 20	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
1823930	102519	INDUSTRIAL FINANSWER - IDAHO-UT 2005	IDU	$24	$0	$0	$0	$0	$0	$24	$0	$0
1823930	102520	LOW INCOME WZ - IDAHO-UT 2005	IDU	$27	$0	$0	$0	$0	$0	$27	$0	$0
1823930	102521	NEEA - IDAHO - UTAH 2005	IDU	$119	$0	$0	$0	$0	$0	$119	$0	$0
1823930	102522	SELF AUDIT - IDAHO-UT 2005	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102523	IRRIGATION INTERRUPTIBLE IDAHO - UT 2005	IDU	$175	$0	$0	$0	$0	$0	$175	$0	$0
1823930	102524	WEATHERIZATION LOANS - RESIDENTIAL/ID-UT	IDU	$1	$0	$0	$0	$0	$0	$1	$0	$0
1823930	102573	ENERGY FINANSWER ID/UT 2006	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102574	INDUSTRIAL FINANSWER-ID-UT 2006	IDU	$3	$0	$0	$0	$0	$0	$3	$0	$0
1823930	102575	LOW INCOME WZ -ID-UT 2006	IDU	$144	$0	$0	$0	$0	$0	$144	$0	$0
1823930	102576	NEEA-IDAHO-UTAH 2006	IDU	$359	$0	$0	$0	$0	$0	$359	$0	$0
1823930	102577	IRRIGATION INTERRUPTIBLE ID-UT 2006	IDU	$361	$0	$0	$0	$0	$0	$361	$0	$0
1823930	102578	WEATHERIZATION LOANS-RESDL/ID-UT 2006	IDU	$2	$0	$0	$0	$0	$0	$2	$0	$0
1823930	102579	REFRIGERATOR RECYCLING PGM-ID-UT 2006	IDU	$143	$0	$0	$0	$0	$0	$143	$0	$0
1823930	102580	COMMERCIAL FINANSWER EXPR-ID-UT 2006	IDU	$117	$0	$0	$0	$0	$0	$117	$0	$0
1823930	102581	INDUSTRIAL FINANSWER EXPR-ID-UT 2006	IDU	$47	$0	$0	$0	$0	$0	$47	$0	$0
1823930	102582	IRRIGATION EFFICIENCY PRGRM-ID-UT 2006	IDU	$246	$0	$0	$0	$0	$0	$246	$0	$0
1823930	102758	HOME ENERGY EFFICIENCY INCENTIVE PROGM-I	IDU	$103	$0	$0	$0	$0	$0	$103	$0	$0
1823930	102808	WEATHERIZATION LOANS RESIDTL/ ID-UT 2007	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102809	ENERGY FINANSWER IDU 2007	OTHER	$4	$0	$0	$0	$0	$0	$0	$0	$4
1823930	102810	Industrial Finanswer ID - 2007	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	102811	IRRIGATION INTERRUPTIBLE ID-UT 2007	OTHER	$846	$0	$0	$0	$0	$0	$0	$0	$846
1823930	102812	LOW INCOME WZ - ID-UT 2007	OTHER	$101	$0	$0	$0	$0	$0	$0	$0	$101
1823930	102813	NEEA - IDAHO - UTAH 2007	OTHER	$361	$0	$0	$0	$0	$0	$0	$0	$361
1823930	102814	REFRIGERATOR RECYCLING PGM - ID-UT 2007	OTHER	$123	$0	$0	$0	$0	$0	$0	$0	$123
1823930	102815	COMMERCIAL FINANSWER EXPR - ID-UT 2007	OTHER	$61	$0	$0	$0	$0	$0	$0	$0	$61
1823930	102816	INDUSTRIAL FINANSWER EXPR - ID-UT 2007	OTHER	$120	$0	$0	$0	$0	$0	$0	$0	$120
1823930	102817	IRRIGATION EFFICIENCY PRGRM - ID-UT 2007	OTHER	$275	$0	$0	$0	$0	$0	$0	$0	$275
1823930	102818	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	$229	$0	$0	$0	$0	$0	$0	$0	$229
1823930	102896	ENERGY FINANSWER - ID/UT 2008	OTHER	$19	$0	$0	$0	$0	$0	$0	$0	$19
1823930	102897	INDUSTRIAL FINANSWER - ID-UT 2008	OTHER	$102	$0	$0	$0	$0	$0	$0	$0	$102
1823930	102898	IRRIGATION INTERRUPTIBLE - IDAHO - 2008	OTHER	$3,127	$0	$0	$0	$0	$0	$0	$0	$3,127
1823930	102899	LOW INCOME WEATHERIZATION - IDAHO 2008	OTHER	$165	$0	$0	$0	$0	$0	$0	$0	$165
1823930	102900	NEEA - IDAHO - 2008	OTHER	$317	$0	$0	$0	$0	$0	$0	$0	$317

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1823930	102901	REFRIGERATOR RECYCLING PRGM - IDAHO 2008	OTHER	$113	$0	$0	$0	$0	$0	$0	$0	$113
1823930	102902	COMMERCIAL FINANSWER EXPRESS - IDAHO 200	OTHER	$108	$0	$0	$0	$0	$0	$0	$0	$108
1823930	102903	INDUSTRIAL FINANSWER - IDAHO - 2008	OTHER	$58	$0	$0	$0	$0	$0	$0	$0	$58
1823930	102904	IRRIGATION EFFICIENCY PRGM - IDAHO - 200	OTHER	$268	$0	$0	$0	$0	$0	$0	$0	$268
1823930	102905	HOME ENERGY EFF INCENTIVE PROGRAM - IDAH	OTHER	$490	$0	$0	$0	$0	$0	$0	$0	$490
1823930	102957	CATEGORY 1 - WYOMING - 2008	OTHER	$17	$0	$0	$0	$0	$0	$0	$0	$17
1823930	102958	CATEGORY 2 - WYOMING - 2008	OTHER	$9	$0	$0	$0	$0	$0	$0	$0	$9
1823930	102959	CATEGORY 3 - WYOMING - 2008	OTHER	$33	$0	$0	$0	$0	$0	$0	$0	$33
1823930	102966	ENERGY FINANSWER - ID/UT 2009	OTHER	$50	$0	$0	$0	$0	$0	$0	$0	$50
1823930	102967	INDUSTRIAL FINANSWER - ID-UT 2009	OTHER	$309	$0	$0	$0	$0	$0	$0	$0	$309
1823930	102968	IRRIGATION INTERRUPTIBLE ID-UT 2009	OTHER	$3,816	$0	$0	$0	$0	$0	$0	$0	$3,816
1823930	102969	LOW INCOME WZ - ID-UT 2009	OTHER	$198	$0	$0	$0	$0	$0	$0	$0	$198
1823930	102970	NEEA - IDAHO - UTAH 2009	OTHER	$287	$0	$0	$0	$0	$0	$0	$0	$287
1823930	102971	REFRIGERATOR RECYCLING PGM - ID-UT 2009	OTHER	$108	$0	$0	$0	$0	$0	$0	$0	$108
1823930	102972	COMMERCIAL FINANSWER EXPR - ID-UT 2009	OTHER	$190	$0	$0	$0	$0	$0	$0	$0	$190
1823930	102973	INDUSTRIAL FINANSWER EXPR - ID-UT 2009	OTHER	$74	$0	$0	$0	$0	$0	$0	$0	$74
1823930	102974	IRRIGATION EFFICIENCY PRGRM - ID-UT 2009	OTHER	$807	$0	$0	$0	$0	$0	$0	$0	$807
1823930	102975	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	$594	$0	$0	$0	$0	$0	$0	$0	$594
1823930	103061	ENERGY FINANSWER - ID/UT 2010	OTHER	$47	$0	$0	$0	$0	$0	$0	$0	$47
1823930	103062	INDUSTRIAL FINANSWER - ID-UT 2010	OTHER	$322	$0	$0	$0	$0	$0	$0	$0	$322
1823930	103063	IRRIGATION INTERRUPTIBLE ID-UT 2010	OTHER	$4,283	$0	$0	$0	$0	$0	$0	$0	$4,283
1823930	103064	LOW INCOME WZ - ID-UT 2010	OTHER	$134	$0	$0	$0	$0	$0	$0	$0	$134
1823930	103065	NEEA - IDAHO - UTAH 2010	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	103066	REFRIGERATOR RECYCLING PGM - ID-UT 2010	OTHER	$166	$0	$0	$0	$0	$0	$0	$0	$166
1823930	103067	COMMERCIAL FINANSWER EXPR - ID-UT 2010	OTHER	$513	$0	$0	$0	$0	$0	$0	$0	$513
1823930	103068	INDUSTRIAL FINANSWER EXPR - ID-UT 2010	OTHER	$107	$0	$0	$0	$0	$0	$0	$0	$107
1823930	103069	IRRIGATION EFFICIENCY PRGRM - ID-UT 2010	OTHER	$637	$0	$0	$0	$0	$0	$0	$0	$637
1823930	103070	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	$1,305	$0	$0	$0	$0	$0	$0	$0	$1,305
1823930	103171	ENERGY FINANSWER - ID/UT 2011	OTHER	$23	$0	$0	$0	$0	$0	$0	$0	$23
1823930	103172	INDUSTRIAL FINANSWER - ID-UT 2011	OTHER	$143	$0	$0	$0	$0	$0	$0	$0	$143
1823930	103173	IRRIGATION INTERRUPTIBLE ID-UT 2011	OTHER	$37	$0	$0	$0	$0	$0	$0	$0	$37
1823930	103174	LOW INCOME WZ - ID-UT 2011	OTHER	$425	$0	$0	$0	$0	$0	$0	$0	$425
1823930	103176	REFRIGERATOR RECYCLING PGM - ID-UT 2011	OTHER	$126	$0	$0	$0	$0	$0	$0	$0	$126
1823930	103177	COMMERCIAL FINANSWER EXPR - ID-UT 2011	OTHER	$632	$0	$0	$0	$0	$0	$0	$0	$632
1823930	103178	INDUSTRIAL FINANSWER EXPR - ID-UT 2011	OTHER	$77	$0	$0	$0	$0	$0	$0	$0	$77
1823930	103179	IRRIGATION EFFICIENCY PRGRM - ID-UT 2011	OTHER	$508	$0	$0	$0	$0	$0	$0	$0	$508
1823930	103180	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	$699	$0	$0	$0	$0	$0	$0	$0	$699
1823930	103312	ENERGY FINANSWER - ID 2012	OTHER	$9	$0	$0	$0	$0	$0	$0	$0	$9
1823930	103313	INDUSTRIAL FINANSWER - ID 2012	OTHER	$95	$0	$0	$0	$0	$0	$0	$0	$95
1823930	103315	LOW INCOME WZ - ID- 2012	OTHER	$174	$0	$0	$0	$0	$0	$0	$0	$174
1823930	103317	REFRIGERATOR RECYCLING PGM - ID 2012	OTHER	$51	$0	$0	$0	$0	$0	$0	$0	$51
1823930	103318	COMMERCIAL FINANSWER EXPR - ID 2012	OTHER	$276	$0	$0	$0	$0	$0	$0	$0	$276
1823930	103319	INDUSTRIAL FINANSWER EXPR - ID 2012	OTHER	$158	$0	$0	$0	$0	$0	$0	$0	$158
1823930	103320	IRRIGATION EFFICIENCY PRGRM - ID 2012	OTHER	$283	$0	$0	$0	$0	$0	$0	$0	$283
1823930	103321	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	$366	$0	$0	$0	$0	$0	$0	$0	$366
1823930	103322	COMMERCIAL DIRECT INSTALL - ID 2012	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	103396	ENERGY MANAGEMENT-COMM - UT 2012	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	103397	ENERGY MANAGEMENT-IND - UT 2012	OTHER	$1	$0	$0	$0	$0	$0	$0	$0	$1
1823930	103399	ENERGY MANAGEMENT-COMM - WA 2012	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	103400	ENERGY MANAGEMENT-IND - WA 2012	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930	103403	ENERGY MGMT INDUST- WY CAT2 -2012	OTHER	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823930 Total				**$27,489**	**$0**	**$0**	**$0**	**$0**	**$0**	**$2,510**	**$0**	**$24,979**
1823940	102146	UT CARRYING CHARGE - 2001/2002	OTHER	$4,178	$0	$0	$0	$0	$0	$0	$0	$4,178
1823940	102188	WA REVENUE RECOVERY - CARRYING CHG PENAL	OTHER	-$680	$0	$0	$0	$0	$0	$0	$0	-$680

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Regulatory Assests (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823940	102766	DSR CARRYING CHARGES	IDU	$172	$0	$0	$0	$0	$0	$172	$0	$0
1823940	103140	Wy DSM - Cat1 - Carrying Charges	OTHER	-$72	$0	$0	$0	$0	$0	$0	$0	-$72
1823940	103141	Wy DSM - Cat2 - Carrying Charges	OTHER	-$38	$0	$0	$0	$0	$0	$0	$0	-$38
1823940	103142	Wy DSM - Cat3 - Carrying Charges	OTHER	-$63	$0	$0	$0	$0	$0	$0	$0	-$63
1823940	103279	CA CARRYING CHRG LIEE - 2011	OTHER	-$19	$0	$0	$0	$0	$0	$0	$0	-$19
1823940 Total				**$3,480**	**$0**	**$0**	**$0**	**$0**	**$0**	**$172**	**$0**	**$3,308**
1823960	101684	NET LOST REVN COMM	UT	$1	$0	$0	$0	$0	$1	$0	$0	$0
1823960	101688	NET LOST REVN IND	UT	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823960	101692	NET LOST EF RETRO	UT	$1	$0	$0	$0	$0	$1	$0	$0	$0
1823960	101696	NET LOST EF CUSTOM	UT	$4	$0	$0	$0	$0	$4	$0	$0	$0
1823960	101698	NET LOST EF PRESCRIPT	UT	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823960	101700	NET LOST EF COMMERCIAL	UT	$3	$0	$0	$0	$0	$3	$0	$0	$0
1823960 Total				**$11**	**$0**	**$0**	**$0**	**$0**	**$11**	**$0**	**$0**	**$0**
1823990	138010	Reg Asset Current - Decom Costs	OTHER	$323	$0	$0	$0	$0	$0	$0	$0	$323
1823990	138020	Reg Asset Current - DSM	OTHER	$4,108	$0	$0	$0	$0	$0	$0	$0	$4,108
1823990	138030	Reg Asset Current - OR SB 408	OTHER	-$33	$0	$0	$0	$0	$0	$0	$0	-$33
1823990	138040	Reg Asset Current - New Res/Renewables	OTHER	$3,034	$0	$0	$0	$0	$0	$0	$0	$3,034
1823990	138050	Reg Asset Current - Def Net Power Costs	OTHER	$65,733	$0	$0	$0	$0	$0	$0	$0	$65,733
1823990	138060	Reg Asset Current - BPA Balancing Accts	OTHER	$1,183	$0	$0	$0	$0	$0	$0	$0	$1,183
1823990	138070	Reg Asset Current - Intervenor/Eval Fees	OTHER	$66	$0	$0	$0	$0	$0	$0	$0	$66
1823990	138080	Reg Asset Current - Transition Severance	OTHER	$1	$0	$0	$0	$0	$0	$0	$0	$1
1823990	138090	Reg Asset Current - Solar Feed-In	OTHER	$1,191	$0	$0	$0	$0	$0	$0	$0	$1,191
1823990	138190	Reg Asset Current - Other	OTHER	$665	$0	$0	$0	$0	$0	$0	$0	$665
1823990	186090	CONTRA REG ASSET - DSM RESERVE	OTHER	-$115	$0	$0	$0	$0	$0	$0	$0	-$115
1823990	186095	RegA - DSM - Recl to Curr	OTHER	-$4,108	$0	$0	$0	$0	$0	$0	$0	-$4,108
1823990	186099	Regulatory Asset - Balance Reclass	OTHER	$11,811	$0	$0	$0	$0	$0	$0	$0	$11,811
1823990	186100	Calif Alternative Rate for Energy (CARE)	OTHER	-$198	$0	$0	$0	$0	$0	$0	$0	-$198
1823990	186501	Powerdale Hydro Decom Reg Asset - CA	CA	$15	$15	$0	$0	$0	$0	$0	$0	$0
1823990	186502	POWERDALE HYDRO DECOM REG ASSET - ID	IDU	$204	$0	$0	$0	$0	$0	$204	$0	$0
1823990	186504	POWERDALE HYDRO DECOM REG ASSET - WA	WA	$497	$0	$0	$497	$0	$0	$0	$0	$0
1823990	186595	RegA - Decom Costs - Recl to Curr	OTHER	-$323	$0	$0	$0	$0	$0	$0	$0	-$323
1823990	187028	TRANSITION COSTS-RETIREMENT & DISPLACE	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823990	187050	CHOLLA PLANT TRANSACTION COSTS	SGCT	$5,706	$87	$1,491	$444	$897	$2,461	$324	$0	$0
1823990	187051	WASHINGTON COLSTRIP #3 REGULATORY ASSET	SE		$0	$0	$0	$0	$0	$0	$0	$0
1823990	187051	WASHINGTON COLSTRIP #3 REGULATORY ASSET	WA	$448	$0	$0	$448	$0	$0	$0	$0	$0
1823990	187058	TRAIL MOUNTAIN MINE CLOSURE COSTS	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1823990	187096	Reg Asset - Tax Rev Req Adj-WY	WYU	$71	$0	$0	$0	$71	$0	$0	$0	$0
1823990	187214	OR - MEHC Transition Service Costs	OTHER	$1	$0	$0	$0	$0	$0	$0	$0	$1
1823990	187221	Reg Asset - Tax Adj on PR Benefits - CA	OTHER	$199	$0	$0	$0	$0	$0	$0	$0	$199
1823990	187222	Reg Asset - Tax Adj on PR Benefits - ID	OTHER	$524	$0	$0	$0	$0	$0	$0	$0	$524
1823990	187223	Reg Asset - Tax Adj on PR Benefits - OR	OTHER	$4,472	$0	$0	$0	$0	$0	$0	$0	$4,472
1823990	187224	Reg Asset - Tax Adj on PR Benefits - UT	OTHER	$3,623	$0	$0	$0	$0	$0	$0	$0	$3,623
1823990	187226	Reg Asset - Tax Adj on PR Benefits - WY	OTHER	$1,429	$0	$0	$0	$0	$0	$0	$0	$1,429
1823990	187245	RegA - Transition Severance - Recl to Cu	OTHER	-$1	$0	$0	$0	$0	$0	$0	$0	-$1
1823990	187255	RegA - BPA Balancing Accts - Recl to Cur	OTHER	-$1,183	$0	$0	$0	$0	$0	$0	$0	-$1,183
1823990	187300	CA - Jan 2010 Storm Costs	OTHER	$6	$0	$0	$0	$0	$0	$0	$0	$6
1823990	187350	ID - Deferred Overburden Costs	OTHER	$228	$0	$0	$0	$0	$0	$0	$0	$228
1823990	187351	WY - Deferred Overburden Costs	WYP	$635	$0	$0	$0	$635	$0	$0	$0	$0
1823990	187365	Reg Asset - Naughton Unit #3 Costs	OTHER	$7,724	$0	$0	$0	$0	$0	$0	$0	$7,724
1823990	187367	Contra Reg Asset - Naughton U3 - OR	OTHER	-$2,044	$0	$0	$0	$0	$0	$0	$0	-$2,044
1823990	187368	Contra Reg Asset - Naughton U3 - WA	OTHER	-$612	$0	$0	$0	$0	$0	$0	$0	-$612
1823990	187370	Reg Asset - OR Solar Feed-In Tariff	OTHER	$526	$0	$0	$0	$0	$0	$0	$0	$526
1823990	187371	REG ASSET - CA SOLAR FEED-IN TARIFF	OTHER	-$560	$0	$0	$0	$0	$0	$0	$0	-$560
1823990	187372	Reg Asset - OR Solar Feed-In Tariff 2012	OTHER	$1,224	$0	$0	$0	$0	$0	$0	$0	$1,224

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Regulatory Assests (Actuals)
Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823990	187385	RegA - Solar Feed-In - Recl to Curr	OTHER	-$1,191	$0	$0	$0	$0	$0	$0	$0	-$1,191
1823990	187495	RegA - Other - Recl to Curr	OTHER	-$665	$0	$0	$0	$0	$0	$0	$0	-$665
1823990	187802	Reg Asset - CA ECAC CY2012	OTHER	$100	$0	$0	$0	$0	$0	$0	$0	$100
1823990	187807	CONTRA REG ASSET - CA ECAC CY2012	OTHER	-$10	$0	$0	$0	$0	$0	$0	$0	-$10
1823990	187812	Reg Asset - ID ECAM Dec11-Nov12	OTHER	$10,040	$0	$0	$0	$0	$0	$0	$0	$10,040
1823990	187817	Contra Reg Asset - ID ECAM Dec11-Nov12	OTHER	-$1,093	$0	$0	$0	$0	$0	$0	$0	-$1,093
1823990	187821	Reg Asset - UT EBA Oct-Dec11	OTHER	$9,332	$0	$0	$0	$0	$0	$0	$0	$9,332
1823990	187822	Reg Asset - UT EBA CY2012	OTHER	$3,872	$0	$0	$0	$0	$0	$0	$0	$3,872
1823990	187832	Reg Asset - UT RBA CY2012	OTHER	-$3,797	$0	$0	$0	$0	$0	$0	$0	-$3,797
1823990	187842	Contra Reg Asset - UT EBA CY2012	OTHER	-$387	$0	$0	$0	$0	$0	$0	$0	-$387
1823990	187852	Reg Asset - WY ECAM CY2012	OTHER	$5,830	$0	$0	$0	$0	$0	$0	$0	$5,830
1823990	187862	Reg Asset - WY RRA CY2012	OTHER	-$1,510	$0	$0	$0	$0	$0	$0	$0	-$1,510
1823990	187872	Contra Reg Asset - WY ECAM CY2012	OTHER	-$583	$0	$0	$0	$0	$0	$0	$0	-$583
1823990	187881	Deferred Exc RECs in Rates-UT (2011-12)	OTHER	-$134	$0	$0	$0	$0	$0	$0	$0	-$134
1823990	187883	Deferred Exc RECs in Rates-WY (2011-12)	OTHER	$1,898	$0	$0	$0	$0	$0	$0	$0	$1,898
1823990	187892	Deferral of Excess RECs in Rates - WA	OTHER	$1,335	$0	$0	$0	$0	$0	$0	$0	$1,335
1823990	187905	CA - DEF NET POWER COSTS	OTHER	$1,262	$0	$0	$0	$0	$0	$0	$0	$1,262
1823990	187911	REG ASSET - LAKE SIDE LIQ. DAMAGES - WY	WYP	$963	$0	$0	$0	$963	$0	$0	$0	$0
1823990	187913	Reg Asset - Goodnoe Hills Liq. Damages -	WYP	$457	$0	$0	$0	$457	$0	$0	$0	$0
1823990	187920	OR-RCAC REV REQUIREMENT	OTHER	-$14	$0	$0	$0	$0	$0	$0	$0	-$14
1823990	187921	WA-Chehalis Plant Rev Reqmt - Reg Asset	WA	$10,500	$0	$0	$10,500	$0	$0	$0	$0	$0
1823990	187925	RegA - New Res/Renewables - Recl to Curr	OTHER	-$3,034	$0	$0	$0	$0	$0	$0	$0	-$3,034
1823990	187930	OR SB 408 REG ASSET	OTHER	-$34	$0	$0	$0	$0	$0	$0	$0	-$34
1823990	187935	RegA - OR SB 408 - Recl to Curr	OTHER	$33	$0	$0	$0	$0	$0	$0	$0	$33
1823990	187936	SB 408 REG ASSET - MCBIT (EVEN YEAR 1)	OTHER	-$28	$0	$0	$0	$0	$0	$0	$0	-$28
1823990	187955	Defd UT Ind Eval Fee	UT	$26	$0	$0	$0	$0	$26	$0	$0	$0
1823990	187956	CA DEFERRED INTERVENOR FUNDING	OTHER	$33	$0	$0	$0	$0	$0	$0	$0	$33
1823990	187957	DEFERRED OR INDEPENDENT EVALUATOR FEES	OTHER	-$6	$0	$0	$0	$0	$0	$0	$0	-$6
1823990	187958	ID Deferred Intervenor Funding	IDU	$71	$0	$0	$0	$0	$0	$71	$0	$0
1823990	187965	RegA - Intervenor/Eval Fees - Recl to Cu	OTHER	-$66	$0	$0	$0	$0	$0	$0	$0	-$66
1823990	187972	Deferred Net Power Costs - WY 11	OTHER	$26,633	$0	$0	$0	$0	$0	$0	$0	$26,633
1823990	187975	Reg Asset - CA ECAC	OTHER	$231	$0	$0	$0	$0	$0	$0	$0	$231
1823990	187982	Deferred Net Power Costs - ID 11	OTHER	$10,538	$0	$0	$0	$0	$0	$0	$0	$10,538
1823990	187983	"Reg Asset - ID ECAM Dec10-Nov11, Mnsant	OTHER	$6,273	$0	$0	$0	$0	$0	$0	$0	$6,273
1823990	187984	"Reg Asset - ID ECAM Dec10-Nov11, Agrium	OTHER	$407	$0	$0	$0	$0	$0	$0	$0	$407
1823990	187985	Utah ECAM Regulatory Asset	OTHER	$59,405	$0	$0	$0	$0	$0	$0	$0	$59,405
1823990	187988	Deferred Net Power Costs - OR	OTHER	-$101	$0	$0	$0	$0	$0	$0	$0	-$101
1823990	187992	Contra Reg Asset - CA - Def NPC	OTHER	-$71	$0	$0	$0	$0	$0	$0	$0	-$71
1823990	187994	Contra Reg Asset - WY - Def NPC	OTHER	-$2,967	$0	$0	$0	$0	$0	$0	$0	-$2,967
1823990	187995	Utah ECAM Regulatory Asset - Contra	OTHER	-$933	$0	$0	$0	$0	$0	$0	$0	-$933
1823990	187998	RegA - Def Net Power Costs - Recl to Cur	OTHER	-$65,733	$0	$0	$0	$0	$0	$0	$0	-$65,733
1823990	187999	Reg Asset - Def NPC Balance Reclass	OTHER	$5,640	$0	$0	$0	$0	$0	$0	$0	$5,640
1823990 Total				**$178,992**	**$102**	**$1,491**	**$11,889**	**$3,023**	**$2,487**	**$600**	**$0**	**$159,400**
1823993	187060	CHOLLA PLANT TRANSACTION COSTS-OR	OR	-$274	$0	-$274	$0	$0	$0	$0	$0	$0
1823993 Total				**-$274**	**$0**	**-$274**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
1823994	187061	CHOLLA PLANT TRANSACTION COSTS-WA	WA	-$493	$0	$0	-$493	$0	$0	$0	$0	$0
1823994 Total				**-$493**	**$0**	**$0**	**-$493**	**$0**	**$0**	**$0**	**$0**	**$0**
1823995	187062	CHOLLA PLANT TRANSACTION COSTS-ID	IDU	-$168	$0	$0	$0	$0	$0	-$168	$0	$0
1823995 Total				**-$168**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$168**	**$0**	**$0**
1823999	186001	DSM Regulatory Assets-Accruals	OTHER	$6,522	$0	$0	$0	$0	$0	$0	$0	$6,522
1823999 Total				**$6,522**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$6,522**
Grand Total				**$181,437**	**$711**	**$3,963**	**$13,327**	**$4,677**	**$11,485**	**$3,726**	**$24**	**$143,525**

PACIFICORP
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Depreciation Reserve (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	3102000	LAND RIGHTS	SG	-$25,691	-$392	-$6,693	-$1,994	-$4,027	-$11,042	-$1,456	-$86	$0
1080000	3103000	WATER RIGHTS	SG	-$15,156	-$232	-$3,949	-$1,176	-$2,376	-$6,514	-$859	-$51	$0
1080000	3110000	STRUCTURES AND IMPROVEMENTS	SG	-$456,857	-$6,978	-$119,025	-$35,462	-$71,614	-$196,362	-$25,884	-$1,532	$0
1080000	3120000	BOILER PLANT EQUIPMENT	SG	-$1,361,285	-$20,793	-$354,656	-$105,665	-$213,387	-$585,096	-$77,125	-$4,564	$0
1080000	3140000	TURBOGENERATOR UNITS	SG	-$374,821	-$5,725	-$97,652	-$29,094	-$58,755	-$161,102	-$21,236	-$1,257	$0
1080000	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	-$194,545	-$2,972	-$50,685	-$15,101	-$30,496	-$83,617	-$11,022	-$652	$0
1080000	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	-$34	-$1	-$9	-$3	-$5	-$15	-$2	$0	$0
1080000	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	-$14,630	-$223	-$3,812	-$1,136	-$2,293	-$6,288	-$829	-$49	$0
1080000	3302000	LAND RIGHTS	SG-P	-$4,738	-$72	-$1,234	-$368	-$743	-$2,036	-$268	-$16	$0
1080000	3302000	LAND RIGHTS	SG-U	-$43	-$1	-$11	-$3	-$7	-$19	-$2	$0	$0
1080000	3303000	WATER RIGHTS	SG-U	-$113	-$2	-$30	-$9	-$18	-$49	-$6	$0	$0
1080000	3304000	FLOOD RIGHTS	SG-P	-$169	-$3	-$44	-$13	-$27	-$73	-$10	-$1	$0
1080000	3304000	FLOOD RIGHTS	SG-U	-$78	-$1	-$20	-$6	-$12	-$34	-$4	$0	$0
1080000	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	-$205	-$3	-$53	-$16	-$32	-$88	-$12	-$1	$0
1080000	3310000	STRUCTURES AND IMPROVE	SG-P	-$1	$0	$0	$0	$0	$0	$0	$0	$0
1080000	3310000	STRUCTURES AND IMPROVE	SG-U	-$4,770	-$73	-$1,243	-$370	-$748	-$2,050	-$270	-$16	$0
1080000	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	-$20,520	-$313	-$5,346	-$1,593	-$3,217	-$8,820	-$1,163	-$69	$0
1080000	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	-$853	-$13	-$222	-$66	-$134	-$367	-$48	-$3	$0
1080000	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	-$7,846	-$120	-$2,044	-$609	-$1,230	-$3,372	-$445	-$26	$0
1080000	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	-$143	-$2	-$37	-$11	-$22	-$61	-$8	$0	$0
1080000	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	-$4,540	-$69	-$1,183	-$352	-$712	-$1,951	-$257	-$15	$0
1080000	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	-$786	-$12	-$205	-$61	-$123	-$338	-$45	-$3	$0
1080000	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	-$993	-$15	-$259	-$77	-$156	-$427	-$56	-$3	$0
1080000	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	-$15,800	-$241	-$4,116	-$1,226	-$2,477	-$6,791	-$895	-$53	$0
1080000	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	-$116,102	-$1,773	-$30,248	-$9,012	-$18,199	-$49,902	-$6,578	-$389	$0
1080000	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	-$11,840	-$181	-$3,085	-$919	-$1,856	-$5,089	-$671	-$40	$0
1080000	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	-$2,862	-$44	-$746	-$222	-$449	-$1,230	-$162	-$10	$0
1080000	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	-$173	-$3	-$45	-$13	-$27	-$74	-$10	-$1	$0
1080000	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	-$54	-$1	-$14	-$4	-$9	-$23	-$3	$0	$0
1080000	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	-$24	$0	-$6	-$2	-$4	-$10	-$1	$0	$0
1080000	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	-$32,580	-$498	-$8,488	-$2,529	-$5,107	-$14,003	-$1,846	-$109	$0
1080000	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	-$10,461	-$160	-$2,726	-$812	-$1,640	-$4,496	-$593	-$35	$0
1080000	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	-$13,030	-$199	-$3,395	-$1,011	-$2,042	-$5,600	-$738	-$44	$0
1080000	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	-$4,170	-$64	-$1,087	-$324	-$654	-$1,793	-$236	-$14	$0
1080000	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	-$1,685	-$26	-$439	-$131	-$264	-$724	-$95	-$6	$0
1080000	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	-$24	$0	-$6	-$2	-$4	-$11	-$1	$0	$0
1080000	3350000	MISC POWER PLANT EQUIP	SG-U	-$104	-$2	-$27	-$8	-$16	-$45	-$6	$0	$0
1080000	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	-$1,067	-$16	-$278	-$83	-$167	-$459	-$60	-$4	$0
1080000	3353000	MISC POWER PLANT EQUIP - RECREATION	SG-P	-$4	$0	-$1	$0	-$1	-$2	$0	$0	$0
1080000	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	-$5,826	-$89	-$1,518	-$452	-$913	-$2,504	-$330	-$20	$0
1080000	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	-$756	-$12	-$197	-$59	-$118	-$325	-$43	-$3	$0
1080000	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1080000	3410000	STRUCTURES & IMPROVEMENTS	SG	-$28,229	-$431	-$7,355	-$2,191	-$4,425	-$12,133	-$1,599	-$95	$0
1080000	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	-$1,943	-$30	-$506	-$151	-$305	-$835	-$110	-$7	$0
1080000	3430000	PRIME MOVERS	SG	-$399,604	-$6,104	-$104,109	-$31,018	-$62,640	-$171,754	-$22,640	-$1,340	$0
1080000	3440000	GENERATORS	SG	-$64,456	-$985	-$16,793	-$5,003	-$10,104	-$27,704	-$3,652	-$216	$0
1080000	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	-$40,000	-$611	-$10,421	-$3,105	-$6,270	-$17,193	-$2,266	-$134	$0
1080000	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	-$2,036	-$31	-$531	-$158	-$319	-$875	-$115	-$7	$0
1080000	3502000	LAND RIGHTS	SG	-$29,918	-$457	-$7,795	-$2,322	-$4,690	-$12,859	-$1,695	-$100	$0
1080000	3520000	STRUCTURES & IMPROVEMENTS	SG	-$20,315	-$310	-$5,293	-$1,577	-$3,185	-$8,732	-$1,151	-$68	$0
1080000	3530000	STATION EQUIPMENT	SG	-$269,497	-$4,116	-$70,212	-$20,919	-$42,245	-$115,833	-$15,269	-$904	$0
1080000	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	-$24,082	-$368	-$6,274	-$1,869	-$3,775	-$10,351	-$1,364	-$81	$0
1080000	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	-$8,049	-$123	-$2,097	-$625	-$1,262	-$3,460	-$456	-$27	$0
1080000	3540000	TOWERS AND FIXTURES	SG	-$213,079	-$3,255	-$55,513	-$16,539	-$33,401	-$91,584	-$12,072	-$714	$0

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	3550000	POLES AND FIXTURES	SG	-$277,081	-$4,232	-$72,188	-$21,507	-$43,434	-$119,092	-$15,698	-$929	$0
1080000	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	-$409,739	-$6,259	-$106,749	-$31,804	-$64,228	-$176,111	-$23,214	-$1,374	$0
1080000	3570000	UNDERGROUND CONDUIT	SG	-$630	-$10	-$164	-$49	-$99	-$271	-$36	-$2	$0
1080000	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	-$1,506	-$23	-$392	-$117	-$236	-$647	-$85	-$5	$0
1080000	3590000	ROADS AND TRAILS	SG	-$3,533	-$54	-$920	-$274	-$554	-$1,519	-$200	-$12	$0
1080000	3602000	LAND RIGHTS	CA	-$536	-$536	$0	$0	$0	$0	$0	$0	$0
1080000	3602000	LAND RIGHTS	IDU	-$410	$0	$0	$0	$0	$0	-$410	$0	$0
1080000	3602000	LAND RIGHTS	OR	-$2,439	$0	-$2,439	$0	$0	$0	$0	$0	$0
1080000	3602000	LAND RIGHTS	UT	-$2,522	$0	$0	$0	$0	-$2,522	$0	$0	$0
1080000	3602000	LAND RIGHTS	WA	-$136	$0	$0	-$136	$0	$0	$0	$0	$0
1080000	3602000	LAND RIGHTS	WYP	-$1,037	$0	$0	$0	-$1,037	$0	$0	$0	$0
1080000	3602000	LAND RIGHTS	WYU	-$557	$0	$0	$0	-$557	$0	$0	$0	$0
1080000	3610000	STRUCTURES & IMPROVEMENTS	CA	-$658	-$658	$0	$0	$0	$0	$0	$0	$0
1080000	3610000	STRUCTURES & IMPROVEMENTS	IDU	-$441	$0	$0	$0	$0	$0	-$441	$0	$0
1080000	3610000	STRUCTURES & IMPROVEMENTS	OR	-$3,885	$0	-$3,885	$0	$0	$0	$0	$0	$0
1080000	3610000	STRUCTURES & IMPROVEMENTS	UT	-$7,518	$0	$0	$0	$0	-$7,518	$0	$0	$0
1080000	3610000	STRUCTURES & IMPROVEMENTS	WA	-$640	$0	$0	-$640	$0	$0	$0	$0	$0
1080000	3610000	STRUCTURES & IMPROVEMENTS	WYP	-$2,303	$0	$0	$0	-$2,303	$0	$0	$0	$0
1080000	3610000	STRUCTURES & IMPROVEMENTS	WYU	-$75	$0	$0	$0	-$75	$0	$0	$0	$0
1080000	3620000	STATION EQUIPMENT	CA	-$4,358	-$4,358	$0	$0	$0	$0	$0	$0	$0
1080000	3620000	STATION EQUIPMENT	IDU	-$8,329	$0	$0	$0	$0	$0	-$8,329	$0	$0
1080000	3620000	STATION EQUIPMENT	OR	-$58,653	$0	-$58,653	$0	$0	$0	$0	$0	$0
1080000	3620000	STATION EQUIPMENT	UT	-$82,100	$0	$0	$0	$0	-$82,100	$0	$0	$0
1080000	3620000	STATION EQUIPMENT	WA	-$14,964	$0	$0	-$14,964	$0	$0	$0	$0	$0
1080000	3620000	STATION EQUIPMENT	WYP	-$38,788	$0	$0	$0	-$38,788	$0	$0	$0	$0
1080000	3620000	STATION EQUIPMENT	WYU	-$2,654	$0	$0	$0	-$2,654	$0	$0	$0	$0
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	-$162	-$162	$0	$0	$0	$0	$0	$0	$0
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	-$248	$0	$0	$0	$0	$0	-$248	$0	$0
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	-$1,981	$0	-$1,981	$0	$0	$0	$0	$0	$0
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	-$2,391	$0	$0	$0	$0	-$2,391	$0	$0	$0
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	-$626	$0	$0	-$626	$0	$0	$0	$0	$0
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	-$1,631	$0	$0	$0	-$1,631	$0	$0	$0	$0
1080000	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	-$21	$0	$0	$0	-$21	$0	$0	$0	$0
1080000	3640000	"POLES, TOWERS AND FIXTURES"	CA	-$27,818	-$27,818	$0	$0	$0	$0	$0	$0	$0
1080000	3640000	"POLES, TOWERS AND FIXTURES"	IDU	-$44,191	$0	$0	$0	$0	$0	-$44,191	$0	$0
1080000	3640000	"POLES, TOWERS AND FIXTURES"	OR	-$219,323	$0	-$219,323	$0	$0	$0	$0	$0	$0
1080000	3640000	"POLES, TOWERS AND FIXTURES"	UT	-$180,874	$0	$0	$0	$0	-$180,874	$0	$0	$0
1080000	3640000	"POLES, TOWERS AND FIXTURES"	WA	-$50,075	$0	$0	-$50,075	$0	$0	$0	$0	$0
1080000	3640000	"POLES, TOWERS AND FIXTURES"	WYP	-$38,410	$0	$0	$0	-$38,410	$0	$0	$0	$0
1080000	3640000	"POLES, TOWERS AND FIXTURES"	WYU	-$8,373	$0	$0	$0	-$8,373	$0	$0	$0	$0
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	-$12,830	-$12,830	$0	$0	$0	$0	$0	$0	$0
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	-$15,852	$0	$0	$0	$0	$0	-$15,852	$0	$0
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	-$132,370	$0	-$132,370	$0	$0	$0	$0	$0	$0
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	-$76,174	$0	$0	$0	$0	-$76,174	$0	$0	$0
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	-$29,234	$0	$0	-$29,234	$0	$0	$0	$0	$0
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	-$35,838	$0	$0	$0	-$35,838	$0	$0	$0	$0
1080000	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	-$4,597	$0	$0	$0	-$4,597	$0	$0	$0	$0
1080000	3660000	UNDERGROUND CONDUIT	CA	-$8,194	-$8,194	$0	$0	$0	$0	$0	$0	$0
1080000	3660000	UNDERGROUND CONDUIT	IDU	-$3,053	$0	$0	$0	$0	$0	-$3,053	$0	$0
1080000	3660000	UNDERGROUND CONDUIT	OR	-$37,893	$0	-$37,893	$0	$0	$0	$0	$0	$0
1080000	3660000	UNDERGROUND CONDUIT	UT	-$58,781	$0	$0	$0	$0	-$58,781	$0	$0	$0
1080000	3660000	UNDERGROUND CONDUIT	WA	-$10,946	$0	$0	-$10,946	$0	$0	$0	$0	$0
1080000	3660000	UNDERGROUND CONDUIT	WYP	-$7,524	$0	$0	$0	-$7,524	$0	$0	$0	$0
1080000	3660000	UNDERGROUND CONDUIT	WYU	-$2,536	$0	$0	$0	-$2,536	$0	$0	$0	$0

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1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	-$14,541	-$14,541	$0	$0	$0	$0	$0	$0	$0
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	-$9,867	$0	$0	$0	$0	$0	-$9,867	$0	$0
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	-$62,560	$0	-$62,560	$0	$0	$0	$0	$0	$0
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	-$167,290	$0	$0	$0	$0	-$167,290	$0	$0	$0
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	-$9,516	$0	$0	-$9,516	$0	$0	$0	$0	$0
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	-$18,111	$0	$0	$0	-$18,111	$0	$0	$0	$0
1080000	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	-$12,756	$0	$0	$0	-$12,756	$0	$0	$0	$0
1080000	3680000	LINE TRANSFORMERS	CA	-$22,948	-$22,948	$0	$0	$0	$0	$0	$0	$0
1080000	3680000	LINE TRANSFORMERS	IDU	-$21,382	$0	$0	$0	$0	$0	-$21,382	$0	$0
1080000	3680000	LINE TRANSFORMERS	OR	-$175,370	$0	-$175,370	$0	$0	$0	$0	$0	$0
1080000	3680000	LINE TRANSFORMERS	UT	-$90,165	$0	$0	$0	$0	-$90,165	$0	$0	$0
1080000	3680000	LINE TRANSFORMERS	WA	-$44,447	$0	$0	-$44,447	$0	$0	$0	$0	$0
1080000	3680000	LINE TRANSFORMERS	WYP	-$28,813	$0	$0	$0	-$28,813	$0	$0	$0	$0
1080000	3680000	LINE TRANSFORMERS	WYU	-$4,485	$0	$0	$0	-$4,485	$0	$0	$0	$0
1080000	3691000	SERVICES - OVERHEAD	CA	-$3,584	-$3,584	$0	$0	$0	$0	$0	$0	$0
1080000	3691000	SERVICES - OVERHEAD	IDU	-$3,263	$0	$0	$0	$0	$0	-$3,263	$0	$0
1080000	3691000	SERVICES - OVERHEAD	OR	-$23,970	$0	-$23,970	$0	$0	$0	$0	$0	$0
1080000	3691000	SERVICES - OVERHEAD	UT	-$24,826	$0	$0	$0	$0	-$24,826	$0	$0	$0
1080000	3691000	SERVICES - OVERHEAD	WA	-$7,015	$0	$0	-$7,015	$0	$0	$0	$0	$0
1080000	3691000	SERVICES - OVERHEAD	WYP	-$4,125	$0	$0	$0	-$4,125	$0	$0	$0	$0
1080000	3691000	SERVICES - OVERHEAD	WYU	-$584	$0	$0	$0	-$584	$0	$0	$0	$0
1080000	3692000	SERVICES - UNDERGROUND	CA	-$5,995	-$5,995	$0	$0	$0	$0	$0	$0	$0
1080000	3692000	SERVICES - UNDERGROUND	IDU	-$7,015	$0	$0	$0	$0	$0	-$7,015	$0	$0
1080000	3692000	SERVICES - UNDERGROUND	OR	-$48,215	$0	-$48,215	$0	$0	$0	$0	$0	$0
1080000	3692000	SERVICES - UNDERGROUND	UT	-$33,775	$0	$0	$0	$0	-$33,775	$0	$0	$0
1080000	3692000	SERVICES - UNDERGROUND	WA	-$11,424	$0	$0	-$11,424	$0	$0	$0	$0	$0
1080000	3692000	SERVICES - UNDERGROUND	WYP	-$10,085	$0	$0	$0	-$10,085	$0	$0	$0	$0
1080000	3692000	SERVICES - UNDERGROUND	WYU	-$2,314	$0	$0	$0	-$2,314	$0	$0	$0	$0
1080000	3700000	METERS	CA	-$1,803	-$1,803	$0	$0	$0	$0	$0	$0	$0
1080000	3700000	METERS	IDU	-$6,661	$0	$0	$0	$0	$0	-$6,661	$0	$0
1080000	3700000	METERS	OR	-$33,198	$0	-$33,198	$0	$0	$0	$0	$0	$0
1080000	3700000	METERS	UT	-$23,995	$0	$0	$0	$0	-$23,995	$0	$0	$0
1080000	3700000	METERS	WA	-$1,930	$0	$0	-$1,930	$0	$0	$0	$0	$0
1080000	3700000	METERS	WYP	-$1,610	$0	$0	$0	-$1,610	$0	$0	$0	$0
1080000	3700000	METERS	WYU	-$655	$0	$0	$0	-$655	$0	$0	$0	$0
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	CA	-$218	-$218	$0	$0	$0	$0	$0	$0	$0
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	-$117	$0	$0	$0	$0	$0	-$117	$0	$0
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	OR	-$2,527	$0	-$2,527	$0	$0	$0	$0	$0	$0
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	UT	-$3,335	$0	$0	$0	$0	-$3,335	$0	$0	$0
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	WA	-$281	$0	$0	-$281	$0	$0	$0	$0	$0
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	-$921	$0	$0	$0	-$921	$0	$0	$0	$0
1080000	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	-$147	$0	$0	$0	-$147	$0	$0	$0	$0
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	-$579	-$579	$0	$0	$0	$0	$0	$0	$0
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	-$418	$0	$0	$0	$0	$0	-$418	$0	$0
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	-$8,973	$0	-$8,973	$0	$0	$0	$0	$0	$0
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	-$11,631	$0	$0	$0	$0	-$11,631	$0	$0	$0
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	-$2,201	$0	$0	-$2,201	$0	$0	$0	$0	$0
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	-$2,641	$0	$0	$0	-$2,641	$0	$0	$0	$0
1080000	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	-$870	$0	$0	$0	-$870	$0	$0	$0	$0
1080000	3892000	LAND RIGHTS	IDU	-$3	$0	$0	$0	$0	$0	-$3	$0	$0
1080000	3892000	LAND RIGHTS	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1080000	3892000	LAND RIGHTS	UT	-$19	$0	$0	$0	$0	-$19	$0	$0	$0
1080000	3892000	LAND RIGHTS	WYP	-$5	$0	$0	$0	-$5	$0	$0	$0	$0
1080000	3892000	LAND RIGHTS	WYU	-$2	$0	$0	$0	-$2	$0	$0	$0	$0

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1080000	3900000	STRUCTURES AND IMPROVEMENTS	CA	-$602	-$602	$0	$0	$0	$0	$0	$0	$0
1080000	3900000	STRUCTURES AND IMPROVEMENTS	CN	-$1,803	-$45	-$547	-$125	-$134	-$883	-$70	$0	$0
1080000	3900000	STRUCTURES AND IMPROVEMENTS	IDU	-$3,976	$0	$0	$0	$0	$0	-$3,976	$0	$0
1080000	3900000	STRUCTURES AND IMPROVEMENTS	OR	-$5,593	$0	-$5,593	$0	$0	$0	$0	$0	$0
1080000	3900000	STRUCTURES AND IMPROVEMENTS	SG	-$2,142	-$33	-$558	-$166	-$336	-$921	-$121	-$7	$0
1080000	3900000	STRUCTURES AND IMPROVEMENTS	SO	-$19,717	-$427	-$5,399	-$1,491	-$2,832	-$8,430	-$1,090	-$48	$0
1080000	3900000	STRUCTURES AND IMPROVEMENTS	UT	-$11,536	$0	$0	$0	$0	-$11,536	$0	$0	$0
1080000	3900000	STRUCTURES AND IMPROVEMENTS	WA	-$5,524	$0	$0	-$5,524	$0	$0	$0	$0	$0
1080000	3900000	STRUCTURES AND IMPROVEMENTS	WYP	-$1,155	$0	$0	$0	-$1,155	$0	$0	$0	$0
1080000	3900000	STRUCTURES AND IMPROVEMENTS	WYU	-$1,390	$0	$0	$0	-$1,390	$0	$0	$0	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CA	-$36	-$36	$0	$0	$0	$0	$0	$0	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	CN	-$707	-$17	-$214	-$49	-$53	-$346	-$27	$0	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	IDU	-$11	$0	$0	$0	$0	$0	-$11	$0	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	OR	-$178	$0	-$178	$0	$0	$0	$0	$0	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SG	-$26	$0	-$7	-$2	-$4	-$11	-$1	$0	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	SO	-$7,220	-$156	-$1,977	-$546	-$1,037	-$3,087	-$399	-$17	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	UT	-$69	$0	$0	$0	$0	-$69	$0	$0	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WA	-$9	$0	$0	-$9	$0	$0	$0	$0	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYP	-$147	$0	$0	$0	-$147	$0	$0	$0	$0
1080000	3903000	STRUCTURES & IMPROVEMENTS - PANELS	WYU	-$3	$0	$0	$0	-$3	$0	$0	$0	$0
1080000	3910000	OFFICE FURNITURE	CA	-$56	-$56	$0	$0	$0	$0	$0	$0	$0
1080000	3910000	OFFICE FURNITURE	CN	-$1,308	-$32	-$397	-$91	-$98	-$640	-$50	$0	$0
1080000	3910000	OFFICE FURNITURE	IDU	-$56	$0	$0	$0	$0	$0	-$56	$0	$0
1080000	3910000	OFFICE FURNITURE	OR	-$951	$0	-$951	$0	$0	$0	$0	$0	$0
1080000	3910000	OFFICE FURNITURE	SG	-$1,609	-$25	-$419	-$125	-$252	-$691	-$91	-$5	$0
1080000	3910000	OFFICE FURNITURE	SO	-$7,383	-$160	-$2,022	-$558	-$1,061	-$3,157	-$408	-$18	$0
1080000	3910000	OFFICE FURNITURE	UT	-$361	$0	$0	$0	$0	-$361	$0	$0	$0
1080000	3910000	OFFICE FURNITURE	WA	-$422	$0	$0	-$422	$0	$0	$0	$0	$0
1080000	3910000	OFFICE FURNITURE	WYP	-$309	$0	$0	$0	-$309	$0	$0	$0	$0
1080000	3910000	OFFICE FURNITURE	WYU	-$23	$0	$0	$0	-$23	$0	$0	$0	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	-$117	-$117	$0	$0	$0	$0	$0	$0	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	-$4,244	-$105	-$1,287	-$294	-$316	-$2,078	-$164	$0	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	-$398	$0	$0	$0	$0	$0	-$398	$0	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	-$1,038	$0	-$1,038	$0	$0	$0	$0	$0	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	-$22	$0	-$5	-$2	-$4	-$9	-$1	$0	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	-$893	-$14	-$233	-$69	-$140	-$384	-$51	-$3	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	-$22,348	-$484	-$6,120	-$1,690	-$3,210	-$9,555	-$1,235	-$54	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	-$1,277	$0	$0	$0	$0	-$1,277	$0	$0	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	-$458	$0	$0	-$458	$0	$0	$0	$0	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	-$1,431	$0	$0	$0	-$1,431	$0	$0	$0	$0
1080000	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	-$54	$0	$0	$0	-$54	$0	$0	$0	$0
1080000	3913000	OFFICE EQUIPMENT	CN	-$2	$0	-$1	$0	$0	-$1	$0	$0	$0
1080000	3913000	OFFICE EQUIPMENT	OR	-$10	$0	-$10	$0	$0	$0	$0	$0	$0
1080000	3913000	OFFICE EQUIPMENT	SG	-$322	-$5	-$84	-$25	-$51	-$139	-$18	-$1	$0
1080000	3913000	OFFICE EQUIPMENT	SO	-$80	-$2	-$22	-$6	-$11	-$34	-$4	$0	$0
1080000	3913000	OFFICE EQUIPMENT	UT	-$21	$0	$0	$0	$0	-$21	$0	$0	$0
1080000	3913000	OFFICE EQUIPMENT	WYP	-$1	$0	$0	$0	-$1	$0	$0	$0	$0
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	-$46	-$46	$0	$0	$0	$0	$0	$0	$0
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	-$189	$0	$0	$0	$0	$0	-$189	$0	$0
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	-$913	$0	-$913	$0	$0	$0	$0	$0	$0
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	-$251	-$4	-$65	-$19	-$39	-$108	-$14	-$1	$0
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	-$564	-$12	-$154	-$43	-$81	-$241	-$31	-$1	$0
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	-$1,265	$0	$0	$0	$0	-$1,265	$0	$0	$0
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	-$153	$0	$0	-$153	$0	$0	$0	$0	$0

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(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	-$176	$0	$0	$0	-$176	$0	$0	$0	$0
1080000	3920100	1/4 TON MINI-PICKUPS AND VANS	WYU	-$19	$0	$0	$0	-$19	$0	$0	$0	$0
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	IDU	-$10	$0	$0	$0	$0	$0	-$10	$0	$0
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	OR	-$166	$0	-$166	$0	$0	$0	$0	$0	$0
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	SG	-$30	$0	-$8	-$2	-$5	-$13	-$2	$0	$0
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	SO	-$132	-$3	-$36	-$10	-$19	-$56	-$7	$0	$0
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	UT	-$175	$0	$0	$0	$0	-$175	$0	$0	$0
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	WA	-$19	$0	$0	-$19	$0	$0	$0	$0	$0
1080000	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	-$32	$0	$0	$0	-$32	$0	$0	$0	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	-$239	-$239	$0	$0	$0	$0	$0	$0	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	-$726	$0	$0	$0	$0	$0	-$726	$0	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	-$2,815	$0	-$2,815	$0	$0	$0	$0	$0	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	-$76	-$1	-$19	-$6	-$13	-$32	-$5	$0	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	-$3,260	-$50	-$849	-$253	-$511	-$1,401	-$185	-$11	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	-$727	-$16	-$199	-$55	-$104	-$311	-$40	-$2	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	-$3,881	$0	$0	$0	$0	-$3,881	$0	$0	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	-$450	$0	$0	-$450	$0	$0	$0	$0	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	-$661	$0	$0	$0	-$661	$0	$0	$0	$0
1080000	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	-$177	$0	$0	$0	-$177	$0	$0	$0	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	-$293	-$293	$0	$0	$0	$0	$0	$0	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	-$845	$0	$0	$0	$0	$0	-$845	$0	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	-$3,264	$0	-$3,264	$0	$0	$0	$0	$0	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	-$119	-$2	-$29	-$9	-$21	-$51	-$8	$0	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	-$2,027	-$31	-$528	-$157	-$318	-$871	-$115	-$7	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	-$291	-$6	-$80	-$22	-$42	-$125	-$16	-$1	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	-$5,439	$0	$0	$0	$0	-$5,439	$0	$0	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	-$1,076	$0	$0	-$1,076	$0	$0	$0	$0	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	-$1,080	$0	$0	$0	-$1,080	$0	$0	$0	$0
1080000	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	-$255	$0	$0	$0	-$255	$0	$0	$0	$0
1080000	3920600	DUMP TRUCKS	OR	-$44	$0	-$44	$0	$0	$0	$0	$0	$0
1080000	3920600	DUMP TRUCKS	SE	-$2	$0	-$1	$0	$0	-$1	$0	$0	$0
1080000	3920600	DUMP TRUCKS	SG	-$1,342	-$20	-$350	-$104	-$210	-$577	-$76	-$4	$0
1080000	3920600	DUMP TRUCKS	SO	-$27	-$1	-$7	-$2	-$4	-$11	-$1	$0	$0
1080000	3920600	DUMP TRUCKS	UT	-$75	$0	$0	$0	$0	-$75	$0	$0	$0
1080000	3920900	TRAILERS	CA	-$124	-$124	$0	$0	$0	$0	$0	$0	$0
1080000	3920900	TRAILERS	IDU	-$231	$0	$0	$0	$0	$0	-$231	$0	$0
1080000	3920900	TRAILERS	OR	-$666	$0	-$666	$0	$0	$0	$0	$0	$0
1080000	3920900	TRAILERS	SE	-$26	$0	-$6	-$2	-$5	-$11	-$2	$0	$0
1080000	3920900	TRAILERS	SG	-$659	-$10	-$172	-$51	-$103	-$283	-$37	-$2	$0
1080000	3920900	TRAILERS	SO	-$234	-$5	-$64	-$18	-$34	-$100	-$13	-$1	$0
1080000	3920900	TRAILERS	UT	-$1,476	$0	$0	$0	$0	-$1,476	$0	$0	$0
1080000	3920900	TRAILERS	WA	-$158	$0	$0	-$158	$0	$0	$0	$0	$0
1080000	3920900	TRAILERS	WYP	-$688	$0	$0	$0	-$688	$0	$0	$0	$0
1080000	3920900	TRAILERS	WYU	-$137	$0	$0	$0	-$137	$0	$0	$0	$0
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	-$23	-$23	$0	$0	$0	$0	$0	$0	$0
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	-$22	$0	$0	$0	$0	$0	-$22	$0	$0
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	-$96	$0	-$96	$0	$0	$0	$0	$0	$0
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	-$109	-$2	-$28	-$8	-$17	-$47	-$6	$0	$0
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	-$16	$0	-$4	-$1	-$2	-$7	-$1	$0	$0
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	-$88	$0	$0	$0	$0	-$88	$0	$0	$0
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	-$17	$0	$0	-$17	$0	$0	$0	$0	$0
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	-$40	$0	$0	$0	-$40	$0	$0	$0	$0
1080000	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	-$5	$0	$0	$0	-$5	$0	$0	$0	$0
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	-$89	$0	-$89	$0	$0	$0	$0	$0	$0

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	-$184	-$3	-$48	-$14	-$29	-$79	-$10	-$1	$0
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	-$163	-$4	-$45	-$12	-$23	-$70	-$9	$0	$0
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	-$420	$0	$0	$0	$0	-$420	$0	$0	$0
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	-$102	$0	$0	-$102	$0	$0	$0	$0	$0
1080000	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	-$42	$0	$0	$0	-$42	$0	$0	$0	$0
1080000	3923000	TRANSPORTATION EQUIPMENT	SO	-$481	-$10	-$132	-$36	-$69	-$206	-$27	-$1	$0
1080000	3930000	STORES EQUIPMENT	CA	-$120	-$120	$0	$0	$0	$0	$0	$0	$0
1080000	3930000	STORES EQUIPMENT	IDU	-$145	$0	$0	$0	$0	$0	-$145	$0	$0
1080000	3930000	STORES EQUIPMENT	OR	-$1,276	$0	-$1,276	$0	$0	$0	$0	$0	$0
1080000	3930000	STORES EQUIPMENT	SG	-$1,655	-$25	-$431	-$128	-$259	-$711	-$94	-$6	$0
1080000	3930000	STORES EQUIPMENT	SO	-$203	-$4	-$56	-$15	-$29	-$87	-$11	$0	$0
1080000	3930000	STORES EQUIPMENT	UT	-$1,564	$0	$0	$0	$0	-$1,564	$0	$0	$0
1080000	3930000	STORES EQUIPMENT	WA	-$253	$0	$0	-$253	$0	$0	$0	$0	$0
1080000	3930000	STORES EQUIPMENT	WYP	-$578	$0	$0	$0	-$578	$0	$0	$0	$0
1080000	3930000	STORES EQUIPMENT	WYU	-$37	$0	$0	$0	-$37	$0	$0	$0	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	-$380	-$380	$0	$0	$0	$0	$0	$0	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	-$651	$0	$0	$0	$0	$0	-$651	$0	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	-$4,915	$0	-$4,915	$0	$0	$0	$0	$0	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	-$4	$0	-$1	$0	-$1	-$2	$0	$0	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	-$11,981	-$183	-$3,121	-$930	-$1,878	-$5,150	-$679	-$40	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	-$2,240	-$49	-$613	-$169	-$322	-$958	-$124	-$5	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	-$5,133	$0	$0	$0	$0	-$5,133	$0	$0	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	-$1,359	$0	$0	-$1,359	$0	$0	$0	$0	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	-$1,832	$0	$0	$0	-$1,832	$0	$0	$0	$0
1080000	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	-$257	$0	$0	$0	-$257	$0	$0	$0	$0
1080000	3950000	LABORATORY EQUIPMENT	CA	-$272	-$272	$0	$0	$0	$0	$0	$0	$0
1080000	3950000	LABORATORY EQUIPMENT	IDU	-$602	$0	$0	$0	$0	$0	-$602	$0	$0
1080000	3950000	LABORATORY EQUIPMENT	OR	-$5,051	$0	-$5,051	$0	$0	$0	$0	$0	$0
1080000	3950000	LABORATORY EQUIPMENT	SE	-$7	$0	-$2	-$1	-$1	-$3	$0	$0	$0
1080000	3950000	LABORATORY EQUIPMENT	SG	-$3,293	-$50	-$858	-$256	-$516	-$1,415	-$187	-$11	$0
1080000	3950000	LABORATORY EQUIPMENT	SO	-$2,505	-$54	-$686	-$189	-$360	-$1,071	-$138	-$6	$0
1080000	3950000	LABORATORY EQUIPMENT	UT	-$3,428	$0	$0	$0	$0	-$3,428	$0	$0	$0
1080000	3950000	LABORATORY EQUIPMENT	WA	-$984	$0	$0	-$984	$0	$0	$0	$0	$0
1080000	3950000	LABORATORY EQUIPMENT	WYP	-$1,518	$0	$0	$0	-$1,518	$0	$0	$0	$0
1080000	3950000	LABORATORY EQUIPMENT	WYU	-$468	$0	$0	$0	-$468	$0	$0	$0	$0
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	CA	-$471	-$471	$0	$0	$0	$0	$0	$0	$0
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	IDU	-$730	$0	$0	$0	$0	$0	-$730	$0	$0
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	OR	-$2,543	$0	-$2,543	$0	$0	$0	$0	$0	$0
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SG	-$265	-$4	-$69	-$21	-$42	-$114	-$15	-$1	$0
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SO	-$133	-$3	-$37	-$10	-$19	-$57	-$7	$0	$0
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	UT	-$2,353	$0	$0	$0	$0	-$2,353	$0	$0	$0
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WA	-$689	$0	$0	-$689	$0	$0	$0	$0	$0
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYP	-$955	$0	$0	$0	-$955	$0	$0	$0	$0
1080000	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYU	-$215	$0	$0	$0	-$215	$0	$0	$0	$0
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	-$81	-$81	$0	$0	$0	$0	$0	$0	$0
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	-$47	$0	$0	$0	$0	$0	-$47	$0	$0
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	-$262	$0	-$262	$0	$0	$0	$0	$0	$0
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	-$62	-$1	-$16	-$5	-$10	-$27	-$3	$0	$0
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	-$778	$0	$0	$0	$0	-$778	$0	$0	$0
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	-$70	$0	$0	$0	-$70	$0	$0	$0	$0
1080000	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	-$75	$0	$0	$0	-$75	$0	$0	$0	$0
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	-$354	-$354	$0	$0	$0	$0	$0	$0	$0
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	-$363	$0	$0	$0	$0	$0	-$363	$0	$0
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	-$2,406	$0	-$2,406	$0	$0	$0	$0	$0	$0

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Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	-$365	-$6	-$95	-$28	-$57	-$157	-$21	-$1	$0
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	-$119	-$3	-$33	-$9	-$17	-$51	-$7	$0	$0
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	-$3,319	$0	$0	$0	$0	-$3,319	$0	$0	$0
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	-$881	$0	$0	-$881	$0	$0	$0	$0	$0
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	-$571	$0	$0	$0	-$571	$0	$0	$0	$0
1080000	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	-$224	$0	$0	$0	-$224	$0	$0	$0	$0
1080000	3961000	CRANES	OR	-$80	$0	-$80	$0	$0	$0	$0	$0	$0
1080000	3961000	CRANES	SG	-$1,156	-$18	-$301	-$90	-$181	-$497	-$66	-$4	$0
1080000	3961000	CRANES	SO	-$26	-$1	-$7	-$2	-$4	-$11	-$1	$0	$0
1080000	3961000	CRANES	UT	-$1	$0	$0	$0	$0	-$1	$0	$0	$0
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	-$83	$0	-$83	$0	$0	$0	$0	$0	$0
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SE	-$21	$0	-$5	-$2	-$4	-$9	-$1	$0	$0
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	-$6,353	-$97	-$1,655	-$493	-$996	-$2,730	-$360	-$21	$0
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	-$493	-$11	-$135	-$37	-$71	-$211	-$27	-$1	$0
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	-$500	$0	$0	$0	$0	-$500	$0	$0	$0
1080000	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	-$90	$0	$0	$0	-$90	$0	$0	$0	$0
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	-$356	-$356	$0	$0	$0	$0	$0	$0	$0
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	-$412	$0	$0	$0	$0	$0	-$412	$0	$0
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	-$2,560	$0	-$2,560	$0	$0	$0	$0	$0	$0
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	-$59	-$1	-$15	-$5	-$9	-$25	-$3	$0	$0
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	-$150	-$3	-$41	-$11	-$22	-$64	-$8	$0	$0
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	-$4,123	$0	$0	$0	$0	-$4,123	$0	$0	$0
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	-$722	$0	$0	-$722	$0	$0	$0	$0	$0
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	-$735	$0	$0	$0	-$735	$0	$0	$0	$0
1080000	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	-$103	$0	$0	$0	-$103	$0	$0	$0	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	-$121	-$121	$0	$0	$0	$0	$0	$0	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	-$216	$0	$0	$0	$0	$0	-$216	$0	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	-$477	$0	-$477	$0	$0	$0	$0	$0	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	-$7	$0	-$2	$0	-$1	-$3	$0	$0	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	-$1,995	-$30	-$520	-$155	-$313	-$857	-$113	-$7	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	-$85	-$2	-$23	-$6	-$12	-$36	-$5	$0	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	-$1,198	$0	$0	$0	$0	-$1,198	$0	$0	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	-$358	$0	$0	-$358	$0	$0	$0	$0	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	-$238	$0	$0	$0	-$238	$0	$0	$0	$0
1080000	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	-$203	$0	$0	$0	-$203	$0	$0	$0	$0
1080000	3970000	COMMUNICATION EQUIPMENT	CA	-$874	-$874	$0	$0	$0	$0	$0	$0	$0
1080000	3970000	COMMUNICATION EQUIPMENT	CN	-$593	-$15	-$180	-$41	-$44	-$291	-$23	$0	$0
1080000	3970000	COMMUNICATION EQUIPMENT	IDU	-$1,273	$0	$0	$0	$0	$0	-$1,273	$0	$0
1080000	3970000	COMMUNICATION EQUIPMENT	OR	-$14,528	$0	-$14,528	$0	$0	$0	$0	$0	$0
1080000	3970000	COMMUNICATION EQUIPMENT	SE	-$24	$0	-$6	-$2	-$4	-$10	-$1	$0	$0
1080000	3970000	COMMUNICATION EQUIPMENT	SG	-$27,364	-$418	-$7,129	-$2,124	-$4,289	-$11,762	-$1,550	-$92	$0
1080000	3970000	COMMUNICATION EQUIPMENT	SO	-$14,842	-$322	-$4,064	-$1,122	-$2,132	-$6,346	-$820	-$36	$0
1080000	3970000	COMMUNICATION EQUIPMENT	UT	-$9,194	$0	$0	$0	$0	-$9,194	$0	$0	$0
1080000	3970000	COMMUNICATION EQUIPMENT	WA	-$4,714	$0	$0	-$4,714	$0	$0	$0	$0	$0
1080000	3970000	COMMUNICATION EQUIPMENT	WYP	-$6,215	$0	$0	$0	-$6,215	$0	$0	$0	$0
1080000	3970000	COMMUNICATION EQUIPMENT	WYU	-$958	$0	$0	$0	-$958	$0	$0	$0	$0
1080000	3972000	MOBILE RADIO EQUIPMENT	CA	-$16	-$16	$0	$0	$0	$0	$0	$0	$0
1080000	3972000	MOBILE RADIO EQUIPMENT	IDU	-$49	$0	$0	$0	$0	$0	-$49	$0	$0
1080000	3972000	MOBILE RADIO EQUIPMENT	OR	-$283	$0	-$283	$0	$0	$0	$0	$0	$0
1080000	3972000	MOBILE RADIO EQUIPMENT	SE	-$1	$0	$0	$0	$0	$0	$0	$0	$0
1080000	3972000	MOBILE RADIO EQUIPMENT	SG	-$177	-$3	-$46	-$14	-$28	-$76	-$10	-$1	$0
1080000	3972000	MOBILE RADIO EQUIPMENT	SO	-$100	-$2	-$27	-$8	-$14	-$43	-$6	$0	$0
1080000	3972000	MOBILE RADIO EQUIPMENT	UT	-$650	$0	$0	$0	$0	-$650	$0	$0	$0
1080000	3972000	MOBILE RADIO EQUIPMENT	WA	-$178	$0	$0	-$178	$0	$0	$0	$0	$0

PACIFICORP
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Depreciation Reserve (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	3972000	MOBILE RADIO EQUIPMENT	WYP	-$161	$0	$0	$0	-$161	$0	$0	$0	$0
1080000	3972000	MOBILE RADIO EQUIPMENT	WYU	-$38	$0	$0	$0	-$38	$0	$0	$0	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	CA	-$13	-$13	$0	$0	$0	$0	$0	$0	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	CN	-$129	-$3	-$39	-$9	-$10	-$63	-$5	$0	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	IDU	-$36	$0	$0	$0	$0	$0	-$36	$0	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	OR	-$244	$0	-$244	$0	$0	$0	$0	$0	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	SE	-$1	$0	$0	$0	$0	-$1	$0	$0	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	SG	-$768	-$12	-$200	-$60	-$120	-$330	-$43	-$3	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	SO	-$1,676	-$36	-$459	-$127	-$241	-$717	-$93	-$4	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	UT	-$160	$0	$0	$0	$0	-$160	$0	$0	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	WA	-$61	$0	$0	-$61	$0	$0	$0	$0	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	WYP	-$109	$0	$0	$0	-$109	$0	$0	$0	$0
1080000	3980000	MISCELLANEOUS EQUIPMENT	WYU	-$10	$0	$0	$0	-$10	$0	$0	$0	$0
1080000	3992200	LAND RIGHTS	SE	-$37,893	-$569	-$9,354	-$2,780	-$6,573	-$16,081	-$2,397	-$137	$0
1080000	3993000	"ENGINEERING SUPP-OFF WORK(SECY,MAP,DRAF	SE	-$25,669	-$385	-$6,337	-$1,883	-$4,453	-$10,894	-$1,624	-$93	$0
1080000	3994100	SURFACE - PLANT EQUIPMENT	SE	-$8,000	-$120	-$1,975	-$587	-$1,388	-$3,395	-$506	-$29	$0
1080000	3994400	SURFACE - ELECTRIC POWER FACILITIES	SE	-$1,556	-$23	-$384	-$114	-$270	-$661	-$98	-$6	$0
1080000	3994500	UNDERGROUND - COAL MINE EQUIPMENT	SE	-$36,088	-$542	-$8,909	-$2,648	-$6,260	-$15,316	-$2,283	-$131	$0
1080000	3994600	LONGWALL SHIELDS	SE	-$4,332	-$65	-$1,069	-$318	-$751	-$1,838	-$274	-$16	$0
1080000	3994700	LONGWALL EQUIPMENT	SE	-$1,349	-$20	-$333	-$99	-$234	-$573	-$85	-$5	$0
1080000	3994800	MAINLINE EXTENSION	SE	-$9,637	-$145	-$2,379	-$707	-$1,672	-$4,090	-$610	-$35	$0
1080000	3994900	SECTION EXTENSION	SE	-$2,134	-$32	-$527	-$157	-$370	-$906	-$135	-$8	$0
1080000	3995100	VEHICLES	SE	-$747	-$11	-$184	-$55	-$130	-$317	-$47	-$3	$0
1080000	3995200	HEAVY CONSTRUCTION EQUIPMENT	SE	-$3,101	-$47	-$766	-$228	-$538	-$1,316	-$196	-$11	$0
1080000	3996000	MISCELLANEOUS GENERAL EQUIPMENT	SE	-$1,141	-$17	-$282	-$84	-$198	-$484	-$72	-$4	$0
1080000	3996100	COMPUTERS - MAINFRAME	SE	-$354	-$5	-$87	-$26	-$61	-$150	-$22	-$1	$0
1080000	3997000	MINE DEVELOPMENT AND ROAD EXTENSION	SE	-$29,493	-$443	-$7,281	-$2,164	-$5,116	-$12,516	-$1,866	-$107	$0
1080000 Total				**-$7,204,775**	**-$183,007**	**-$2,116,891**	**-$575,229**	**-$1,012,410**	**-$2,895,025**	**-$406,117**	**-$16,096**	**$0**
1085000	144135	PRODUCTION PLANT - ACCUM DEPN-NON-CLASSI	SG-P	$0	$0	$0	$0	$0	$0	$0	$0	$0
1085000	144145	TRANSMISSION PLANT ACCUM DEPN-NON-CLASSI	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1085000	144205	GENERAL PLANT- ACCUM DEPN-NON-CLASS	SO		$0	$0	$0	$0	$0	$0	$0	$0
1085000	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-P	-$419	-$6	-$109	-$32	-$66	-$180	-$24	-$1	$0
1085000	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-U	-$274	-$4	-$71	-$21	-$43	-$118	-$16	-$1	$0
1085000	145139	PRODUCTION PLANT-ACCUM DEPRECIATION	SG	$25,188	$385	$6,562	$1,955	$3,948	$10,826	$1,427	$84	$0
1085000	145149	TRANSMISSION PLANT ACCUMULATED DEPR NON-	SG	$5,623	$86	$1,465	$436	$881	$2,417	$319	$19	$0
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	CA	$11	$11	$0	$0	$0	$0	$0	$0	$0
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	IDU	-$34	$0	$0	$0	$0	$0	-$34	$0	$0
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	OR	$818	$0	$818	$0	$0	$0	$0	$0	$0
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	UT	$695	$0	$0	$0	$0	$695	$0	$0	$0
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WA	$100	$0	$0	$100	$0	$0	$0	$0	$0
1085000	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WYU	$152	$0	$0	$0	$152	$0	$0	$0	$0
1085000	145189	MOTOR VEHICLES & MOBILE PLANT - ACCUM DE	SO	$3,050	$66	$835	$231	$438	$1,304	$169	$7	$0
1085000 Total				**$34,910**	**$537**	**$9,500**	**$2,669**	**$5,311**	**$14,944**	**$1,841**	**$108**	**$0**
Grand Total				**-$7,169,865**	**-$182,469**	**-$2,107,391**	**-$572,560**	**-$1,007,099**	**-$2,880,082**	**-$404,276**	**-$15,988**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Amortization Reserve (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1110000	3020000	FRANCHISES AND CONSENTS	IDU	-$785	$0	$0	$0	$0	$0	-$785	$0	$0
1110000	3020000	FRANCHISES AND CONSENTS	SG	-$2,739	-$42	-$714	-$213	-$429	-$1,177	-$155	-$9	$0
1110000	3020000	FRANCHISES AND CONSENTS	SG-P	-$30,399	-$464	-$7,920	-$2,360	-$4,765	-$13,066	-$1,722	-$102	$0
1110000	3020000	FRANCHISES AND CONSENTS	SG-U	-$4,203	-$64	-$1,095	-$326	-$659	-$1,807	-$238	-$14	$0
1110000	3031040	INTANGIBLE PLANT	OR	-$57	$0	-$57	$0	$0	$0	$0	$0	$0
1110000	3031040	INTANGIBLE PLANT	SG	-$6,420	-$98	-$1,673	-$498	-$1,006	-$2,760	-$364	-$22	$0
1110000	3031050	REGIONAL CONST MGMT SYS	SO	-$10,788	-$234	-$2,954	-$816	-$1,550	-$4,612	-$596	-$26	$0
1110000	3031080	FUEL MGMT SYSTEM	SO	-$3,285	-$71	-$900	-$248	-$472	-$1,405	-$182	-$8	$0
1110000	3031230	AUTOMATE POLE CARD SYSTEM	SO	-$4,410	-$96	-$1,208	-$333	-$633	-$1,885	-$244	-$11	$0
1110000	3031470	RILDA CANYON ROAD IMPROVEMENTS	SE	-$1,702	-$26	-$420	-$125	-$295	-$722	-$108	-$6	$0
1110000	3031680	DISTRIBUTION AUTOMATION PILOT	SO	-$12,438	-$270	-$3,406	-$940	-$1,787	-$5,318	-$687	-$30	$0
1110000	3031760	RECORD CENTER MGMT SOFTWARE	SO	-$284	-$6	-$78	-$21	-$41	-$121	-$16	-$1	$0
1110000	3031780	OUTAGE REPORTING SYSTEM	SO	-$3,498	-$76	-$958	-$264	-$502	-$1,496	-$193	-$8	$0
1110000	3031830	CUSTOMER SERVICE SYSTEM	CN	-$96,212	-$2,376	-$29,176	-$6,668	-$7,174	-$47,107	-$3,711	$0	$0
1110000	3032040	SAP	SO	-$128,193	-$2,779	-$35,105	-$9,692	-$18,414	-$54,808	-$7,086	-$309	$0
1110000	3032090	ENERGY COMMODITY SYS SOFTWARE	SO	-$9,974	-$216	-$2,731	-$754	-$1,433	-$4,264	-$551	-$24	$0
1110000	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	-$1,660	-$36	-$455	-$126	-$238	-$710	-$92	-$4	$0
1110000	3032260	DWHS - DATA WAREHOUSE	SO	-$1,158	-$25	-$317	-$88	-$166	-$495	-$64	-$3	$0
1110000	3032270	ENTERPRISE DATA WAREHOUSE	SO	-$5,470	-$119	-$1,498	-$414	-$786	-$2,339	-$302	-$13	$0
1110000	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	-$2,908	-$63	-$796	-$220	-$418	-$1,243	-$161	-$7	$0
1110000	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	-$1,725	-$37	-$472	-$130	-$248	-$738	-$95	-$4	$0
1110000	3032360	2002 GRID NET POWER COST MODELING	SO	-$8,843	-$192	-$2,422	-$669	-$1,270	-$3,781	-$489	-$21	$0
1110000	3032400	INCEDENT MANAGEMENT ANALYSIS PROGRAM	SO	-$5,286	-$115	-$1,448	-$400	-$759	-$2,260	-$292	-$13	$0
1110000	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	-$12,491	-$271	-$3,421	-$944	-$1,794	-$5,341	-$690	-$30	$0
1110000	3032480	OUTAGE CALL HANDLING INTEGRATION	CN	-$1,981	-$49	-$601	-$137	-$148	-$970	-$76	$0	$0
1110000	3032510	OPERATIONS MAPPING SYSTEM	SO	-$10,357	-$225	-$2,836	-$783	-$1,488	-$4,428	-$572	-$25	$0
1110000	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	-$1,892	-$41	-$518	-$143	-$272	-$809	-$105	-$5	$0
1110000	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	-$2,233	-$48	-$611	-$169	-$321	-$955	-$123	-$5	$0
1110000	3032600	SINGLE PERSON SCHEDULING	SO	-$8,475	-$184	-$2,321	-$641	-$1,217	-$3,623	-$468	-$20	$0
1110000	3032640	TIBCO SOFTWARE	SO	-$3,863	-$84	-$1,058	-$292	-$555	-$1,652	-$214	-$9	$0
1110000	3032670	C&T OFFICIAL RECORD INFO SYSTEM	SO	-$1,586	-$34	-$434	-$120	-$228	-$678	-$88	-$4	$0
1110000	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	-$1,581	-$24	-$412	-$123	-$248	-$680	-$90	-$5	$0
1110000	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	-$40	-$1	-$11	-$3	-$6	-$17	-$2	$0	$0
1110000	3032730	IMPROVEMENTS TO PLANT OWNED BY JAMES RIV	SG	-$11,429	-$175	-$2,978	-$887	-$1,792	-$4,913	-$648	-$38	$0
1110000	3032760	SWIFT 2 IMPROVEMENTS	SG	-$3,394	-$52	-$884	-$263	-$532	-$1,459	-$192	-$11	$0
1110000	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	-$44	-$1	-$11	-$3	-$7	-$19	-$2	$0	$0
1110000	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	-$22	$0	-$6	-$2	-$3	-$10	-$1	$0	$0
1110000	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	-$3	$0	-$1	$0	$0	-$1	$0	$0	$0
1110000	3032830	VCPRO - VISUALCOMPUSETPRO XEROX CUST STM	SO	-$2,179	-$47	-$597	-$165	-$313	-$931	-$120	-$5	$0
1110000	3032860	WEB SOFTWARE	SO	-$1,267	-$27	-$347	-$96	-$182	-$542	-$70	-$3	$0
1110000	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	-$477	-$7	-$124	-$37	-$75	-$205	-$27	-$2	$0
1110000	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	-$4,066	-$88	-$1,114	-$307	-$584	-$1,738	-$225	-$10	$0
1110000	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	-$8,163	-$125	-$2,127	-$634	-$1,280	-$3,508	-$462	-$27	$0
1110000	3033120	RANGER EMS/SCADA SYSTEM	SG	-$66	-$1	-$17	-$5	-$10	-$28	-$4	$0	$0
1110000	3033120	RANGER EMS/SCADA SYSTEM	SO	-$23,983	-$520	-$6,567	-$1,813	-$3,445	-$10,254	-$1,326	-$58	$0
1110000	3033120	RANGER EMS/SCADA SYSTEM	WYP	-$212	$0	$0	$0	-$212	$0	$0	$0	$0
1110000	3033140	ETAGM - Electronic Tagging Sys-Merchant	SO	-$1,417	-$31	-$388	-$107	-$204	-$606	-$78	-$3	$0
1110000	3033170	GTX VERSION 7 SOFTWARE	CN	-$2,254	-$56	-$684	-$156	-$168	-$1,104	-$87	$0	$0
1110000	3033180	HPOV - HP Openview Software	SO	-$1,902	-$41	-$521	-$144	-$273	-$813	-$105	-$5	$0
1110000	3033190	ITRON METER READING SOFTWARE	CN	-$2,171	-$54	-$658	-$150	-$162	-$1,063	-$84	$0	$0
1110000	3033300	SECID - CUST SECURE WEB LOGIN	CN	-$822	-$20	-$249	-$57	-$61	-$403	-$32	$0	$0
1110000	3033310	C&T - ENERGY TRADING SYSTEM	SO	-$3,420	-$74	-$936	-$259	-$491	-$1,462	-$189	-$8	$0
1110000	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	-$2,722	-$42	-$709	-$211	-$427	-$1,170	-$154	-$9	$0
1110000	3033360	DSM REPORTING & TRACKING SOFTWARE	SO	-$622	-$13	-$170	-$47	-$89	-$266	-$34	-$2	$0

PACIFICORP
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Amortization Reserve (Actuals)
Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1110000	3033370	DISTRIBUTION INTANGIBLES	WYP	-$3	$0	$0	$0	-$3	$0	$0	$0	$0
1110000	3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG	-$300	-$5	-$78	-$23	-$47	-$129	-$17	-$1	$0
1110000	3034900	MISC - MISCELLANEOUS	CN	-$11	$0	-$3	-$1	-$1	-$5	$0	$0	$0
1110000	3034900	MISC - MISCELLANEOUS	IDU	$0	$0	$0	$0	$0	$0	$0	$0	$0
1110000	3034900	MISC - MISCELLANEOUS	OR	-$5	$0	-$5	$0	$0	$0	$0	$0	$0
1110000	3034900	MISC - MISCELLANEOUS	SE	-$92	-$1	-$23	-$7	-$16	-$39	-$6	$0	$0
1110000	3034900	MISC - MISCELLANEOUS	SG	-$15,497	-$237	-$4,038	-$1,203	-$2,429	-$6,661	-$878	-$52	$0
1110000	3034900	MISC - MISCELLANEOUS	SO	-$1,227	-$27	-$336	-$93	-$176	-$525	-$68	-$3	$0
1110000	3034900	MISC - MISCELLANEOUS	UT	-$43	$0	$0	$0	$0	-$43	$0	$0	$0
1110000	3034900	MISC - MISCELLANEOUS	WYP	-$158	$0	$0	$0	-$158	$0	$0	$0	$0
1110000	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	-$474	-$7	-$123	-$37	-$74	-$204	-$27	-$2	$0
1110000	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-U	-$103	-$2	-$27	-$8	-$16	-$44	-$6	$0	$0
1110000	3326000	RESERVOIR, DAMS, WATERWAYS, LEASE HOLDS	SG-U	-$404	-$6	-$105	-$31	-$63	-$174	-$23	-$1	$0
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	-$292	-$292	$0	$0	$0	$0	$0	$0	$0
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CN	-$3,135	-$77	-$951	-$217	-$234	-$1,535	-$121	$0	$0
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	-$3,902	$0	-$3,902	$0	$0	$0	$0	$0	$0
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	-$12,094	-$262	-$3,312	-$914	-$1,737	-$5,171	-$668	-$29	$0
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	-$13	$0	$0	$0	$0	-$13	$0	$0	$0
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	-$1,641	$0	$0	-$1,641	$0	$0	$0	$0	$0
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	-$4,089	$0	$0	$0	-$4,089	$0	$0	$0	$0
1110000	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYU	-$41	$0	$0	$0	-$41	$0	$0	$0	$0
1110000 Total				**-$501,095**	**-$10,653**	**-$140,014**	**-$38,179**	**-$68,719**	**-$216,302**	**-$26,218**	**-$1,010**	**$0**
1119000	146209	Other Intangible Assets-Non-Rec	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1119000 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grand Total				**-$501,095**	**-$10,653**	**-$140,014**	**-$38,179**	**-$68,719**	**-$216,302**	**-$26,218**	**-$1,010**	**$0**

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Income Tax Balance (Actuals)
Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1901000	ACCUM DEF INC TAX	190101	ADIT-AMORT OF DEBT DISC & EXP	SNP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190103	ADIT-OBSOLETE MINE INVENTORY	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190105	ADIT-DEFERRED COMP	SO		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190107	ADIT-FED INC TAX INTEREST	SO		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190111	ADIT-BAD DEBT	BADDEBT	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190113	"ADIT-SICK LEAVE, VACATION & PT"	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190115	ADIT-INJURY & DAMAGES	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190119	ADIT-SERP UTILITY	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190121	CHOLLA/GE CONTRACT AMORT	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190126	TROJAN-ADDITIONAL DECOMMISSION	TROJD	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190127	TROJAN-ADDITIONAL DECOMMISSION-STATE	TROJD		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190128	ADIT-MISC. DEF TAX DEBITS	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190130	ADIT-MISC. DEF REG. ASSET	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190134	ADIT-NONCASH PENSION/BONUS/SEVER	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190135	ADIT-NONCASH PENSION/BONUS/SEVER-ST	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190136	ADIT-UTILITY ASSET WRITE DOWN	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190138	ADIT-MISC. ACCRUALS	SNP	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190143	MONSANTO CONTRACT-STATE	SE		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190148	ADIT- BONUS LIABILITY	SO		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190152	ADIT- GLENROCK 263A	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190154	ADIT- DSR LOAN SALE-FED	SO		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190158	REDDING RENEGOTIATED CONTRACT	SG		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190172	SEC 174 R&E EXPEND	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190174	ADIT-SEVERANCE	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190177	ADIT-UTAH RELOCATION-STATE	SO		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190400	PMI-VACATION/BONUS ADJ.	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190401	PMI-RENT EXP (SAFE HARBOR LEASE)	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190402	PMI-SEC. 263A ADJ.	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190403	PMI-RECL TRUST EARN-INTEREST	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190404	PMI-WY EXTRACTION TAXES	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190409	PMI SEC. 263 A ADJ-STATE	SE		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190411	PMI-WY EXTRACTION TAX-STATE	SE		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190500	CMC-ACCRUED FINAL RECLAM.	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190503	CMC-VACATION ACCRUAL-STATE	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	190504	CMC-AMORT. OVERBURDEN	SE		$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287250	DTA 705.301 Reg Lia - OR 2010 Protoc Def	OR	$923	$0	$923	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287251	DTA 705.500 Reg Lia-PD Decom Costs - UT	UT	$205	$0	$0	$0	$0	$205	$0	$0	$0
1901000	ACCUM DEF INC TAX	287252	DTA 705.263 Reg Lia - Sale of REC's-WA	OTHER	$6,571	$0	$0	$0	$0	$0	$0	$0	$6,571
1901000	ACCUM DEF INC TAX	287253	DTA 705.400 Reg Lia - OR Inj & Dam Reser	OR	$71	$0	$71	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287255	DTA 705.451 Reg Lia - OR Property Ins Re	OR	$1,128	$0	$1,128	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287257	DTA 705.453 Reg Lia - ID Property Ins Re	IDU	$33	$0	$0	$0	$0	$0	$33	$0	$0
1901000	ACCUM DEF INC TAX	287258	DTA 705.454 Reg Lia - UT Property Ins Re	UT	-$259	$0	$0	$0	$0	-$259	$0	$0	$0
1901000	ACCUM DEF INC TAX	287259	DTA 705.455 Reg Lia - WY Property Ins Re	WYP	$103	$0	$0	$0	$103	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287267	DTA 415.704 RL- Tax Rev Req Adj -UT	UT	$23	$0	$0	$0	$0	$23	$0	$0	$0
1901000	ACCUM DEF INC TAX	287270	Valuation Allowance for DTA	SO	-$1,257	-$27	-$344	-$95	-$181	-$537	-$69	-$3	$0
1901000	ACCUM DEF INC TAX	287271	DTA 705.336 RL - Sale of RECs - UT	OTHER	$9,103	$0	$0	$0	$0	$0	$0	$0	$9,103
1901000	ACCUM DEF INC TAX	287274	DTA 705.261 Reg Liab-Sale of RECs-OR	OTHER	$965	$0	$0	$0	$0	$0	$0	$0	$965
1901000	ACCUM DEF INC TAX	287278	DTA 605.102 Trojan Decommissioning Costs	OR	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287281	DTA - CA AMT CREDIT	OTHER	$241	$0	$0	$0	$0	$0	$0	$0	$241
1901000	ACCUM DEF INC TAX	287285	DTA 610.148 Reg Liability-Def NPC Balanc	OTHER	$226	$0	$0	$0	$0	$0	$0	$0	$226
1901000	ACCUM DEF INC TAX	287291	DTA 705.300 Reg Liability - Deferred Ben	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287299	DTA 705.265 Reg Liab-OR Energy Conservat	OR	$882	$0	$882	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287304	DTA 610.146 OR REG ASSET/LIAB CONS	OR	$73	$0	$73	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287309	DTA 705.200 Oregon Gain on Sale-Halsey	OTHER	$15	$0	$0	$0	$0	$0	$0	$0	$15
1901000	ACCUM DEF INC TAX	287314	DTA 415.700 Reg liability BPA balancing	OTHER	$1,024	$0	$0	$0	$0	$0	$0	$0	$1,024
1901000	ACCUM DEF INC TAX	287323	DTA 505.400 Bonus Liab. Elec.-Cash Basis	SO	$87	$2	$24	$7	$12	$37	$5	$0	$0
1901000	ACCUM DEF INC TAX	287324	DTA 720.200 Deferred Comp. Accrual - Cas	SO	$3,556	$77	$974	$269	$511	$1,520	$197	$9	$0
1901000	ACCUM DEF INC TAX	287325	DTA 505.510 Vacation Accrual - PMI	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287326	DTA 720.500 Severance Accrual - Cash Ba	SO	$7	$0	$2	$1	$1	$3	$0	$0	$0
1901000	ACCUM DEF INC TAX	287327	DTA 720.300 Pension/Retirement Accrual -	SO	$898	$19	$246	$68	$129	$384	$50	$2	$0
1901000	ACCUM DEF INC TAX	287328	DTA 720.310 SERP	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287332	DTA 505.600 Vacation Accrual-Cash Basis	SO	$15,031	$326	$4,116	$1,136	$2,159	$6,427	$831	$36	$0
1901000	ACCUM DEF INC TAX	287337	DTA 715.105 MCI F.O.G. WIRE LEASE	SG	$212	$3	$55	$16	$33	$91	$12	$1	$0

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Income Tax Balance (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1901000	ACCUM DEF INC TAX	287338	DTA415.110 Def Reg Asset-Transmission Sr	SG	$557	$9	$145	$43	$87	$239	$32	$2	$0
1901000	ACCUM DEF INC TAX	287340	DTA 220.100 Bad Debts Allowance - Cash B	BADDEBT	$5,515	$211	$2,615	$780	$298	$1,358	$253	$0	$0
1901000	ACCUM DEF INC TAX	287341	DTA 910.530 Injuries & Damages Accrual -	SO	$2,075	$45	$568	$157	$298	$887	$115	$5	$0
1901000	ACCUM DEF INC TAX	287343	DTA 415.120 Def Reg Asset-Foote Creek Co	SG	$163	$2	$43	$13	$26	$70	$9	$1	$0
1901000	ACCUM DEF INC TAX	287344	DTA 715.800 Redding Contract - Prepaid	SG	$835	$13	$218	$65	$131	$359	$47	$3	$0
1901000	ACCUM DEF INC TAX	287345	DTA 145.030 Distribution O&M Amort of Wr	SNPD	$807	$27	$217	$50	$86	$389	$38	$0	$0
1901000	ACCUM DEF INC TAX	287349	DTA 505.100 Trail Mountain Accrued Liabi	SE	$445	$7	$110	$33	$77	$189	$28	$2	$0
1901000	ACCUM DEF INC TAX	287354	DTA 505.140 MISC CURRENT & ACCRUED LIAB	SO	$1,692	$37	$463	$128	$243	$723	$93	$4	$0
1901000	ACCUM DEF INC TAX	287357	DTA 715.350 OTHER ENVIROMENTAL LIABILITI	SO	$4,783	$104	$1,310	$362	$687	$2,045	$264	$12	$0
1901000	ACCUM DEF INC TAX	287360	DTA 425.700 Special Assessment - DOE	TROJD	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287370	DTA 425.215 Unearned Joint Use Pole Cont	OTHER	$1,391	$0	$0	$0	$0	$0	$0	$0	$1,391
1901000	ACCUM DEF INC TAX	287371	DTA 930.100 Oregon BETC Credits	OR	$2,495	$0	$2,495	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287373	DTA 910.580 Wasach workers comp reserve	SO	$1,537	$33	$421	$116	$221	$657	$85	$4	$0
1901000	ACCUM DEF INC TAX	287389	DTA 610.145, OR CONSOLIDATION	OTHER	$2,877	$0	$0	$0	$0	$0	$0	$0	$2,877
1901000	ACCUM DEF INC TAX	287393	DTA 425.110 TENANT LEASE ALLOW - PSU CAL	CN	$29	$1	$9	$2	$2	$14	$1	$0	$0
1901000	ACCUM DEF INC TAX	287396	DTA425.110 Tenant Lease Allowances	OTHER	-$3,240	$0	$0	$0	$0	$0	$0	$0	-$3,240
1901000	ACCUM DEF INC TAX	287413	DTA 720.550 ACCRUED CIC SEVERANCE	SO	-$10	$0	-$3	-$1	-$1	-$4	-$1	$0	$0
1901000	ACCUM DEF INC TAX	287415	DTA 205.200 M&S INV	SE	$1,289	$19	$318	$95	$224	$547	$82	$5	$0
1901000	ACCUM DEF INC TAX	287417	DTA 605.710 REVERSE	OTHER	$4,444	$0	$0	$0	$0	$0	$0	$0	$4,444
1901000	ACCUM DEF INC TAX	287430	DTA 505.125 Accrued Royalties	SE	$63	$1	$15	$5	$11	$27	$4	$0	$0
1901000	ACCUM DEF INC TAX	287431	DTA 505.160 Cal PUC Fee	CA	$9	$9	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287435	DTA 105.154 SECTION 383 CAPITAL LOSS CAR	OTHER	$37	$0	$0	$0	$0	$0	$0	$0	$37
1901000	ACCUM DEF INC TAX	287437	DTA Net Operating Loss Carryforwrd-State	SO	$77,021	$1,670	$21,092	$5,823	$11,064	$32,930	$4,257	$186	$0
1901000	ACCUM DEF INC TAX	287441	DTA 605.100 Trojan Decom Cost-Regulatory	TROJD	$1,918	$29	$495	$147	$306	$823	$111	$7	$0
1901000	ACCUM DEF INC TAX	287442	DTA 610.135 SB 1149 Costs	OTHER	$372	$0	$0	$0	$0	$0	$0	$0	$372
1901000	ACCUM DEF INC TAX	287446	DTA 205.100 Coal Pile Inventory Adjustme	SE	$2,549	$38	$629	$187	$442	$1,082	$161	$9	$0
1901000	ACCUM DEF INC TAX	287449	DTA Federal Detriment of State NOL	SO	-$27,053	-$586	-$7,408	-$2,045	-$3,886	-$11,566	-$1,495	-$65	$0
1901000	ACCUM DEF INC TAX	287453	DTA 610.143 WA PRGRM	OTHER	$177	$0	$0	$0	$0	$0	$0	$0	$177
1901000	ACCUM DEF INC TAX	287473	DTA 705.270 Reg Liab	OTHER	$676	$0	$0	$0	$0	$0	$0	$0	$676
1901000	ACCUM DEF INC TAX	287474	DTA 705.271 Reg Liab	OTHER	$42	$0	$0	$0	$0	$0	$0	$0	$42
1901000	ACCUM DEF INC TAX	287475	DTA 705.272 Reg Liab	OTHER	$22	$0	$0	$0	$0	$0	$0	$0	$22
1901000	ACCUM DEF INC TAX	287476	DTA 705.273 Reg Liab	OTHER	$663	$0	$0	$0	$0	$0	$0	$0	$663
1901000	ACCUM DEF INC TAX	287477	DTA 705.274 Reg Liab	OTHER	$6	$0	$0	$0	$0	$0	$0	$0	$6
1901000	ACCUM DEF INC TAX	287478	DTA 705.275 Reg Liab	OTHER	$54	$0	$0	$0	$0	$0	$0	$0	$54
1901000	ACCUM DEF INC TAX	287479	DTA 105.221 Saf Har	SG	$37,612	$575	$9,799	$2,919	$5,896	$16,166	$2,131	$126	$0
1901000	ACCUM DEF INC TAX	287482	DTA 205.025 PMI Fuel Cost Adjustment	SE	$1,467	$22	$362	$108	$254	$622	$93	$5	$0
1901000	ACCUM DEF INC TAX	287491	DTA - BETC CREDIT CARRYFORWARD	SG	$5,176	$79	$1,349	$402	$811	$2,225	$293	$17	$0
1901000	ACCUM DEF INC TAX	287706	DTL 610.100 COAL MINE DEVT PMI	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000	ACCUM DEF INC TAX	287723	DTL 205.411 PMI SEC. 263A	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
1901000 Total					**$168,356**	**$2,744**	**$43,410**	**$10,789**	**$20,045**	**$57,676**	**$7,660**	**$366**	**$25,667**
1901090	FAS109 DEF TAX ASS	287374	DTA 100.105 FAS 109 Deferred Tax Liabili	WA	$1,271	$0	$0	$1,271	$0	$0	$0	$0	$0
1901090 Total					**$1,271**	**$0**	**$0**	**$1,271**	**$0**	**$0**	**$0**	**$0**	**$0**
2811000	AC DEF TAX-ACCL AM	286601	ACCUM DIT - PPL EMERGENCY FACILITIES	DGP		$0	$0	$0	$0	$0	$0	$0	$0
2811000	AC DEF TAX-ACCL AM	286602	ACCUM DIT-PPL EMERGENCY FACILITIES-STATE	DGP	$0	$0	$0	$0	$0	$0	$0	$0	$0
2811000	AC DEF TAX-ACCL AM	287960	DTL 105.128 Accel Depr Pollution Cntrl F	SG	-$178,289	-$2,723	-$46,450	-$13,839	-$27,948	-$76,631	-$10,101	-$598	$0
2811000 Total					**-$178,289**	**-$2,723**	**-$46,450**	**-$13,839**	**-$27,948**	**-$76,631**	**-$10,101**	**-$598**	**$0**
2820000	AC DEF INCTX-PROPT	287704	DTL 105.143/165 Basis Diff - Intangibles	SO	-$912	-$20	-$250	-$69	-$131	-$390	-$50	-$2	$0
2820000 Total					**-$912**	**-$20**	**-$250**	**-$69**	**-$131**	**-$390**	**-$50**	**-$2**	**$0**
2821000	AC DEF TAX-UTILITY	287001	ADIT - DEVELOPMENT 30% AMORT	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2821000	AC DEF TAX-UTILITY	287007	ACCUM DEFERRED INC TAX - ADRLF	DITBAL	$0	$0	$0	$0	$0	$0	$0	$0	$0
2821000	AC DEF TAX-UTILITY	287008	ADIT - FEDERAL - PROPERTY, PLANT & EQUIP	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
2821000	AC DEF TAX-UTILITY	287011	ACCUM DEFERRED INC TAX - METHD	DITBAL		$0	$0	$0	$0	$0	$0	$0	$0
2821000	AC DEF TAX-UTILITY	287015	ADIT - STATE - PROPERTY, PLANT & EQUIPME	DITBAL	$0	$0	$0	$0	$0	$0	$0	$0	$0
2821000	AC DEF TAX-UTILITY	287019	ACCUM DEFERRED INC TAX - STATE - GLLIF	DITBAL	$0	$0	$0	$0	$0	$0	$0	$0	$0
2821000	AC DEF TAX-UTILITY	287026	CHOLLA TAX BENEFITS AMORT	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
2821000	AC DEF TAX-UTILITY	287029	CHOLLA CONTRACT DISCOUNT AMORT	SG		$0	$0	$0	$0	$0	$0	$0	$0
2821000	AC DEF TAX-UTILITY	287031	PMI - DEPRECIATION (TAX)	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2821000	AC DEF TAX-UTILITY	287605	DTL PP&E Powertax	DITBAL	-$3,360,555	-$73,645	-$909,311	-$203,954	-$471,368	-$1,452,964	-$187,763	-$9,408	$0
2821000	AC DEF TAX-UTILITY	287608	DTL Safe Harbor Lease Cholla	SG	-$4,458	-$68	-$1,161	-$346	-$699	-$1,916	-$253	-$15	$0
2821000	AC DEF TAX-UTILITY	287740	DTL 110.200 TAX PERCENTAGE DEPLETION	SE	$291	$4	$72	$21	$50	$123	$18	$1	$0
2821000	AC DEF TAX-UTILITY	287753	DTL 110.100 BOOK DEPLETION	SE	-$5,917	-$89	-$1,461	-$434	-$1,026	-$2,511	-$374	-$21	$0
2821000	AC DEF TAX-UTILITY	287766	DTL 610.100N Amort	SO	$264	$6	$72	$20	$38	$113	$15	$1	$0
2821000	AC DEF TAX-UTILITY	287771	DTL 110.205 SRC tax depletion	SE	$518	$8	$128	$38	$90	$220	$33	$2	$0

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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2821000	AC DEF TAX-UTILITY	287962	DTL - Fixed Assets - State Modifications	SO	$36,092	$782	$9,884	$2,729	$5,184	$15,431	$1,995	$87	$0
2821000	AC DEF TAX-UTILITY	287963	DTL - Fixed Assets - State Modif (Fed De	SO	-$12,632	-$274	-$3,459	-$955	-$1,815	-$5,401	-$698	-$30	$0
2821000 Total					**-$3,346,399**	**-$73,275**	**-$905,237**	**-$202,882**	**-$469,546**	**-$1,446,905**	**-$187,028**	**-$9,385**	**$0**
2831000	AC DEF IN TX UTIL	287501	ADIT MISC. CONTRACTS/DEPOSITS	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287503	ADIT MISC. DEF. CREDITS	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287504	ADIT OTHER M-1 LINE 8 DIFFS - STATE	SO		$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287507	ACCUM DIT - FAS106	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287508	ACCUM DIT - FAS106 - STATE	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287509	ADIT REGULATORY ASSET 186.2 - FED	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287511	ACCUM DIT - COAL PILE INVENTORY	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287512	ACCUM DIT - COAL PILE INVENTORY - STATE	SE		$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287515	DIT - POST MERGER DEBT LOST	SNP	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287520	ACCUM DIT-APS ABANDONMENT-STATE	SG		$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287521	ACCUM DIT - WEATHERIZATION	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287525	ADIT - PREPAID TAXES	GPS	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287527	ADIT - TRUST INC + EXP	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287531	ADIT - ENVIRONMENTAL CLEANUP	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287533	ADIT - EXTRACTION TAX	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287534	ADIT - EXTRACTION TAX - STATE	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287545	ADIT - POLLUTION CONTROL	SNP	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287549	R&E - BSIP-SAP WRITE-OFF	SO	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287552	PMI - MISC	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287560	GCC - BONUS LIABILITY	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287570	DTL 415.701 CA Deferred Intervenor Fundi	CA	-$12	-$12	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287571	DTL 415.702 Reg Asset-Lake Side Liq. Dam	WYU	-$371	$0	$0	$0	-$371	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287573	DTL 415.873 Deferred Excess NPC-WA Hydro	WA	-$310	$0	$0	-$310	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287575	DTL 425.125 Deferred Coal Cost-Arch	SE	$0	$0	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287576	DTL 415.822 RgAst UT	OTHER	-$2,877	$0	$0	$0	$0	$0	$0	$0	-$2,877
2831000	AC DEF IN TX UTIL	287577	DTL 415.820 Contra Pensn Reg Asset MMT &	OR	$2,695	$0	$2,695	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287579	DTL 415.822 Reg Asset _ Pension MMT_UT	UT	-$645	$0	$0	$0	$0	-$645	$0	$0	$0
2831000	AC DEF IN TX UTIL	287581	DTL 415.824 Contra Pensn Reg Asset MMT &	CA	$244	$244	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287582	DTL 415.825 Contra Pensn Reg Asset CTG_W	WA	$386	$0	$0	$386	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287584	DTL 415.827 Reg Asset - FAS 158 Post - R	OR	-$513	$0	-$513	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287586	DTL 415.829 Reg Asset - Post - Ret MMT_U	UT	-$634	$0	$0	$0	$0	-$634	$0	$0	$0
2831000	AC DEF IN TX UTIL	287588	DTL 415.831 Reg Asset - Post - Ret MMT_C	CA	-$46	-$46	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287590	DTL 415.840 Reg Asset - Deferred OR Ind	OTHER	$73	$0	$0	$0	$0	$0	$0	$0	$73
2831000	AC DEF IN TX UTIL	287591	DTL 415.301 Environmental Clean-up Accrl	WA	$285	$0	$0	$285	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287593	DTL 415.874 Deferred Net Power Costs-WY	OTHER	-$13,545	$0	$0	$0	$0	$0	$0	$0	-$13,545
2831000	AC DEF IN TX UTIL	287596	DTL 415.892 Deferred Net Power Costs - I	OTHER	-$8,828	$0	$0	$0	$0	$0	$0	$0	-$8,828
2831000	AC DEF IN TX UTIL	287597	DTL 415.703 Goodnoe Hills Liquidation Da	WYP	-$177	$0	$0	$0	-$177	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287614	DTL 430.100 Weatherization	SO	$1,231	$27	$337	$93	$177	$526	$68	$3	$0
2831000	AC DEF IN TX UTIL	287616	DTL Interim provision reg assets/Liabil	OTHER	$2,466	$0	$0	$0	$0	$0	$0	$0	$2,466
2831000	AC DEF IN TX UTIL	287634	DTL 415.300 Environmental Clean-up Accru	SO	-$8,434	-$183	-$2,310	-$638	-$1,212	-$3,606	-$466	-$20	$0
2831000	AC DEF IN TX UTIL	287635	DTL 415.500 Cholla Plt Transact Costs-AP	SGCT	-$2,378	-$36	-$622	-$185	-$374	-$1,026	-$135	$0	$0
2831000	AC DEF IN TX UTIL	287639	DTL 415.510 WA Disallowed Colstrip 3-Wri	WA	-$180	$0	$0	-$180	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287640	DTL 415.680 Deferred Intervener Funding	OR	-$131	$0	-$131	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287647	DTL 425.100 IDAHO DEFERRED REGULATORY EX	IDU	-$22	$0	$0	$0	$0	$0	-$22	$0	$0
2831000	AC DEF IN TX UTIL	287653	DTL 425.250 TGS Buyout	SG	-$47	-$1	-$12	-$4	-$7	-$20	-$3	$0	$0
2831000	AC DEF IN TX UTIL	287656	DTL 425.280 Joseph Settlement	SG	-$317	-$5	-$83	-$25	-$50	-$136	-$18	-$1	$0
2831000	AC DEF IN TX UTIL	287661	DTL 425.360 Hermiston Swap	SG	-$1,602	-$24	-$417	-$124	-$251	-$688	-$91	-$5	$0
2831000	AC DEF IN TX UTIL	287662	DTL 210.100 Prepaid Taxes - OR PUC	OR	-$274	$0	-$274	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287664	DTL 210.120 Prepaid Taxes - UT PUC	UT	-$876	$0	$0	$0	$0	-$876	$0	$0	$0
2831000	AC DEF IN TX UTIL	287665	DTL 210.130 Prepaid Taxes - ID PUC	IDU	-$90	$0	$0	$0	$0	$0	-$90	$0	$0
2831000	AC DEF IN TX UTIL	287669	DTL 210.180 PRE MEM	SO	-$1,539	-$33	-$421	-$116	-$221	-$658	-$85	-$4	$0
2831000	AC DEF IN TX UTIL	287675	DTL 740.100 Post Merger Loss-Reacq Debt	SNP	-$3,672	-$73	-$970	-$270	-$532	-$1,616	-$202	-$9	$0
2831000	AC DEF IN TX UTIL	287685	DTL 425.380 Idaho Customer Balancing Acc	IDU	-$491	$0	$0	$0	$0	$0	-$491	$0	$0
2831000	AC DEF IN TX UTIL	287708	DTL 210.200 PREPAID PROPERTY TAXES	GPS	-$5,950	-$129	-$1,629	-$450	-$855	-$2,544	-$329	-$14	$0
2831000	AC DEF IN TX UTIL	287747	DTL 705.240 CA Energy Program	CA	$90	$90	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287750	DTL 425.310 Hydro Relicensing Obligation	OTHER	-$9,737	$0	$0	$0	$0	$0	$0	$0	-$9,737
2831000	AC DEF IN TX UTIL	287760	DTL 415.896 WA - Chehalis Plant Rev Req	WA	-$4,554	$0	$0	-$4,554	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287770	DTL 120.205 TRAPPER MINE-EQUITY EARNINGS	OTHER	-$1,611	$0	$0	$0	$0	$0	$0	$0	-$1,611
2831000	AC DEF IN TX UTIL	287772	DTL 505.800 State Tax Ded on Fed TR	OTHER	-$16	$0	$0	$0	$0	$0	$0	$0	-$16
2831000	AC DEF IN TX UTIL	287779	DTL 415.850 Unrec Plt	SG	-$841	-$13	-$219	-$65	-$132	-$362	-$48	-$3	$0

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A MIDAMERICAN ENERGY HOLDINGS COMPANY

Deferred Income Tax Balance (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2831000	AC DEF IN TX UTIL	287781	DTL 415.870 Def CA	OTHER	-$800	$0	$0	$0	$0	$0	$0	$0	-$800
2831000	AC DEF IN TX UTIL	287783	DTL 415.880 Def Ut	UT	-$29	$0	$0	$0	$0	-$29	$0	$0	$0
2831000	AC DEF IN TX UTIL	287784	DTL 415.900 OR SB RE	OTHER	-$2,622	$0	$0	$0	$0	$0	$0	$0	-$2,622
2831000	AC DEF IN TX UTIL	287787	DTL 415.895 OR _RCAC SEP-DEC 07	OR	$3	$0	$3	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287860	DTL 415.855 Reg Asset-CA-Jan10 Storm Cos	OTHER	-$25	$0	$0	$0	$0	$0	$0	$0	-$25
2831000	AC DEF IN TX UTIL	287861	DTL 415.857 Reg Asset-ID-Def Overburden	OTHER	-$67	$0	$0	$0	$0	$0	$0	$0	-$67
2831000	AC DEF IN TX UTIL	287862	DTL 415.893 OR MEHC Transition Service C	OTHER	-$346	$0	$0	$0	$0	$0	$0	$0	-$346
2831000	AC DEF IN TX UTIL	287863	DTL 415.851 Powerdale Decom Cost Amort-C	CA	-$13	-$13	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287864	DTL 415.852 Powerdale Decom Cost Amort-I	IDU	-$81	$0	$0	$0	$0	$0	-$81	$0	$0
2831000	AC DEF IN TX UTIL	287866	DTL 415.854 Powerdale Decom Cost Amort-W	WA	-$242	$0	$0	-$242	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287868	DTL 415.858 Reg Asset-WY-Def Overburden	WYP	-$185	$0	$0	$0	-$185	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287871	DTL 415.866 Reg Asset-OR Solar Feed-In T	OTHER	-$482	$0	$0	$0	$0	$0	$0	$0	-$482
2831000	AC DEF IN TX UTIL	287872	DTL 720.841 RA Tax Adj on PR Benefit-CA	OTHER	-$75	$0	$0	$0	$0	$0	$0	$0	-$75
2831000	AC DEF IN TX UTIL	287873	DTL 720.842 RA Tax Adj on PR Benefit-ID	OTHER	-$199	$0	$0	$0	$0	$0	$0	$0	-$199
2831000	AC DEF IN TX UTIL	287874	DTL 720.843 RA Tax Adj on PR Benefit-OR	OTHER	-$1,697	$0	$0	$0	$0	$0	$0	$0	-$1,697
2831000	AC DEF IN TX UTIL	287875	DTL 720.844 RA Tax Adj on PR Benefit-UT	OTHER	-$1,375	$0	$0	$0	$0	$0	$0	$0	-$1,375
2831000	AC DEF IN TX UTIL	287877	DTL 720.846 RA Tax Adj on PR Benefit-WY	OTHER	-$542	$0	$0	$0	$0	$0	$0	$0	-$542
2831000	AC DEF IN TX UTIL	287878	DTL 415.406 RA Utah ECAM	OTHER	-$25,726	$0	$0	$0	$0	$0	$0	$0	-$25,726
2831000	AC DEF IN TX UTIL	287879	DTL 415.898 Deferred Coal Cost Naughton	SE	-$2,611	-$39	-$645	-$192	-$453	-$1,108	-$165	-$9	$0
2831000	AC DEF IN TX UTIL	287880	DTL 415.897 Transition Severance Cost CA	CA	-$17	-$17	$0	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287881	DTL 415.705 RA # Tax Rev Req Adj-WY	WYU	-$27	$0	$0	$0	-$27	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287882	DTL 415.876 Deferred Net Power Costs-OR	OTHER	$23	$0	$0	$0	$0	$0	$0	$0	$23
2831000	AC DEF IN TX UTIL	287884	DTL 415.867 Reg Asset - CA Solar Feed-in	OTHER	$93	$0	$0	$0	$0	$0	$0	$0	$93
2831000	AC DEF IN TX UTIL	287887	DTL 415.881 Def of Excess RECs UT	OTHER	$6	$0	$0	$0	$0	$0	$0	$0	$6
2831000	AC DEF IN TX UTIL	287888	DTL 415.882 Def of Excess RECs WA	OTHER	-$259	$0	$0	$0	$0	$0	$0	$0	-$259
2831000	AC DEF IN TX UTIL	287889	DTL 415.883 Def of Excess RECs WY	OTHER	$196	$0	$0	$0	$0	$0	$0	$0	$196
2831000	AC DEF IN TX UTIL	287942	DTL 430.112 Reg Asset - Other - Balance	OTHER	-$519	$0	$0	$0	$0	$0	$0	$0	-$519
2831000	AC DEF IN TX UTIL	287943	DTL 430.113 Reg Asset - Def NPC Balance	OTHER	-$226	$0	$0	$0	$0	$0	$0	$0	-$226
2831000	AC DEF IN TX UTIL	287947	DTL 415.501 Cholla Plant Transaction Cos	IDU	$70	$0	$0	$0	$0	$0	$70	$0	$0
2831000	AC DEF IN TX UTIL	287948	DTL 415.502 Cholla Plant Transaction Cos	OR	$114	$0	$114	$0	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287949	DTL 415.503 Cholla Plant Transaction Cos	WA	$206	$0	$0	$206	$0	$0	$0	$0	$0
2831000	AC DEF IN TX UTIL	287967	DTL LT Prepaid IBEW 57 Pension Contribut	OTHER	-$2,145	$0	$0	$0	$0	$0	$0	$0	-$2,145
2831000 Total					**-$102,851**	**-$264**	**-$5,097**	**-$6,385**	**-$4,670**	**-$13,422**	**-$2,088**	**-$63**	**-$70,861**
Grand Total					**-$3,458,823**	**-$73,539**	**-$913,624**	**-$211,115**	**-$482,249**	**-$1,479,672**	**-$191,607**	**-$9,682**	**-$45,194**

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A MIDAMERICAN ENERGY HOLDINGS COMPANY

Investment Tax Credit Balance (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2551000	285602	ACCUM DEF ITC - PPL - 1983	ITC84	-$291	-$10	-$206	-$41	-$32	$0	$0	$0	$0
2551000	285603	ACCUM DEF ITC - PPL - 1984	ITC85	-$524	-$28	-$355	-$70	-$61	$0	$0	$0	$0
2551000	285604	ACCUM DEF ITC - PPL - 1985	ITC85	-$823	-$45	-$557	-$110	-$96	$0	$0	$0	$0
2551000	285605	ACCUM DEF ITC - PPL - 1986	ITC86	-$863	-$41	-$558	-$113	-$134	$0	$0	$0	$0
2551000	285606	ACCUM DEF ITC - PPL - 1987	ITC88	-$148	-$6	-$91	-$22	-$25	$0	$0	$0	$0
2551000	285607	ACCUM DEF ITC - PPL - 1988	ITC89	-$340	-$17	-$191	-$52	-$70	$0	$0	$0	$0
2551000	285608	JIM BRIDGER RETROFIT ITC - PPL	ITC90	-$244	-$4	-$39	-$10	-$42	-$115	-$34	$0	$0
2551000 Total				**-$3,233**	**-$150**	**-$1,997**	**-$418**	**-$459**	**-$115**	**-$34**	**$0**	**$0**
Grand Total				**-$3,233**	**-$150**	**-$1,997**	**-$418**	**-$459**	**-$115**	**-$34**	**$0**	**$0**

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A MIDAMERICAN ENERGY HOLDINGS COMPANY

Customer Advances (Actuals)

Balance as of June 2012
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2520000	0	CUSTOMER ADVANCES FOR CONSTRUCTION	CN	$0	$0	$0	$0	$0	$0	$0	$0	$0
2520000	0	CUSTOMER ADVANCES FOR CONSTRUCTION	SG	$0	$0	$0	$0	$0	$0	$0	$0	$0
2520000	210550	Payments Received Uncompleted Projects	IDU	-$1	$0	$0	$0	$0	$0	-$1	$0	$0
2520000	210550	Payments Received Uncompleted Projects	OR	-$1,775	$0	-$1,775	$0	$0	$0	$0	$0	$0
2520000	210550	Payments Received Uncompleted Projects	SG	-$3,972	-$61	-$1,035	-$308	-$623	-$1,707	-$225	-$13	$0
2520000	210550	Payments Received Uncompleted Projects	UT	-$763	$0	$0	$0	$0	-$763	$0	$0	$0
2520000	210550	Payments Received Uncompleted Projects	WYP	-$118	$0	$0	$0	-$118	$0	$0	$0	$0
2520000	210550	Payments Received Uncompleted Projects	WYU	-$1,489	$0	$0	$0	-$1,489	$0	$0	$0	$0
2520000	210553	Transmission Payments Received - Capital	SG	-$3,332	-$51	-$868	-$259	-$522	-$1,432	-$189	-$11	$0
2520000	285460	Transm Intercon Deposits - w/3rd Party	SG	-$11,342	-$173	-$2,955	-$880	-$1,778	-$4,875	-$643	-$38	$0
2520000 Total				**-$22,791**	**-$285**	**-$6,633**	**-$1,447**	**-$4,529**	**-$8,777**	**-$1,057**	**-$63**	**$0**
2521000	0	CUSTOMER ADVANCES FOR CONSTRUCTION - UPL	CN	$0	$0	$0	$0	$0	$0	$0	$0	$0
2521000 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2521100	0	CUSTOMER ADVANCES FOR CONST-REFUNDABLE-P	CN	$0	$0	$0	$0	$0	$0	$0	$0	$0
2521100 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2523990	0	CUSTOMER ADV-POTENT REFUND - CSS	CN	$0	$0	$0	$0	$0	$0	$0	$0	$0
2523990 Total				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grand Total				**-$22,791**	**-$285**	**-$6,633**	**-$1,447**	**-$4,529**	**-$8,777**	**-$1,057**	**-$63**	**$0**

CONFIDENTIAL
Docket No. UE 263
Exhibit PAC/1003
Witness: Gary W. Tawwater

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Gary W. Tawwater

PacifiCorp's Property Tax Estimation Procedure

March 2013

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 263
Exhibit PAC/1004
Witness: Gary W. Tawwater

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gary W. Tawwater

Lake Side 2 Plant Investment

March 2013

PacifiCorp
Oregon General Rate Case - December 2014
Lake Side 2 Project

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	ALLOCATED	REF#
Investment In Service							
Adjustment to Plant in Service:							
Generation Plant - Capital Addition	343	3	661,725,143	SG	26.0530%	172,399,262	Page 3
Adjustment to Depreciation Reserve:							
Generation Plant - Capital Addition	108SP	3	(11,577,433)	SG	26.0530%	(3,016,269)	Page 3
Adjustment to Depreciation Expense:							
Generation Plant - Capital Addition	403SP	3	21,373,722	SG	26.0530%	5,568,496	Page 3
Adjustment to O&M Expense:							
Lake Side 2	548	3	3,378,659	SG	26.0530%	880,242	Page 6
Adjustments to Tax:							
Schedule M Adjustment	SCHMAT	3	15,933,130	SG	26.0530%	4,151,059	Page 4
Schedule M Adjustment	SCHMDT	3	170,588,158	SG	26.0530%	44,443,336	Page 4
Deferred Income Tax Expense	41010	3	58,693,130	SG	26.0530%	15,291,322	Page 4
ADIT Balance	282	3	(95,593,598)	SG	26.0530%	(24,905,002)	Page 4

Description of Exhibit:

This exhibit adds the Lake Side 2 capital project to rate base, as discussed in detail in the direct testimony of Company witness Mr. Stefan Bird. The figures above represent the capital investment, depreciation expense, accumulated depreciation, O&M, and tax impacts associated with this generation plant investment that will be placed into service in the second quarter of 2014. The total Oregon-allocated annual revenue requirement associated with this generation plant investment is shown on page two.

PacifiCorp
Oregon General Rate Case
Revenue Requirement: Lake Side 2 Project

	Lake Side 2 Addition			
	Total Company	Oregon Allocated	Price Change	Results with Price Change
Operating Revenues:				
General Business Revenues	-	-	22,671,085	22,671,085
Interdepartmental	-	-		
Special Sales	-	-		
Other Operating Revenues	-	-		
Total Operating Revenues	-	-	22,671,085	22,671,085
Operating Expenses:				
Steam Production	3,378,659	880,242		880,242
Nuclear Production	-	-		-
Hydro Production	-	-		-
Other Power Supply	-	-		-
Embedded Cost Differential	-	-		-
Transmission	-	-		-
Distribution	-	-		-
Customer Accounting	-	-	135,848	135,848
Customer Service & Info	-	-		-
Sales	-	-		-
Administrative & General	-	-		-
Total O&M Expenses	3,378,659	880,242	135,848	1,016,090
Depreciation	21,373,722	5,568,496		5,568,496
Amortization	-	-		
Taxes Other Than Income	-	-	539,572	539,572
Income Taxes - Federal	(64,635,508)	(16,836,383)	7,348,972	(9,487,411)
Income Taxes - State	(8,782,892)	(2,287,785)	998,603	(1,289,182)
Income Taxes - Def Net	58,693,130	15,291,322		15,291,322
Investment Tax Credit Adj.	-	-		
Misc Revenue & Expense	-	-		
Total Operating Expenses:	10,027,111	2,615,893	9,022,995	11,638,887
Operating Rev For Return:	(10,027,111)	(2,615,893)	13,648,090	11,032,197
Rate Base:				
Electric Plant In Service	661,725,143	172,399,262		172,399,262
Plant Held for Future Use	-	-		
Misc Deferred Debits	-	-		
Elec Plant Acq Adj	-	-		
Nuclear Fuel	-	-		
Prepayments	-	-		
Fuel Stock	-	-		
Material & Supplies	-	-		
Working Capital	-	(367,100)		(367,100)
Weatherization Loans	-	-		
Misc Rate Base	-	-		
Total Electric Plant:	661,725,143	172,032,162		172,032,162
Rate Base Deductions:				
Accum Prov For Deprec	(11,577,433)	(3,016,269)		(3,016,269)
Accum Prov For Amort	-	-		
Accum Def Income Tax	(95,593,598)	(24,905,002)		(24,905,002)
Unamortized ITC	-	-		
Customer Adv For Const	-	-		
Customer Service Deposits	-	-		
Misc Rate Base Deductions	-	-		
Total Rate Base Deductions	(107,171,031)	(27,921,270)		(27,921,270)
Total Rate Base:	554,554,112	144,110,891		144,110,891
Return on Rate Base		-1.82%		7.66%
Return on Equity		-8.38%		9.80%
TAX CALCULATION:				
Operating Revenue	(24,752,381)	(6,448,738)	21,995,665	15,546,927
Other Deductions	-	-		-
Interest (AFUDC)	-	-		-
Interest	14,048,364	3,650,721		3,650,721
Schedule "M" Additions	15,933,130	4,151,059		4,151,059
Schedule "M" Deductions	170,588,158	44,443,336		44,443,336
Income Before Tax	(193,455,773)	(50,391,736)	21,995,665	(28,396,071)
State Income Taxes	(8,782,892)	(2,287,785)	998,603	(1,289,182)
Oregon/Utah State Tax Credits	-	-	-	-
Total State Income Taxes	(8,782,892)	(2,287,785)	998,603	(1,289,182)
Taxable Income	(184,672,881)	(48,103,951)	20,997,062	(27,106,890)
Federal Taxes Before Credits	(64,635,508)	(16,836,383)	7,348,972	(9,487,411)
Renewable Energy Tax Credit	-	-	-	-
Federal Income Taxes	(64,635,508)	(16,836,383)	7,348,972	(9,487,411)

PacifiCorp
Oregon General Rate Case - December 2014
Lake Side 2 Project

Depreciation Rate (Other Generation SG)	3.230%

Lake Side 2 Project

	Capital Addition Pieces		Depreciation Pieces (Capital)	
Month	**Addition Per Month**	**Capital Addition Balance**	**Depreciation Expense**	**Depreciation Reserve**
May-14	661,725,143	661,725,143	890,572	(890,572)
Jun-14	-	661,725,143	1,781,144	(2,671,715)
Jul-14	-	661,725,143	1,781,144	(4,452,859)
Aug-14	-	661,725,143	1,781,144	(6,234,002)
Sep-14	-	661,725,143	1,781,144	(8,015,146)
Oct-14	-	661,725,143	1,781,144	(9,796,289)
Nov-14	-	661,725,143	1,781,144	(11,577,433)
Dec-14	-	661,725,143	1,781,144	(13,358,576)
Jan-15	-	661,725,143	1,781,144	(15,139,720)
Feb-15	-	661,725,143	1,781,144	(16,920,863)
Mar-15	-	661,725,143	1,781,144	(18,702,007)
Apr-15	-	661,725,143	1,781,144	(20,483,150)
May-15	-	661,725,143	1,781,144	(22,264,294)
Total	661,725,143	**661,725,143**	**21,373,722**	**(11,577,433)**
		13 Month Average	Annual Level	13 Month Average
		Ref. Page 1	**Ref. Page 1**	**Ref. Page 1**

PacifiCorp
Oregon General Rate Case - December 2014
Lake Side 2 Build - In Service Q2 2014
Assumption: 603,366,660 qualifies for 50% Tax Bonus Depreciation in 2014

Basis Information		Tax Depreciation		
Description	**Cost**	**Method**	**Convention**	**Recovery Period**
Land	0	Non -Depreciable		
Land Rights	0	Straight-Line	Mid-Month	84-Years
Non-Land - Pollution Control	0	Straight-Line	Mo. after in-svc Mo.	84-Months
Non-Land	661,725,143	MACRS	Half-Year	20-Years
Total	661,725,143			

	Tax Depreciation						Accumulated Deferred Income Tax Calculation				
	Straight-Line / 84-Months			MACRS / 20-Years						Debit/(Credit)	
Month	**Bonus**	**-**	**Total**	**Bonus**	**360,041,813**	**Total**	**Total Tax Depreciation**	**Book Depreciation**	**Book-Tax Difference**	**Deferred Income Tax Expense**	**Accumulated Deferred Income Tax**
12/31/2013	-	-	-	-	-	-	-	-	-	-	-
1/31/2014	-	-	-	-	-	-	-	-	-	-	-
2/28/2014	-	-	-	-	-	-	-	-	-	-	-
3/31/2014	-	-	-	75,420,833	3,375,392	78,796,225	(78,796,225)	2,799,064	(75,997,161)	28,841,683	(28,841,683)
4/30/2014	-	-	-	-	-	-	-	-	-	-	(28,841,683)
5/31/2014	-	-	-	-	-	-	-	-	-	-	(28,841,683)
6/30/2014	-	-	-	75,420,833	3,375,392	78,796,225	(78,796,225)	2,799,064	(75,997,161)	28,841,683	(57,683,366)
7/31/2014	-	-	-	-	-	-	-	-	-	-	(57,683,366)
8/31/2014	-	-	-	-	-	-	-	-	-	-	(57,683,366)
9/30/2014	-	-	-	75,420,832	3,375,392	78,796,224	(78,796,224)	2,799,063	(75,997,161)	28,841,683	(86,525,049)
10/31/2014	-	-	-	-	-	-	-	-	-	-	(86,525,049)
11/30/2014	-	-	-	-	-	-	-	-	-	-	(86,525,049)
12/31/2014	-	-	-	75,420,832	3,375,392	78,796,224	(78,796,224)	2,799,063	(75,997,161)	28,841,683	(115,366,732)
Total 2014	**-**	**-**	**-**	**301,683,330**	**13,501,568**	**315,184,898**	**(315,184,898)**	**11,196,254**	**(303,988,644)**	**115,366,732**	
1/31/2015	-	-	-	-	-	-	-	-	-	-	(115,366,732)
2/28/2015	-	-	-	-	-	-	-	-	-	-	(115,366,732)
3/31/2015	-	-	-	-	6,497,855	6,497,855	(6,497,855)	5,167,502	(1,330,353)	504,882	(115,871,614)
4/30/2015	-	-	-	-	-	-	-	-	-	-	(115,871,614)
5/31/2015	-	-	-	-	-	-	-	-	-	-	(115,871,614)
6/30/2015	-	-	-	-	6,497,855	6,497,855	(6,497,855)	5,167,502	(1,330,353)	504,882	(116,376,496)
7/31/2015	-	-	-	-	-	-	-	-	-	-	(116,376,496)
8/31/2015	-	-	-	-	-	-	-	-	-	-	(116,376,496)
9/30/2015	-	-	-	-	6,497,855	6,497,855	(6,497,855)	5,167,502	(1,330,353)	504,882	(116,881,378)
10/31/2015	-	-	-	-	-	-	-	-	-	-	(116,881,378)
11/30/2015	-	-	-	-	-	-	-	-	-	-	(116,881,378)
12/31/2015	-	-	-	-	6,497,854	6,497,854	(6,497,854)	5,167,502	(1,330,352)	504,882	(117,386,260)
Total 2015	**-**	**-**	**-**	**-**	**25,991,419**	**25,991,419**	**(25,991,419)**	**20,670,008**	**(5,321,411)**	**2,019,528**	
											(95,593,598)
											June 2015 13-Mo. Avg Balance

Straight-Line Depreciation Table: Mid-Month Convention	
Recovery Year	**84-Months**
1	8.333%
2	14.286%
3	14.286%
4	14.286%
5	14.286%
6	14.286%
7	14.286%
8	5.952%
9	0.000%
10	0.000%
11	0.000%
12	0.000%
13	0.000%
14	0.000%
15	0.000%
16	0.000%
17	0.000%
18	0.000%
19	0.000%
20	0.000%
21	0.000%
Total	**100.00%**

MACRS Depreciation Table: Half-Year Convention	
Recovery Year	**20-Year**
1	3.750%
2	7.219%
3	6.677%
4	6.177%
5	5.713%
6	5.285%
7	4.888%
8	4.522%
9	4.462%
10	4.461%
11	4.462%
12	4.461%
13	4.462%
14	4.461%
15	4.462%
16	4.461%
17	4.462%
18	4.461%
19	4.462%
20	4.461%
21	2.231%
Total	**100.00%**

Summary of Current and Deferred Expense for 12 months ended June 2015		
Tax Depreciation	170,588,158	SCHMDT
Book Depreciation	15,933,130	SCHMAT
Deferred Tax Expense	58,693,130	41010

PacifiCorp
Oregon General Rate Case - December 2014
Lake Side 2 Project

SG Allocation Factor	26.0530%
Federal Tax Rate	35.0000%
State Tax Rate	4.54%

Capital Structure and Cost			
	%	**Cost**	**Weighted Cost**
Debt	47.600%	5.322%	2.533%
Preferred	0.300%	5.427%	0.016%
Common	52.100%	9.800%	5.106%
			7.655%

Revenue Sensitive Items	
Operating Revenue	100%
Operating Deductions	
Uncollectable Accounts	0.599%
Taxes Other - Franchise Tax	2.300%
Taxes Other - Revenue Tax	0.00%
Taxes Other - Resource Supplier	0.080%
Taxes Other - Gross Receipts	0.00%
Sub-Total	97.021%
State Income Tax @ 4.54%	4.405%
Sub-Total	92.616%
Federal Income Tax @ 35.00%	32.416%
Net Operating Income	60.200%

Lake Side 2 Plant
Oregon General Rate Case - December 2014
Operations and Maintenance Expense
In $000

O&M	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014	Jan 2015	Feb 2015	Mar 2015	Apr 2015	May 2015	12 ME May-15
Labor	109	109	109	109	109	109	109	101	101	101	101	124	1,288
Employee Expense	10	3	4	2	3	4	0	4	0	1	0	4	35
Materials	65	52	59	71	48	55	75	82	78	117	74	62	837
Contracts	178	62	20	126	39	23	102	197	35	289	46	49	1,166
Other	3	2	2	10	2	3	3	4	8	6	4	4	53
Total Routine	365	227	194	317	200	194	289	388	222	514	226	244	3,379

CONFIDENTIAL
Docket No. UE 263
Exhibit PAC/1005
Witness: Gary W. Tawwater

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Gary W. Tawwater

Global Insight Escalation Indices

March 2013

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 263
Exhibit PAC/1100
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of C. Craig Paice

March 2013

DIRECT TESTIMONY OF C. CRAIG PAICE

TABLE OF CONTENTS

ATTACHED EXHIBITS

- Exhibit PAC/1101 – Unbundled Results of Operations—Summary and Detail
- Exhibit PAC/1102 – Functionalized Oregon Results of Operations Report
- Exhibit PAC/1103 – Ancillary Services Revenue Requirement
- Exhibit PAC/1104 – Oregon Marginal Cost of Service Study
- Exhibit PAC/1105 – Functionalized Revenue Requirement vs. Current Revenues
- Exhibit PAC/1106 – Functional Factors
- Exhibit PAC/1107 – Oregon Marginal Cost Study

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is C. Craig Paice. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as a Regulatory Specialist in the Regulation Department.

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor of Science Degree in Business Management from Brigham Young University in 1976. I have also attended various educational, professional, and electric industry seminars during my career with the Company. I have been employed by PacifiCorp since the merger with Utah Power & Light Company in 1989. Beginning in 1978 I was employed by Utah Power & Light Company, holding various positions in the accounting, customer service, and regulatory areas.

Q. What are your current responsibilities?

A. My primary responsibilities are to prepare, present, and explain the results of the Company's cost of service studies to regulators and interested parties in jurisdictions where PacifiCorp provides retail electric service.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present the Company's proposed revenue requirement for each of the unbundled service categories, the Company's functionalization procedures, and the Oregon Marginal Cost Study.

UNBUNDLED CLASS REVENUE REQUIREMENTS

Q. Please identify Exhibit PAC/1101 and explain what it shows.

A. Exhibit PAC/1101 shows the Company's proposed revenue requirement for each of the unbundled service categories required by OAR 860-038-0200: Generation (also referred to as Production), Transmission, Distribution, Ancillary Services, Consumer Services—Billing, Consumer Services—Metering, Consumer Services—Other, Retail Services, and Investment in Public Purposes.

No revenue requirement is shown for the Retail Services or Investment in Public Purposes categories. The Company separately accounts for the costs associated with unregulated retail activities and is not seeking regulatory cost recovery for these items. Public purpose revenues are collected under a separate tariff.

Q. How was the revenue requirement determined for each of the unbundled categories?

A. Rate base balances, revenues, and expenses were either assigned or allocated to unbundled categories in accordance with OAR 860-038-0200. Traditional revenue requirement methodology (i.e., recovery of costs plus a return on rate base), was then used to determine a revenue requirement for each category. Rate base balances, revenues and expenses are from PacifiCorp's Oregon Results of Operations Report, as filed by Mr. Gary W. Tawwater. The application of PacifiCorp's proposed rate increase is shown on page 2 of Exhibit PAC/1101.

Q. Please identify Exhibit PAC/1102 and explain what it shows.

A. Exhibit PAC/1102, Tab 1 is the summary page from PacifiCorp's December 2014

Functionalized Oregon Results of Operations Report (Functionalized Oregon Results of Operations Report) and is the basis for the unbundled revenue requirement in Exhibit PAC/1101. It separates the results of operations into the unbundled categories identified above.

Q. Please explain how the rate base balances, revenues and expenses in the Functionalized Oregon Results of Operations Report were apportioned among the unbundled categories.

A. The detail of PacifiCorp's Functionalized Results of Operations Report by Federal Energy Regulatory Commission (FERC) account is found in Exhibit PAC/1102, Tab 2. The functionalization procedures in this case are consistent with those approved in Order No. 01-787 and implemented in Advice No. 01-020. Functional factors employed in the development of these results are provided in Exhibit PAC/1106.

Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?

A. The revenue requirement for Ancillary Services was estimated by applying PacifiCorp's prices for Regulation and Frequency Response Service, Spinning Reserve Service, and Supplemental Reserve Service to the relevant billing determinants of PacifiCorp's total Oregon retail load. This is shown in Exhibit PAC/1103. The costs associated with providing these services are included in the Generation function. The estimated revenue for Ancillary Services is treated as an offsetting revenue credit against the Generation revenue requirement.

Q. Please identify Exhibit PAC/1104.

A. Exhibit PAC/1104 contains a summary from PacifiCorp's State of Oregon December 2014 Marginal Cost Study (Marginal Cost Study). The Marginal Cost Study is described in more detail later in my testimony.

Q. Please identify Exhibit PAC/1105 and explain what it shows.

A. Page 1 of Exhibit PAC/1105 is the derivation of functionalized class revenue requirements and a comparison with current revenues. This exhibit is based on the results of both the Functionalized Oregon Results of Operations Report and the Marginal Cost Study. Present class revenues are shown on line 1 and megawatt-hours (MWh) are shown on line 2. Full long-run marginal costs for each customer class, separated by function, are shown on lines 5 through 11. Lines 15 through 23 show each class' share of total marginal costs for each function as well as each class' share of revenue and MWh. Lines 27 through 36 show the assignment of functional revenue requirement. The total revenue requirement for each unbundled category, as determined earlier is shown in the total column. The total for each function is then allocated to a particular customer class based on that class' share of total marginal cost for that function. For example, the residential class accounts for 42.24 percent of generation marginal costs and is assigned 42.24 percent of the generation revenue requirement. Regulatory and franchise fees are considered part of the distribution function; however, for the purpose of assigning cost responsibility, the fees have been broken out separately. Regulatory and franchise fees have been assigned on the basis of class revenue. Lines 38 through 45 compare the total revenue requirement by class to the present class revenues collected from base rates as shown on line 1.

Q. Please explain what is shown on pages 2 and 3 of Exhibit PAC/1105.

A. Pages 2 and 3 of Exhibit PAC/1105 provides a reconciliation between Operating Revenues and Target Revenue Requirement as shown on page 1 of this exhibit, with those shown in Exhibits PAC/1101 and PAC/1102. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PAC/1105 accounts for all Oregon test period revenue sources. Page 3 accounts for all revenue sources included in the Target Revenue Requirement.

MARGINAL COST STUDY

Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.

A. The Marginal Cost Study is found in Exhibit PAC/1107. This study shows, by customer class, PacifiCorp's marginal cost of resources required to produce one additional unit of electricity, or to add one additional customer. Exhibit PAC/1107 contains a marginal cost and circuit model procedures narrative, various summary tables, and 15 sections of supporting data.

Q. Is this Marginal Cost Study similar to studies the Company has previously filed?

A. Yes. This study is similar with the cost of service study presented in the Company's 2012 general rate case, docket UE 246 (2012 Rate Case), however it includes two modifications recommended by parties in that proceeding. First, since the Company is subject to Oregon's renewable portfolio standard (RPS) and a percentage of its retail electricity sales must be from qualified renewable resources, it is appropriate for the calculation of marginal generation energy costs to include renewable resource costs. The Company submitted a compliance filing for tariff changes to provide qualified facilities with an option for avoided cost pricing for renewable resources in docket UM 1396. The Marginal Cost Study has been modified to recognize the impact of renewable energy resources on generation energy costs. This revision follows Staff's recommendation in the 2012 Rate Case.

Second, the Company's distribution circuit model has been revised to include commitment and demand costs on the circuit model trunk, branches six and seven, as is done for branches one through five. Previously, trunk costs were considered to be 100 percent demand-related. Trunk costs should be considered both demand and commitment related since these costs are recognized on all other branches of the circuit and because no specific engineering data is available to support the position that circuit model trunk costs are exclusively demand-related. This revision is consistent with recommendations made by Staff of the Commission and Industrial Customers of Northwest Utilities in the 2012 Rate Case. Both revisions in the Marginal Cost Study illustrate reasonable methods of cost derivation.

Q. How are marginal costs calculated?

A. One-year marginal costs include only changes in operating costs while 10-year and 20-year marginal costs also include the cost of expanding facilities. The costs of these added facilities result in long-run costs that are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. They do not include any demand-related generation, transmission, or distribution costs. A detailed description of marginal cost procedures is included in Exhibit PAC/1107, Tab 1.

Q. Please describe the marginal cost summary tables included in Exhibit PAC/1107, Tab 2.

A. Tables 1 and 2 of Exhibit PAC/1107 summarize the one-year, 10-year and 20-year marginal costs on a mills-per-kWh or dollars-per-customer basis. Table 3 summarizes the unit costs based on the results of the long-run (20-year) marginal cost study. Unit costs are shown for generation, transmission, distribution and various customer service functional categories. Table 3 also includes energy usage, peak demand, and number of customers by customer class for the 12 month period ending June 30, 2014 (Test Period). This information is used to calculate annual long-run marginal costs by class shown on Table 4.

Q. Please explain how generation marginal costs are calculated.

A. Marginal generation costs in this study are based on the Company's currently approved Oregon avoided cost calculations. New resource costs are based on the fixed and variable cost of a combined cycle combustion turbine, which operates as a base load unit. Recognizing that base load generation produces the dual products of capacity and energy, capacity costs are determined using the fixed costs of a simple cycle combustion turbine. Generation energy costs are calculated by combining the remaining fixed and all variable costs of the combined cycle turbine plus renewable wind resource costs. Renewable resource costs included in the marginal cost of service study are based on a Wyoming wind facility (35 percent capacity factor) shown in Table 6.3 of the Company's 2011 integrated resource plan (IRP) which is consistent with the renewable avoided cost compliance filing in docket UM 1396. These costs are weighted according to the Oregon RPS requirements for each year during the long-run marginal cost period. This results in weightings of five percent for 2014, 15 percent for 2015-2019, 20 percent for 2020-2024, and 25 percent for 2025-2032. Non-renewable marginal energy costs are reduced by one minus the renewable weighting percentage, added to the weighted renewable costs, summed and present valued to determine marginal energy costs. Weighting the cost of renewable energy by the Oregon mandatory RPS requirements is a straightforward and easily understood method of recognizing these costs. Marginal generation capacity and energy costs are summarized on Table 5 of Exhibit PAC/1107.

Q. How are transmission costs calculated?

A. Transmission costs are based on a five-year analysis of forecasted expenditures to meet increased load on the transmission system. Expenditures identified as growth-related are used to develop marginal transmission costs. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand. Bulk power lines are classified both to demand and energy in the same proportions as the long-run marginal costs of generation resources. Marginal transmission costs are summarized on Table 6 of Exhibit PAC/1107.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 7 of Exhibit PAC/1107 provides a unit cost summary by class and load size of marginal distribution costs. Distribution costs are classified into three components: (1) demand-related, shown in dollars per kW/year; (2) commitment-related, shown in dollars per customer/year; and (3) billing-related, shown in dollars per customer/year. Commitment-related distribution costs consist of the costs of transformers, poles and conductor that are not determined by the level of demand customers place on the system. Demand-related distribution costs include additional costs of larger transformers, substations, poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system.

Q. Please describe how the marginal costs of distribution line transformers are calculated.

A. Marginal transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of this statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Q. Please describe how the marginal costs of distribution circuits are calculated.

A. Marginal costs of distribution poles and wires are calculated using the Company's

Distribution Circuit Model. The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics and current cost estimates for Oregon. Customer locations are based on actual customer distances from the substation as determined by the Company's Computer Aided Design Operations (CADOPS) database. The results are segregated into commitment-related and demand-related costs for each customer class. A detailed description of the updated circuit model is also included in the marginal cost procedures in Exhibit PAC/1107, Tab 1.

Q. How are substation marginal costs calculated?

A. Marginal substation costs are determined using the per kW cost of substation additions being considered for a five-year period. The cost per kW is determined by dividing the growth-related distribution substation investment in the capital budget horizon by the related increase in substation capacity. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class.

Q. What is included in the service drop category?

A. The service drop category includes the marginal cost of service drops with associated operation and maintenance (O&M). Current typical installed costs for service drops are determined for each customer load size.

Q. What is included in the metering category?

A. The metering category includes the marginal cost of metering equipment with associated O&M and meter reading expense. Current typical installed metering costs are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M is based on historical expenditures.

Q. What is included in the billing and customer service/other categories?

A. This category includes the costs of billing, payment processing and debt recovery, meter reading expense and all the remaining customer accounting and customer service activities. Meter reading expense is based on historical costs and allocated to customer classes based on typical meter reading times. Customer accounting and customer service expense are based on historical expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/1101
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Unbundled Results of Operations
Summary and Detail

March 2013

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2014 Forecast

Function		Revenue Requirement
Production		$ 758,147,348
Transmission		$ 172,699,101
Distribution		$ 270,841,837
Ancillary		$ 10,815,424
Customer Billing		$ 12,263,553
Customer Metering		$ 27,452,258
Customer Other		$ 11,948,816
Retail Service	a	$ -
Public Purposes	b	$ -
Total State of Oregon		$ 1,264,168,337

a - Retail Services are conducted as unregulated activities.
b - DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2014 Forecast

									Consumer					Distribution Components		
		ROR	ROE	Total	Production	Trans-mission	Distribution	Ancillary	Billing	Metering	Other	Retail Service [a]	Public Purposes [b]	Poles & Wires	DSM	Franchise Fees
1	Functionalized Situs Revenues @ Earned	6.68%	7.92%	1,209,176,480	731,008,398	160,007,255	256,604,310	10,815,424	12,068,217	26,862,813	11,810,063	-	-	227,584,074	-	29,020,236
2	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Oregon General Business Revenue			1,209,176,480	731,008,398	160,007,255	256,604,310	10,815,424	12,068,217	26,862,813	11,810,063	-	-	227,584,074	-	29,020,236
4																
5	Target Increase in Return	7.66%	9.80%	33,105,333	16,725,071	7,821,674	7,989,436	0	120,381	363,261	85,510			7,989,436	-	-
6																
7	Add															
8	Uncollectible Expense			329,519	162,620	76,051	85,313	0	1,170	3,532	831	-	-	77,682	-	7,631
9	Franchise & Energy Supplier Taxes			1,264,813			1,264,813									1,264,813
10	Other Revenue Based Taxes			43,993	21,711	10,153	11,390	0	156	472	111	-	-	10,371	-	1,019
11	Inc Taxes - State			2,422,250	1,223,740	572,296	584,571	0	8,808	26,579	6,257	-	-	584,571	-	-
12	Inc Taxes - Federal			17,825,948	9,005,807	4,211,671	4,302,004	0	64,820	195,602	46,044	-	-	4,302,004	-	-
13	Total Increase Needed			54,991,857	27,138,950	12,691,846	14,237,527	0	195,336	589,446	138,753	-	-	12,964,065	-	1,273,462
14																
15	Total Oregon General Business Revenue @	7.66%	9.80%	1,264,168,337	758,147,348	172,699,101	270,841,837	10,815,424	12,263,553	27,452,258	11,948,816	-	-	240,548,139	-	30,293,698
16	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Unbundled Revenue Requirement			1,264,168,337	758,147,348	172,699,101	270,841,837	10,815,424	12,263,553	27,452,258	11,948,816	-	-	240,548,139	-	30,293,698
18																
19	Rate Base			3,384,540,086	1,709,895,907	799,652,754	816,803,942	0	12,307,164	37,138,163	8,742,157			816,803,942	-	-
					50.521%	23.627%	24.133%	0.000%	0.364%	1.097%	0.258%	0.000%	0.000%	24.133%	0.000%	0.000%

Source:
Total Column : Exhibit PPL 1002
Row 1: Exhibit PPL 1002
Row 8: Uncollectible 0.5992%
Row 9: Franchise Tax @ 2.3000%
Row 11: Inc Taxes - State 4.5400%
Row 12: Inc Taxes - Federal 35.0000%

Notes:
a - Retail Services are conducted as unregulated activities.
b -DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

Docket No. UE 263
Exhibit PAC/1102
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Functionalized Oregon Results of Operations Report

March 2013

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2014 Forecast

Description of Account Summary:	Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Other
Operating Revenues								
General Business Revenues	1,209,176,480	731,008,398	160,007,255	256,604,310	10,815,424	12,068,217	26,862,813	11,810,063
General Business Revenues	-	-	-	-	-	-	-	-
Interdepartmental	-	-	-	-	-	-	-	-
Special Sales	124,030,465	124,030,465	-	-	-	-	-	-
Other Operating Revenues	39,567,427	24,587,364	15,283,971	5,324,887	(10,815,423)	4,516,362	275,407	394,859
Total Operating Revenues	1,372,774,372	879,626,227	175,291,227	261,929,198	0	16,584,579	27,138,220	12,204,922
Operating Expenses:								
Steam Production	295,682,196	295,682,196	-	-	-	-	-	-
Nuclear Production	-	-	-	-	-	-	-	-
Hydro Production	11,123,151	11,123,151	-	-	-	-	-	-
Other Power Supply	275,447,938	275,447,938	-	-	-	-	-	-
ECD	(8,792,171)	(8,792,171)	-	-	-	-	-	-
Transmission	53,595,523	223,488	53,372,034	-	-	-	-	-
Distribution	71,951,511	-	-	66,574,210	-	-	5,377,301	-
Customer Accounts	35,929,744	4,793,178	955,181	1,427,280	0	11,279,901	11,073,978	6,400,227
Customer Service	4,067,911	-	-	1,857,183	-	-	-	2,210,728
Sales	-	-	-	-	-	-	-	-
Administrative & General	47,652,586	13,386,814	3,333,211	24,990,991	-	1,658,025	2,944,903	1,338,643
Total ● & M Expenses	786,658,390	591,864,594	57,660,426	94,849,664	0	12,937,925	19,396,182	9,949,598
Depreciation	211,121,763	133,512,238	26,243,300	47,783,574	-	637,862	2,592,740	352,049
Amortization Expense	14,529,658	8,142,571	1,107,221	1,775,085	-	1,542,633	1,049,704	912,444
Taxes Other Than Income	67,523,836	18,948,869	7,473,605	40,143,458	0	239,984	567,868	150,052
Income Taxes - Federal	18,023,530	(2,877,175)	(1,941,254)	21,298,250	0	218,477	1,306,020	19,212
Income Taxes - State	4,676,658	1,836,610	(263,783)	2,894,067	0	29,687	177,466	2,611
Income Taxes - Def Net	44,337,342	14,113,852	31,621,709	(1,358,010)	-	156,233	(431,667)	235,224
Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
Misc Revenue & Expense	(90,219)	(88,958)	(4,625)	3,257	-	-	107	-
Total Operating Expenses	1,146,780,957	765,452,600	121,896,599	207,389,346	0	15,762,802	24,658,420	11,621,188
Operating Revenue for Return	225,993,416	114,173,627	53,394,628	54,539,851	0	821,777	2,479,799	583,734
Rate Base:								
Electric Plant in Service	6,686,362,611	3,160,115,197	1,352,085,584	2,012,009,634	-	39,766,883	98,132,123	24,253,190
Plant Held for Future Use	-	-	-	-	-	-	-	-
Misc Deferred Debits	73,870,456	39,598,456	8,456,513	13,629,346	-	3,367,299	5,768,613	3,050,230
Elec Plant Acq Adj	10,072,737	10,072,737	-	-	-	-	-	-
Nuclear Fuel	-	-	-	-	-	-	-	-
Prepayments	7,197,975	3,820,191	594,246	1,475,528	-	363,404	618,052	326,555
Fuel Stock	60,471,050	60,471,050	-	-	-	-	-	-
Material & Supplies	58,580,887	48,915,316	376,217	9,023,646	-	-	265,708	-
Working Capital	29,005,460	15,525,127	2,046,254	7,076,560	0	1,229,571	2,062,278	1,065,669
Weatherization Loans	(1,219)	-	-	(1,219)	-	-	-	-
Miscellaneous Rate Base	-	-	-	-	-	-	-	-
Total Electric Plant	6,925,559,957	3,338,518,074	1,363,558,813	2,043,213,495	0	44,727,157	106,846,776	28,695,643
Rate Base Deductions:								
Accum Prov For Depr	(2,359,864,735)	(1,082,257,679)	(344,451,326)	(888,949,099)	-	(3,452,521)	(38,912,299)	(1,841,811)
Accum Prov For Amort	(152,115,135)	(55,321,137)	(7,082,668)	(30,559,434)	-	(26,028,869)	(17,669,079)	(15,453,948)
Accum Def Income Taxes	(1,014,614,465)	(485,408,452)	(208,288,502)	(303,438,082)	-	(2,613,649)	(12,500,149)	(2,365,631)
Unamortized ITC	(593,249)	(261,565)	(31,609)	(158,241)	-	(39,411)	(66,998)	(35,426)
Customer Adv for Const	(5,758,640)	-	(3,822,938)	(1,870,973)	-	-	(64,729)	-
Customer Service Deposits	-	-	-	-	-	-	-	-
Misc. Rate Base Deductions	(8,073,647)	(5,373,333)	(229,017)	(1,433,725)	-	(285,544)	(495,358)	(256,670)
Total Rate Base Deductions	(3,541,019,871)	(1,628,622,166)	(563,906,060)	(1,226,409,553)	-	(32,419,993)	(69,708,612)	(19,953,486)
Total Rate Base	3,384,540,086	1,709,895,907	799,652,754	816,803,942	0	12,307,164	37,138,163	8,742,157
Return on Rate Base	6.6772%	6.6772%	6.6772%	6.6772%	6.6772%	6.6772%	6.6772%	6.6772%
Return on Equity	7.9226%	7.9226%	7.9226%	7.9226%	7.9226%	7.9226%	7.9226%	7.9226%

2010 PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Sales to Ultimate Customers											
440	Residential Sales										
			S	583,299,297	731,008,398	160,007,255	256,604,310	10,815,424	12,068,217	26,862,813	11,810,063
	Less Klamath Surcharge Revenue										
		P	S	-	-	-	-	-	-	-	-
				583,299,297	731,008,398	160,007,255	256,604,310	10,815,424	12,068,217	26,862,813	11,810,063
442	Commercial & Industrial Sales										
			S	621,158,232							
		P	SE	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-
				621,158,232	-	-	-	-	-	-	-
444	Public Street & Highway Lighting										
			S	4,718,952							
			SO	-							
				4,718,952	-	-	-	-	-	-	-
445	Other Sales to Public Authority										
			S	-							
				-	-	-	-	-	-	-	-
448	Interdepartmental										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Sales to Ultimate Customers				**1,209,176,460**	**731,008,396**	**160,007,255**	**256,604,310**	**10,815,424**	**12,068,217**	**26,862,813**	**11,810,063**
447	Sales for Resale-Non NPC										
		P	S	1,024,807	1,024,807	-	-	-	-	-	-
				1,024,807	1,024,807	-	-	-	-	-	-
447NPC	Sales for Resale-NPC										
		P	SG	123,005,658	123,005,658	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				123,005,658	123,005,658	-	-	-	-	-	-
	Total Sales for Resale			124,030,465	124,030,465	-	-	-	-	-	-
449	Provision for Rate Refund										
		P	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Sales from Electricity				**1,333,206,945**	**855,038,863**	**160,007,255**	**256,604,310**	**10,815,424**	**12,068,217**	**26,862,813**	**11,810,063**
450	Forfeited Discounts & Interest										
		C_BILLING	S	3,713,451	-	-	-	-	3,713,451	-	-
		C_BILLING	SO	-	-	-	-	-	-	-	-
				3,713,451	-	-	-	-	3,713,451	-	-
451	Misc Electric Revenue										
		CSS_SYS	S	1,449,104	-	-	-	-	797,007	260,839	391,258
		GP	SG	-	-	-	-	-	-	-	-
		DSM	SO	1,131	-	-	1,131	-	-	-	-
				1,450,235	-	-	1,131	-	797,007	260,839	391,258
453	Water Sales										
		P	SG	3,151	3,151	-	-	-	-	-	-
				3,151	3,151	-	-	-	-	-	-
454	Rent of Electric Property										
		D	S	5,032,337	-	-	5,032,337	-	-	-	-
		T	SG	1,468,338	-	1,468,338	-	-	-	-	-
		GP	SO	992,634	469,140	200,726	298,696	-	5,904	14,568	3,601
				7,493,310	469,140	1,669,064	5,331,033	-	5,904	14,568	3,601
	Oregon Ancillary Services				10,815,423			(10,815,423)			
456	Other Electric Revenue										
		OTHSGR	S	-	-	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-
		OTHSE	SE	2,803,790	2,063,461	740,329	-	-	-	-	-
		OTHSO	SO	(7,277)	-	-	(7,277)	-	-	-	-
		OTHSGR	SG	24,110,767	11,236,188	12,874,579	-	-	-	-	-
				26,907,280	13,299,649	13,614,908	(7,277)	-	-	-	-
	Total Other Electric Revenues			**39,567,427**	**24,587,364**	**15,283,971**	**5,324,887**	**(10,815,423)**	**4,516,362**	**275,407**	**394,859**
Total Electric Operating Revenues				**1,372,774,372**	**879,626,227**	**175,291,227**	**261,929,198**	**0**	**16,584,579**	**27,138,220**	**12,204,922**

Miscellaneous Revenues											
41160	Gain on Sale of Utility Plant - CR										
		D	S	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
		G	SO	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
41170	Loss on Sale of Utility Plant										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
4118	Gain from Emission Allowances										
		P	S	-	-	-	-	-	-	-	-
		P	SE	(50,884)	(50,884)	-	-	-	-	-	-
				(50,884)	(50,884)	-	-	-	-	-	-
41181	Gain from Disposition of NOX Credits										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
4194	Impact Housing Interest Income										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
421	(Gain) / Loss on Sale of Utility Plant										
		D	S	165	-	-	165	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
		T	SG	(7,020)	-	(7,020)	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-
		PTD	SO	10,482	4,888	2,395	3,092	-	-	107	-
		P	SG	(42,962)	(42,962)	-	-	-	-	-	-
				(39,335)	(38,074)	(4,625)	3,257	-	-	107	-
Total Miscellaneous Revenues				**(90,219)**	**(68,956)**	**(4,625)**	**3,257**	**-**	**-**	**107**	**-**
Miscellaneous Expenses											
4311	Interest on Customer Deposits										
		C_BILLING	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Miscellaneous Expenses				-	-	-	-	-	-	-	-
Net Misc Revenue and Expense				**(90,219)**	**(86,956)**	**(4,625)**	**3,257**	**-**	**-**	**107**	**-**
500	Operation Supervision & Engineering										
		P	SG	4,293,290	4,293,290	-	-	-	-	-	-
		P	SG	563,290	563,290	-	-	-	-	-	-
				4,856,580	4,856,580	-	-	-	-	-	-
501	Fuel Related-Non NPC										
		P	SE	4,137,627	4,137,627	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	841,721	841,721	-	-	-	-	-	-
				4,979,348	4,979,348	-	-	-	-	-	-
501NPC	Fuel Related-NPC										
		P	S	-	-	-	-	-	-	-	-
		P	SE	188,644,039	188,644,039	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	14,739,632	14,739,632	-	-	-	-	-	-
				203,383,671	203,383,671	-	-	-	-	-	-
	Total Fuel Related			208,363,019	208,363,019	-	-	-	-	-	-
502	Steam Expenses										
		P	SG	7,912,844	7,912,844	-	-	-	-	-	-
		P	SG	2,429,930	2,429,930	-	-	-	-	-	-
				10,342,774	10,342,774	-	-	-	-	-	-
503	Steam From Other Sources-Non-NPC										
		P	SE	(27)	(27)	-	-	-	-	-	-
				(27)	(27)	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC										
		P	SE	833,147	833,147	-	-	-	-	-	-
				833,147	833,147	-	-	-	-	-	-
505	Electric Expenses										
		P	SG	845,200	845,200	-	-	-	-	-	-
		P	SG	276,583	276,583	-	-	-	-	-	-
				1,121,783	1,121,783	-	-	-	-	-	-
506	Misc Steam Expense										
		P	SG	15,389,570	15,389,570	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SG	497,527	497,527	-	-	-	-	-	-
				15,887,098	15,887,098	-	-	-	-	-	-

507	Rents										
		P	SG	90,977	90,977	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				90,977	90,977	-	-	-	-	-	-
510	Maint Supervision & Engineering										
		P	SG	(722,307)	(722,307)	-	-	-	-	-	-
		P	SG	544,499	544,499	-	-	-	-	-	-
				(177,808)	(177,808)	-	-	-	-	-	-
511	Maintenance of Structures										
		P	SG	6,280,414	6,280,414	-	-	-	-	-	-
		P	SG	232,235	232,235	-	-	-	-	-	-
				6,512,649	6,512,649	-	-	-	-	-	-
512	Maintenance of Boiler Plant										
		P	SG	32,649,593	32,649,593	-	-	-	-	-	-
		P	SG	1,439,645	1,439,645	-	-	-	-	-	-
				34,089,237	34,089,237	-	-	-	-	-	-
513	Maintenance of Electric Plant										
		P	SG	10,289,627	10,289,627	-	-	-	-	-	-
		P	SG	165,311	165,311	-	-	-	-	-	-
				10,454,938	10,454,938	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant										
		P	SG	2,667,084	2,667,084	-	-	-	-	-	-
		P	SG	640,745	640,745	-	-	-	-	-	-
				3,307,829	3,307,829	-	-	-	-	-	-
Total Steam Power Generation				**295,682,196**	**295,682,196**	-	-	-	-	-	-
517	Operation Super & Engineering										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
518	Nuclear Fuel Expense										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
519	Coolants and Water										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
520	Steam Expenses										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
523	Electric Expenses										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
524	Misc. Nuclear Expenses										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
528	Maintenance Super & Engineering										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
529	Maintenance of Structures										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
530	Maintenance of Reactor Plant										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
531	Maintenance of Electric Plant										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
532	Maintenance of Misc Nuclear										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Nuclear Power Generation				-	-	-	-	-	-	-	-

535	Operation Super & Engineering										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	1,987,462	1,987,462	-	-	-	-	-	-
		P	SG	(148,275)	(148,275)	-	-	-	-	-	-
				1,839,187	1,839,187	-	-	-	-	-	-
536	Water For Power										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	59,955	59,955	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				59,955	59,955	-	-	-	-	-	-
537	Hydraulic Expenses										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	1,016,394	1,016,394	-	-	-	-	-	-
		P	SG	81,403	81,403	-	-	-	-	-	-
				1,097,796	1,097,796	-	-	-	-	-	-
538	Electric Expenses										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
539	Misc Hydro Expenses										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	3,939,365	3,939,365	-	-	-	-	-	-
		P	SG	1,885,835	1,885,835	-	-	-	-	-	-
				5,825,200	5,825,200	-	-	-	-	-	-
540	Rents (Hydro Generation)										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	(45,592)	(45,592)	-	-	-	-	-	-
		P	SG	8,993	8,993	-	-	-	-	-	-
				(36,599)	(36,599)	-	-	-	-	-	-
541	Maint Supervision & Engineering										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	105	105	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				105	105	-	-	-	-	-	-
542	Maintenance of Structures										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	251,700	251,700	-	-	-	-	-	-
		P	SG	56,022	56,022	-	-	-	-	-	-
				307,722	307,722	-	-	-	-	-	-
543	Maintenance of Dams & Waterways										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	464,112	464,112	-	-	-	-	-	-
		P	SG	154,627	154,627	-	-	-	-	-	-
				618,739	618,739	-	-	-	-	-	-
544	Maintenance of Electric Plant										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	547,363	547,363	-	-	-	-	-	-
		P	SG	129,556	129,556	-	-	-	-	-	-
				676,919	676,919	-	-	-	-	-	-
545	Maintenance of Misc Hydro Plant										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	528,476	528,476	-	-	-	-	-	-
		P	SG	205,650	205,650	-	-	-	-	-	-
				734,126	734,126	-	-	-	-	-	-
Total Hydraulic Power Generation				**11,123,151**	**11,123,151**	-	-	-	-	-	-

546	Operation Super & Engineering										
		P	SG	132,781	132,781	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				132,781	132,781	-	-	-	-	-	-
547	Fuel-Non-NPC										
		P	SE	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
547NPC	Fuel-NPC										
		P	SE	82,542,321	82,542,321	-	-	-	-	-	-
		P	SE	1,761,181	1,761,181	-	-	-	-	-	-
				84,303,502	84,303,502	-	-	-	-	-	-
548	Generation Expense										
		P	SG	3,919,088	3,919,088	-	-	-	-	-	-
		P	SG	201,230	201,230	-	-	-	-	-	-
				4,120,318	4,120,318	-	-	-	-	-	-
549	Miscellaneous Other										
		P	S	-	-	-	-	-	-	-	-
		P	SG	3,395,462	3,395,462	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				3,395,462	3,395,462	-	-	-	-	-	-
550	Maint Supervision & Engineering										
		P	S	384,295	384,295	-	-	-	-	-	-
		P	SG	1,187,358	1,187,358	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				1,571,652	1,571,652	-	-	-	-	-	-
551	Maint Supervision & Engineering										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
552	Maintenance of Structures										
		P	SG	385,970	385,970	-	-	-	-	-	-
		P	SG	22,713	22,713	-	-	-	-	-	-
				408,684	408,684	-	-	-	-	-	-
553	Maint of Generation & Electric Plant										
		P	SG	4,378,054	4,378,054	-	-	-	-	-	-
		P	SG	257,111	257,111	-	-	-	-	-	-
				4,635,165	4,635,165	-	-	-	-	-	-
554	Maintenance of Misc. Other										
		P	SG	1,123,604	1,123,604	-	-	-	-	-	-
		P	SG	64,716	64,716	-	-	-	-	-	-
				1,188,320	1,188,320	-	-	-	-	-	-
Total Other Power Generation				**99,755,885**	**99,755,885**	-	-	-	-	-	-
555	Purchased Power-Non NPC										
		P	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
555NPC	Purchased Power-NPC										
		P	S	(138,381)	(138,381)	-	-	-	-	-	-
		P	SG	154,020,272	154,020,272	-	-	-	-	-	-
		P	SE	6,389,539	6,389,539	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	DGP	-	-	-	-	-	-	-	-
				160,271,430	160,271,430	-	-	-	-	-	-
	Total Purchased Power			160,271,430	160,271,430	-	-	-	-	-	-
556	System Control & Load Dispatch										
		P	SG	487,183	487,183	-	-	-	-	-	-
				487,183	487,183	-	-	-	-	-	-
557	Other Expenses										
		P	S	(53,813)	(53,813)	-	-	-	-	-	-
		P	SG	14,723,251	14,723,251	-	-	-	-	-	-
		P	SGCT	293,409	293,409	-	-	-	-	-	-
		P	SE	(29,407)	(29,407)	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-
	Less Klamath Surcharge Expense										
		P	SG	-	-	-	-	-	-	-	-
				14,933,440	14,933,440	-	-	-	-	-	-
Total Other Power Supply				**175,692,053**	**175,692,053**	-	-	-	-	-	-
TOTAL PRODUCTION EXPENSE				**582,253,285**	**582,253,285**	-	-	-	-	-	-

	Embedded Cost Differentials										
	Company Owned Hy	P	DGP	-	-	-	-	-	-	-	-
	Company Owned Hy	P	SG	-	-	-	-	-	-	-	-
	Mid-C Contract	P	MC	-	-	-	-	-	-	-	-
	Mid-C Contract	P	SG	-	-	-	-	-	-	-	-
	Existing QF Contract	P	S	-	-	-	-	-	-	-	-
	Existing QF Contract	P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Hydro Endowment Fixed Dollar Proposal										
	Klamath Surcharge Sit	P	S	(11,925,675)	(11,925,675)	-	-	-	-	-	-
	ECD Hydro	P	S	5,699,936	5,699,936	-	-	-	-	-	-
	Mid-C Contract	P	MC	(6,844,413)	(6,844,413)	-	-	-	-	-	-
	Mid-C Contract	P	SG	4,277,981	4,277,981	-	-	-	-	-	-
	Klamath Dam Remova	P	S	-	-	-	-	-	-	-	-
	Less Klamath Surcharge Expense										
		P	SG	-	-	-	-	-	-	-	-
				(8,792,171)	(8,792,171)	-	-	-	-	-	-
560	Operation Supervision & Engineering										
		T	SG	1,223,901	-	1,223,901	-	-	-	-	-
				1,223,901	-	1,223,901	-	-	-	-	-
561	Load Dispatching										
		T	SG	2,488,123	-	2,488,123	-	-	-	-	-
				2,488,123	-	2,488,123	-	-	-	-	-
562	Station Expense										
		T	SG	724,217	-	724,217	-	-	-	-	-
				724,217	-	724,217	-	-	-	-	-
563	Overhead Line Expense										
		T	SG	93,685	-	93,685	-	-	-	-	-
				93,685	-	93,685	-	-	-	-	-
564	Underground Line Expense										
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
565	Transmission of Electricity by Others-Non NPC										
		T	SG	-	-	-	-	-	-	-	-
		T	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
565NPC	Transmission of Electricity by Others-NPC										
		T	SG	36,065,734	-	36,065,734	-	-	-	-	-
		T	SE	1,260,307	-	1,260,307	-	-	-	-	-
				37,326,041	-	37,326,041	-	-	-	-	-
	Total Transmission of Electricity by Others			37,326,041	-	37,326,041	-	-	-	-	-
566	Misc Transmission Expense										
		T	SG	595,181	-	595,181	-	-	-	-	-
				595,181	-	595,181	-	-	-	-	-
567	Rents - Transmission										
		T	SG	610,466	-	610,466	-	-	-	-	-
				610,466	-	610,466	-	-	-	-	-
568	Maint Supervision & Engineering										
		T	SG	600,397	-	600,397	-	-	-	-	-
				600,397	-	600,397	-	-	-	-	-
569	Maintenance of Structures										
		T	SG	1,218,529	-	1,218,529	-	-	-	-	-
				1,218,529	-	1,218,529	-	-	-	-	-
570	Maintenance of Station Equipment										
		STEP_UP	SG	2,823,874	223,488	2,600,386	-	-	-	-	-
				2,823,874	223,488	2,600,386	-	-	-	-	-
571	Maintenance of Overhead Lines										
		T	SG	5,405,898	-	5,405,898	-	-	-	-	-
				5,405,898	-	5,405,898	-	-	-	-	-
572	Maintenance of Underground Lines										
		T	SG	25,846	-	25,846	-	-	-	-	-
				25,846	-	25,846	-	-	-	-	-

573	Maint of Misc Transmission Plant											
		T	SG	459,363	-	459,363	-	-	-	-	-
				459,363	-	459,363	-	-	-	-	-
TOTAL TRANSMISSION EXPENSE				53,595,523	223,488	53,372,034	-	-	-	-	-
580	Operation Supervision & Engineering										
		D_SPLIT	S	(3,245)	-	-	(3,137)	-	-	(109)	-
		D_SPLIT	SNPD	3,591,656	-	-	3,471,553	-	-	120,103	-
				3,588,411	-	-	3,468,416	-	-	119,995	-
581	Load Dispatching										
		D	S	1	-	-	1	-	-	-	-
		D	SNPD	3,704,034	-	-	3,704,034	-	-	-	-
				3,704,035	-	-	3,704,035	-	-	-	-
582	Station Expense										
		D	S	1,162,254	-	-	1,162,254	-	-	-	-
		D	SNPD	10,238	-	-	10,238	-	-	-	-
				1,172,492	-	-	1,172,492	-	-	-	-
583	Overhead Line Expenses										
		D	S	3,054,562	-	-	3,054,562	-	-	-	-
		D	SNPD	5,027	-	-	5,027	-	-	-	-
				3,059,589	-	-	3,059,589	-	-	-	-
584	Underground Line Expense										
		D	S	-	-	-	-	-	-	-	-
		D	SNPD	294	-	-	294	-	-	-	-
				294	-	-	294	-	-	-	-
585	Street Lighting & Signal Systems										
		D	S	-	-	-	-	-	-	-	-
		D	SNPD	61,928	-	-	61,928	-	-	-	-
				61,928	-	-	61,928	-	-	-	-
586	Meter Expenses										
		C_Meter	S	3,293,344	-	-	-	-	-	3,293,344	-
		C_Meter	SNPD	347,683	-	-	-	-	-	347,683	-
				3,641,027	-	-	-	-	-	3,641,027	-
587	Customer Installation Expenses										
		D	S	4,710,389	-	-	4,710,389	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-
				4,710,389	-	-	4,710,389	-	-	-	-
588	Misc. Distribution Expenses										
		D	S	89,574	-	-	89,574	-	-	-	-
		D	SNPD	976,590	-	-	976,590	-	-	-	-
				1,066,164	-	-	1,066,164	-	-	-	-
908	Rents										
		D	S	1,778,965	-	-	1,778,965	-	-	-	-
		D	SNPD	13,786	-	-	13,786	-	-	-	-
				1,792,751	-	-	1,792,751	-	-	-	-
590	Maint Supervision & Engineering										
		D_SPLIT	S	317,553	-	-	306,934	-	-	10,619	-
		D_SPLIT	SNPD	982,858	-	-	949,992	-	-	32,866	-
				1,300,411	-	-	1,256,926	-	-	43,485	-
591	Maintenance of Structures										
		D	S	946,146	-	-	946,146	-	-	-	-
		D	SNPD	39,954	-	-	39,954	-	-	-	-
				986,101	-	-	986,101	-	-	-	-
592	Maintenance of Station Equipment										
		D	S	3,168,320	-	-	3,168,320	-	-	-	-
		D	SNPD	480,116	-	-	480,116	-	-	-	-
				3,648,436	-	-	3,648,436	-	-	-	-
593	Maintenance of Overhead Lines										
		D	S	33,549,409	-	-	33,549,409	-	-	-	-
		D	SNPD	289,905	-	-	289,905	-	-	-	-
				33,839,314	-	-	33,839,314	-	-	-	-
594	Maintenance of Underground Lines										
		D	S	5,981,807	-	-	5,981,807	-	-	-	-
		D	SNPD	1,777	-	-	1,777	-	-	-	-
				5,983,583	-	-	5,983,583	-	-	-	-
595	Maintenance of Line Transformers										
		D	S	-	-	-	-	-	-	-	-
		D	SNPD	243,347	-	-	243,347	-	-	-	-
				243,347	-	-	243,347	-	-	-	-
596	Maint of Street Lighting & Signal Sys.										
		D	S	1,233,766	-	-	1,233,766	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-
				1,233,766	-	-	1,233,766	-	-	-	-
597	Maintenance of Meters										
		C_Meter	S	1,242,254	-	-	-	-	-	1,242,254	-
		C_Meter	SNPD	330,540	-	-	-	-	-	330,540	-
				1,572,794	-	-	-	-	-	1,572,794	-

599	Maint of Misc. Distribution Plant											
		D	S	495,575	-	-	495,575	-	-	-	-
		D	SNPD	(148,897)	-	-	(148,897)	-	-	-	-
				346,679	-	-	346,679	-	-	-	-
TOTAL DISTRIBUTION EXPENSE				71,951,511	-	-	66,574,210	-	-	5,377,301	-
901	Supervision										
		CUST901	S	169	-	-	-	-	81	43	45
		CUST901	CN	920,192	-	-	-	-	441,031	231,922	247,239
				920,362	-	-	-	-	441,112	231,965	247,285
902	Meter Reading Expense										
		C_Meter	S	9,948,404	-	-	-	-	-	9,948,404	-
		C_Meter	CN	743,637	-	-	-	-	-	743,637	-
				10,692,042	-	-	-	-	-	10,692,042	-
903	Customer Receipts & Collections										
		CUST903	S	2,108,965	-	-	-	-	1,351,444	-	757,521
		CUST903	CN	14,664,234	-	-	-	-	9,396,974	-	5,267,261
				16,773,200	-	-	-	-	10,748,418	-	6,024,782
904	Uncollectible Accounts										
		REVREQ	S	7,394,970	4,738,440	944,273	1,410,981	0	89,339	146,190	65,746
		P	SG	-	-	-	-	-	-	-	-
		REVREQ	CN	85,425	54,737	10,908	16,299	0	1,032	1,689	759
				7,480,395	4,793,178	955,181	1,427,280	0	90,371	147,879	66,506
905	Misc. Customer Accounts Expense										
		CUST905	S	6,413	-	-	-	-	-	210	6,203
		CUST905	CN	57,333	-	-	-	-	-	1,882	55,451
				63,747	-	-	-	-	-	2,092	61,654
TOTAL CUSTOMER ACCOUNTS EXPENSE				35,929,744	4,793,178	955,181	1,427,280	0	11,279,901	11,073,978	6,400,227
907	Supervision										
		C_Service	S	-	-	-	-	-	-	-	-
		C_Service	CN	94,482	-	-	-	-	-	-	94,482
				94,482	-	-	-	-	-	-	94,482
908	Customer Assistance										
		DSM	S	1,857,183	-	-	1,857,183	-	-	-	-
		C_Service	CN	479,255	-	-	-	-	-	-	479,255
				2,336,438	-	-	1,857,183	-	-	-	479,255
909	Informational & Instructional Adv										
		C_Service	S	618,357	-	-	-	-	-	-	618,357
		C_Service	CN	981,431	-	-	-	-	-	-	981,431
				1,599,789	-	-	-	-	-	-	1,599,789
910	Misc. Customer Service										
		C_Service	S	-	-	-	-	-	-	-	-
		C_Service	CN	37,203	-	-	-	-	-	-	37,203
				37,203	-	-	-	-	-	-	37,203
TOTAL CUSTOMER SERVICE EXPENSE				4,067,911	-	-	1,857,183	-	-	-	2,210,728
911	Supervision										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
912	Demonstration & Selling Expense										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
913	Advertising Expense										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
916	Misc. Sales Expense										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL SALES EXPENSE				-	-	-	-	-	-	-	-
Total Customer Service Exp Including Sales				4,067,911	-	-	1,857,183	-	-	-	2,210,728

784	920	Administrative & General Salaries										
785			LABOR	S	(843,161)	(371,748)	(44,924)	(224,899)	-	(56,012)	(95,220)	(50,348)
786			LABOR	CN	-	-	-	-	-	-	-	-
787			LABOR	SO	20,349,628	8,972,206	1,084,247	5,427,987	-	1,351,866	2,298,156	1,215,166
788					19,506,477	8,600,459	1,039,323	5,203,088	-	1,295,854	2,202,936	1,164,818
789												
790	921	Office Supplies & expenses										
791			LABOR	S	62,672	27,632	3,339	16,717	-	4,163	7,078	3,742
792			LABOR	CN	22,661	9,991	1,207	6,044	-	1,505	2,559	1,353
793			LABOR	SO	2,526,709	1,114,033	134,625	673,965	-	167,854	285,350	150,881
794					2,612,041	1,151,656	139,172	696,726	-	173,523	294,987	155,977
795												
796	922	Office Supplies & expenses										
797			LABOR	S	-	-	-	-	-	-	-	-
798			LABOR	CN	-	-	-	-	-	-	-	-
799			LABOR	SO	(7,554,977)	(3,331,010)	(402,536)	(2,015,187)	-	(501,892)	(853,210)	(451,141)
800					(7,554,977)	(3,331,010)	(402,536)	(2,015,187)	-	(501,892)	(853,210)	(451,141)
801												
802	923	Outside Services										
803			LABOR	S	132,235	58,303	7,046	35,272	-	8,785	14,934	7,896
804			LABOR	CN	-	-	-	-	-	-	-	-
805			LABOR	SO	1,788,456	788,535	95,291	477,046	-	118,811	201,977	106,797
806					1,920,691	846,838	102,336	512,318	-	127,595	216,910	114,693
807												
808	924	Property Insurance										
809			DPW	S	6,959,234	-	-	6,747,353	-	-	211,881	-
810			PT	SG	-	-	-	-	-	-	-	-
811			GP	SO	1,867,216	882,485	377,580	561,868	-	11,105	27,404	6,773
812					8,826,450	882,485	377,580	7,309,221	-	11,105	239,286	6,773
813												
814	925	Injuries & Damages										
			DPW	S	3,369,178	-	-	3,266,600	-	-	102,578	-
815			LABOR	SO	1,078,716	475,609	57,475	287,733	-	71,661	121,823	64,415
816					4,447,894	475,609	57,475	3,554,332	-	71,661	224,401	64,415
817												
818	926	Employee Pensions & Benefits										
819			LABOR	S	-	-	-	-	-	-	-	-
820			LABOR	CN	-	-	-	-	-	-	-	-
821			LABOR	SO	-	-	-	-	-	-	-	-
822					-	-	-	-	-	-	-	-
823												
824	927	Franchise Requirements										
825			DSM	S	-	-	-	-	-	-	-	-
826			DSM	SG	-	-	-	-	-	-	-	-
827					-	-	-	-	-	-	-	-
828												
829	928	Regulatory Commission Expense										
830			D	S	4,961,857	-	-	4,961,857	-	-	-	-
831			C_SERVICE	CN	-	-	-	-	-	-	-	-
832			D	SO	737,317	-	-	737,317	-	-	-	-
833			FERC	SG	1,020,298	528,348	491,950	-	-	-	-	-
834					6,719,472	528,348	491,950	5,699,174	-	-	-	-
835												
836	929	Duplicate Charges										
837			LABOR	S	-	-	-	-	-	-	-	-
838			LABOR	SO	(2,220,054)	(978,828)	(118,287)	(592,169)	-	(147,483)	(250,719)	(132,569)
839					(2,220,054)	(978,828)	(118,287)	(592,169)	-	(147,483)	(250,719)	(132,569)
840												
841	930	Misc General Expenses										
842			LABOR	S	919,899	405,586	49,013	245,371	-	61,111	103,887	54,931
843			C_SERVICE	CN	-	-	-	-	-	-	-	-
844			LABOR	SO	3,065,558	1,351,613	163,336	817,696	-	203,651	346,204	183,058
845					3,985,457	1,757,199	212,349	1,063,067	-	264,762	450,092	237,989
846												
847	931	Rents										
848			LABOR	S	1,233,499	543,853	65,722	329,019	-	81,944	139,303	73,658
849			LABOR	SO	1,716,217	756,685	91,442	457,778	-	114,012	193,819	102,483
850					2,949,716	1,300,538	157,164	786,797	-	195,956	333,122	176,141
851												
852	935	Maintenance of General Plant										
853			G	S	145,770	48,648	28,840	62,656	-	3,658	1,968	-
854			B_Center	CN	6,566	-	-	-	-	5,018	-	1,548
855			G	SO	6,307,081	2,104,872	1,247,844	2,710,968	-	158,267	85,130	-
856					6,459,418	2,153,520	1,276,684	2,773,624	-	166,943	87,098	1,548
857												
858	TOTAL ADMINISTRATIVE & GEN EXPENSE				47,652,586	13,386,814	3,333,211	24,990,991	-	1,658,025	2,944,903	1,338,643
859												
860												
861	TOTAL O&M EXPENSE				766,658,390	591,664,594	57,660,426	94,849,664	0	12,937,925	19,396,162	9,949,598

862	403SP	Steam Depreciation										
863			P	SG	12,473,885	12,473,885	-	-	-	-	-	-
864			P	SG	11,276,619	11,276,619	-	-	-	-	-	-
865			P	SG	63,894,040	63,894,040	-	-	-	-	-	-
866			P	SG	6,422,173	6,422,173	-	-	-	-	-	-
867					94,066,718	94,066,718	-	-	-	-	-	-
868												
869	403NP	Nuclear Depreciation										
870			P	SG	-	-	-	-	-	-	-	-
871					-	-	-	-	-	-	-	-
872												
873	403HP	Hydro Depreciation										
874		Pre-Merger Pacific	P	SG	1,293,159	1,293,159	-	-	-	-	-	-
875		Pre-Merger Utah	P	SG	354,670	354,670	-	-	-	-	-	-
876		Post-Merger Pacific	P	SG	5,416,944	5,416,944	-	-	-	-	-	-
877		Post-Merger Utah	P	SG	1,426,998	1,426,998	-	-	-	-	-	-
878					8,491,771	8,491,771	-	-	-	-	-	-
879												
880	403OP	Other Production Depreciation										
			P	S	-	-	-	-	-	-	-	-
881			P	SG	-	-	-	-	-	-	-	-
882			P	SG	25,766,218	25,766,218	-	-	-	-	-	-
883			P	SG	824,256	824,256	-	-	-	-	-	-
884			P	SG	-	-	-	-	-	-	-	-
885					26,590,474	26,590,474	-	-	-	-	-	-
886												
887	403TP	Transmission Depreciation										
			T_Split	S	-	-	-	-	-	-	-	-
888			T_Split	SG	2,608,927	65,004	2,543,923	-	-	-	-	-
889			T_Split	SG	2,995,458	74,634	2,920,824	-	-	-	-	-
890			T_Split	SG	19,145,006	477,013	18,667,993	-	-	-	-	-
891					24,749,391	616,651	24,132,740	-	-	-	-	-
892												
893												
894												
895	403	Distribution Depreciation										
896	360	Land & Land Rights	D	S	35,535	-	-	35,535	-	-	-	-
897	361	Structures	D	S	272,282	-	-	272,282	-	-	-	-
898	362	Station Equipment	D	S	3,993,370	-	-	3,993,370	-	-	-	-
899	363	Storage Battery Equipr	D	S	-	-	-	-	-	-	-	-
900	364	Poles & Towers	D	S	12,318,181	-	-	12,318,181	-	-	-	-
901	365	OH Conductors	D	S	6,651,382	-	-	6,651,382	-	-	-	-
902	366	UG Conduit	D	S	2,009,910	-	-	2,009,910	-	-	-	-
903	367	UG Conductor	D	S	3,384,785	-	-	3,384,785	-	-	-	-
904	368	Line Trans	D	S	10,615,455	-	-	10,615,455	-	-	-	-
905	369	Services	D	S	4,252,927	-	-	4,252,927	-	-	-	-
906	370	Meters	C_Meter	S	2,061,203	-	-	-	-	-	2,061,203	-
907	371	Inst Cust Prem	D	S	113,968	-	-	113,968	-	-	-	-
908	372	Leased Property	D	S	-	-	-	-	-	-	-	-
909	373	Street Lighting	D	S	639,042	-	-	639,042	-	-	-	-
910					46,348,040	-	-	44,286,837	-	-	2,061,203	-
911												
912	403GP	General Depreciation										
913			TD	S	4,416,126	-	1,890,941	2,440,744	-	-	84,441	-
914			G-DGP	SG	12,559	8,429	4,131	-	-	-	-	-
915			G-DGU	SG	7,831	5,256	2,576	-	-	-	-	-
916			P	SE	4,309	4,309	-	-	-	-	-	-
917			B_Center	CN	490,505	-	-	-	-	374,862	-	115,643
918			G-SG	SG	1,941,461	1,939,484	1,976	-	-	-	-	-
919			LABOR	SO	3,958,939	1,745,507	210,936	1,055,993	-	263,000	447,097	236,406
920			P	SG	1,549	1,549	-	-	-	-	-	-
921			P	SG	42,088	42,088	-	-	-	-	-	-
922					10,875,368	3,746,623	2,110,559	3,496,737	-	637,862	531,538	352,049
923												
924	403GV0	General Vehicles										
925			G-SG	SG	-	-	-	-	-	-	-	-
926					-	-	-	-	-	-	-	-
927												
928	403MP	Mining Depreciation										
929			P	SE	-	-	-	-	-	-	-	-
930					-	-	-	-	-	-	-	-
931												
932	403EP	Experimental Plant Depreciation										
933			P	SG	-	-	-	-	-	-	-	-
934			P	SG	-	-	-	-	-	-	-	-
935					-	-	-	-	-	-	-	-
936	4031	ARO Depreciation										
937			P	S	-	-	-	-	-	-	-	-
938					-	-	-	-	-	-	-	-
939												
940												
941	**TOTAL DEPRECIATION EXPENSE**				**211,121,763**	**133,512,238**	**26,243,300**	**47,783,574**	**-**	**637,862**	**2,592,740**	**352,049**
942												
943	404GP	Amort of LT Plant - Capital Lease Gen										
944			TD	S	231,371	-	99,071	127,876	-	-	4,424	-
945			I-SG	SG	-	-	-	-	-	-	-	-
946			LABOR	SO	350,218	154,412	18,660	93,416	-	23,266	39,551	20,913
947			I-DGU	SG	-	-	-	-	-	-	-	-
948			B_Center	CN	82,899	-	-	-	-	63,354	-	19,544
949			I-DGP	SG	-	-	-	-	-	-	-	-
950					664,488	154,412	117,731	221,292	-	86,620	43,975	40,458
951												
952	404SP	Amort of LT Plant - Cap Lease Steam										
953			P	SG	-	-	-	-	-	-	-	-
954			P	SG	-	-	-	-	-	-	-	-
955					-	-	-	-	-	-	-	-

404IP	Amort of LT Plant - Intangible Plant										
		TD	S	11,762	-	5,036	6,500	-	-	225	-
		P	SE	82,985	82,985	-	-	-	-	-	-
		I-SG	SG	1,768,294	1,512,369	255,925	-	-	-	-	-
		LABOR	SO	5,800,830	2,557,602	309,074	1,547,293	-	385,361	655,108	346,393
		CSS_SYS	CN	1,946640	-	-	-	-	1,070,652	350,395	525,593
		I-SG	SG	2,819,616	2,411,534	408,082	-	-	-	-	-
		I-SG	SG	78,583	67,210	11,373	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-
		I-DGU	SG	4,195	4,195	-	-	-	-	-	-
				12,512,905	6,635,894	989,490	1,553,793	-	1,456,013	1,005,728	871,986
404MP	Amort of LT Plant - Mining Plant										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
404OP	Amort of LT Plant - Other Plant										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
404HP	Amortization of Other Electric Plant										
	Pre-Merger Pacific	P	SG	81,184	81,184	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	11,602	11,602	-	-	-	-	-	-
	Post-Merger Plant	P	SG	-	-	-	-	-	-	-	-
				92,786	92,786	-	-	-	-	-	-
Total Amortization of Limited Term Plant				13,270,179	6,883,092	1,107,221	1,775,085	-	1,542,633	1,049,704	912,444
405	Amortization of Other Electric Plant										
		GP	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
406	Amortization of Plant Acquisition Adj										
		P	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	1,259,479	1,259,479	-	-	-	-	-	-
		P	SO	-	-	-	-	-	-	-	-
				1,259,479	1,259,479	-	-	-	-	-	-
407	Amort of Prop Losses, Unrec Plant, etc										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL AMORTIZATION EXPENSE				14,529,658	8,142,571	1,107,221	1,775,085	-	1,542,633	1,049,704	912,444
408	Taxes Other Than Income										
		D	S	29,020,236	-	-	29,020,236	-	-	-	-
		GP	GPS	35,428,526	16,744,264	7,164,194	10,660,884	-	210,710	519,965	128,509
		REVREQ	SO	2,423,122	1,552,653	309,411	462,338	0	29,274	47,902	21,543
		P	SE	202,385	202,385	-	-	-	-	-	-
		P	SG	449,567	449,567	-	-	-	-	-	-
		DSM	OPRV-ID	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-
		GP	SG	-	-	-	-	-	-	-	-
				67,523,836	18,948,869	7,473,605	40,143,458	0	239,984	567,868	150,052
41140	Deferred Investment Tax Credit - Fed										
		PTD	DGU	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
41141	Deferred Investment Tax Credit - Idaho										
		PTD	DGU	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL DEFERRED ITC				-	-	-	-	-	-	-	-
427	Interest on Long-Term Debt										
		NP	S	85,739,606	41,541,824	20,550,799	22,439,393	-	211,259	853,430	142,902
		NP	SNP	-	-	-	-	-	-	-	-
				85,739,606	41,541,824	20,550,799	22,439,393	-	211,259	853,430	142,902

1044												
1045	428	Amortization of Debt Disc & Exp										
1046			NP	SNP	-	-	-	-	-	-	-	-
1047					-	-	-	-	-	-	-	-
1048												
1049	429	Amortization of Premium on Debt										
1050			NP	SNP	-	-	-	-	-	-	-	-
1051					-	-	-	-	-	-	-	-
1052												
1053	431	Other Interest Expense										
1054			NUTIL	OTH	-	-	-	-	-	-	-	-
1055			GP	SO	-	-	-	-	-	-	-	-
1056			NP	SNP	-	-	-	-	-	-	-	-
1057					-	-	-	-	-	-	-	-
1058												
1059	432	AFUDC - Borrowed										
1060			NP	SNP	-	-	-	-	-	-	-	-
1061					-	-	-	-	-	-	-	-
1062												
1063		Total Electric Interest Deductions for Tax			85,739,606	41,541,824	20,550,799	22,439,393	-	211,259	853,430	142,902
1064												
1065		Non-Utility Portion of Interest										
1066			427 NUTIL	NUTIL	-	-	-	-	-	-	-	-
1067			428 NUTIL	NUTIL	-	-	-	-	-	-	-	-
1068			429 NUTIL	NUTIL	-	-	-	-	-	-	-	-
1069			431 NUTIL	NUTIL	-	-	-	-	-	-	-	-
1070												
1071		Total Non-utility Interest			-	-	-	-	-	-	-	-
1072												
1073		Total Interest Deductions for Tax			85,739,606	41,541,824	20,550,799	22,439,393	-	211,259	853,430	142,902
1074												
1075												
1076	419	Interest & Dividends										
1077			GP	S	-	-	-	-	-	-	-	-
1078			GP	SNP	(16,809,094)	(7,944,330)	(3,399,058)	(5,058,065)	-	(99,971)	(246,698)	(60,971)
1079		Total Operating Deductions for Tax			(16,809,094)	(7,944,330)	(3,399,058)	(5,058,065)	-	(99,971)	(246,698)	(60,971)
1080												
1081												
1082	41010	Deferred Income Tax - Federal-DR										
1083			GP	S	20,423	9,652	4,130	6,146	-	121	300	74
1084			P	SCHMDEXP	-	-	-	-	-	-	-	-
1085			PT	SG	9,662	6,484	3,178	-	-	-	-	-
1086			LABOR	SO	(252,484)	(111,321)	(13,453)	(67,347)	-	(16,773)	(28,514)	(15,077)
1087			NP	SNP	9,591,052	4,646,975	2,298,865	2,510,128	-	23,632	95,467	15,985
1088			P	SE	441,566	441,566	-	-	-	-	-	-
1089			PT	SG	14,245,244	9,560,119	4,685,125	-	-	-	-	-
1090			GP	GPS	6,002,232	2,836,781	1,213,744	1,806,146	-	35,698	88,092	21,772
1091			TAXDEPR	TAXDEPR	113,552,622	45,035,975	40,154,379	26,940,410	-	499,332	612,282	310,244
1092			C_BILLING	BADDEBT	-	-	-	-	-	-	-	-
1093			CSS_SYS	CN	-	-	-	-	-	-	-	-
1094			IBT	IBT	-	-	-	-	-	-	-	-
1095			D	SNPD	-	-	-	-	-	-	-	-
1096					143,610,316	62,426,230	48,345,968	31,195,483	-	542,010	767,626	332,998
1097												
1098												
1099												
1100	41110	Deferred Income Tax - Federal-CR										
1101			GP	S	(597,475)	(282,379)	(120,819)	(179,788)	-	(3,553)	(8,769)	(2,167)
1102			P	SE	-	-	-	-	-	-	-	-
1103			C_BILLING	BADDEBT	(0)	-	-	-	-	(0)	-	-
1104			NP	SNP	(6,872,542)	(3,329,826)	(1,647,269)	(1,798,652)	-	(16,934)	(68,408)	(11,454)
1105			PT	SG	601	404	198	-	-	-	-	-
1106			D_SPLIT	CIAC	(4,743,797)	-	-	(4,585,167)	-	-	(158,630)	-
1107			LABOR	SO	(1,409,248)	(621,341)	(75,086)	(375,898)	-	(93,619)	(159,151)	(84,152)
1108			D	SNPD	-	-	-	-	-	-	-	-
1109			CSS_SYS	CN	-	-	-	-	-	-	-	-
1110			P	SGCT	(111,352)	(111,352)	-	-	-	-	-	-
1111			BOOKDEPR	SCHMDEXP	(85,398,299)	(43,827,022)	(14,881,282)	(25,613,989)	-	(271,671)	(804,335)	-
1112			P	TROJD	-	-	-	-	-	-	-	-
1113			IBT	IBT	-	-	-	-	-	-	-	-
1114			P	SG	-	-	-	-	-	-	-	-
1115			P	SG	-	-	-	-	-	-	-	-
1116			P	SG	-	-	-	-	-	-	-	-
1117			P	SG	(140,862)	(140,862)	-	-	-	-	-	-
1118			P	SG	-	-	-	-	-	-	-	-
1119					(99,272,974)	(48,312,379)	(16,724,259)	(32,553,493)	-	(385,777)	(1,199,292)	(97,774)
1120												
1121	TOTAL DEFERRED INCOME TAXES				44,337,342	14,113,852	31,621,709	(1,358,010)	-	156,233	(431,667)	235,224
1122	SCHMAF	Additions - Flow Through										
1123			SCHMAF	S	-	-	-	-	-	-	-	-
1124			SCHMAF	SNP	-	-	-	-	-	-	-	-
1125			SCHMAF	SO	-	-	-	-	-	-	-	-
1126			SCHMAF	SE	-	-	-	-	-	-	-	-
1127			P	TROJP	-	-	-	-	-	-	-	-
1128			SCHMAF	SG	-	-	-	-	-	-	-	-
1129					-	-	-	-	-	-	-	-

SCHMAP	Additions - Permanent										
		P	S	-	-	-	-	-	-	-	-
		P	SE	4,444	4,444	-	-	-	-	-	-
		PTD	SNP	-	-	-	-	-	-	-	-
		SCHMAP-SO	SO	186,205	86,233	25,892	49,334	-	6,679	12,062	6,004
		SCHMAP	SG	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	19,367	9,939	3,375	5,809	-	62	182	-
				210,015	100,616	29,267	55,143	-	6,741	12,244	6,004
SCHMAT	Additions - Temporary										
		SCHMAT-SITUS	S	-	-	-	-	-	-	-	-
		SCHMAT-SG	SG	-	-	-	-	-	-	-	-
		D_SPLIT	CIAC	12,499,794	-	-	12,081,807	-	-	417,987	-
		SCHMAT-SNP	SNP	18,108,987	8,862,184	4,335,595	4,758,156	-	2,118	150,008	926
		P	TROJD	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	0	-	-	-	-	0	-	-
		SCHMAT-SE	SE	-	-	-	-	-	-	-	-
		SCHMAT-SG	SG	-	-	-	-	-	-	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-
		SCHMAT-SO	SO	3,713,335	1,718,762	512,839	983,906	-	134,455	242,515	120,859
		SCHMAT-SNP	SNPD	-	-	-	-	-	-	-	-
		P	SGCT	293,409	293,409	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	225,022,527	115,483,182	39,211,832	67,492,264	-	715,846	2,119,403	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				259,638,052	126,357,536	44,060,266	85,316,133	-	852,419	2,929,913	121,785
TOTAL SCHEDULE - M ADDITIONS				259,848,068	126,458,152	44,089,533	85,371,277	-	859,160	2,942,158	127,789
SCHMDF	Deductions - Flow Through										
		SCHMDF	S	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
SCHMDP	Deductions - Permanent										
		SCHMDP	S	-	-	-	-	-	-	-	-
		P	SE	121,920	121,920	-	-	-	-	-	-
		SCHMDP	SNP	100,675	46,655	5,732	25,831	-	6,233	10,622	5,603
		SCHMDP	IBT	96,797	44,858	5,511	24,836	-	5,993	10,212	5,387
		P	SG	-	-	-	-	-	-	-	-
		SCHMDP-SO	SO	-	-	-	-	-	-	-	-
				319,393	213,433	11,243	50,666	-	12,226	20,834	10,990
SCHMDT	Deductions - Temporary										
		SCHMDT-SITUS	S	53,813	29,381	3,719	8,403	-	1,378	2,380	8,552
		SCHMDT	BADDEBT	-	-	-	-	-	-	-	-
		SCHMDT-SNP	SNP	25,272,198	12,362399	6,058,557	6,642,649	-	-	208,594	-
		SCHMDT	CN	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	25,458	25,458	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-
		P	SE	1,163,515	1,163,515	-	-	-	-	-	-
		SCHMDT-SG	SG	37,535,886	37,535,886	-	-	-	-	-	-
		SCHMDT-GPS	GPS	15,815,739	7,736,584	3,791,540	4,157,074	-	-	130,541	-
		SCHMDT-SO	SO	(665,291)	(290,757)	(111,598)	(228,248)	-	(9,192)	(17,604)	(7,892)
		TAXDEPR	TAXDEPR	299,208,512	118,668,743	105,805,854	70,987,353	-	1,315,728	1,613,348	817,486
		SCHMDT-SNP	SNPD	-	-	-	-	-	-	-	-
				378,409,830	177,231,210	115,548,071	81,567,231	-	1,307,914	1,937,258	818,146
TOTAL SCHEDULE - M DEDUCTIONS				378,729,222	177,444,643	115,559,314	81,617,897	-	1,320,141	1,958,092	829,136
TOTAL SCHEDULE - M ADJUSTMENTS				(118,881,155)	(50,986,491)	(71,469,781)	3,753,380	-	(460,981)	984,065	(701,347)
40911	State Income Taxes										
		IBT	S	4,776,937	1,936,890	(263,783)	2,894,067	0	29,687	177,466	2,611
		IBT	IBT	-	-	-	-	-	-	-	-
	Renewable Energy Credits	P	SG	(100,279)	(100,279)	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-
TOTAL STATE TAXES				4,676,658	1,836,610	(263,783)	2,894,067	0	29,687	177,466	2,611
Calculation of Taxable Income:											
	Operating Revenues			1,372,774,372	879,626,227	175,291,227	261,929,198	0	16,584,579	27,138,220	12,204,922
	Operating Deductions:										
	O & M Expenses			786,658,390	591,864,594	57,660,426	94,849,664	0	12,937,925	19,396,182	9,949,598
	Depreciation Expense			211,121,763	133,512,238	26,243,300	47,783,574	-	637,862	2,592,740	352,049
	Amortization Expense			14,529,658	8,142,571	1,107,221	1,775,085	-	1,542,633	1,049,704	912,444
	Taxes Other Than Income			67,523,836	18,948,869	7,473,605	40,143,458	0	239,984	567,868	150,052
	Interest & Dividends (AFUDC-Equity)			(16,809,094)	(7,944,330)	(3,399,058)	(5,058,065)	-	(99,971)	(246,698)	(60,971)
	Misc Revenue & Expense			(90,219)	(88,958)	(4,625)	3,257	-	-	107	-
	Total Operating Deductions			1,062,934,333	744,434,983	89,080,869	179,496,974	0	15,258,433	23,359,903	11,303,171
	Other Deductions:										
	Interest Deductions			85,739,606	41,541,824	20,560,799	22,439,393	-	211,259	853,430	142,902
	Interest on PCRBS			-	-	-	-	-	-	-	-
	Schedule M Adjustments			(118,881,155)	(50,986,491)	(71,469,781)	3,753,380	-	(460,981)	984,065	(701,347)
	Income Before State Taxes			105,219,278	42,662,929	(5,810,222)	63,746,210	0	653,907	3,908,951	57,502
	State Income Taxes			4,676,658	1,836,610	(263,783)	2,894,067	0	29,687	177,466	2,611
Total Taxable Income				100,542,620	40,826,319	(5,546,439)	60,852,143	0	624,220	3,731,486	54,892
Tax Rate				35%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
Federal Income Tax - Calculated				35,189,917	14,289,212	(1,941,254)	21,298,250	0	218,477	1,306,020	19,212

Adjustments to Calculated Tax											
40910	PMI	P	SE	(4,444)	(4,444)	-	-	-	-	-	-
40910	Renewable Energy Credits	P	SG	(17,161,943)	(17,161,943)	-	-	-	-	-	-
40910		P	SO	-	-	-	-	-	-	-	-
40910		P	S	-	-	-	-	-	-	-	-
Federal Income Tax				18,023,530	(2,877,175)	(1,941,254)	21,298,250	0	218,477	1,306,020	19,212
TOTAL OPERATING EXPENSES				**1,146,780,957**	**765,452,600**	**121,896,599**	**207,389,346**	**0**	**15,762,802**	**24,658,420**	**11,621,188**
310	Land and Land Rights										
		P	SG	606,573	606,573	-	-	-	-	-	-
		P	SG	9,066,040	9,066,040	-	-	-	-	-	-
		P	SG	13,915,473	13,915,473	-	-	-	-	-	-
		P	S	-	-	-	-	-	-	-	-
		P	SG	643,182	643,182	-	-	-	-	-	-
				24,231,267	24,231,267	-	-	-	-	-	-
311	Structures and Improvements										
		P	SG	60,787,159	60,787,159	-	-	-	-	-	-
		P	SG	84,452,517	84,452,517	-	-	-	-	-	-
		P	SG	91,654,276	91,654,276	-	-	-	-	-	-
		P	SG	15,674,041	15,674,041	-	-	-	-	-	-
				252,567,993	252,567,993	-	-	-	-	-	-
312	Boiler Plant Equipment										
		P	SG	151,701,214	151,701,214	-	-	-	-	-	-
		P	SG	136,424,889	136,424,889	-	-	-	-	-	-
		P	SG	717,534,013	717,534,013	-	-	-	-	-	-
		P	SG	85,327,456	85,327,456	-	-	-	-	-	-
				1,090,987,572	1,090,987,572	-	-	-	-	-	-
314	Turbogenerator Units										
		P	SG	31,727,795	31,727,795	-	-	-	-	-	-
		P	SG	35,157,839	35,157,839	-	-	-	-	-	-
		P	SG	166,029,069	166,029,069	-	-	-	-	-	-
		P	SG	17,247,508	17,247,508	-	-	-	-	-	-
				250,162,212	250,162,212	-	-	-	-	-	-
315	Accessory Electric Equipment										
		P	SG	22,584,584	22,584,584	-	-	-	-	-	-
		P	SG	35,715,900	35,715,900	-	-	-	-	-	-
		P	SG	42,262,893	42,262,893	-	-	-	-	-	-
		P	SG	17,542,545	17,542,545	-	-	-	-	-	-
				118,105,922	118,105,922	-	-	-	-	-	-
316	Misc Power Plant Equipment										
		P	SG	1,207,194	1,207,194	-	-	-	-	-	-
		P	SG	1,324,846	1,324,846	-	-	-	-	-	-
		P	SG	5,128,178	5,128,178	-	-	-	-	-	-
		P	SG	1,082,504	1,082,504	-	-	-	-	-	-
				8,742,723	8,742,723	-	-	-	-	-	-
317	Steam Plant ARO										
		P	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
SP	Unclassified Steam Plant - Account 300										
		P	SG	(5,923,724)	(5,923,724)	-	-	-	-	-	-
				(5,923,724)	(5,923,724)	-	-	-	-	-	-
Total Steam Production Plant				**1,738,873,965**	**1,738,873,965**	-	-	-	-	-	-
320	Land and Land Rights										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
321	Structures and Improvements										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
322	Reactor Plant Equipment										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
323	Turbogenerator Units										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
324	Land and Land Rights										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
325	Misc Power Plant Equipment										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-

1325												
1326	NP	Unclassified Nuclear Plant - Acct 300										
1327			P	SG	-	-	-	-	-	-	-	-
1328					-	-	-	-	-	-	-	-
1329												
1330												
1331	**Total Nuclear Production Plant**				-	-	-	-	-	-	-	-
1332												
1333	330	Land and Land Rights										
1334		Pre-Merger Pacific	P	SG	2,748,859	2,748,859	-	-	-	-	-	-
1335		Pre-Merger Utah	P	SG	1,372,142	1,372,142	-	-	-	-	-	-
1336		Post-Merger Pacific	P	SG	3,918,270	3,918,270	-	-	-	-	-	-
1337		Post-Merger Utah	P	SG	175,304	175,304	-	-	-	-	-	-
1338					8,214,575	8,214,575	-	-	-	-	-	-
1339												
1340	331	Structures and Improvements										
1341		Pre-Merger Pacific	P	SG	5,346,899	5,346,899	-	-	-	-	-	-
1342		Pre-Merger Utah	P	SG	1,365,578	1,365,578	-	-	-	-	-	-
1343		Post-Merger Pacific	P	SG	28,017,495	28,017,495	-	-	-	-	-	-
1344		Post-Merger Utah	P	SG	2,300,587	2,300,587	-	-	-	-	-	-
1345					37,030,559	37,030,559	-	-	-	-	-	-
1346												
1347	332	Reservoirs, Dams & Waterways										
1348		Pre-Merger Pacific	P	SG	37,367,654	37,367,654	-	-	-	-	-	-
1349		Pre-Merger Utah	P	SG	4,754,884	4,754,884	-	-	-	-	-	-
1350		Post-Merger Pacific	P	SG	88,384,446	88,384,446	-	-	-	-	-	-
1351		Post-Merger Utah	P	SG	18,923,555	18,923,555	-	-	-	-	-	-
1352					149,430,539	149,430,539	-	-	-	-	-	-
1353												
1354	333	Water Wheel, Turbines, & Generators										
1355		Pre-Merger Pacific	P	SG	7,834,151	7,834,151	-	-	-	-	-	-
1356		Pre-Merger Utah	P	SG	2,199,284	2,199,284	-	-	-	-	-	-
1357		Post-Merger Pacific	P	SG	13,044,048	13,044,048	-	-	-	-	-	-
1358		Post-Merger Utah	P	SG	7,921,667	7,921,667	-	-	-	-	-	-
1359					30,999,150	30,999,150	-	-	-	-	-	-
1360												
1361	334	Accessory Electric Equipment										
1362		Pre-Merger Pacific	P	SG	1,068,814	1,068,814	-	-	-	-	-	-
1363		Pre-Merger Utah	P	SG	910,693	910,693	-	-	-	-	-	-
1364		Post-Merger Pacific	P	SG	13,374,960	13,374,960	-	-	-	-	-	-
1365		Post-Merger Utah	P	SG	1,951,470	1,951,470	-	-	-	-	-	-
1366					17,305,936	17,305,936	-	-	-	-	-	-
1367												
1368												
1369												
1370	335	Misc Power Plant Equipment										
1371		Pre-Merger Pacific	P	SG	298,311	298,311	-	-	-	-	-	-
1372		Pre-Merger Utah	P	SG	41,091	41,091	-	-	-	-	-	-
1373		Post-Merger Pacific	P	SG	271,857	271,857	-	-	-	-	-	-
1374		Post-Merger Utah	P	SG	3,278	3,278	-	-	-	-	-	-
1375					614,536	614,536	-	-	-	-	-	-
1376												
1377	336	Roads, Railroads & Bridges										
1378		Pre-Merger Pacific	P	SG	1,197,841	1,197,841	-	-	-	-	-	-
1379		Pre-Merger Utah	P	SG	214,355	214,355	-	-	-	-	-	-
1380		Post-Merger Pacific	P	SG	2,791,348	2,791,348	-	-	-	-	-	-
1381		Post-Merger Utah	P	SG	189,331	189,331	-	-	-	-	-	-
1382					4,392,876	4,392,876	-	-	-	-	-	-
1383												
1384	337	Hydro Plant ARO										
1385			P	S	-	-	-	-	-	-	-	-
1386					-	-	-	-	-	-	-	-
1387												
1388	HP	Unclassified Hydro Plant - Acct 300										
1389		Pre-Merger Pacific	P	S	-	-	-	-	-	-	-	-
1390		Pre-Merger Utah	P	SG	-	-	-	-	-	-	-	-
1391		Post-Merger Pacific	P	SG	-	-	-	-	-	-	-	-
1392			P	SG	-	-	-	-	-	-	-	-
1393					-	-	-	-	-	-	-	-
1394												
1395	**Total Hydraulic Plant**				**247,988,172**	**247,988,172**	-	-	-	-	-	-
1396												
1397	340	Land and Land Rights										
			P	S	75,000	75,000	-	-	-	-	-	-
1398			P	SG	7,527,915	7,527,915	-	-	-	-	-	-
1399			P	SG	-	-	-	-	-	-	-	-
1400			P	SG	-	-	-	-	-	-	-	-
1401					7,602,915	7,602,915	-	-	-	-	-	-
1402												
1403	341	Structures and Improvements										
1404			P	SG	40,767,746	40,767,746	-	-	-	-	-	-
1405			P	SG	42,600	42,600	-	-	-	-	-	-
1406			P	SG	1,104,727	1,104,727	-	-	-	-	-	-
1407					41,915,072	41,915,072	-	-	-	-	-	-
1408												
1409	342	Fuel Holders, Producers & Accessories										
1410			P	SG	2,194,842	2,194,842	-	-	-	-	-	-
1411			P	SG	-	-	-	-	-	-	-	-
1412			P	SG	641,463	641,463	-	-	-	-	-	-
1413					2,836,305	2,836,305	-	-	-	-	-	-
1414												
1415	343	Prime Movers										
1416			P	S	-	-	-	-	-	-	-	-
1417			P	SG	11,439	11,439	-	-	-	-	-	-
1418			P	SG	596,683,815	596,683,815	-	-	-	-	-	-
1419			P	SG	14,027,695	14,027,695	-	-	-	-	-	-
1420					610,722,949	610,722,949	-	-	-	-	-	-

1421													
1422	344	Generators											
1423			P	S	-	-	-	-	-	-	-	-
1424			P	SG	-	-	-	-	-	-	-	-
1425			P	SG	86,071,938	86,071,938	-	-	-	-	-	-
1426			P	SG	4,153,942	4,153,942	-	-	-	-	-	-
1427					90,225,880	90,225,880	-	-	-	-	-	-
1428												
1429	345	Accessory Electric Plant										
1430			P	SG	60,930,177	60,930,177	-	-	-	-	-	-
1431			P	SG	40,795	40,795	-	-	-	-	-	-
1432			P	SG	783,430	783,430	-	-	-	-	-	-
1433					61,754,403	61,754,403	-	-	-	-	-	-
1434												
1435												
1436												
1437	346	Misc Power Plant Equipment										
1438			P	SG	3,078,276	3,078,276	-	-	-	-	-	-
1439			P	SG	3,078	3,078	-	-	-	-	-	-
1440					3,081,354	3,081,354	-	-	-	-	-	-
1441												
1442	347	Other Production ARO										
1443			P	S	-	-	-	-	-	-	-	-
1444					-	-	-	-	-	-	-	-
1445												
1446	OP	Unclassified Other Prod Plant-Acct 300										
1447			P	S	-	-	-	-	-	-	-	-
1448			P	SG	-	-	-	-	-	-	-	-
1449					-	-	-	-	-	-	-	-
1450												
1451	**Total Other Production Plant**				818,138,877	818,138,877	-	-	-	-	-	-
1452												
1453	Experimental Plant											
1454	103	Experimental Plant										
1455			P	SG	-	-	-	-	-	-	-	-
1456	**Total Experimental Plant**				-	-	-	-	-	-	-	-
1457												
1458	**TOTAL PRODUCTION PLANT**				2,805,001,014	2,805,001,014	-	-	-	-	-	-
1459	350	Land and Land Rights										
1460			T	SG	5,501,412	-	5,501,412	-	-	-	-	-
1461			T	SG	12,627,770	-	12,627,770	-	-	-	-	-
1462			T	SG	32,618,125	-	32,618,125	-	-	-	-	-
1463					50,747,308	-	50,747,308	-	-	-	-	-
1464												
1465	352	Structures and Improvements										
1466			T	S	-	-	-	-	-	-	-	-
1467			T	SG	1,936,629	-	1,936,629	-	-	-	-	-
1468			T	SG	4,711,221	-	4,711,221	-	-	-	-	-
1469			T	SG	33,790,899	-	33,790,899	-	-	-	-	-
1470					40,438,749	-	40,438,749	-	-	-	-	-
1471												
1472	353	Station Equipment										
1473			STEP_UP	SG	31,625,715	2,502,936	29,122,779	-	-	-	-	-
1474			STEP_UP	SG	46,688,610	3,695,050	42,993,560	-	-	-	-	-
1475			STEP_UP	SG	354,455,138	28,052,441	326,402,697	-	-	-	-	-
1476					432,769,463	34,250,427	398,519,036	-	-	-	-	-
1477												
1478	354	Towers and Fixtures										
1479			T	SG	40,495,726	-	40,495,726	-	-	-	-	-
1480			T	SG	34,727,518	-	34,727,518	-	-	-	-	-
1481			T	SG	181,212,767	-	181,212,767	-	-	-	-	-
1482					256,436,010	-	256,436,010	-	-	-	-	-
1483												
1484	355	Poles and Fixtures										
			T	S	-	-	-	-	-	-	-	-
1485			T	SG	14,983,556	-	14,983,556	-	-	-	-	-
1486			T	SG	28,622,181	-	28,622,181	-	-	-	-	-
1487			T	SG	307,936,033	-	307,936,033	-	-	-	-	-
1488					351,541,770	-	351,541,770	-	-	-	-	-
1489												
1490	356	Clearing and Grading										
1491			T	SG	48,269,143	-	48,269,143	-	-	-	-	-
1492			T	SG	41,019,497	-	41,019,497	-	-	-	-	-
1493			T	SG	145,955,569	-	145,955,569	-	-	-	-	-
1494					235,244,209	-	235,244,209	-	-	-	-	-
1495												
1496	357	Underground Conduit										
1497			T	SG	1,660	-	1,660	-	-	-	-	-
1498			T	SG	23,878	-	23,878	-	-	-	-	-
1499			T	SG	826,019	-	826,019	-	-	-	-	-
1500					851,557	-	851,557	-	-	-	-	-
1501												
1502	358	Underground Conductors										
1503			T	SG	-	-	-	-	-	-	-	-
1504			T	SG	283,340	-	283,340	-	-	-	-	-
1505			T	SG	1,664,665	-	1,664,665	-	-	-	-	-
1506					1,948,005	-	1,948,005	-	-	-	-	-
1507												
1508	359	Roads and Trails										
1509			T	SG	485,376	-	485,376	-	-	-	-	-
1510			T	SG	114,767	-	114,767	-	-	-	-	-
1511			T	SG	2,418,536	-	2,418,536	-	-	-	-	-
1512					3,018,678	-	3,018,678	-	-	-	-	-
1513												
1514	TP	Unclassified Trans Plant - Acct 300										
1515			T	SG	1,650,247	-	1,650,247	-	-	-	-	-
1516					1,650,247	-	1,650,247	-	-	-	-	-
1517												
1518	TS0	Unclassified Trans Sub Plant - Acct 300										
1519			T	SG	-	-	-	-	-	-	-	-
1520					-	-	-	-	-	-	-	-

TOTAL TRANSMISSION PLANT				1,374,645,997	34,250,427	1,340,395,570	-	-	-	-	-
360	Land and Land Rights											
		D	S	13,747,277	-	-	13,747,277	-	-	-	-
				13,747,277	-	-	13,747,277	-	-	-	-
361	Structures and Improvements											
		D	S	23,042,848	-	-	23,042,848	-	-	-	-
				23,042,848	-	-	23,042,848	-	-	-	-
362	Station Equipment											
		D	S	221,536,435	-	-	221,536,435	-	-	-	-
				221,536,435	-	-	221,536,435	-	-	-	-
363	Storage Battery Equipment											
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
364	Poles, Towers & Fixtures											
		D	S	342,298,106	-	-	342,298,106	-	-	-	-
				342,298,106	-	-	342,298,106	-	-	-	-
365	Overhead Conductors											
		D	S	243,862,816	-	-	243,862,816	-	-	-	-
				243,862,816	-	-	243,862,816	-	-	-	-
366	Underground Conduit											
		D	S	88,808,786	-	-	88,808,786	-	-	-	-
				88,808,786	-	-	88,808,786	-	-	-	-
367	Underground Conductors											
		D	S	166,647,716	-	-	166,647,716	-	-	-	-
				166,647,716	-	-	166,647,716	-	-	-	-
368	Line Transformers											
		D	S	407,895,211	-	-	407,895,211	-	-	-	-
				407,895,211	-	-	407,895,211	-	-	-	-
369	Services											
		D	S	235,004,248	-	-	235,004,248	-	-	-	-
				235,004,248	-	-	235,004,248	-	-	-	-
370	Meters											
		C_Meter	S	61,385,492	-	-	-	-	-	61,385,492	-
				61,385,492	-	-	-	-	-	61,385,492	-
371	Installations on Customers' Premises											
		D	S	2,593,477	-	-	2,593,477	-	-	-	-
				2,593,477	-	-	2,593,477	-	-	-	-
372	Leased Property											
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
373	Street Lights											
		D	S	22,911,460	-	-	22,911,460	-	-	-	-
				22,911,460	-	-	22,911,460	-	-	-	-
DP	Unclassified Dist Plant - Acct 300											
		D	S	5,984,241	-	-	5,984,241	-	-	-	-
				5,984,241	-	-	5,984,241	-	-	-	-
DS0	Unclassified Dist Sub Plant - Acct 300											
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL DISTRIBUTION PLANT				1,835,718,113	-	-	1,774,332,820	-	-	61,385,492	-
389	Land and Land Rights											
		D_SPLIT	S	4,601,321	-	-	4,447,455	-	-	153,866	-
		B_Center	CN	342,221	-	-	-	-	261,538	-	80,683
		G-DGU	SG	87	58	28	-	-	-	-	-
		G-SG	SG	320	319	0	-	-	-	-	-
		LABOR	SO	1,532,615	675,734	81,659	408,804	-	101,815	173,084	91,519
				6,476,563	676,112	81,688	4,856,259	-	363,353	326,949	172,202
390	Structures and Improvements											
		D_SPLIT	S	33,734,032	-	-	32,605,983	-	-	1,128,049	-
		G-DGP	SG	92,528	62,096	30,432	-	-	-	-	-
		G-DGU	SG	425,680	285,678	140,002	-	-	-	-	-
		B_Center	CN	3,735,417	-	-	-	-	2,854,745	-	880,672
		G-SG	SG	1,394,731	1,393,311	1,420	-	-	-	-	-
		LABOR	SO	28,235,624	12,449,163	1,504,420	7,531,469	-	1,875,748	3,188,749	1,686,074
				67,618,011	14,190,249	1,676,274	40,137,452	-	4,730,493	4,316,798	2,566,746

391	Office Furniture & Equipment											
		D_SPLIT	S	3,217,356	-	-	3,109,770	-	-	107,587	-
		G-DGP	SG	-	-	-	-	-	-	-	-
		G-DGU	SG	1,380	926	454	-	-	-	-	-
		B_Center	CN	2,619,224	-	-	-	-	2,001,709	-	617,515
		G-SG	SG	1,187,468	1,186,259	1,209	-	-	-	-	-
		P	SE	8,279	8,279	-	-	-	-	-	-
		LABOR	SO	15,143,116	6,676,641	806,839	4,039,220	-	1,005,987	1,710,166	904,262
		P	SG	23,622	23,622	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				22,200,445	7,895,726	808,502	7,148,990	-	3,007,696	1,817,753	1,521,778
392	Transportation Equipment										
		D_SPLIT	S	23,846,950	-	-	23,049,520	-	-	797,430	-
		LABOR	SO	2,020,833	890,991	107,672	539,030	-	134,248	228,220	120,673
		G-SG	SG	4,641,748	4,637,024	4,725	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-
		G-DGU	SG	202,986	136,226	66,760	-	-	-	-	-
		P	SE	110,686	110,686	-	-	-	-	-	-
		G-DGP	SG	31,033	20,827	10,207	-	-	-	-	-
		P	SG	89,618	89,618	-	-	-	-	-	-
		P	SG	11,634	11,634	-	-	-	-	-	-
				30,955,489	5,897,006	189,363	23,588,550	-	134,248	1,025,650	120,673
393	Stores Equipment										
		D_SPLIT	S	2,815,609	-	-	2,721,456	-	-	94,153	-
		G-DGP	SG	18,172	12,195	5,977	-	-	-	-	-
		G-DGU	SG	37,769	25,347	12,422	-	-	-	-	-
		LABOR	SO	87,275	38,480	4,650	23,279	-	5,798	9,856	5,212
		G-SG	SG	1,273,308	1,272,012	1,296	-	-	-	-	-
		P	SG	14,061	14,061	-	-	-	-	-	-
				4,246,193	1,362,095	24,345	2,744,735	-	5,798	104,009	5,212
394	Tools, Shop & Garage Equipment										
		D_SPLIT	S	10,862,111	-	-	10,498,887	-	-	363,224	-
		G-DGP	SG	280,770	188,427	92,343	-	-	-	-	-
		G-SG	SG	5,629,856	5,624,126	5,730	-	-	-	-	-
		LABOR	SO	1,033,680	455,752	55,075	275,720	-	68,669	116,737	61,726
		P	SE	1,387	1,387	-	-	-	-	-	-
		G-SG	SG	145,573	145,425	148	-	-	-	-	-
		P	SG	479,987	479,987	-	-	-	-	-	-
		P	SG	23,425	23,425	-	-	-	-	-	-
				18,456,788	6,918,529	153,296	10,774,607	-	68,669	479,961	61,726
395	Laboratory Equipment										
		D_SPLIT	S	9,673,147	-	-	9,349,682	-	-	323,465	-
		G-DGP	SG	395	265	130	-	-	-	-	-
		G-DGU	SG	1,399	939	460	-	-	-	-	-
		LABOR	SO	1,446,072	637,577	77,048	385,720	-	96,065	163,310	86,351
		P	SE	1,875	1,875	-	-	-	-	-	-
		G-SG	SG	1,679,703	1,677,994	1,710	-	-	-	-	-
		P	SG	65,914	65,914	-	-	-	-	-	-
		P	SG	3,653	3,653	-	-	-	-	-	-
				12,872,160	2,388,217	79,348	9,735,402	-	96,065	486,775	86,351
396	Power Operated Equipment										
		D_SPLIT	S	34,331,104	-	-	33,183,089	-	-	1,148,015	-
		G-DGP	SG	220,176	147,762	72,414	-	-	-	-	-
		G-SG	SG	8,907,457	8,898,391	9,066	-	-	-	-	-
		LABOR	SO	525,569	231,725	28,003	140,188	-	34,915	59,354	31,384
		G-DGU	SG	410,128	275,241	134,887	-	-	-	-	-
		P	SE	11,117	11,117	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	260,488	260,488	-	-	-	-	-	-
				44,666,038	9,824,722	244,370	33,323,278	-	34,915	1,207,369	31,384
397	Communication Equipment										
		D_SPLIT	S	59,628,025	-	-	57,634,094	-	-	1,993,931	-
		G-DGP	SG	(267,813)	(179,732)	(88,081)	-	-	-	-	-
		G-DGU	SG	(844,837)	(566,978)	(277,859)	-	-	-	-	-
		LABOR	SO	13,184,587	5,813,120	702,487	3,516,809	-	875,878	1,488,982	787,310
		B_Center	CN	239,663	-	-	-	-	183,159	-	56,504
		G-SG	SG	32,722,005	32,688,699	33,306	-	-	-	-	-
		P	SE	26,943	26,943	-	-	-	-	-	-
		G-SG	SG	438,838	438,392	447	-	-	-	-	-
		G-SG	SG	(5,655)	(5,649)	(6)	-	-	-	-	-
				105,121,757	38,214,795	370,294	61,150,903	-	1,059,038	3,482,913	843,814
398	Misc Equipment										
		D_SPLIT	S	1,082,798	-	-	1,046,590	-	-	36,208	-
		G-DGP	SG	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-
		B_Center	CN	65,378	-	-	-	-	49,964	-	15,414
		LABOR	SO	810,840	357,502	43,202	216,281	-	53,866	91,571	48,419
		P	SE	412	412	-	-	-	-	-	-
		G-SG	SG	539,272	538,723	549	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				2,498,700	896,637	43,751	1,262,870	-	103,830	127,779	63,832
399	Coal Mine										
		P	SE	119,019,960	119,019,960	-	-	-	-	-	-
MP	Unclassified Mine Plant	P	SE	-	-	-	-	-	-	-	-
				119,019,960	119,019,960	-	-	-	-	-	-
399L	WIDCO Capital Lease										
		P	SE	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-

1011390	General Capital Leases										
		D_SPLIT	S	5,882,166	-	-	5,685,470	-	-	196,697	-
		P	SG	8,791,562	8,791,562	-	-	-	-	-	-
		LABOR	SO	3,467,957	1,529,032	184,776	925,030	-	230,383	391,649	207,087
				18,141,686	10,320,594	184,776	6,610,500	-	230,383	588,345	207,087
	Remove Capital Leases			(18,141,686)	(10,320,594)	(184,776)	(6,610,500)	-	(230,383)	(588,345)	(207,087)
				-	-	-	-	-	-	-	-
1011346	General Gas Line Capital Leases										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
GP	Unclassified Gen Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		LABOR	SO	2,026,818	893,629	107,991	540,626	-	134,646	228,896	121,030
		B_Center	CN	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-
				2,026,818	893,629	107,991	540,626	-	134,646	228,896	121,030
399G	Unclassified Gen Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT				436,158,921	208,177,677	3,779,221	195,263,673	-	9,738,750	13,604,853	5,594,747
301	Organization										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
302	Franchise & Consent										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		I-SG	SG	1,448,182	1,238,587	209,595	-	-	-	-	-
		I-DGP	SG	44,587,087	44,587,087	-	-	-	-	-	-
		I-DGU	SG	2,353,948	2,353,948	-	-	-	-	-	-
		I-DGP	SG	(249,285)	(249,285)	-	-	-	-	-	-
		I-DGU	SG	150,434	150,434	-	-	-	-	-	-
				48,290,368	48,080,773	209,595	-	-	-	-	-
303	Miscellaneous Intangible Plant										
		D_SPLIT	S	3,992,922	-	-	3,859,400	-	-	133,521	-
		LABOR	SG	36,105,703	15,919,102	1,923,745	9,630,706	-	2,398,573	4,077,545	2,156,031
		LABOR	SO	108,433,769	47,808,743	5,777,452	28,923,235	-	7,203,470	12,245,810	6,475,059
		P	SE	877,462	877,462	-	-	-	-	-	-
		CSS_SYS	CN	37,138,343	-	-	-	-	20,426,089	6,684,902	10,027,353
		I-DGP	SG	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-
				186,548,199	64,605,307	7,701,197	42,413,341	-	30,028,133	23,141,779	18,658,443
303	Less Non-Utility Plant										
		I-SITUS	S	-	-	-	-	-	-	-	-
				186,548,199	64,605,307	7,701,197	42,413,341	-	30,028,133	23,141,779	18,658,443
IP	Unclassified Intangible Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL INTANGIBLE PLANT				234,838,566	112,686,079	7,910,792	42,413,341	-	30,028,133	23,141,779	18,658,443
TOTAL ELECTRIC PLANT IN SERVICE				6,686,362,611	3,160,115,197	1,352,085,584	2,012,009,634	-	39,766,683	98,132,123	24,253,190
105	Plant Held For Future Use										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		G	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
114	Electric Plant Acquisition Adjustments										
		P	S	-	-	-	-	-	-	-	-
		P	SG	37,676,495	37,676,495	-	-	-	-	-	-
		P	SG	3,793,502	3,793,502	-	-	-	-	-	-
				41,469,998	41,469,998	-	-	-	-	-	-
115	Accum Provision for Asset Acquisition Adjustments										
		P	S	-	-	-	-	-	-	-	-
		P	SG	(27,780,898)	(27,780,898)	-	-	-	-	-	-
		P	SG	(3,616,363)	(3,616,363)	-	-	-	-	-	-
				(31,397,261)	(31,397,261)	-	-	-	-	-	-

120	Nuclear Fuel										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
124	Weatherization										
		DSM	S	0	-	-	0	-	-	-	-
		DSM	SO	(1,220)	-	-	(1,220)	-	-	-	-
				(1,219)	-	-	(1,219)	-	-	-	-
182W	Weatherization										
		DSM	S	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
186W	Weatherization										
		DSM	S	-	-	-	-	-	-	-	-
		DSM	CN	-	-	-	-	-	-	-	-
		DSM	CNP	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Total Weatherization			(1,219)	-	-	(1,219)	-	-	-	-
151	Fuel Stock										
		P	DEU	-	-	-	-	-	-	-	-
		P	SE	59,388,157	59,388,157	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	2,664,985	2,664,985	-	-	-	-	-	-
				62,053,142	62,053,142	-	-	-	-	-	-
152	Fuel Stock - Undistributed										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
25316	DG&T Working Capital Deposit										
		P	SE	(876,360)	(876,360)	-	-	-	-	-	-
				(876,360)	(876,360)	-	-	-	-	-	-
25317	DG&T Working Capital Deposit										
		P	SE	(705,732)	(705,732)	-	-	-	-	-	-
				(705,732)	(705,732)	-	-	-	-	-	-
25319	Provo Working Capital Deposit										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Total Fuel Stock			60,471,050	60,471,050	-	-	-	-	-	-
154	Materials and Supplies										
		MSS	S	30,297,434	25,298,500	194,575	4,666,937	-	-	137,422	-
		MSS	SG	1,224,506	1,022,468	7,864	188,620	-	-	5,554	-
		MSS	SE	1,474,735	1,231,411	9,471	227,164	-	-	6,689	-
		MSS	SO	55,778	46,575	358	8,592	-	-	253	-
		MSS	SG	24,288,363	20,280,897	155,984	3,741,316	-	-	110,166	-
		MSS	SG	407	340	3	63	-	-	2	-
		MSS	SNPD	(612,831)	(511,717)	(3,936)	(94,399)	-	-	(2,780)	-
		MSS	SG	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-
		MSS	SG	1,923,620	1,606,232	12,354	296,309	-	-	8,725	-
		MSS	SG	-	-	-	-	-	-	-	-
				58,652,012	48,974,705	376,674	9,034,602	-	-	266,031	-
163	Stores Expense Undistributed										
		MSS	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit										
		MSS	SG	(71,125)	(59,389)	(457)	(10,956)	-	-	(323)	-
				(71,125)	(59,389)	(457)	(10,956)	-	-	(323)	-
	Total Materials & Supplies			58,580,887	48,915,316	376,217	9,023,646	-	-	265,708	-
165	Prepayments										
		LABOR	S	2,425,369	1,069,352	129,226	646,934	-	161,122	273,905	144,829
		GP	GPS	59,185	27,972	11,968	17,809	-	352	869	215
		PT	SG	885,088	593,991	291,097	-	-	-	-	-
		P	SE	788,688	788,688	-	-	-	-	-	-
		LABOR	SO	3,039,645	1,340,188	161,955	810,784	-	201,930	343,278	181,511
				7,197,975	3,820,191	594,246	1,475,528	-	363,404	618,052	326,555
182M	Misc Regulatory Assets										
		DDS2	S	(165,924)	(141,844)	(1,929)	4,166	-	(26,118)	(153)	(46)
		DEFSG	SG	-	-	-	-	-	-	-	-
		P	SGCT	904,678	904,678	-	-	-	-	-	-
		DEFSG	SG	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		LABOR	SO	51,075,700	22,519,415	2,721,361	13,623,749	-	3,393,060	5,768,160	3,049,955
				51,814,454	23,282,249	2,719,431	13,627,915	-	3,366,942	5,768,007	3,049,909

1900													
1901	186M	Misc Deferred Debits											
1902			LABOR	S	-	-	-	-	-	-	-	-
1903			P	SG	-	-	-	-	-	-	-	-	-
1904			P	SG	-	-	-	-	-	-	-	-	-
1905			DEFSG	SG	18,683,106	12,946,310	5,736,795	-	-	-	-	-
1906			LABOR	SO	5,366	2,366	286	1,431	-	356	606	320
1907			P	SE	3,367,531	3,367,531	-	-	-	-	-	-
1908			P	SG	-	-	-	-	-	-	-	-
1909			GP	EXCTAX	-	-	-	-	-	-	-	-
1910					22,056,002	16,316,207	5,737,081	1,431	-	356	606	320
1911												
1912	Working Capital											
1913	CWC	Cash Working Capital										
1914			CWC	S	17,821,360	12,392,747	1,278,940	3,235,213	0	272,865	435,890	205,704
1915			CWC	SO	-	-	-	-	-	-	-	-
1916			CWC	SE	-	-	-	-	-	-	-	-
1917					17,821,360	12,392,747	1,278,940	3,235,213	0	272,865	435,890	205,704
1918												
1919	OWC	Other Working Capital										
1920	131	Cash	GP	SNP	-	-	-	-	-	-	-	-
1921	135	Working Funds	GP	SG	-	-	-	-	-	-	-	-
1922	141	Notes Receivable	GP	SO	-	-	-	-	-	-	-	-
1923	143	Other Accounts Receival	LABOR	SO	15,843,339	6,985,371	844,148	4,225,995	-	1,052,504	1,789,244	946,076
1924	232	Accounts Payable	LABOR	S	-	-	-	-	-	-	-	-
1925	232	Accounts Payable	LABOR	SO	(1,442,052)	(635,805)	(76,834)	(384,648)	-	(95,798)	(162,856)	(86,111)
1926	232	Accounts Payable	P	SE	(544,120)	(544,120)	-	-	-	-	-	-
1927	232	Accounts Payable	P	SG	(22,503)	(22,503)	-	-	-	-	-	-
1928	2533	Other Deferred Credits -	P	S	-	-	-	-	-	-	-	-
1929	2533	Other Deferred Credits -	P	SE	(1,705,857)	(1,705,857)	-	-	-	-	-	-
1930	230	Asset Retirement Obligat	P	SE	(703,535)	(703,535)	-	-	-	-	-	-
1931	230	Asset Retirement Obligat	P	S	-	-	-	-	-	-	-	-
1932	254105	ARO Regulatory Liability	P	S	-	-	-	-	-	-	-	-
1933	254105	ARO Regulatory Liability	P	SE	(241,171)	(241,171)	-	-	-	-	-	-
1934	2533	Cholla Reclamation	P	SE	-	-	-	-	-	-	-	-
1935					11,184,100	3,132,360	767,314	3,841,348	-	956,706	1,626,388	859,964
1936												
1937	Total Working Capital				29,005,460	15,525,127	2,046,254	7,076,560	0	1,229,571	2,062,278	1,065,669
1938	Miscellaneous Rate Base											
1939	18221	Unrec Plant & Reg Study Costs										
1940			P	S	-	-	-	-	-	-	-	-
1941												
1942					-	-	-	-	-	-	-	-
1943												
1944	18222	Nuclear Plant - Trojan										
1945			P	S	-	-	-	-	-	-	-	-
1946			P	TROJP	-	-	-	-	-	-	-	-
1947			P	TROJD	-	-	-	-	-	-	-	-
1948					-	-	-	-	-	-	-	-
1949												
1950												
1951												
1952	1869	Misc Deferred Debits-Trojan										
1953			P	S	-	-	-	-	-	-	-	-
1954			P	SG	-	-	-	-	-	-	-	-
1955					-	-	-	-	-	-	-	-
1956												
1957	TOTAL MISCELLANEOUS RATE BASE				-	-	-	-	-	-	-	-
1958												
1959	**TOTAL RATE BASE ADDITIONS**				**239,197,347**	**178,402,877**	**11,473,230**	**31,203,861**	**0**	**4,960,274**	**8,714,652**	**4,442,453**
1960	235	Customer Service Deposits										
1961			C_BILLING	S	-	-	-	-	-	-	-	-
1962			C_BILLING	CN	-	-	-	-	-	-	-	-
1963					-	-	-	-	-	-	-	-
1964												
1965	2281	Prov for Property Insurar	LABOR	SO	-	-	-	-	-	-	-	-
1966	2282	Prov for Injuries & Dama	LABOR	SO	(3,461,096)	(1,526,007)	(184,410)	(923,200)	-	(229,927)	(390,874)	(206,677)
1967	2283	Prov for Pensions and Be	LABOR	SO	(837,195)	(369,122)	(44,607)	(223,310)	-	(55,617)	(94,547)	(49,993)
1968	2283	Prov for Pensions and Be	LABOR	SO	-	-	-	-	-	-	-	-
1969	254	Reg Liabilities - Insuranc	LABOR	SE	-	-	-	-	-	-	-	-
1970					(4,298,291)	(1,895,128)	(229,017)	(1,146,511)	-	(285,544)	(486,421)	(256,670)
1971												
1972	22844	Accum Hydro Relicensing Obligation										
1973			P	S	-	-	-	-	-	-	-	-
1974			P	SG	-	-	-	-	-	-	-	-
1975					-	-	-	-	-	-	-	-
1976												
1977	22841	Chehalis Rate Base	P	SG	(385,470)	(385,470)	-	-	-	-	-	-
1978	230	Asset Retirement Obligat	P	TROJP	-	-	-	-	-	-	-	-
1979	254105	ARO Regulatory Liability	P	TROJP	(836,419)	(836,419)	-	-	-	-	-	-
1980	254		P	S	298,028	298,028	-	-	-	-	-	-
1981					(923,862)	(923,862)	-	-	-	-	-	-
1982												
1983	252	Customer Advances for Construction										
1984			D_SPLIT	S	(1,935,702)	-	-	(1,870,973)	-	-	(64,729)	-
1985			T	SE	-	-	-	-	-	-	-	-
1986			T	SG	(3,822,938)	-	(3,822,938)	-	-	-	-	-
1987			D_SPLIT	SO	-	-	-	-	-	-	-	-
1988			B_Center	CN	-	-	-	-	-	-	-	-
1989					(5,758,640)	-	(3,822,938)	(1,870,973)	-	-	(64,729)	-
1990												
1991	25398	SO2 Emissions										
1992			P	SE	(30,052)	(30,052)	-	-	-	-	-	-
1993					(30,052)	(30,052)	-	-	-	-	-	-

25399	Other Deferred Credits										
		D_SPLIT	S	(297,151)	-	-	(287,214)	-	-	(9,937)	-
		LABOR	SO	-	-	-	-	-	-	-	-
		P	SG	(2,524,291)	(2,524,291)	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
				(2,821,441)	(2,524,291)	-	(287,214)	-	-	(9,937)	-
190	Accumulated Deferred Income Taxes										
		D_SPLIT	S	1,681,887	-	-	1,625,645	-	-	56,241	-
		CSS_SYS	CN	3,233	-	-	-	-	1,778	582	873
		LABOR	SO	22,217,888	9,795,927	1,183,790	5,926,320	-	1,475,978	2,509,145	1,326,728
		P	GPS	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	1,998,619	-	-	-	-	1,998,619	-	-
		P	TROJD	485,256	485,256	-	-	-	-	-	-
		P	SG	888,291	888,291	-	-	-	-	-	-
		P	SE	(7,774,748)	(7,774,748)	-	-	-	-	-	-
		LABOR	SNP	-	-	-	-	-	-	-	-
		D_SPLIT	SNPD	534,242	-	-	516,377	-	-	17,865	-
		P	SG	-	-	-	-	-	-	-	-
				20,034,667	3,394,726	1,183,790	8,068,342	-	3,476,375	2,583,833	1,327,601
281	Accumulated Deferred Income Taxes										
		P	S	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
282	Accumulated Deferred Income Taxes										
		GP	S	(1,033,679,794)	(488,538,749)	(209,025,987)	(311,047,101)	-	(6,147,771)	(15,170,759)	(3,749,428)
		CSS_SYS	CN	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		ACCMDIT	DITBAL	2	1	0	0	-	0	0	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG-P	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG-U	-	-	-	-	-	-	-	-
		LABOR	SO	5,775,312	2,546,351	307,714	1,540,486	-	383,665	652,226	344,869
		P	SG	-	-	-	-	-	-	-	-
		P	SE	(1,439,826)	(1,439,826)	-	-	-	-	-	-
		P	SG	3,347,526	3,347,526	-	-	-	-	-	-
				(1,025,996,781)	(484,084,698)	(208,718,273)	(309,506,614)	-	(5,764,105)	(14,518,532)	(3,404,558)
283	Accumulated Deferred Income Taxes										
		GP	S	(471,523)	(222,851)	(95,349)	(141,887)	-	(2,804)	(6,920)	(1,710)
		P	SG	(488,201)	(488,201)	-	-	-	-	-	-
		P	SE	(643,161)	(643,161)	-	-	-	-	-	-
		LABOR	SO	(3,910,022)	(1,723,940)	(208,330)	(1,042,945)	-	(259,751)	(441,573)	(233,485)
		GP	GPS	(2,023,440)	(956,320)	(409,171)	(608,878)	-	(12,034)	(29,697)	(7,340)
		LABOR	SNP	(772,670)	(340,672)	(41,169)	(206,099)	-	(51,330)	(87,260)	(46,140)
		P	TROJD	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SGCT	(343,334)	(343,334)	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-
				(8,652,352)	(4,718,480)	(754,018)	(1,999,810)	-	(325,919)	(565,450)	(288,674)
TOTAL ACCUMULATED DEF INCOME TAX				(1,014,614,465)	(485,408,452)	(208,288,502)	(303,438,082)	-	(2,613,649)	(12,500,149)	(2,365,631)
255	Accumulated Investment Tax Credit										
		LABOR	S	-	-	-	-	-	-	-	-
		LABOR	ITC84	-	-	-	-	-	-	-	-
		LABOR	ITC85	(128,615)	(56,707)	(6,853)	(34,306)	-	(8,544)	(14,525)	(7,680)
		LABOR	ITC86	(251,275)	(110,788)	(13,388)	(67,024)	-	(16,693)	(28,377)	(15,005)
		LABOR	ITC88	(55,814)	(24,608)	(2,974)	(14,888)	-	(3,708)	(6,303)	(3,333)
		LABOR	ITC89	(127,487)	(56,209)	(6,793)	(34,005)	-	(8,469)	(14,398)	(7,613)
		LABOR	ITC90	(30,059)	(13,253)	(1,602)	(8,018)	-	(1,997)	(3,395)	(1,795)
		LABOR	DGU	-	-	-	-	-	-	-	-
				(593,249)	(261,565)	(31,609)	(158,241)	-	(39,411)	(66,998)	(35,426)
TOTAL RATE BASE DEDUCTIONS				**(1,029,040,001)**	**(491,043,350)**	**(212,372,066)**	**(306,901,021)**	**-**	**(2,936,604)**	**(13,127,234)**	**(2,657,727)**
108SP	Steam Prod Plant Accumulated Depr										
		P	S	-	-	-	-	-	-	-	-
		P	SG	(201,910,764)	(201,910,764)	-	-	-	-	-	-
		P	SG	(216,585,864)	(216,585,864)	-	-	-	-	-	-
		P	SG	(287,917,731)	(287,917,731)	-	-	-	-	-	-
		P	SG	(51,561,270)	(51,561,270)	-	-	-	-	-	-
				(757,975,629)	(757,975,629)	-	-	-	-	-	-
108NP	Nuclear Prod Plant Accumulated Depr										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr										
		P	S	-	-	-	-	-	-	-	-
	Pre-Merger Pacific	P	SG	(40,623,886)	(40,623,886)	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	(7,780,561)	(7,780,561)	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	(20,075,478)	(20,075,478)	-	-	-	-	-	-
	Post-Merger Utah	P	SG	(7,020,472)	(7,020,472)	-	-	-	-	-	-
				(75,500,397)	(75,500,397)	-	-	-	-	-	-

2092	108OP	Other Production Plant - Accum Depr											
2093			P	S	-	-	-	-	-	-	-	-	
2094			P	SG	(216,010)	(216,010)	-	-	-	-	-	-	
2095			P	SG	-	-	-	-	-	-	-	-	
2096			P	SG	(163,110,469)	(163,110,469)	-	-	-	-	-	-	
2097			P	SG	(6,766,009)	(6,766,009)	-	-	-	-	-	-	
2098					(170,092,488)	(170,092,488)	-	-	-	-	-	-	
2100	108EP	Experimental Plant - Accum Depr											
2101			P	SG	-	-	-	-	-	-	-	-	
2102			P	SG	-	-	-	-	-	-	-	-	
2103					-	-	-	-	-	-	-	-	
2105		**TOTAL PRODUCTION PLANT DEPRECIATION**			**(1,003,568,515)**	**(1,003,568,515)**	-	-	-	-	-	-	
2107	108TP	Transmission Plant Accumulated Depr											
			T_Split	S	-	-	-	-	-	-	-	-	
2108			T_Split	SG	(98,164,765)	(2,445,855)	(95,718,910)	-	-	-	-	-	
2109			T_Split	SG	(106,791,432)	(2,660,796)	(104,130,636)	-	-	-	-	-	
2110			T_Split	SG	(147,231,914)	(3,668,403)	(143,563,511)	-	-	-	-	-	
2111		**TOTAL TRANS PLANT ACCUM DEPR**			**(352,188,111)**	**(8,775,054)**	**(343,413,057)**	-	-	-	-	-	
2112	108360	Land and Land Rights											
2113			D	S	(3,036,579)	-	-	(3,036,579)	-	-	-	-	
2114					(3,036,579)	-	-	(3,036,579)	-	-	-	-	
2116	108361	Structures and Improvements											
2117			D	S	(4,753,117)	-	-	(4,753,117)	-	-	-	-	
2118					(4,753,117)	-	-	(4,753,117)	-	-	-	-	
2120	108362	Station Equipment											
2121			D	S	(69,456,044)	-	-	(69,456,044)	-	-	-	-	
2122					(69,456,044)	-	-	(69,456,044)	-	-	-	-	
2124	108363	Storage Battery Equipment											
2125			D	S	-	-	-	-	-	-	-	-	
2126					-	-	-	-	-	-	-	-	
2128	108364	Poles, Towers & Fixtures											
2129			D	S	(229,450,519)	-	-	(229,450,519)	-	-	-	-	
2130					(229,450,519)	-	-	(229,450,519)	-	-	-	-	
2132	108365	Overhead Conductors											
2133			D	S	(139,179,797)	-	-	(139,179,797)	-	-	-	-	
2134					(139,179,797)	-	-	(139,179,797)	-	-	-	-	
2136	108366	Underground Conduit											
2137			D	S	(41,103,042)	-	-	(41,103,042)	-	-	-	-	
2138					(41,103,042)	-	-	(41,103,042)	-	-	-	-	
2140	108367	Underground Conductors											
2141			D	S	(70,115,550)	-	-	(70,115,550)	-	-	-	-	
2142					(70,115,550)	-	-	(70,115,550)	-	-	-	-	
2144	108368	Line Transformers											
2145			D	S	(186,964,718)	-	-	(186,964,718)	-	-	-	-	
2146					(186,964,718)	-	-	(186,964,718)	-	-	-	-	
2148	108369	Services											
2149			D	S	(78,427,201)	-	-	(78,427,201)	-	-	-	-	
2150					(78,427,201)	-	-	(78,427,201)	-	-	-	-	
2152	108370	Meters											
2153			C_Meter	S	(34,981,635)	-	-	-	-	-	(34,981,635)	-	
2154					(34,981,635)	-	-	-	-	-	(34,981,635)	-	
2158	108371	Installations on Customers' Premises											
2159			D	S	(2,615,875)	-	-	(2,615,875)	-	-	-	-	
2160					(2,615,875)	-	-	(2,615,875)	-	-	-	-	
2162	108372	Leased Property											
2163			D	S	-	-	-	-	-	-	-	-	
2164					-	-	-	-	-	-	-	-	
2166	108373	Street Lights											
2167			D	S	(9,596,236)	-	-	(9,596,236)	-	-	-	-	
2168					(9,596,236)	-	-	(9,596,236)	-	-	-	-	
2170	108D00	Unclassified Dist Plant - Acct 300											
2171			D_SPLIT	S	-	-	-	-	-	-	-	-	
2172					-	-	-	-	-	-	-	-	
2174	108DS	Unclassified Dist Sub Plant - Acct 300											
2175			D_SPLIT	S	-	-	-	-	-	-	-	-	
2176					-	-	-	-	-	-	-	-	
2178	108DP	Unclassified Dist Sub Plant - Acct 300											
2179			D_SPLIT	S	817,585	-	-	790,245	-	-	27,340	-	
2180					817,585	-	-	790,245	-	-	27,340	-	
2183		**TOTAL DISTRIBUTION PLANT DEPR**			**(868,862,729)**	-	-	**(833,908,433)**	-	-	**(34,954,295)**	-	

108GP	General Plant Accumulated Depr											
		D_SPLIT	S	(51,479,635)	-	-	(49,758,182)	-	-	(1,721,453)	-
		G-DGP	SG	(104,971)	(70,447)	(34,524)	-	-	-	-	-
		G-DGU	SG	212,288	142,469	69,820	-	-	-	-	-
		G-SG	SG	(17,570,378)	(17,552,494)	(17,884)	-	-	-	-	-
		B_Center	CN	(2,796,112)	-	-	-	-	(2,136,893)	-	(659,219)
		LABOR	SO	(19,804,133)	(8,731,696)	(1,056,183)	(5,282,483)	-	(1,315,628)	(2,236,551)	(1,182,592)
		P	SE	(63,603)	(63,603)	-	-	-	-	-	-
		G-SG	SG	(10,806)	(10,795)	(11)	-	-	-	-	-
		G-SG	SG	(478,736)	(478,248)	(487)	-	-	-	-	-
				(92,096,086)	(26,764,815)	(1,038,269)	(55,040,665)	-	(3,452,521)	(3,958,004)	(1,841,811)
108MP	Mining Plant Accumulated Depr.										
		P	S	-	-	-	-	-	-	-	-
		P	SE	(43,149,295)	(43,149,295)	-	-	-	-	-	-
				(43,149,295)	(43,149,295)	-	-	-	-	-	-
108MP	Less Centralia Situs Depreciation										
		P	S	-	-	-	-	-	-	-	-
				(43,149,295)	(43,149,295)	-	-	-	-	-	-
1081390	Accum Depr - Capital Lease										
		LABOR	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
1081399	Accum Depr - Capital Lease										
		P	S	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT ACCUM DEPR				(135,245,381)	(69,914,110)	(1,038,269)	(55,040,665)	-	(3,452,521)	(3,958,004)	(1,841,811)
TOTAL ACCUM DEPR - PLANT IN SERVICE				(2,359,864,735)	(1,082,257,679)	(344,451,326)	(888,949,099)	-	(3,452,521)	(38,912,299)	(1,841,811)
111SP	Accum Prov for Amort-Steam										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
111GP	Accum Prov for Amort-General										
		D_SPLIT	S	(4,290,302)	-	-	(4,146,836)	-	-	(143,466)	-
		CSS_SYS	CN	(1,074,919)	-	-	-	-	(591,205)	(193,485)	(290,228)
		I-SG	SG	-	-	-	-	-	-	-	-
		LABOR	SO	(3,837,234)	(1,691,847)	(204,451)	(1,023,530)	-	(254,915)	(433,353)	(229,138)
		P	SE	-	-	-	-	-	-	-	-
				(9,202,455)	(1,691,847)	(204,451)	(5,170,366)	-	(846,120)	(770,303)	(519,366)
111HP	Accum Prov for Amort-Hydro										
	Pre-Merger Pacific	P	SG	-	-	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	-	-	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	(245,235)	(245,235)	-	-	-	-	-	-
	Post-Merger Utah	P	SG	(149,407)	(149,407)	-	-	-	-	-	-
				(394,642)	(394,642)	-	-	-	-	-	-
111IP	Accum Prov for Amort-Intangible Plant										
		D_SPLIT	S	(77,091)	-	-	(74,513)	-	-	(2,578)	-
		LABOR	SG	249,285	109,910	13,282	66,493	-	16,560	28,153	14,886
		LABOR	SG	(97,798)	(43,119)	(5,211)	(26,086)	-	(6,497)	(11,045)	(5,840)
		P	SE	(540,835)	(540,835)	-	-	-	-	-	-
		LABOR	SG	(13,160,239)	(5,802,385)	(701,190)	(3,510,315)	-	(874,261)	(1,486,232)	(785,856)
		I-SG	SG	(11,509,766)	(9,843,961)	(1,665,805)	-	-	-	-	-
		I-SG	SG	(1,076,474)	(920,676)	(155,798)	-	-	-	-	-
		CSS_SYS	CN	(34,323,704)	-	-	-	-	(18,878,037)	(6,178,267)	(9,267,400)
		P	SG	-	-	-	-	-	-	-	-
		P	SG	(85,411)	(85,411)	-	-	-	-	-	-
		LABOR	SO	(81,896,004)	(36,108,170)	(4,363,495)	(21,844,646)	-	(5,440,514)	(9,248,806)	(4,890,372)
				(142,518,037)	(53,234,648)	(6,878,217)	(25,389,067)	-	(25,182,748)	(16,898,775)	(14,934,582)
111IP	Less Non-Utility Plant										
		NUTIL	OTH	-	-	-	-	-	-	-	-
				(142,518,037)	(53,234,648)	(6,878,217)	(25,389,067)	-	(25,182,748)	(16,898,775)	(14,934,582)
111390	Accum Amtr - Capital Lease										
		LABOR	S	(2,469,170)	(1,088,664)	(131,560)	(658,618)	-	(164,032)	(278,852)	(147,445)
		P	SG	(1,359,231)	(1,359,231)	-	-	-	-	-	-
		LABOR	SO	117,477	51,796	6,259	31,335	-	7,804	13,267	7,015
				(3,710,924)	(2,396,099)	(125,300)	(627,282)	-	(156,228)	(265,585)	(140,430)
	Remove Capital Lease Amtr			3,710,924	2,396,099	125,300	627,282	-	156,228	265,585	140,430
TOTAL ACCUM PROV FOR AMORTIZATION				(152,115,135)	(55,321,137)	(7,082,668)	(30,559,434)	-	(26,028,869)	(17,669,079)	(15,453,948)

Docket No. UE 263
Exhibit PAC/1103
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Ancillary Services Revenue Requirement

March 2013

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
CY 2012 Ancillary Services Revenue
12 Months Ended December 31, 2014 Forecast

Line	Item	Notes	Thermal Resource	Hydro Resource	Other Resource	Firm Purchases	Total Resources
1	System Resources CY 2014 (MWh)	(Note 1)	52,890,059	3,942,712	3,155,210	12,186,756	72,174,737
2	Plant allocated to Oregon based on JAM dollars	(Note 2)	26.05%	26.05%	26.05%	26.05%	
3	Oregon share of Resource Providing Service by type (MWh)	(Line 1 x Line 2)	13,779,448	1,027,195	822,083	3,175,016	18,803,741
4	Resource type % of total		73.28%	5.46%	4.37%	16.89%	100.00%
5	Oregon Retail Load, Including Losses, by resource type	(Line 4 x Line 5 Total)	10,772,358	803,030	642,679	2,482,132	14,700,200
6	FERC Tariff Ancillary Service Charges						
	Regulation and Frequency Response Service						
7	Billing Determinant (Load Energy MWh)		NA	NA	NA	NA	14,700,200
8	Charge ($/MWh)		NA	NA	NA	NA	0.1600
9	Total Cost	(Line 8 x Line 9)	NA	NA	NA	NA	$2,352,032
	Operating Reservice - Spinning Reserve Service						
10	Billing Determinant (Generated Energy in MWh)		10,772,358	803,030	642,679	2,482,132	14,700,200
11	Charge ($/MWh)		0.3730	0.2660	NA	NA	
12	Total Cost	(Line 11 x Line 12)	$4,018,090	$213,606			$4,231,696
	Operating Reservice - Supplemental Reserve Service						
13	Billing Determinant (Generated Energy in MWh)		10,772,358	803,030	642,679	2,482,132	14,700,200
14	Charge ($/MWh)		0.3730	0.2660	NA	NA	
15	Total Cost	(Line 14 x Line 15)	$4,018,090	$213,606			$4,231,696
16	Oregon Annual Ancillary Service Revenue ($ x thousands)	Line 10 + Line 13 + Line 16)					$10,815,423

Note 1 - Source :Net Power Cost Analysis

Note 2 - CY 2013 JAM Model

Total Electric Plant in Service by Plant Type ($ x Millions)		Thermal	Hydro	Other	Total
Oregon		1,738.9	248.0	818.1	2,805.0
System		6,674.4	951.9	3,140.1	10,766.3
Percent of System		26.05%	26.05%	26.05%	26.05%

Account 555 Purchased Power - SG	Dollars
Oregon	154,020,272
System	591,180,527
Percent of System	26.05%

Production Plant	TOTAL	OTHER	OREGON
Total Steam Production Plant	6,674,370,926	4,935,496,961	1,738,873,965
Total Hydraulic Plant	951,860,271	703,872,100	247,988,172
Total Other Production Plant	3,140,073,567	2,321,934,690	818,138,877
TOTAL PRODUCTION PLANT	10,766,304,764	7,961,303,750	2,805,001,014

Docket No. UE 263
Exhibit PAC/1104
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Oregon Marginal Cost of Service Summary

March 2013

Exhibit PAC/1104
Paice/1

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2014 Forecast
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	Sch 41	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Marginal Cost																			
1	Generation	$215,252	$94,605	$10,187	$8,758	$17	$8,171	$11,251	$14,790	$285	$3,092	$16,990	$1,508	$8,647	$7,079	$806	$16,371	$9,779	$2,916	
2	Transmission	$354,191	$155,669	$16,763	$14,411	$28	$13,445	$18,514	$24,337	$469	$5,088	$27,956	$2,481	$14,229	$11,649	$1,326	$26,937	$16,091	$4,798	
3	Distribution																			
4	Poles	$52,618	$30,387	$3,377	$2,742	$7	$1,897	$2,667	$3,417	$78	$548	$3,030	$268	$1,006	$798	$11	$191	$0	$2,196	
5	Conductor	$79,429	$44,324	$4,603	$3,738	$9	$3,017	$4,239	$5,433	$125	$986	$5,452	$481	$2,294	$1,819	$23	$364	$0	$2,523	
6	Substations	$70,546	$34,339	$3,128	$2,540	$6	$2,728	$3,834	$4,913	$113	$1,048	$5,796	$511	$2,960	$2,347	$218	$5,126	$0	$937	
7	Subtotal: Pole, Cond, Subs	$202,593	$109,050	$11,109	$9,021	$22	$7,642	$10,740	$13,762	$317	$2,582	$14,277	$1,260	$6,260	$4,964	$252	$5,681	$0	$5,656	
8	Transformers	$14,967	$10,359	$573	$394	$0	$441	$589	$727	$0	$152	$808	$0	$411	$0	$43	$0	$0	$468	
9	Distribution subtotal	$217,560	$119,409	$11,682	$9,415	$22	$8,083	$11,329	$14,489	$317	$2,734	$15,085	$1,260	$6,671	$4,964	$295	$5,681	$0	$6,124	
10																				
11	Total Demand Related	$787,003	$369,683	$38,632	$32,584	$67	$29,699	$41,094	$53,616	$1,071	$10,914	$60,031	$5,249	$29,547	$23,692	$2,427	$48,989	$25,870	$13,838	
12	(Lines 1+2+9)																			
13																				
14	Energy Related Marginal Cost																			
15	Generation Energy Related	$616,337	$256,657	$28,122	$24,350	$53	$20,863	$31,617	$41,712	$861	$9,747	$49,707	$4,247	$25,008	$21,685	$2,460	$49,228	$37,622	$11,365	$1,033
16	Transmission Energy Related	$43,168	$17,976	$1,970	$1,705	$4	$1,461	$2,214	$2,921	$60	$683	$3,481	$297	$1,752	$1,519	$172	$3,448	$2,635	$796	$72
17	Total Energy	$659,505	$274,633	$30,091	$26,055	$57	$22,324	$33,831	$44,633	$921	$10,429	$53,189	$4,544	$26,760	$23,204	$2,633	$52,676	$40,257	$12,161	$1,106
18																				
19	Customer Related Marginal Cost																			
20	Poles	$80,224	$61,587	$9,847	$1,578	$7	$435	$334	$186	$6	$14	$37	$3	$4	$3	$0	$0	$0	$2,819	$3,362
21	Conductor	$37,186	$29,746	$4,756	$763	$3	$211	$162	$90	$3	$7	$17	$1	$3	$1	$0	$0	$0	$1,362	$61
22	Transformers	$85,223	$56,351	$10,495	$2,482	$0	$3,247	$2,849	$1,706	$0	$222	$573	$0	$115	$0	$3	$0	$0	$7,111	$69
23	Service Drops	$62,761	$47,762	$8,093	$2,708	$0	$1,201	$963	$1,032	$0	$107	$532	$0	$357	$0	$7	$0	$0	$0	$0
24	Meters	$12,746	$8,972	$1,256	$349	$90	$151	$126	$446	$117	$47	$120	$98	$31	$127	$1	$67	$474	$273	$2
25	Meter Reading	$10,598	$8,131	$1,513	$243	$1	$186	$143	$80	$2	$14	$37	$3	$19	$11	$0	$6	$2	$205	$2
26	Billing & Collections	$19,550	$16,596	$2,066	$331	$1	$158	$122	$68	$2	$7	$18	$2	$13	$8	$0	$4	$1	$127	$25
27	Uncollectables	$5,608	$5,029	$119	$19	$0	$91	$70	$39	$1	$28	$73	$7	$63	$37	$1	$20	$6	$7	$0
28	Customer Service / Other	$5,163	$4,347	$564	$90	$0	$45	$34	$19	$1	$3	$7	$1	$3	$2	$0	$1	$0	$38	$7
29	Total Commitment & Billing Rel.	$319,060	$238,521	$38,709	$8,563	$103	$5,724	$4,803	$3,665	$132	$449	$1,414	$115	$608	$190	$12	$98	$482	$11,942	$3,529
30																				
31	Total Revenue @ Full MC																			
32	Generation	$831,589	$351,262	$38,309	$33,108	$70	$29,034	$42,868	$56,502	$1,146	$12,839	$66,697	$5,755	$33,655	$28,764	$3,266	$65,599	$47,401	$14,281	$1,033
33	Transmission	$397,359	$173,645	$18,733	$16,116	$32	$14,906	$20,728	$27,258	$529	$5,771	$31,437	$2,778	$15,981	$13,168	$1,498	$30,385	$18,726	$5,594	$72
34	Distribution	$482,954	$314,855	$44,872	$16,945	$32	$13,177	$15,638	$17,503	$325	$3,084	$16,245	$1,264	$7,150	$4,969	$305	$5,681	$0	$17,415	$3,493
35	Customer - Billing	$19,550	$16,596	$2,066	$331	$1	$158	$122	$68	$2	$7	$18	$2	$13	$8	$0	$4	$1	$127	$25
36	Customer - Metering	$23,344	$17,103	$2,769	$592	$91	$336	$269	$526	$119	$61	$156	$102	$50	$139	$1	$73	$475	$478	$5
37	Customer - Other	$5,163	$4,347	$564	$90	$0	$45	$34	$19	$1	$3	$7	$1	$3	$2	$0	$1	$0	$38	$7
38	Revenue (less Uncollectables)	$1,759,960	$877,808	$107,313	$67,183	$226	$57,657	$79,659	$101,876	$2,123	$21,764	$114,562	$9,901	$56,853	$47,049	$5,071	$101,742	$66,604	$37,934	$4,635
39																				
40	Customer - Uncollectables	$5,608	$5,029	$119	$19	$0	$91	$70	$39	$1	$28	$73	$7	$63	$37	$1	$20	$6	$7	$0
41	Total Revenue	$1,765,568	$882,837	$107,432	$67,202	$226	$57,748	$79,729	$101,915	$2,124	$21,792	$114,635	$9,908	$56,915	$47,086	$5,072	$101,762	$66,609	$37,940	$4,635

Docket No. UE 263
Exhibit PAC/1105
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Functionalized Revenue Requirement vs. Current Revenues

March 2013

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2014 Unbundled Revenue Requirement Allocation by Rate Schedule

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)			
			Residential	**General Service**		**General Service**		**General Service**			**Large Power Service**		**Irrigation**	**Street Lgt.**		**Street Lighting**	
		Total		**Sch 23**		**Sch 28**		**Sch 30**			**Sch 48T**		**Sch 41**	**Sch 51, 53, 54**	Sch 51	Sch 53	Sch 54
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)			(sec)	(sec)	(sec)
1	**Total Operating Revenues**	$1,192,004	$582,985	$113,863	$110	$168,990	$1,552	$94,427	$6,825	$42,861	$103,079	$49,397	$25,360,982	$2,555	$1,923	$533	$99
2	**MWh**	13,006,345	5,379,569	1,099,810	1,147	1,974,277	18,574	1,246,164	91,598	575,746	1,529,473	829,896	238,210	$21,882	11,008	9,669	1,205
3																	
4	**Functionalized 20 Year Full Marginal Costs - Class $**																
5	Generation	$831,589	$351,262	$71,416	$70	$128,404	$1,146	$79,536	$5,755	$36,922	$94,363	$47,401	$14,281	$1,033	$546	$428	$60
6	Transmission	$397,359	$173,645	$34,849	$32	$62,893	$529	$37,208	$2,778	$17,479	$43,553	$18,726	$5,594	$72	$38	$30	$4
7	Distribution	$482,956	$314,855	$61,818	$32	$46,319	$325	$19,329	$1,264	$7,455	$10,649	$0	$17,415	$3,495	$3,338	$105	$51
8	Customer - Billing	$19,550	$16,596	$2,398	$1	$347	$2	$25	$2	$14	$12	$1	$127	$25	$14	$8	$3
9	Customer - Metering	$23,342	$17,103	$3,361	$91	$1,131	$119	$217	$102	$51	$211	$475	$478	$2	$0	$0	$2
10	Customer - Other	$5,163	$4,347	$655	$0	$98	$1	$10	$1	$3	$3	$0	$38	$7	$4	$2	$1
11	Total	$1,759,960	$877,808	$174,497	$226	$239,192	$2,123	$136,326	$9,901	$61,923	$148,791	$66,604	$37,934	$4,635	$3,940	573	122
12																	
13	**Functional Revenue Requirement Allocation Factors**																
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**																
15	Generation	100.00%	42.24%	8.59%	0.01%	15.44%	0.14%	9.56%	0.69%	4.44%	11.35%	5.70%	1.72%	0.12%	0.07%	0.05%	0.01%
16	Transmission	100.00%	43.70%	8.77%	0.01%	15.83%	0.13%	9.36%	0.70%	4.40%	10.96%	4.71%	1.41%	0.02%	0.01%	0.01%	0.00%
17	Distribution	100.00%	65.19%	12.80%	0.01%	9.59%	0.07%	4.00%	0.26%	1.54%	2.20%	0.00%	3.61%	0.72%	0.69%	0.02%	0.01%
18	Ancillary Service	100.00%	42.24%	8.59%	0.01%	15.44%	0.14%	9.56%	0.69%	4.44%	11.35%	5.70%	1.72%	0.12%	0.07%	0.05%	0.01%
19	Customer - Billing	100.00%	84.89%	12.26%	0.01%	1.78%	0.01%	0.13%	0.01%	0.07%	0.06%	0.01%	0.65%	0.13%	0.07%	0.04%	0.02%
20	Customer - Metering	100.00%	73.27%	14.40%	0.39%	4.84%	0.51%	0.93%	0.43%	0.22%	0.91%	2.04%	2.05%	0.01%	0.00%	0.00%	0.01%
21	Customer - Other	100.00%	84.20%	12.68%	0.01%	1.90%	0.01%	0.20%	0.01%	0.07%	0.06%	0.01%	0.73%	0.13%	0.07%	0.04%	0.02%
22	Embedded DSM - (MWh)	100.00%	41.36%	8.46%	0.01%	15.18%	0.14%	9.58%	0.70%	4.43%	11.76%	6.38%	1.83%	0.17%	0.08%	0.07%	0.01%
23	Franchise & Energy Supplier Taxes	100.00%	48.91%	9.55%	0.01%	14.18%	0.13%	7.92%	0.57%	3.60%	8.65%	4.14%	2.13%	0.21%	0.16%	0.04%	0.01%
24																	
25																	
26	**Functionalized Class Revenue Requirement - (Target)**																
27	Generation	$747,123	$315,584	$64,163	$63	$115,362	$1,030	$71,457	$5,170	$33,171	$84,778	$42,586	$12,830	$928	$490	$384	$54
28	Transmission	$170,188	$74,372	$14,926	$14	$26,937	$227	$15,936	$1,190	$7,486	$18,654	$8,020	$2,396	$31	$16	$13	$2
29	Distribution	$237,050	$154,541	$30,342	$16	$22,735	$160	$9,487	$620	$3,659	$5,227	$0	$8,548	$1,715	$1,639	$52	$25
30	Ancillary Services	$10,658	$4,502	$915	$1	$1,646	$15	$1,019	$74	$473	$1,209	$608	$183	$13	$7	$5	$1
31	Customer - Billing	$12,085	$10,259	$1,482	$1	$215	$1	$16	$1	$8	$7	$1	$79	$16	$9	$5	$2
32	Customer - Metering	$27,053	$19,822	$3,896	$105	$1,310	$138	$252	$118	$59	$245	$551	$555	$3	$0	$0	$3
33	Customer - Other	$11,775	$9,914	$1,493	$1	$224	$1	$23	$2	$8	$7	$1	$86	$15	$8	$5	$2
34	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Franchise & Energy Supplier Taxes	$29,853	$14,601	$2,852	$3	$4,232	$39	$2,365	$171	$1,073	$2,582	$1,237	$635	$64	$48	$13	$2
36	Total	$1,245,787	$603,595	$120,068	$203	$172,660	$1,610	$100,556	$7,346	$45,938	$112,709	$53,004	$25,312	$2,786	$2,218	$478	$91
37																	
38	**Ratio of Operating Revn to Revenue Requirement-(Target)**	95.68%	96.59%	94.83%	54.40%	97.87%	96.34%	93.91%	92.91%	93.30%	91.46%	93.20%	100.19%	91.70%	86.70%	111.57%	109.36%
39	(Line 1 / Line 36)																
40																	
41	**Increase or (Decrease)**	$53,783	$20,610	$6,205	$93	$3,670	$59	$6,129	$521	$3,077	$9,631	$3,607	($49)	$231	$295	($55)	($8)
42	(Line 36 - Line 1)																
43																	
44																	
45	**Percent Increase (Decrease)**	4.51%	3.54%	5.45%	83.83%	2.17%	3.80%	6.49%	7.63%	7.18%	9.34%	7.30%	-0.19%	9.05%	15.34%	-10.37%	-8.55%
46	(Line 41 / Line 1)																

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2014 Functionalized Revenue - Earned
($ 000)

		A	B	C	D	E	F	G	H	I	J
Line No.	Description	Generation	Transmission	Distribution	Ancillary	C Billing	C Metering	C Other	DSM	Franchise & ESA	Total
1	Earned Functional Revenue Requirement	$731,008	$160,007	227,584	$10,815	$12,068	$26,863	$11,810	$0	29,020	$1,209,176
2											
3	Percent of Total	60.46%	13.23%	18.82%	0.89%	1.00%	2.22%	0.98%	0.00%	2.40%	100.00%
4											
5	Revenue From Classes Included in MC Study	$720,627	$157,735	$224,352	$10,662	$11,897	$26,481	$11,642	$0	$28,608	$1,192,004
6											
7	Other Revenues										
8	Partial Requirements - Sch. 47 pri										$9,299
9	Partial Requirements - Sch. 47 trn										$2,034
10	USBR Billed Revenue										$0
11	AGA										$2,439
12	Lighting										$3,402
13											
14	Total Oregon Situs Revenue										$1,209,176

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2014 Functionalized Revenue - Target
($ 000)

Line No.	Description	A Generation	B Transmission	C Distribution	D Ancillary	E C Billing	F C Metering	G C Other	H DSM	I Franchise & ESA	J Total	
1	Target Functional Revenue Requirement	$758,147	$172,699	$240,548	$10,815	$12,264	$27,452	$11,949	$0	$30,294	$1,264,168	
2												
3	Percent of Total	59.97%	13.66%	19.03%	0.86%	0.97%	2.17%	0.95%	0.00%	2.40%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$747,123	$170,188	$237,050	$10,658	$12,085	$27,053	$11,775	$0	$29,853	$ 1,245,787	53,783
6												
7	Other Revenues											54,992
8	Partial Requirements - Sch. 47 pri										$10,170	$871
9	Partial Requirements - Sch. 47 trn										$2,064	$30
10	USBR Billed Revenue										$0	$0
11	AGA										$2,439	$0
12	Lighting										$3,709	$307
13												$0
14	Total Oregon Situs Revenue										$1,264,168	53,783

Docket No. UE 263
Exhibit PAC/1106
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Functional Factors

March 2013

PacifiCorp
12 Months Ended June 2012
FUNCTIONAL FACTORS

Function	Description	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM	Total
ANC	Ancillary Function	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
B_Center	Business Centers	0.0000%	0.0000%	0.0000%	0.0000%	76.4237%	0.0000%	23.5763%	0.0000%	100.0000%
BOOKDEPR	Book Depreciation	51.3207%	17.4257%	29.9936%	0.0000%	0.3181%	0.9419%	0.0000%	0.0000%	100.0000%
C_BILLING	Customer Billing	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%
C_METER	Customer Metering	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	100.0000%
C_SERVICE	Customer Other	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100.0000%
CSS_SYS	CSS System	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%	100.0000%
CUST	Customer	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%	100.0000%
CUST901	Supervision	0.0000%	0.0000%	0.0000%	0.0000%	47.9281%	25.2037%	26.8682%	0.0000%	100.0000%
CUST903	Cust. Records & Coll. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	64.0809%	0.0000%	35.9191%	0.0000%	100.0000%
CUST905	Misc. Customer Acct. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	3.2820%	96.7180%	0.0000%	100.0000%
D	Distribution Only	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DDS2	Deferred Debits - Situs	85.4874%	1.1627%	-2.5108%	0.0000%	15.7407%	0.0920%	0.0280%	0.0000%	100.0000%
DDS6	Deferred Debits - Situs	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DDSO2	Deferred Debits - System Overhead	10.7493%	3.5831%	85.6676%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DDSO6	Deferred Debits - System Overhead	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DEFSG	Deferred Debit - System Generation	69.2942%	30.7058%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DSM	Demand Side Management	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DPW	Distribution Poles & Wires	0.0000%	0.0000%	96.9554%	0.0000%	0.0000%	3.0446%	0.0000%	0.0000%	100.0000%
ESD	Environmental Services Department	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
FERC	FERC Fees	51.7837%	48.2163%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G	General Plant	33.3732%	19.7848%	42.9829%	0.0000%	2.5094%	1.3498%	0.0000%	0.0000%	100.0000%
G-SG	General Plant - SG Factor	99.8982%	0.1018%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-SITUS	General Plant - SITUS Factor	0.0000%	26.9250%	70.8501%	0.0000%	0.0000%	2.2248%	0.0000%	0.0000%	100.0000%
I	Intangible Plant	55.0601%	15.5533%	13.5528%	0.0000%	8.0973%	3.6531%	4.0834%	0.0000%	100.0000%
I-DGP	Intangible Plant - DGP Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-DGU	Intangible Plant - DGU Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-SG	Intangible Plant - SG Factor	85.5270%	14.4730%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-SITUS	Intangible Plant - SITUS Factor	2.4499%	48.2879%	47.7624%	0.0000%	0.0000%	1.4998%	0.0000%	0.0000%	100.0000%
LABOR	Direct Labor Expense	44.0903%	5.3281%	26.6736%	0.0000%	6.6432%	11.2934%	5.9714%	0.0000%	100.0000%
MSS	Materials & Supplies	83.5005%	0.6422%	15.4037%	0.0000%	0.0000%	0.4536%	0.0000%	0.0000%	100.0000%
NONE	Not Functionalized	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
NUTIL	Non-Utility	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
OTHDGP	Other Revenues - DGP Factor	46.6024%	53.3976%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHDGU	Other Revenues - DGU Factor	46.6024%	53.3976%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSE	Other Revenues - SE Factor	73.5954%	26.4046%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSG	Other Revenues - SG Factor	46.6024%	53.3976%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSGR	Other Revenues - Rolled-In SG Factor	46.6024%	53.3976%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSITUS	Other Revenues - SITUS	0.5770%	0.0000%	99.4230%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSO	Other Revenues - SO Factor	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
P	Production	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMA	Schedule M Additions	50.7343%	19.1984%	27.6455%	0.0000%	0.8859%	1.1406%	0.3951%	0.0000%	100.0000%
SCHMAF	Schedule M Additions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAP	Schedule M Additions - Permanent	46.8397%	13.7683%	26.2335%	0.0000%	3.5518%	6.4140%	3.1926%	0.0000%	100.0000%
SCHMAP-SO	Schedule M Additions - Permanent-SO	46.3107%	13.9053%	26.4946%	0.0000%	3.5872%	6.4778%	3.2244%	0.0000%	100.0000%
SCHMAT	Schedule M Additions - Temporary	50.7685%	19.2461%	27.6579%	0.0000%	0.8625%	1.0944%	0.3706%	0.0000%	100.0000%
SCHMAT-SG	Schedule M Additions - Temporary-SG	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAT-SE	Schedule M Additions - Temporary-SE	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAT-SITUS	Schedule M Additions - Temporary-SITUS	68.3484%	11.8482%	15.4045%	0.0000%	0.4790%	1.1266%	2.7933%	0.0000%	100.0000%
SCHMAT-SNP	Schedule M Additions - Temporary-SNP	48.9380%	23.9417%	26.2751%	0.0000%	0.0117%	0.8284%	0.0051%	0.0000%	100.0000%
SCHMAT-SO	Schedule M Additions - Temporary-SO	46.2862%	13.8107%	26.4966%	0.0000%	3.6209%	6.5309%	3.2547%	0.0000%	100.0000%
SCHMD	Schedule M Deductions	50.4308%	26.6428%	19.2544%	0.0000%	0.3808%	0.5839%	2.7073%	0.0000%	100.0000%
SCHMDF	Schedule M Deductions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDP	Schedule M Deductions - Permanent	46.3420%	5.6933%	25.6574%	0.0000%	6.1914%	10.5504%	5.5654%	0.0000%	100.0000%
SCHMDP-SO	Schedule M Deductions - Permanent- SO	44.0903%	5.3281%	26.6736%	0.0000%	6.6432%	11.2934%	5.9714%	0.0000%	100.0000%
SCHMDT	Schedule M Deductions - Temporary	50.4578%	26.7807%	19.2122%	0.0000%	0.3425%	0.5183%	2.6884%	0.0000%	100.0000%
SCHMDT-GPS	Schedule M Deductions - Temporary-GPS	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%	0.0000%	100.0000%
SCHMDT-SG	Schedule M Deductions - Temporary-SG	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDT-SITUS	Schedule M Deductions - Temporary-SITUS	54.5982%	6.9114%	15.6152%	0.0000%	2.5604%	4.4229%	15.8919%	0.0000%	100.0000%
SCHMDT-SNP	Schedule M Deductions - Temporary-SNP	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%	0.0000%	100.0000%
SCHMDT-SO	Schedule M Deductions - Temporary-SO	43.7037%	16.7744%	34.3080%	0.0000%	1.3816%	2.6461%	1.1862%	0.0000%	100.0000%
STEP_UP	Step-up Transformers	7.9142%	92.0858%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
T	Transmission	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
TAXDEPR	Tax Depreciation	39.6609%	35.3619%	23.7250%	0.0000%	0.4397%	0.5392%	0.2732%	0.0000%	100.0000%

PacifiCorp
12 Months Ended June 2012
FERC FORM 1 Funtionalization Factors

Factor	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
PLANT	22,009,335	10,766,305	5,276,344	5,785,024			181,662	0	0
UNCLASSIFIED PLANT	0							0	0
TOTAL PLANT	22,009,335	10,766,305	5,276,344	5,785,024	0	0	181,662	0	0
PLANT %									
P	100.0000%	100.0000%							
T	100.0000%		100.0000%						
CUST						100.0000%			
DPW	100.0000%			96.9554%			3.0446%		
PTD	100.0000%	48.9170%	23.9732%	26.2844%			0.8254%	0.0000%	0.0000%
PT	100.0000%	67.1105%	32.8895%						
TD	100.0000%		46.9299%	51.4543%			1.6158%		

Source: Oregon Results of Operations

Factor	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
Material & Supplies	111,804,926	93,357,638	718,031	17,222,137			507,120	0	0
Material & Supplies %	100.0000%	83.5005%	0.6422%	15.4037%	0.0000%	0.0000%	0.4536%	0.0000%	0.0000%

Source: Ferc Form 1 (2011) - pg. 227

Meter Percent of Total Distribution		
Account 370	181,662	3.04%
Total Distribution	5,966,687	100.00%

Source: Oregon Results of Operations

Factor	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
FERC (mWh)	30,244,302	15,661,605	14,582,697	0	0	0	0	0	0
FERC %	100.0000%	51.7837%	48.2163%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Source: 2012 FERC reporting requirment No. 582

PacifiCorp
12 Months Ended June 2012
Depreciation Expense

Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
CUST	1,748	-	-	-	-	1,748	-	-	-
DPW	153,056	-	-	148,396	-	-	4,660	-	-
G-DGP	354	173	85	93	-	-	3	-	-
G-DGU	836	561	275	-	-	-	-	-	-
G-SG	5,959	-	2,797	3,066	-	-	96	-	-
G-SITUS	13,171	-	3,546	9,332	-	-	293	-	-
P	273,964	273,964	-	-	-	-	-	-	-
PTD	14,945	7,310	3,583	3,928	-	-	123	-	-
T	85,469	-	85,469	-	-	-	-	-	-
Book Depreciation	549,503	282,009	95,755	164,815	-	1,748	5,176	-	-
BookDepr Factor	100.00%	51.3207%	17.4257%	29.9936%	0.0000%	0.3181%	0.9419%	0.0000%	0.0000%
P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.9554%	0.0000%	0.0000%	3.0446%	0.0000%	0.0000%
G-DGP	100.0000%	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%	0.0000%
G-DGU	100.0000%	67.1105%	32.8895%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
G-SG	100.0000%	0.0000%	46.9299%	51.4543%	0.0000%	0.0000%	1.6158%	0.0000%	0.0000%
G-SITUS	100.0000%	0.0000%	26.9250%	70.8501%	0.0000%	0.0000%	2.2248%	0.0000%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
PTD	100.0000%	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%	0.0000%
TD	100.0000%	0.0000%	46.9299%	51.4543%	0.0000%	0.0000%	1.6158%	0.0000%	0.0000%
G	100.0000%	33.3732%	19.7848%	42.9829%	0.0000%	2.5094%	1.3498%	0.0000%	0.0000%

PacifiCorp
CSS System Allocation Factor
Business Center Allocation Factor
12 Months Ended June 2012

Description	Total	Production	Transmission	Distribution	Retail	Ancillary	C_Billing	C_Metering	C_Service
Customer Service System (CSS)									
CSS_SYS	100.0000%						55.0000%	18.0000%	27.0000%

The size is based on the lines of code; regardless of type of code.
Some Additional Code related to general use and system maintenance is assumed to be shared by all functions.

Description	Total	Production	Transmission	Distribution	Retail	Ancillary	C_Billing	C_Metering	C_Service
Business Center Expenses									
Wasatch Business Center -									
2011	10,820,613						10,809,730		10,883
2011 Support	1,714,790						857,395		857,395
Portland Business Center -									
2011	21,781,128						15,663,735		6,117,392
2011 Support	4,181,424						2,090,712		2,090,712
Total	$ 38,497,955						$ 29,421,573		$ 9,076,383
B_CENTER	100.0000%						76.4237%		23.5763%

PacifiCorp
12 Months Ended June 2012
Summary of Ferc Accounts 901 - 910 by Funtional Groups

Line No.	Description	FERC Account	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1	Supervision	901	2,902,320					1,391,027	731,491	779,802
2	Meter Reading	902	20,781,919					-	20,781,919	-
3	Cust. Records & Coll. Exp.	903	55,464,262					35,542,000	-	19,922,263
4	Misc. Customer Acct. Exp.	905	187,018					-	6,138	180,880
5	Supervision	907	298,102					-	-	298,102
6	Customer Assistance Exp.	908	104,752,679					-	-	104,752,679
7	Information & Instructional Exp.	909	4,824,903					-	-	4,824,903
8	Misc. cust. Serv. & Inform. Exp.	910	117,882					-	-	117,882
9		Total	189,329,085							
10										
11	Uncollectible Accounts	904	15,324,186							
12	Grand Total		204,653,271							

Account	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
CUST901	100.0000%					47.9281%	25.2037%	26.8682%
CUST903	100.0000%					64.0809%	-	35.9191%
CUST905	100.0000%					-	3.2820%	96.7180%

PacifiCorp
12 Months Ended June 2012
Deferred Debits / Reg Assets

	Pri-Acct	Factor	Function	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
RA-SE	182M	SE	P	10,608	10,608	0	0	0	0	0	0
RA-SG	182M	SG	P	0	0	0	0	0	0	0	0
RA-SGCT	182M	SGCT	P	6,267	6,267	0	0	0	0	0	0
RA-SG-P	182M	SG-P	P	0	0	0	0	0	0	0	0
RA-SO	182M	SO	DMSC	6,095	0	0	6,095	0	0	0	0
RA-SO	182M	SO	DPW	0	0	0	0	0	0	0	0
RA-SO	182M	SO	ESD	3,403	1,021	340	2,042	0	0	0	0
RA-SO	182M	SO	P	0	0	0	0	0	0	0	0
RA-SO	182M	SO	TD	0	0	0	0	0	0	0	0
RA-TROJD	182M	TROJD	P	0	0	0	0	0	0	0	0
RA-TROJP	182M	TROJP	P	0	0	0	0	0	0	0	0
RA-OTHER	182M	OTHER	DMSC	5,453	0	0	5,453	0	0	0	0
RA-OTHER	182M	OTHER	CUST	1,579	0	0	0	0	1,579	0	0
RA-OTHER	182M	OTHER	LABOR	12,370	5,454	659	3,300	0	822	1,397	739
RA-OTHER	182M	OTHER	P	122,434	122,434	0	0	0	0	0	0
RA-OTHER	182M	OTHER	PT	435	0	435	0	0	0	0	0
RA-OTHER	182M	OTHER	PTD	8,546	4,180	2,049	2,246	0	0	71	0
RA-OTHER	182M	OTHER	TD	186	0	87	96	0	0	3	0
RA-SITUS	182M	SITUS	CUST	2,977	0	0	0	0	2,977	0	0
RA-SITUS	182M	SITUS	DMSC	-736	0	0	-736	0	0	0	0
RA-SITUS	182M	SITUS	LABOR	89	39	5	24	0	6	10	5
RA-SITUS	182M	SITUS	P	15,721	15,721	0	0	0	0	0	0
RA-SITUS	182M	SITUS	PTD	899	440	216	236	0	0	7	0
	Total-SO			9,498	1,021	340	8,137	-	-	-	-
	Total SITUS			18,950	16,200	220	(476)	-	2,983	17	5
	Total RA			196,326	166,164	3,791	18,755	-	5,384	1,488	744
	DDSO2 FACTOR			100.00%	10.7493%	3.5831%	85.6676%	0.0000%	0.0000%	0.0000%	0.0000%
	DDS2 FACTOR			100.00%	85.4874%	1.1627%	-2.5108%	0.0000%	15.7407%	0.0920%	0.0280%
DD-SE	186M	SE	P	13,381	13,381	0	0	0	0	0	0
DD-SG	186M	SG	P	38,398	38,398	0	0	0	0	0	0
DD-SG	186M	SG	T	17,015	0	17,015	0	0	0	0	0
DD-SO	186M	SO	DMSC	15	0	0	15	0	0	0	0
DD-OTHER	186M	OTHER	DMSC	0	0	0	0	0	0	0	0
DD-OTHER	186M	OTHER	T	-	0	0	0	0	0	0	0
	Total SITUS			-	-	-	-	-	-	-	-
	Total SG			55,413	38,398	17,015	-	-	-	-	-
	Total-SO			15	-	-	15	-	-	-	-
	Total-DD			68,809	51,779	17,015	15	-			-
	DEFSG FACTOR			100.00%	69.2942%	30.7058%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

PacifiCorp
12 Months Ended June 2012
Deferred Debits / Reg Assets

Pri-Acct	Factor	Function	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Major Adjustment										
1998 Early Retirement		LABOR	-	0	0	0	0	0	0	0
1999 Early Retirement		LABOR	-	0	0	0	0	0	0	0
Transition Planning		PTD	-	0	0	0	0	0	0	0
Environmental Clean-up		ESD	-	0	0	0	0	0	0	0
Y2K		PTD	-	0	0	0	0	0	0	0
Subtotal Major Adjustments			-	-	-	-	-	-	-	-
Total 186M SO			15	-	-	15	-	-	-	-
Total 182 &186			265,135	217,943	20,806	18,770	-	5,384	1,488	744

	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
DMSC	100.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.9554%	0.0000%	0.0000%	3.0446%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
ESD	100.0000%	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%
GP	100.0000%	49.5497%	23.0254%	26.0048%	0.0000%	0.3516%	0.9148%	0.1537%
LABOR	100.0000%	44.0903%	5.3281%	26.6736%	0.0000%	6.6432%	11.2934%	5.9714%
P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PT	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PTD	100.0000%	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TAXDEPR	100.0000%	39.6609%	35.3619%	23.7250%	0.0000%	0.4397%	0.5392%	0.2732%
TD	100.0000%	0.0000%	46.9299%	51.4543%	0.0000%	0.0000%	1.6158%	0.0000%

PacifiCorp
12 Months Ended June 2012
General Plant

Description		Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Business Centers		CN	CUST	24,957	0	0	0	0	24,957	0	0
		SE	P	646	646	0	0	0	0	0	0
		SG	P	211,998	211,998	0	0	0	0	0	0
		SG	T	216	0	216	0	0	0	0	0
		SG	TD	0	0	0	0	0	0	0	0
General Plant		SO	DPW	0	0	0	0	0	0	0	0
		SO	PTD	243,824	119,271	58,452	64,088	0	0	2,012	0
		SO	TD	0	0	0	0	0	0	0	0
		SO	P	0	0	0	0	0	0	0	0
	SSGCH	SG	P	0	0	0	0	0	0	0	0
	SSGCT	SG	DPW	0	0	0	0	0	0	0	0
	SSGCT	SG	P	0	0	0	0	0	0	0	0
		SITUS	DPW	218,642	0	0	211,985	0	0	6,657	0
		SITUS	P	0	0	0	0	0	0	0	0
		SITUS	TD	294,275	0	138,103	151,417	0	0	4,755	0
Total-CUST				24,957	0	0	0	0	24,957	0	0
Total-TD				294,275	0	138,103	151,417	0	0	4,755	0
Total-PTD				243,824	119,271	58,452	64,088	0	0	2,012	0
Total-DPW				218,642	0	0	211,985	0	0	6,657	0
Total-SSGCH				0	0	0	0	0	0	0	0
Total-SSGCT				0	0	0	0	0	0	0	0
Total-G-SG				212,214	211,998	216	0	0	0	0	0
Total-UT				646	646	0	0	0	0	0	0
Total-G-Situs				512,917	0	138,103	363,402	0	0	11,412	0
Total-SO				243,824	119,271	58,452	64,088	0	0	2,012	0
Total-General Plant				994,558	331,915	196,771	427,490	0	24,957	13,424	0
G-SG Factor				100.00%	99.8982%	0.1018%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
UT Factor				100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
G-SITUS Factor				100.00%	0.0000%	26.9250%	70.8501%	0.0000%	0.0000%	2.2248%	0.0000%
SO Factor				100.00%	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%
G Allocator				100.00%	33.3732%	19.7848%	42.9829%	0.0000%	2.5094%	1.3498%	0.0000%
Total Gen. Plant				994,558							
Mining				482,121	646	646	0	0	0	0	0
Total			P	1,476,679							

Functional Allocators:			Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
	P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	TD	100.00%	0.00%	46.93%	51.45%	0.00%	0.00%	1.62%	0.00%
	CUST	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
	DPW	100.00%	0.00%	0.00%	96.96%	0.00%	0.00%	3.04%	0.00%
	PTD	100.00%	48.92%	23.97%	26.28%	0.00%	0.00%	0.83%	0.00%
	GP	100.00%	49.55%	23.03%	26.00%	0.00%	0.35%	0.91%	0.15%

PacifiCorp
12 Months Ended June 2012
Intangible Plant
(In 000's)

Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
CN	CSS_SYS	112,500	0	0	0	0	61,875	20,250	30,375
CN	CUST	4,738	0	0	0	0	2,606	853	1,279
CN	C_METER	2,665	0	0	0	0	0	2,665	0
CN	C_SERVICE	1,981	0	0	0	0	0	0	1,981
SE	P	3,662	3,662	0	0	0	0	0	0
SG	P	-	0	0	0	0	0	0	0
SG	PTD	-	0	0	0	0	0	0	0
SG	T	47,647	0	47,647	0	0	0	0	0
SG	P	232,665	232,665	0	0	0	0	0	0
SG	P	48,902	48,902	0	0	0	0	0	0
SO	CUST	2,680	0	0	0	0	1,474	482	724
SO	C_METER	2,908	0	0	0	0	0	2,908	0
SO	C_BILLING	2,179	0	0	0	0	2,179	0	0
SO	DPW	24,000	0	0	23,269	0	0	731	0
SO	P	29,275	29,275	0	0	0	0	0	0
SO	PTD	303,714	148,568	72,810	79,830	0	0	2,507	0
SO	TD	12,688	0	5,954	6,528	0	0	205	0
SO	LABOR	-	0	0	0	0	0	0	0
SITUS	DPW	107	0	0	103	0	0	3	0
SITUS	PTD	463	226	111	122	0	0	4	0
SITUS	T	531	0	531	0	0	0	0	0
SITUS	TD	8,136	0	3,818	4,186	0	0	131	0
Total-DGP		-	-	-	-	-	-	-	-
Total-DGU		-	-	-	-	-	-	-	-
Total-SG		329,214	281,567	47,647	-	-	-	-	-
Total-SITUS		9,236	226	4,460	4,411	-	-	139	-
Total-Intangible		841,439	463,298	130,871	114,039	-	68,134	30,739	34,359
I-SG FACTOR		100.00%	85.5270%	14.4730%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
I-Situs FACTOR		100.00%	2.4499%	48.2879%	47.7624%	0.0000%	0.0000%	1.4998%	0.0000%
I FACTOR		100.00%	55.0601%	15.5533%	13.5528%	0.0000%	8.0973%	3.6531%	4.0834%

Functional Allocators:		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	46.93%	51.45%	0.00%	0.00%	1.62%	0.00%
CSS_SYS	100.00%	0.00%	0.00%	0.00%	0.00%	55.00%	18.00%	27.00%
C_BILLING	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
C_METER	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
C_SERVICE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
CSS_SYS	100.00%	0.00%	0.00%	0.00%	0.00%	55.00%	18.00%	27.00%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	55.00%	18.00%	27.00%
DPW	100.00%	0.00%	0.00%	96.96%	0.00%	0.00%	3.04%	0.00%
PTD	100.00%	48.92%	23.97%	26.28%	0.00%	0.00%	0.83%	0.00%
LABOR	100.00%	44.09%	5.33%	26.67%	0.00%	6.64%	11.29%	5.97%

PacifiCorp
Oregon Labor Costs
12 Months Ended June 2012

Ferc Account	Funct.	FERC Form 1	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
500-554, 913,916	P	52,585,747	52,585,747	-	-	-	-	-	-	-
560-569, 571-573	T	4,759,640	-	4,759,640	-	-	-	-	-	-
580,590	D_Split	1,361,498	-	-	1,320,045	-	-	41,452	-	-
581,585,587-589,591,596,598, 599	D	30,576,978	-	-	30,576,978	-	-	-	-	-
586,597,902	C_Meter	13,269,666	-	-	-	-	-	13,269,666	-	-
901	CUST901	765,106	-	-	-	-	366,701	192,835	205,570	-
903	CUST903	11,824,749	-	-	-	-	7,577,406	-	4,247,343	-
905	CUST905	28,337	-	-	-	-	-	930	27,407	-
907,908	C_Service	2,480,760	-	-	-	-	-	-	2,480,760	-
909,910	C_Service	179,722	-	-	-	-	-	-	179,722	-
570	Step_Up	1,750,357	138,528	1,611,830	-	-	-	-	-	-
	Total Labor	119,582,560	52,724,275	6,371,470	31,897,023	-	7,944,107	13,504,883	7,140,803	-
	LABOR	100.0000%	44.0903%	5.3281%	26.6736%	-	6.6432%	11.2934%	5.9714%	-

Functional Allocation Factor		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
C_METER	100.0000%	-	-	-	-	-	100.000%	-	-
C_Service	100.0000%	-	-	-	-	-	-	100.000%	-
CUST901	100.0000%	-	-	-	-	47.928%	25.204%	26.868%	-
CUST903	100.0000%	-	-	-	-	64.081%	-	35.919%	-
CUST905	100.0000%	-	-	-	-	-	3.282%	96.718%	-
D	100.0000%	-	-	100.000%	-	-	-	-	-
D_SPLIT	100.0000%	-	-	96.955%	-	-	3.045%	-	-
P	100.0000%	100.000%	-	-	-	-	-	-	-
STEP_UP	100.0000%	7.9142%	92.0858%	-	-	-	-	-	-
T	100.0000%	-	100.0000%	-	-	-	-	-	-
1	2	3	4	5	6	7	8	9	10

PacifiCorp
12 Months Ended June 2012
Schedule M

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
						ADDITIONS					
SCHMAP-OTHER	SCHMAP	OTHER	P	-7	(7)	-	-	-	-	-	-
SCHMAP-SCHMDEXP	SCHMAP	SCHMDEXP	LABOR	0	-	-	-	-	-	-	-
SCHMAP-SE	SCHMAP	SE	P	82	82	-	-	-	-	-	-
SCHMAP-SO	SCHMAP	SO	LABOR	4,065	1,792	217	1,084	-	270	459	243
SCHMAP-SO	SCHMAP	SO	PTD	3,464	1,694	830	910	-	-	29	-
	Total-SO			7,529	3,487	1,047	1,995	-	270	488	243
	Total SCHMAP			7,604	3,562	1,047	1,995	-	270	488	243
	SCHMAP-SO			100.00%	46.3107%	13.9053%	26.4946%	0.0000%	3.5872%	6.4778%	3.2244%
	SCHMAP FACTOR			100.00%	46.8397%	13.7683%	26.2335%	0.0000%	3.5518%	6.4140%	3.1926%
SCHMAT-CIAC	SCHMAT	CIAC	DPW	41,148	-	-	39,895	-	-	1,253	-
SCHMAT-BADDEBT	SCHMAT	BADDEBT	CUST	4,403	-	-	-	-	4,403	-	-
SCHMAT-SCHMDEXP	SCHMAT	SCHMDEXP	GP	626,056	310,209	144,152	162,804	-	2,201	5,727	962
SCHMAT-SE	SCHMAT	SE	LABOR	-	-	-	-	-	-	-	-
SCHMAT-SE	SCHMAT	SE	P	26,032	26,032	-	-	-	-	-	-
SCHMAT-SG	SCHMAT	SG	P	(1,994)	(1,994)	-	-	-	-	-	-
SCHMAT-SG	SCHMAT	SG	T	-	-	-	-	-	-	-	-
SCHMAT-SGCT	SCHMAT	SGCT	P	1,122	1,122	-	-	-	-	-	-
SCHMAT-SNP	SCHMAT	SNP	GP	1,770	877	408	460	-	6	16	3
SCHMAT-SNP	SCHMAT	SNP	PTD	51,429	25,158	12,329	13,518	-	-	424	-
SCHMAT-SNPD	SCHMAT	SNPD	DPW	9,557	-	-	9,266	-	-	291	-
SCHMAT-OTHER	SCHMAT	OTHER	DMSC	985	-	-	-	-	-	-	985
SCHMAT-OTHER	SCHMAT	OTHER	GP	-	-	-	-	-	-	-	-
SCHMAT-OTHER	SCHMAT	OTHER	P	45,482	45,482	-	-	-	-	-	-
SCHMAT-OTHER	SCHMAT	OTHER	PTD	19,132	9,359	4,587	5,029	-	-	158	-
SCHMAT-SO	SCHMAT	SO	LABOR	11,567	5,100	616	3,085	-	768	1,306	691
SCHMAT-SO	SCHMAT	SO	PTD	9,655	4,723	2,315	2,538	-	-	80	-
SCHMAT-TROJD	SCHMAT	TROJD	P	13	13	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	DMSC	492	-	-	-	-	-	-	492
SCHMAT-SITUS	SCHMAT	SITUS	DPW	648	-	-	628	-	-	20	-
SCHMAT-SITUS	SCHMAT	SITUS	ESD	100	30	10	60	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	GP	4,582	2,271	1,055	1,192	-	16	42	7
SCHMAT-SITUS	SCHMAT	SITUS	LABOR	1,235	545	66	329	-	82	139	74
SCHMAT-SITUS	SCHMAT	SITUS	P	9,398	9,398	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	PTD	3,604	1,763	864	947	-	-	30	-
SCHMAT-SITUS	SCHMAT	SITUS	T	433	-	433	-	-	-	-	-
	Total-SG			(1,994)	(1,994)	-	-	-	-	-	-
	Total-SE			26,032	26,032	-	-	-	-	-	-
	Total-SNP			53,199	26,035	12,737	13,978	-	6	441	3
	Total-SITUS			20,492	14,006	2,428	3,157	-	98	231	572
	Total SO			21,222	9,823	2,931	5,623	-	768	1,386	691
	Total-SCHMAT			866,849	440,086	166,834	239,752	-	7,477	9,487	3,213
	SCHMAT-SG			100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	SCHMAT-SE			100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	SCHMAT-SNP			100.00%	48.9380%	23.9417%	26.2751%	0.0000%	0.0117%	0.8284%	0.0051%
	SCHMAT-SITUS			100.00%	68.3484%	11.8482%	15.4045%	0.0000%	0.4790%	1.1266%	2.7933%
	SCHMAT-SO			100.00%	46.2862%	13.8107%	26.4966%	0.0000%	3.6209%	6.5309%	3.2547%
	SCHMAT FACTOR			100.00%	50.7685%	19.2461%	27.6579%	0.0000%	0.8625%	1.0944%	0.3706%
SCHMAF-DGP	SCHMAF	DGP	P	-	-	-	-	-	-	-	-
SCHMAF-TROJP	SCHMAF	TROJP	P	-	-	-	-	-	-	-	-
	Total-SCHMAF			-	-	-	-	-	-	-	-
	SCHMAF FACTOR			0.00%							
	Total-SCHMA			874,453	443,648	167,881	241,747	-	7,747	9,974	3,455
	SCHMA FACTOR			100.00%	50.7343%	19.1984%	27.6455%	0.0000%	0.8859%	1.1406%	0.3951%

PacifiCorp
12 Months Ended June 2012
Schedule M

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
						DEDUCTIONS					
SCHMDP-SCHMDEXP	SCHMDP	SCHMDEXP	LABOR	257	113	14	69	-	17	29	15
SCHMDP-SE	SCHMDP	SE	P	475	475	-	-	-	-	-	-
SCHMDP-SG	SCHMDP	SG	P	-	-	-	-	-	-	-	-
SCHMDP-SNP	SCHMDP	SNP	PTD	383	187	92	101	-	-	3	-
SCHMDP-SO	SCHMDP	SO	LABOR	11,496	5,069	613	3,066	-	764	1,298	686
SCHMDP-SO	SCHMDP	SO	PTD	-	-	-	-	-	-	-	-
	Total-SO			11,496	5,069	613	3,066	-	764	1,298	686
	Total-SCHMDP			12,611	5,844	718	3,236	-	781	1,330	702
	SCHMDP-SO			100.00%	44.0903%	5.3281%	26.6736%	0.0000%	6.6432%	11.2934%	5.9714%
	SCHMDP FACTOR			100.00%	46.3420%	5.6933%	25.6574%	0.0000%	6.1914%	10.5504%	5.5654%
SCHMDT-BADDEBT	SCHMDT	BADDEBT	CUST	-	-	-	-	-	-	-	-
SCHMDT-CN	SCHMDT	CN	CUST	48	-	-	-	-	48	-	-
SCHMDT-GPS	SCHMDT	GPS	GP	-	-	-	-	-	-	-	-
SCHMDT-GPS	SCHMDT	GPS	PTD	105,221	51,471	25,225	27,657	-	-	868	-
SCHMDT-OTHER	SCHMDT	OTHER	CUST	-	-	-	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	DMSC	46,653	-	-	-	-	-	-	46,653
SCHMDT-OTHER	SCHMDT	OTHER	DPW	33	-	-	32	-	-	1	-
SCHMDT-OTHER	SCHMDT	OTHER	LABOR	5,652	2,492	301	1,507	-	375	638	337
SCHMDT-OTHER	SCHMDT	OTHER	P	106,235	106,235	-	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	PT	5,812	3,900	1,912	-	-	-	-	-
SCHMDT-OTHER	SCHMDT	OTHER	GP	1,163	576	268	302	-	4	11	2
SCHMDT-SE	SCHMDT	SE	P	33,039	33,039	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	GP	-	-	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	P	200,371	200,371	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	T	-	-	-	-	-	-	-	-
SCHMDT-SNP	SCHMDT	SNP	PTD	78,813	38,553	18,894	20,716	-	-	651	-
SCHMDT-SNPD	SCHMDT	SNPD	DPW	-	-	-	-	-	-	-	-
SCHMDT-SO	SCHMDT	SO	ESD	4,556	1,367	456	2,734	-	-	-	-
SCHMDT-SO	SCHMDT	SO	GP	6,552	3,247	1,509	1,704	-	23	60	10
SCHMDT-SO	SCHMDT	SO	LABOR	3,624	1,598	193	967	-	241	409	216
SCHMDT-SO	SCHMDT	SO	P	-	-	-	-	-	-	-	-
SCHMDT-SO	SCHMDT	SO	PTD	4,361	2,133	1,045	1,146	-	-	36	-
SCHMDT-SSGCH	SCHMDT	SSGCH	P	-	-	-	-	-	-	-	-
SCHMDT-SO	SCHMDT	SO	TAXDEPR	-	-	-	-	-	-	-	-
SCHMDT-TAXDEPR	SCHMDT	TAXDEPR	TAXDEPR	1,309,115	519,207	462,928	310,588	-	5,757	7,059	3,577
SCHMDT-TROJD	SCHMDT	TROJD	P	-	-	-	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	DMSC	606	-	-	-	-	-	-	606
SCHMDT-SITUS	SCHMDT	SITUS	DPW	4	-	-	4	-	-	0	-
SCHMDT-SITUS	SCHMDT	SITUS	GP	950	471	219	247	-	3	9	1
SCHMDT-SITUS	SCHMDT	SITUS	LABOR	1,664	734	89	444	-	111	188	99
SCHMDT-SITUS	SCHMDT	SITUS	P	1,224	1,224	-	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	PTD	-	-	-	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	T	-	-	-	-	-	-	-	-
	Total-GPS			105,221	51,471	25,225	27,657	-	-	868	-
	Total-SG			200,371	200,371	-	-	-	-	-	-
	Total-SNP			78,813	38,553	18,894	20,716	-	-	651	-
	Total-SNPD			-	-	-	-	-	-	-	-
	Total SO			19,094	8,345	3,203	6,551	-	264	505	226
	Total-SITUS			4,448	2,428	307	695	-	114	197	707
	Total SCHMDT			1,915,697	966,618	513,038	368,048	-	6,562	9,930	51,502
	SCHMDT-GPS			100.00%	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%
	SCHMDT-SG			100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	SCHMDT-SNP			100.00%	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%
	SCHMDT-SNPD			0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	SCHMDT-SO			100.00%	43.7037%	16.7744%	34.3080%	0.0000%	1.3816%	2.6461%	1.1862%
	SCHMDT-SITUS			100.00%	54.5982%	6.9114%	15.6152%	0.0000%	2.5604%	4.4229%	15.8919%
	SCHMDT FACTOR			100.00%	50.4578%	26.7807%	19.2122%	0.0000%	0.3425%	0.5183%	2.6884%

PacifiCorp
12 Months Ended June 2012
Schedule M

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
SCHMDF-DGP	SCHMDF	DGP	P	-	-	-	-	-	-	-	-
	Total-SCHMDF			-	-	-	-		-		-
	SCHMDF FACTOR			0.00%							
	Total-SCHMD			1,928,308	972,462	513,756	371,283	-	7,343	11,260	52,204
	SCHMD FACTOR			100.00%	50.4308%	26.6428%	19.2544%	0.0000%	0.3808%	0.5839%	2.7073%
	Net SCHM										
				Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
			DMSC	100.00%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
			DPW	100.00%	0.0000%	0.0000%	96.9554%	0.0000%	0.0000%	3.0446%	0.0000%
			CUST	100.00%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
			ESD	100.00%	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%
			GP	100.00%	49.5497%	23.0254%	26.0048%	0.0000%	0.3516%	0.9148%	0.1537%
			LABOR	100.00%	44.0903%	5.3281%	26.6736%	0.0000%	6.6432%	11.2934%	5.9714%
			P	100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
			PT	100.00%	67.1105%	32.8895%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
			PTD	100.00%	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%
			T	100.00%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
			TAXDEPR	100.00%	39.6609%	35.3619%	23.7250%	0.0000%	0.4397%	0.5392%	0.2732%
			TD	100.00%	0.0000%	46.9299%	51.4543%	0.0000%	0.0000%	1.6158%	0.0000%

PacifiCorp
12 Months Ended June 2012
Step-up Transformer Factor

Asset Class 35340 = GSU and Assoc Equip

Class	Description	Acq.value	Accum.dep.	Book Value
35300	Station Equipment	285,617,063.19	-32,633,447.44	252,983,615.75
35301	Transformers	285,800,653.22	-72,920,716.75	212,879,936.47
35303	Static Var Unit	45,920,253.87	-4,516,316.71	41,403,937.16
35305	Synchronous Condens.	3,732,665.95	-1,453,674.41	2,278,991.54
35307	Regulators	1,171,516.62	-400,834.51	770,682.11
35309	Circuit Breakers	169,027,798.95	-32,871,058.18	136,156,740.77
35311	Capacitor Bank	64,792,862.91	-9,766,024.02	55,026,838.89
35313	Metal Clad Switchgr.	5,396,785.17	-808,675.15	4,588,110.02
35315	Switching Equipment	78,546,583.87	-18,678,566.03	59,868,017.84
35317	Structures & Foundn.	215,171,016.60	-33,789,952.69	181,381,063.91
35319	Relay & Control Eqp.	153,266,771.48	-25,324,728.98	127,942,042.50
35321	Storage Battery Eqp.	7,365,418.33	-1,028,998.09	6,336,420.24
35323	Auxiliary Power Eqp.	3,407,910.21	-535,908.59	2,872,001.62
35325	Grounding System	28,750,803.04	-3,889,830.70	24,860,972.34
35327	Bus,Wire,Cable&Insul	156,668,029.46	-29,300,601.07	127,367,428.39
35329	Station Lighting	2,123,049.37	-489,171.71	1,633,877.66
35331	Mobile Substation	4,495,245.13	-831,297.60	3,663,947.53
35333	Mobile Circuit Swtcr	227,698.97	-65,722.78	161,976.19
35337	Crane Or Hoist	850.74	-592.65	258.09
35339	Fire Protection Sys.	91,267.57	-24,436.02	66,831.55
35340	GSU and Assoc Equip	131,750,391.06	-24,089,149.83	107,661,241.23
35341	Supervsry Cont Equip	16,839,998.62	-7,441,130.97	9,398,867.65
35342	Sprvsry Cntl Eqp 353	745,899.80	-181,716.24	564,183.56
35343	Dispatch Comp. Sys.	24,674.82	-17,944.43	6,730.39
35344	Dsptch Comp Sys(353)	18,339.61	-5,040.37	13,299.24
35345	Dispatch Hardware	952,146.51	-576,119.39	376,027.12
35347	Dsptch Strg Btry Eqp	8,490.14	-5,780.88	2,709.26
35348	Dsptch Strg Btry 353	59,785.18	-16,569.88	43,215.30
35349	Dispatch Time Stdrd	15,974.97	-8,447.80	7,527.17
35350	Dsptch Time Std(353)	44,875.51	-14,422.18	30,453.33
	PacifiCorp Total	1,662,034,820.87	(301,686,876.05)	1,360,347,944.82

		$	Percent	
35340	Step-up Transformers included in Acct 353	107,661,241.23	7.914243%	Production
	Acct 353 other than step-up transformers	1,252,686,703.59	92.085757%	Transmission
35300-35399	Account 353 Station Equipment	1,360,347,944.82	100.000000%	

PacifiCorp
12 Months Ended June 2012
Tax Depreciation

	Total	Production	Transmission	Distribution	General	Mining
Total	1,141,430,297	395,413,215	402,045,870	243,865,335	88,502,212	11,603,665

Conversion to COS Functions	Total	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service	DSM
Percent of GenPlant in Functions (%'s developed in JAM Dec 2014 - use "Total Plant" variable)	100.0000%	51.6196%	1.7917%	30.4394%	0.0000%	5.6714%	6.9542%	3.5237%	0.0000%
Allocation of GenPlant to Functions	88,502,212	45,684,476	1,585,719	26,939,512	-	5,019,284	6,154,652	3,118,570	-
Assignment of Mining to Prod Function	11,603,665	11,603,665							
Adjusted Totals	1,141,430,297	452,701,356	403,631,589	270,804,847	-	5,019,284	6,154,652	3,118,570	-
TAXDEPR FACTOR	100.0000%	39.6609%	35.3619%	23.7250%	0.0000%	0.4397%	0.5392%	0.2732%	0.0000%

PacifiCorp
12 Months Ended June 2012
Gross Plant
(In 000's)

Description	Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
Production Plant		P	10,766,305	10,766,305	0	0	0	0	0	0	0
Transmission Plant		T	5,276,344	0	5,276,344	0	0	0	0	0	0
Distribution Plant		DPW	5,966,687	0	0	5,785,024	0	0	181,662	0	0
Mining	SE	P	482,121	482,121	0	0	0	0	0	0	0
General Plant				0	0	0	0	0	0	0	0
Business Centers	CN	B_Center	24,957	0	0	0	0	19,073	0	5,884	0
Utah Mine	SE	P	646	646	0	0	0	0	0	0	0
	SG	P	211,998	211,998	0	0	0	0	0	0	0
	SG	T	216	0	216	0	0	0	0	0	0
	SO	DPW	0	0	0	0	0	0	0	0	0
	SG	P	0	0	0	0	0	0	0	0	0
	SG	DPW	0	0	0	0	0	0	0	0	0
	SG	P	0	0	0	0	0	0	0	0	0
General Plant	SITUS	DPW	218,642	0	0	211,985	0	0	6,657	0	0
General Plant	SITUS	P	0	0	0	0	0	0	0	0	0
General Plant	SITUS	TD	294,275	0	138,103	151,417	0	0	4,755	0	0
Total General Plant			750,734	212,644	138,319	363,402	0				0
Intangible Plant											
	CN	CSS_SYS	112,500	0	0	0	0	61,875	20,250	30,375	0
	SE	P	3,662	3,662	0	0	0	0	0	0	0
	SG	P	0	0	0	0	0	0	0	0	0
	SG	PTD	0	0	0	0	0	0	0	0	0
	SG	T	47,647	0	47,647	0	0	0	0	0	0
	SG	P	232,665	232,665	0	0	0	0	0	0	0
	SG	P	48,902	48,902	0	0	0	0	0	0	0
	SO	CUST	2,680	0	0	0	0	1,474	482	724	0
	SO	C_METER	2,908	0	0	0	0	0	2,908	0	0
	SO	C_BILLING	2,179	0	0	0	0	2,179	0	0	0
	SO	DPW	24,000	0	0	23,269	0	0	731	0	0
	SO	P	29,275	29,275	0	0	0	0	0	0	0
	SO	PTD	303,714	148,568	72,810	79,830	0	0	2,507	0	0
	SO	TD	12,688	0	5,954	6,528	0	0	205	0	0
	SO	LABOR	0	0	0	0	0	0	0	0	0
Total Intangible Plant			822,820	463,071	126,411	109,627	0				0
Total Gross Plant			24,065,010	11,924,141	5,541,075	6,258,054	0	84,601	220,157	36,983	0
	GP Factor		100.0000%	49.5497%	23.0254%	26.0048%	0.0000%	0.3516%	0.9148%	0.1537%	0.0000%

Functional Allocators:		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TD	100.0000%	0.0000%	46.9299%	51.4543%	0.0000%	0.0000%	1.6158%	0.0000%	0.0000%
B_Center	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	76.4237%	0.0000%	23.5763%	0.0000%
CSS_SYS	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%
C_BILLING	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
C_METER	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
C_SERVICE	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.9554%	0.0000%	0.0000%	3.0446%	0.0000%	0.0000%
PTD	100.0000%	48.9170%	23.9732%	26.2844%	0.0000%	0.0000%	0.8254%	0.0000%	0.0000%
LABOR	100.0000%	44.0903%	5.3281%	26.6736%	0.0000%	6.6432%	11.2934%	5.9714%	0.0000%

PacifiCorp
12 Months Ended June 2012
Account 456

Main Account	Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
456	SO	DMSC	1,870	0	0	1,870	0	0	0	0	0
456	SE	P	31,656	31,656	0	0	0	0	0	0	0
456	SE	T	11,357	0	11,357	0	0	0	0	0	0
456	SG	P	55,130	55,130	0	0	0	0	0	0	0
456	SG	T	63,169	0	63,169	0	0	0	0	0	0
456	SO	DMSC	-27	0	0	-27	0	0	0	0	0
456	SITUS	DMSC	51,572	0	0	51,572	0	0	0	0	0
456	SITUS	P	299	299	0	0	0	0	0	0	0
Total Situs Revenues			51,871	299	0	51,572	0	0	0	0	0
Total CN Revenues			0	0	0	0	0	0	0	0	0
Total SE Revenues			43,013	31,656	11,357	0	0	0	0	0	0
Total SG Revenues			118,299	55,130	63,169	0	0	0	0	0	0
Total SO Revenues			1,843	0	0	1,843	0	0	0	0	0
Total Operation			215,027	87,085	74,526	53,416	0	0	0	0	0
OTHSITUS			100.0000%	0.5770%	0.0000%	99.4230%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
CN Factor			0.0000%								
OTHSE			100.0000%	73.5954%	26.4046%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
OTHSG			100.0000%	46.6024%	53.3976%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
OTHSO			100.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Total Operation Factor			100.0000%	40.4996%	34.6590%	24.8413%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	46.93%	51.45%	0.00%	0.00%	1.62%	0.00%	0.00%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
DPW	100.00%	0.00%	0.00%	96.96%	0.00%	0.00%	3.04%	0.00%	0.00%
PTD	100.00%	48.92%	23.97%	26.28%	0.00%	0.00%	0.83%	0.00%	0.00%
DMSC	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Docket No. UE 263
Exhibit PAC/1107
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Oregon Marginal Cost Study

March 2013

PacifiCorp
Oregon Marginal Cost Study
December 2014

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PacifiCorp
Marginal Cost Study & Circuit Model Procedures

INTRODUCTION

Customer class marginal costs are developed to illustrate the resources required to produce one additional unit of electricity or add one additional customer to the system. One, five, ten and twenty years marginal costs are calculated because the Company believes the Commission should have information about the Company's marginal costs over different time periods. Twenty-year (or long run) marginal costs, however, are the primary time frame used in setting retail tariff prices.

The one-year marginal costs include only changes in operating costs, while ten- and twenty-year marginal costs also include the cost of expanding facilities. The cost of added facilities results in long-run costs, which are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. There are no short-run demand-related generation, transmission or distribution costs. Long-run costs include ten or twenty years of generation costs, transmission and distribution costs.

One, ten and twenty-year marginal costs are summarized by customer class and load size group and shown in mills/kilowatt-hour (kWh). Marginal commitment costs and billing expenses, which are sometimes referred to as customer costs, are shown in dollars per customer per year. Costs are shown for both the one-year and the long-run time periods.

Unit costs are adjusted to 2014 values and are shown by generation, transmission, and distribution functional categories and by demand, energy, and commitment and billing costing classifications. Also included are energy usage, peak demand, and number of customers by customer class for the 12 month period ending December 2014.

One, ten and twenty-year marginal costs in mills/kilowatt-hour (kWh) are shown on "Summary of Marginal Costs Demand & Energy in Mills/kWh" (Sheet 'Table 1'). Marginal commitment costs and billing expenses are shown on "Summary of Marginal Costs Commitment and Billing in $ / Customer / Month" (Sheet 'Table 2'). Unit costs and billing information are shown on "20 Year Costing Inputs and Customer Data Marginal Unit Costs" (Sheet 'Table 3') and total marginal costs are shown on "20 Year Marginal Cost By Load Class" (Sheet 'Table 4').

MARGINAL GENERATION COSTS

The development of marginal generation costs for this study is consistent with the analysis done to prepare the Company's avoided costs filings. Marginal generation costs are based on the Company's most recent avoided cost calculations. The analysis recognizes that baseload generation produces the dual products of capacity and energy. The new resource costs are based on the fixed and variable cost of a Combined Cycle Combustion Turbine (CCCT), which operates as a baseload unit. The cost of the CCCT is split into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT) defines the fixed costs of the CCCT that are assigned to capacity. CCCT fixed costs which are in excess of SCCT fixed costs are assigned to energy. They are added to the variable production cost of the CCCT and renewable wind resource costs. Renewable resource costs are included in the marginal cost of service study for the first time in the current case. These costs are based on a Wyoming wind facility (35% capacity factor) as shown in Table 6.3 of the Company's 2011 integrated resource plan ("IRP") and are weighted according to the Oregon RPS requirements for each year during the long-run marginal cost period. Weightings of five percent for 2014, fifteen percent for 2015-2019, twenty percent for 2020-2024, and twenty-five percent for 2025-2032 are applied to renewables resource costs. Non-renewable marginal energy costs are reduced by the renewable weighting percentage, added to the weighted renewable costs. Total energy and capacity costs are present valued, summed and an annual charge applied to the total. The marginal generation cost calculation is shown in the cost of service study on sheet "Summary of Marginal Generation Costs In Nominal Dollars" (Sheet 'Table 5').

MARGINAL TRANSMISSION COSTS
The calculation of transmission costs are based on a five-year (2014-2018) analysis of forecasted expenditures to meet increased load on the transmission system. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand.

Unlike growth-related system support and local transmission investments, the Company's investment in bulk power lines is classified both to demand and energy in the same proportions as twenty-year marginal costs of generation resources. Bulk transmission costs are classified this way because they are thought to be an integral part of the generation system. The Company's investments in high voltage bulk transmission lines are being made to move both energy and capacity. It is usually not possible to site a thermal plant close to the customers the plant is intended to serve. Instead, bulk power lines are constructed to transmit the energy being generated, along with the accompanying capacity.

Each year's growth-related transmission investments are adjusted to 2014 dollars and the five years are totaled. The total transmission investment is divided by the forecasted growth in system demand over the 5-year period to determine the marginal investment per kilowatt (kW). An annual charge for including an A&G expense loading factor and a transmission O&M loading factor are added to the per kW investment to arrive at long-run transmission marginal cost.

The marginal transmission calculation including the split between demand and energy can be seen in the marginal cost study on page "Marginal Transmission Investment and O&M Expenses" (Sheet 'Transm1'). A summarized version of this page is "Marginal Cost of Transmission Investment and Associated Expenses" (Sheet 'Table 6').

MARGINAL DISTRIBUTION COSTS
Distribution costs are classified into three components: Demand-related, shown in dollars per kW/year, commitment-related, shown in dollars per customer/year, and billing-related, shown in dollars per customer/year. Commitment costs consist of the costs of transformers, poles, and conductor that are not determined by the level of demand customers place on the system. Demand-related costs are the additional costs of larger

transformers, substations, poles, and conductors with sufficient capacity to serve the level of demand a customer class places on the system. Billing costs are the costs of meters, service drops, and customer accounting functions.

A summary of distribution marginal costs showing these three components are on page "Marginal Distribution & Billing Costs By Load Size 2014 Dollars" (Sheet 'Table 7').

Marginal line transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of the statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Line transformer regression results are shown on page "Calculation of Escalation Factors for Transformers (Regression weighted by number of transformer banks)" (Sheet 'XFMR3'). Transformer demand costs are shown on page "Transformer Demand Costs" (Sheet 'XFMR2') and commitment costs are shown on page "Transformer Commitment Costs by Customer Load Class" (Sheet 'XFMR1').

Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model (Sheets 'PC3' through 'PC14'). The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics for the state of Oregon. The model determines the cost of the circuit by using current cost estimates to construct one mile of distribution facilities using each of the Company's single and three phase wire sizes. The results are segregated into commitment related and demand related costs for each customer class. A more detailed description of the circuit model is included as an appendix to this narrative.

Marginal poles and wire costs are shown on page "Hypothetical Circuit Study Results Annual Demand and Commitment Costs" (Sheet 'PC1').

Marginal substation costs are determined using the per kW cost of budgeted and forecasted substation additions for the five year period 2012 - 2016. As part of the capital budgeting process the company determines which substations are approaching their maximum design loading. When load can no longer be shifted to adjacent substations, an upgrade, either greater capacity at the substation or a new substation, is required. The capital investment in common year dollars is totaled across all projects and across the budget-planning horizon to produce total substation investment. The substation investment is divided by the associated incremental substation capacity to get dollars / kW. The dollars per kW is adjusted to an annual value by applying a real levelized carrying charge. Substation marginal costs are classified entirely to demand, and are allocated to customer classes based on the distribution peak load for each class.

Page "Substation Investment" (Sheet 'Dist Sub 2') shows the detail of the substation calculation. "Distribution Substation Costs / kW 2014 Dollars" (Sheet 'Dist Sub 1') shows the annualized cost in $/kW.

The marginal cost of services includes the costs of new service drop investment plus associated O&M expense. Average service drop investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Incremental service drop O&M is based on the average of ten years of historical expenditures.

The metering category includes the marginal cost of metering equipment with associated O&M expense. Average meter investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M expense is based on historical expenditures.

The billing customer service/other category includes the costs of billing, payment processing, debt recovery, meter reading expenses and all remaining customer accounting and customer service activities. Customer accounting and customer service expense are based on the most recent five years of expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

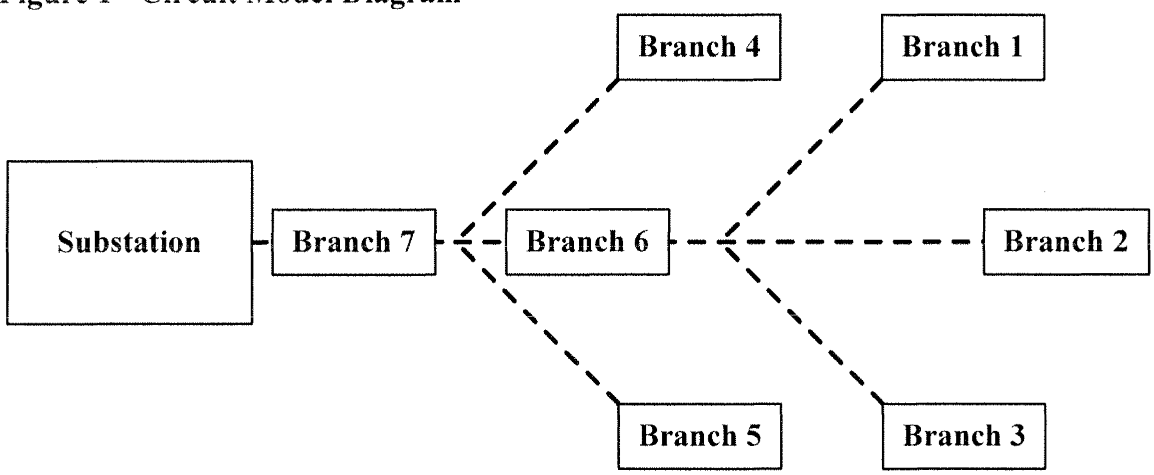
Weighted average installed service drop cost calculations are located on Sheets 'Services 1' through 'Services 3' and the weighted average installed meter cost calculations are included on Sheets 'Meters 1' through 'Meters 5'. The customer accounting and informational expense calculation is on page "Summary of Customer Accounting Expense by Schedule" (Sheet 'Cust Exp Sum'). These calculations are brought together on "Marginal Distribution & Billing Costs By Load Size" (Sheet 'Table 7') to calculate metering reading, billing, collections and customer service related costs ($/Customer/Yr).

PacifiCorp
Distribution Circuit Model
PacifiCorp Distribution Circuit Model

General Overview

The PacifiCorp Distribution Circuit Model is included in Exhibit PAC/1107, Sheets PC 3 through PC 14 and calculates the cost of building a hypothetical circuit (Figure 1, below) with seven branches of equal length using the composite line statistics for a chosen state or service area. A hypothetical circuit is used rather than a sampling of actual existing circuits. This is because the diverse characteristics of PacifiCorp's six state service area, consisting of over 2,000 distribution circuits, makes the selection of any single, or small number of typical circuits impractical. The fundamental concept of the hypothetical circuit is to create a model that reduces the elements of distribution cost assignment to a workable form.

Figure 1 - Circuit Model Diagram



The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and perhaps most importantly, customer location on the circuit. Each customer is assigned cost responsibility for all distribution facilities between the customer's location and the substation (upstream facilities), but no facilities beyond the customer's service location (downstream facilities). The model performs three basic functions. First, it estimates the total cost to build the composite circuit using current construction costs and state specific characteristics. Second, it divides the cost of each branch of the circuit between demand and commitment related costs. Third, it assigns the various types of costs to customer classes.

Required Engineering & Statistical Data

Listed below are the basic statistics that we use to calculate the composite circuit for a given state:

1. Current One Mile Line Construction Cost Estimates for Each Conductor Size
2. Economic Conductor Loading for Each Conductor Size

3. Overhead and Underground Line Miles
4. Number of Poles
5. Number of Circuits -- distribution line points of origin radiating from a substation.
6. Actual Customer Distances from Distribution Substations
7. Number of Customers and Loads by Class
8. Percentages of Three-Phase and Single-Phase Customers by Class

One Mile Line Estimate
The model determines the cost of the circuit by using cost estimates to construct one mile of distribution facilities using each of the Company's single and three-phase wire sizes. These cost estimates are based on typical topography and equipment configuration for an average mile of line construction. Since the number of poles per mile varies between states, we use a factor to adjust the line cost estimate from the system wide average of 26.13 poles per mile to the state average poles per mile. For example, Oregon has an average of 25.86 poles per mile. Figure 2 shows the circuit cost per mile calculation for Oregon.

Figure 2 – Adjusted Oregon Line Costs per Mile

	Wire Sizes	Account 364 Pole Cost per Mile Pole Cost per Mile	 Adjustment Factor	 Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1	1 Phase -1/0 ACSR	$ 27,300	0.990	$ 27,027	$ 13,053	$ 40,080
2	3 Phase - 1/0 ACSR	$ 47,186	0.990	$ 46,714	$ 28,680	$ 75,394
3	3 Phase - 447 AAC & 4\0 AAC	$ 53,129	0.990	$ 52,598	$ 47,812	$ 100,410
4	3 Phase -795 AAC & 477 AAC	$ 56,254	0.990	$ 55,691	$ 105,804	$ 161,495

State	State Specific Account 364 Pole Statistics Poles	 Pole Feet	 Pole Miles	 Poles / Mile	Adjustment Factor
California	55,887	12,430,368	2,354	23.74	0.908
Idaho	99,188	22,947,921	4,346	22.82	0.873
Oregon	371,373	75,818,501	14,360	25.86	0.990
Utah	350,610	60,059,546	11,375	30.82	1.180
Washington	98,696	18,879,273	3,576	27.60	1.056
Wyoming	155,389	38,426,986	7,278	21.35	0.817
Total	1,131,143	228,562,595	43,288	26.13	1.000

Customer Placement
One of the most significant cost drivers of marginal distribution costs is the distance between the customer and the substation. Costs increase as the distance from the substation increases.

The circuit model takes distance into account by assigning customers to the different branches of the circuit based upon actual customer locations. The actual customer distances are derived from PacifiCorp's outage management system (CADOPS). The system is able to accurately trace the flow of electricity from substation to customer as well as ascertain the exact distance it must travel.
Figure 3 shows the Customer Distribution on the Hypothetical Circuit Branch for Oregon.

Figure 3 Customer Distribution

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
		1	2	3	4	5	6	7	Total
1	Residential	0.90%	0.90%	0.90%	3.62%	3.62%	3.62%	86.45%	100.00%
2	GS 0-15 kW (sec) (23)	1.30%	1.30%	1.30%	3.92%	3.92%	3.92%	84.34%	100.00%
3	GS >15 kW (sec) (23)	1.30%	1.30%	1.30%	3.92%	3.92%	3.92%	84.34%	100.00%
4	GS (pri) (23)	1.30%	1.30%	1.30%	3.92%	3.92%	3.92%	84.34%	100.00%
5	GS < 50 kW (sec) (28)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
6	GS 51-100 kW (sec) (28)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
7	GS > 100 kW (sec) (28)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
8	GS (pri) (28)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
9	GS 0-300 kW (sec) (30)	0.52%	0.52%	0.52%	1.26%	1.26%	1.26%	94.65%	100.00%
10	GS >300 kW (sec) (30)	0.52%	0.52%	0.52%	1.26%	1.26%	1.26%	94.65%	100.00%
11	GS (pri) (30)	0.52%	0.52%	0.52%	1.26%	1.26%	1.26%	94.65%	100.00%
12	Irrigation	2.56%	2.56%	2.56%	12.34%	12.34%	12.34%	55.31%	100.00%
13	Large GS 1 - 4 MW (sec)	-	-	-	1.65%	1.65%	1.65%	95.05%	100.00%
14	Large GS 1 - 4 MW (pri)	-	-	-	1.65%	1.65%	1.65%	95.05%	100.00%
15	Large GS + 4 MW (sec)		Large customer are on dedicated circuits and are not included here.						
16	Large GS + 4 MW (pri)		Large customer are on dedicated circuits and are not included here.						

Customer Density

The next significant driver of distribution costs is customer density. The model uses state specific line and customer statistics to calculate the average number of customers by circuit branch. Total state distribution line miles and state customers, by class, are divided by the number of distribution circuits in the state to determine the average length of the composite circuit (line miles / number of circuits) and the number of customers on the circuit (customers / circuits). Figure 4 shows the average number of customers located on each of the seven circuit branches for Oregon.

Figure 4 – Oregon Average Customers by Hypothetical Circuit Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							
		1	2	3	4	5	6	7	Total
	Average Customers								
1	Residential	8.07	8.07	8.07	32.66	32.66	32.66	779.38	901.58
2	GS 0-15 kW (sec) (23)	1.64	1.64	1.64	4.93	4.93	4.93	106.10	125.80
3	GS >15 kW (sec) (23)	0.26	0.26	0.26	0.79	0.79	0.79	17.00	20.16
4	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.08
5	GS < 50 kW (sec) (28)	0.07	0.07	0.07	0.18	0.18	0.18	7.80	8.53
6	GS 51-100 kW (sec) (28)	0.05	0.05	0.05	0.14	0.14	0.14	6.00	6.57
7	GS > 100 kW (sec) (28)	0.03	0.03	0.03	0.08	0.08	0.08	3.35	3.66
8	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
9	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	0.39	0.41
10	GS >300 kW (sec) (30)	0.01	0.01	0.01	0.01	0.01	0.01	0.99	1.05
11	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10
12	Irrigation	0.35	0.35	0.35	1.69	1.69	1.69	7.58	13.71
13	Large GS 1 - 4 MW (sec)	-	-	-	0.00	0.00	0.00	0.19	0.20
14	Large GS 1 - 4 MW (pri)	-	-	-	0.00	0.00	0.00	0.12	0.12
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	10.48	10.48	10.48	40.49	40.49	40.49	929.17	1,082.07

Load Accumulation

The kW load that a customer or class places on the system influences the size of the conductor necessary to serve the load. At each point on the circuit, the conductor must be sized to carry the entire downstream load. At the far ends of the outer branches, loads are minimal. As you move upstream closer to the substation, the load on the circuit becomes greater requiring larger conductor sizes. In the model, load can accumulate two ways. The first occurs as customers accumulate on a branch of the circuit. When enough customers, or load, accumulate it is necessary to increment up to the next wire size. Upstream from that point, customer segments increase in cost due to the increase in wire size. The second method of load accumulation is when several branches converge at a central point on the trunk of the circuit. The trunk branches must be of adequate size to carry the load of the customers on that branch plus all downstream branches.

Figure 5 shows the circuit kW loading on each of the circuit branches for Oregon. Loads are for customers located on that branch. Accumulated loads for branch 6 would be the combined loads of branches 1, 2, 3 and 6. Accumulated loads for branch 7 would be the combined loads of all branches.

Figure 5 – Oregon Circuit kW Load by Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							
		1	2	3	4	5	6	7	Total
	Circuit kW Loads								
1	Residential	16.6	16.6	16.6	67.2	67.2	67.2	1,603.2	1,854.6
2	GS 0-15 kW (sec) (23)	2.2	2.2	2.2	6.6	6.6	6.6	142.5	169.0
3	GS >15 kW (sec) (23)	1.8	1.8	1.8	5.4	5.4	5.4	115.7	137.2
4	GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3
5	GS < 50 kW (sec) (28)	1.1	1.1	1.1	3.1	3.1	3.1	134.8	147.4
6	GS 51-100 kW (sec) (28)	1.6	1.6	1.6	4.3	4.3	4.3	189.4	207.1
7	GS > 100 kW (sec) (28)	2.0	2.0	2.0	5.5	5.5	5.5	242.7	265.3
8	GS (pri) (28)	0.0	0.0	0.0	0.1	0.1	0.1	5.8	6.3
9	GS 0-300 kW (sec) (30)	0.3	0.3	0.3	0.7	0.7	0.7	53.6	56.6
10	GS >300 kW (sec) (30)	1.6	1.6	1.6	4.0	4.0	4.0	296.3	313.0
11	GS (pri) (30)	0.1	0.1	0.1	0.4	0.4	0.4	26.9	28.4
12	Irrigation	1.3	1.3	1.3	6.2	6.2	6.2	28.0	50.6
13	Large GS 1 - 4 MW (sec)	-	-	-	2.6	2.6	2.6	151.9	159.9
14	Large GS 1 - 4 MW (pri)	-	-	-	2.2	2.2	2.2	124.0	130.5
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	28.8	28.8	28.8	108.3	108.3	108.3	3,115.0	3,526.2

Circuit Model Cost Assignment

Line statistics for the PacifiCorp service area show that the distribution system is predominately overhead. To calculate the cost of branch construction, miles per branch is calculated by taking the distance per circuit (total line miles / total number of circuits) and dividing it by the number of branches per circuit (7 branches, see figure 1). Next, using an assumption from distribution engineers that the typical outer branches are 35% single phase, the circuit branch length is split between single and three-phase. The total branch construction cost can then be calculated by taking the single and three-phase distances per branch and multiplying them by the one mile construction costs for poles and conductors, as shown in figure 6. Costs are split between demand and commitment by assuming that the cost of constructing the branch with the smallest single-phase conductor and smallest pole is the commitment related portion and all costs above this amount are demand related. Trunk branches 6 and 7 are shown as 100% three-phase. Figure 6 shows the circuit costs per mile, costs for each branch and miles per branch broken out by single and three-phase for Oregon.

Figure 6 – Adjusted Oregon Line Costs per Mile

Wire Sizes		Account 364 Pole Cost per Mile: Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1 Phase -1/0 ACSR		$ 27,300	0.990	$ 27,027	$ 13,053	$ 40,080
3 Phase - 1/0 ACSR		$ 47,186	0.990	$ 46,714	$ 28,680	$ 75,394
3 Phase - 447 AAC & 4\0 AAC		$ 53,129	0.990	$ 52,598	$ 47,812	$ 100,410
3 Phase -795 AAC & 477 AAC		$ 56,254	0.990	$ 55,691	$ 105,804	$ 161,495

	Costs for Branches 1,2,3,4,5			
Wire Size	1 Phase -1/0 ACSR	3 Phase - 1/0 ACSR	Total	
Poles	$ 49,991	$ 160,467	$ 210,458	
Conductors	$ 24,144	$ 98,518	$ 122,662	
Total	$ 74,134	$ 258,985	$ 333,120	
	Costs for Branch 6		**Cost for Branch 7**	
Wire Size	3 Phase - 447 AAC & 4\0 AAC		3 Phase -795 AAC & 477 AAC	
Poles	$ 277,965		$ 294,315	
Conductors	$ 252,674		$ 559,147	
Total	$ 530,640		$ 853,462	

Miles per Branch	5.28
Single Phase Miles Per Branch	1.85
Three Phase Miles Per Branch	3.44

Customer Circuit Costs

After calculating the cost per mile for single and three-phase construction for all of the branches, we compile the data and create a hypothetical circuit model branch cost sheet, as shown in figure 7. Figure 7 includes the total cost per circuit branch in columns (A) and (B), and the allocation of total cost between commitment and demand in columns (C) through (F) for Oregon.

Figure 7 – Oregon Hypothetical Circuit Model Branch Costs

Conductors Type	(A) Total Cost: Poles	(B) Total Cost: Conductor	(C) Commitment Cost: Poles	(D) Commitment Cost: Conductor	(E) Demand Cost: Poles	(F) Demand Cost: Conductor
Branch 1						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total segment	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 2						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total Segments	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 3						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total Segments	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 4						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total Segments	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 5						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total Segments	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 277,965	$ 252,674	$ 142,831	$ 68,982	$ 135,135	$ 183,692
Total Segments	$ 277,965	$ 252,674	$ 142,831	$ 68,982	$ 135,135	$ 183,692
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 294,315	$ 559,147	$ 142,831	$ 68,982	$ 151,484	$ 490,165
Total segment	$ 294,315	$ 559,147	$ 142,831	$ 68,982	$ 151,484	$ 490,165

Cost Sharing Calculation

As mentioned before, one of the critical factors of cost-responsibility is the location of a customer or class on the circuit branches. Customer classes that locate on all branches share cost responsibility for all branches of the circuit including the trunk. Large industrial customers, who locate on the trunk of the circuit, share cost responsibility for only the trunk. Cost responsibility is determined by calculating the percentage of demand, or percentage of customers, by class that share a particular branch of the circuit. The total branch costs are then multiplied by the share percentage, and the branch costs are totaled by class. To calculate the total branch cost, the applicable cost of branches 6 and 7 are assigned to customers on branches 1, 2, 3, 4 and 5. Demand costs calculated in an earlier step are allocated between customer classes at this point. Figure 8 shows this calculation along with the allocation of branch costs to the individual customer classes for Oregon. Demand costs are totaled for each customer class and divided by circuit kW to get demand cost in dollars per kW.

Figure 8 – Oregon Poles Demand Calculations, Cost Assignment

Line	Branch	1	2	3	4	5	6	7		
1	% Demand	14.78%	14.78%	14.78%	NA	NA	55.66%	NA	100.00%	
2	Branch 6 Cost	$ 19,973	$ 19,973	$ 19,973	NA	NA	$ 75,215	NA	$ 135,135	**$ / kW**
3	% Demand	0.82%	0.82%	0.82%	3.07%	3.07%	3.07%	88.34%	100.00%	
4	Branch 7 Cost	$ 1,235	$ 1,235	$ 1,235	$ 4,652	$ 4,652	$ 4,652	$ 133,822	$ 151,484	
5	Branch Demand Cost	$ 67,627	$ 67,627	$ 67,627	$ 67,627	$ 67,627	NA	NA		Average
6	Total	$ 88,835	$ 88,835	$ 88,835	$ 72,279	$ 72,279	$ 79,868	$ 133,822	$ 624,754	$ 177.18
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 51,297	$ 51,297	$ 51,297	$ 44,845	$ 44,845	$ 49,553	$ 68,876	$ 362,008	$ 195.19
11	GS 0-15 kW (sec) (23)	$ 6,792	$ 6,792	$ 6,792	$ 4,418	$ 4,418	$ 4,882	$ 6,122	$ 40,217	$ 238.03
12	GS >15 kW (sec) (23)	$ 5,516	$ 5,516	$ 5,516	$ 3,588	$ 3,588	$ 3,965	$ 4,972	$ 32,659	$ 238.03
13	GS (pri) (23)	$ 14	$ 14	$ 14	$ 9	$ 9	$ 10	$ 12	$ 80	$ 238.03
14	GS < 50 kW (sec) (28)	$ 3,482	$ 3,482	$ 3,482	$ 2,049	$ 2,049	$ 2,264	$ 5,790	$ 22,597	$ 153.35
15	GS 51-100 kW (sec) (28)	$ 4,893	$ 4,893	$ 4,893	$ 2,880	$ 2,880	$ 3,182	$ 8,136	$ 31,756	$ 153.35
16	GS > 100 kW (sec) (28)	$ 6,269	$ 6,269	$ 6,269	$ 3,690	$ 3,690	$ 4,077	$ 10,425	$ 40,688	$ 153.35
17	GS (pri) (28)	$ 149	$ 149	$ 149	$ 88	$ 88	$ 97	$ 247	$ 966	$ 153.35
18	GS 0-300 kW (sec) (30)	$ 913	$ 913	$ 913	$ 477	$ 477	$ 527	$ 2,301	$ 6,520	$ 115.21
19	GS >300 kW (sec) (30)	$ 5,050	$ 5,050	$ 5,050	$ 2,637	$ 2,637	$ 2,914	$ 12,728	$ 36,065	$ 115.21
20	GS (pri) (30)	$ 458	$ 458	$ 458	$ 239	$ 239	$ 264	$ 1,155	$ 3,273	$ 115.21
21	Irrigation	$ 4,004	$ 4,004	$ 4,004	$ 4,166	$ 4,166	$ 4,604	$ 1,202	$ 26,151	$ 516.84
22	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 1,759	$ 1,759	$ 1,943	$ 6,528	$ 11,988	$ 75.00
23	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 1,435	$ 1,435	$ 1,586	$ 5,328	$ 9,785	$ 75.00
24	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Check Total	$ 88,835	$ 88,835	$ 88,835	$ 72,279	$ 72,279	$ 79,868	$ 133,822	$ 624,754	

Commitment costs are calculated using a similar method. Commitment costs calculated in an earlier step are allocated to classes using percent of customers on a given branch. Commitment dollars are totaled by customer class then divided by the number of customers in the class to get commitment costs in dollars per customer. Figure 9 shows these calculations for Oregon.

Figure 9–Oregon Poles Commitment Calculations, Cost Assignment

	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	14.78%	14.78%	14.78%	NA	NA	55.66%	NA	100.00%	
2	Branch 6 Cost	$ 27,150	$ 27,150	$ 27,150	NA	NA	$ 102,243	NA	$ 183,692	$ / kW
3	% Demand	0.82%	0.82%	0.82%	3.07%	3.07%	3.07%	88.34%	100.00%	
4	Branch 7 Cost	$ 3,997	$ 3,997	$ 3,997	$ 15,053	$ 15,053	$ 15,053	$ 433,013	$ 490,165	
5	Branch Demand Cost	$ 53,680	$ 53,680	$ 53,680	$ 53,680	$ 53,680	NA	NA		average
6	Total	$ 84,827	$ 84,827	$ 84,827	$ 68,734	$ 68,734	$ 117,296	$ 433,013	$ 942,258	$ 267.22
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 48,982	$ 48,982	$ 48,982	$ 42,645	$ 42,645	$ 72,775	$ 222,865	$ 527,877	$ 284.63
11	GS 0-15 kW (sec) (23)	$ 6,486	$ 6,486	$ 6,486	$ 4,202	$ 4,202	$ 7,170	$ 19,810	$ 54,840	$ 324.57
12	GS >15 kW (sec) (23)	$ 5,267	$ 5,267	$ 5,267	$ 3,412	$ 3,412	$ 5,823	$ 16,087	$ 44,533	$ 324.57
13	GS (pri) (23)	$ 13	$ 13	$ 13	$ 8	$ 8	$ 14	$ 39	$ 109	$ 324.57
14	GS < 50 kW (sec) (28)	$ 3,324	$ 3,324	$ 3,324	$ 1,949	$ 1,949	$ 3,326	$ 18,733	$ 35,930	$ 243.83
15	GS 51-100 kW (sec) (28)	$ 4,672	$ 4,672	$ 4,672	$ 2,739	$ 2,739	$ 4,673	$ 26,326	$ 50,492	$ 243.83
16	GS > 100 kW (sec) (28)	$ 5,986	$ 5,986	$ 5,986	$ 3,509	$ 3,509	$ 5,988	$ 33,731	$ 64,695	$ 243.83
17	GS (pri) (28)	$ 142	$ 142	$ 142	$ 83	$ 83	$ 142	$ 801	$ 1,535	$ 243.83
18	GS 0-300 kW (sec) (30)	$ 872	$ 872	$ 872	$ 453	$ 453	$ 774	$ 7,446	$ 11,742	$ 207.47
19	GS >300 kW (sec) (30)	$ 4,822	$ 4,822	$ 4,822	$ 2,507	$ 2,507	$ 4,279	$ 41,186	$ 64,945	$ 207.47
20	GS (pri) (30)	$ 438	$ 438	$ 438	$ 228	$ 228	$ 388	$ 3,738	$ 5,895	$ 207.47
21	Irrigation	$ 3,824	$ 3,824	$ 3,824	$ 3,962	$ 3,962	$ 6,761	$ 3,890	$ 30,046	$ 593.81
22	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 1,672	$ 1,672	$ 2,854	$ 21,122	$ 27,321	$ 170.91
23	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 1,365	$ 1,365	$ 2,329	$ 17,239	$ 22,299	$ 170.91
24	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Check Total	$ 84,827	$ 84,827	$ 84,827	$ 68,734	$ 68,734	$ 117,296	$ 433,013	$ 942,258	

Large Industrial Customers

Distribution studies have shown that very large industrial customers are not placed on a circuit in the same manner as residential or smaller commercial and industrial customers. Rather the customer is located very close to a substation (the average distance in Oregon is 2/3 of a mile) and has a dedicated circuit for their exclusive use. Since they have a dedicated circuit, they do not share in the costs of other common distribution investments, but they are responsible for the entire cost of the dedicated circuit. Dividing the total cost of a 2/3 of a mile circuit by the customer's kW determines the demand cost in dollars per kW for these customers. Table 10 shows this calculation for Oregon.

Table 10 – Oregon Dedicated Circuit Trunk Costs for Large Customers

	Voltage Delivery			
	Large GS + 4 MW (pri)		Large GS + 4 MW (sec)	
	Poles	Conductor	Poles	Conductor
1 Construction Cost Per Mile	$ 55,691	$ 105,804	$ 55,691	$ 105,804
2 Average Trunk Length	0.67 miles		0.67 miles	
3 Total Construction Cost	$ 37,313	$ 70,889	$ 37,313	$ 70,889
4 Customer Peak Demand	4,532 kW		3,097 kW	
5 Demand Cost $/kW	$8.23	$15.64	$12.05	$22.89

Summary

The final step in the circuit model is to bring the various results together in a single summary page. Table 11 shows the results calculated earlier in the study. Note that the $/customer and $/circuit kW is the distribution investment to serve that customer and not the price that the customer is expected to pay.

Table 11 – Oregon Summary of Results

Class	Commitment $/Customer Poles	Commitment $/Customer Conductor	Demand $/Dist. kW Poles	Demand $/Dist. kW Conductor	Typical circuit Customers	Typical circuit kW	Demand $/circuit Poles	Demand $/circuit Conductor
Residential	$ 882.45	$ 426.19	$ 195.19	$ 284.63	901.6	1,854.63	$ 362,008	$ 527,877
GS 0-15 kW (sec) (23)	$ 1,076.48	$ 519.90	$ 238.03	$ 324.57	125.8	168.96	$ 40,217	$ 54,840
GS >15 kW (sec) (23)	$ 1,076.48	$ 519.90	$ 238.03	$ 324.57	20.2	137.21	$ 32,659	$ 44,533
GS (pri) (23)	$ 1,076.48	$ 519.90	$ 238.03	$ 324.57	0.1	0.34	$ 80	$ 109
GS < 50 kW (sec) (28)	$ 673.89	$ 325.46	$ 153.35	$ 243.83	8.5	147.36	$ 22,597	$ 35,930
GS 51-100 kW (sec) (28)	$ 673.89	$ 325.46	$ 153.35	$ 243.83	6.6	207.08	$ 31,756	$ 50,492
GS > 100 kW (sec) (28)	$ 673.89	$ 325.46	$ 153.35	$ 243.83	3.7	265.33	$ 40,688	$ 64,695
GS (pri) (28)	$ 673.89	$ 325.46	$ 153.35	$ 243.83	0.1	6.30	$ 966	$ 1,535
GS 0-300 kW (sec) (30)	$ 492.62	$ 237.92	$ 115.21	$ 207.47	0.4	56.60	$ 6,520	$ 11,742
GS >300 kW (sec) (30)	$ 492.62	$ 237.92	$ 115.21	$ 207.47	1.1	313.04	$ 36,065	$ 64,945
GS (pri) (30)	$ 492.62	$ 237.92	$ 115.21	$ 207.47	0.1	28.41	$ 3,273	$ 5,895
Irrigation	$ 2,438.27	$ 1,177.59	$ 516.84	$ 593.81	13.7	50.60	$ 26,151	$ 30,046
Large GS 1 - 4 MW (sec)	$ 320.55	$ 154.81	$ 75.00	$ 170.91	0.2	159.85	$ 11,988	$ 27,321
Large GS 1 - 4 MW (pri)	$ 320.55	$ 154.81	$ 75.00	$ 170.91	0.1	130.47	$ 9,785	$ 22,299
Total -	$ 923.98	$ 446.25	$ 177.18	$ 267.22	1,082.1	3,526.2	$ 624,754	$ 942,258
Large GS + 4 MW (sec)	$ -	$ -	$ 12.05	$ 22.89	-	3,096.54	$ 37,313	$ 70,889
Large GS + 4 MW (pri)	$ -	$ -	$ 8.23	$ 15.64	-	4,531.91	$ 37,313	$ 70,889
							$ 699,380	$ 1,084,035

	Commitment	Demand	Total
Poles	$ 999,816	$ 699,380	$ 1,699,196
Conductor	$ 482,872	$ 1,084,035	$ 1,566,908
Total	$ 1,482,688	$ 1,783,416	$ 3,266,104

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2014 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
Line	Description		1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	37.71	48.32	51.05	37.71	117.05	119.77
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	37.71	48.32	51.05	37.71	113.88	116.59
5	15+ kW	(sec)	37.72	48.32	51.05	37.72	112.18	114.89
6	Primary	(pri)	36.61	47.07	49.61	36.61	105.48	107.77
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	37.71	48.32	51.05	37.71	116.25	118.97
10	51-100 kW	(sec)	37.71	48.32	51.05	37.71	110.34	113.06
11	> 101kW	(sec)	37.71	48.32	51.05	37.71	109.66	112.38
12	Primary	(pri)	36.66	46.95	49.61	36.66	104.61	107.26
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	37.72	48.32	51.05	37.72	101.75	104.48
16	301+ kW	(sec)	37.71	48.32	51.05	37.71	105.95	108.67
17	Primary	(pri)	36.65	46.96	49.61	36.65	104.26	106.91
18								
19	LPS - Schedule 48T							
20	1 - 4 MW	(sec)	37.71	48.32	51.05	37.71	104.70	107.42
21	1 - 4 MW	(pri)	36.65	46.96	49.61	36.65	97.63	100.27
22	> 4 MW	(sec)	37.72	48.33	51.05	37.72	95.41	98.11
23	> 4 MW	(pri)	36.65	46.96	49.61	36.65	93.11	95.75
24								
25	Trans	(trn)	35.84	45.92	48.51	35.84	77.10	79.68
26								
27								
28	Schedule 41- Irrigation	(sec)	37.71	48.32	51.05	37.71	106.41	109.14

Sources:
(A) Tab 2.13 (1 Year MC:) `1 Year Marginal Costs by Load Class'
(B) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(C) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2014 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'
(D) Column (A)
(E) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(F) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2014 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'

Energy costs include both generation and transmission energy-related costs.

Table 2

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Commitment and Billing in $ / Customer / Month
December 2014 Dollars

			(A)	(B)
			1 Year	10 & 20 Year
Line	Description		1&3 Phase	1&3 Phase
1	Res - Schedule 4	(sec)	$15.59	$40.93
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	17.82	50.68
5	15+ kW	(sec)	30.55	69.95
6	Primary	(pri)	179.67	198.79
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	34.00	106.24
10	51-100 kW	(sec)	35.16	115.86
11	> 101kW	(sec)	72.88	158.69
12	Primary	(pri)	182.98	194.95
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	85.85	187.16
16	301+ kW	(sec)	127.38	228.92
17	Primary	(pri)	195.89	204.64
18				
19	Total			
20	1 - 4 MW	(sec)	396.74	496.78
21	1 - 4 MW	(pri)	254.22	259.91
22	> 4 MW	(sec)	396.74	491.08
23	> 4 MW	(pri)	254.22	254.22
24	Trans	(trn)	4,465.95	4,465.95
25				
26				
27	Schedule 41- Irrigation	(sec)	10.85	127.80
28	Schedule 41- Irrigation	(sec)	10.85	127.80

Footnote:
Short-run commitment and billing costs include the cost of metering, meter overhead and maintenance, service drops, service drop overhead and maintenance, customer accounting and informational expenses, and billing expenses.

Sources:
Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2014 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrigation Sch 41
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
	Billing Units																		
	Demand																		
1	Peak MW @ Meter	System	849	91	79	0	73	101	133	3	28	153	14	78	65	7	151	94	26
2		Distribution	976	89	72	0	78	109	140	3	30	165	15	84	69	6	150	0	27
3		Transformer	3,327	184	127	2	141	189	234	19	49	259	22	132	102	14	228	164	150
4																			
5	Demand Loss Factor		1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.0792	1.1106	1.0792	1.1106	1.0792	1.0426	1.1106
6																			
7	Peak MW @ Generator	System	943	102	87	0	81	112	147	3	31	169	15	86	71	8	163	97	29
8		Distribution	1,083	99	80	0	86	121	155	4	33	183	16	93	74	7	162	N/A	30
9		Transformer	3,695	205	141	N/A	157	210	259	N/A	54	288	N/A	147	N/A	15	N/A	N/A	167
10																			
11	Energy																		
12	Energy - Annual MWh	@ Meter	5,379,569	589,432	510,378	1,147	437,292	662,698	874,287	18,574	204,293	1,041,871	91,598	524,179	467,708	51,567	1,061,765	829,896	238,210
13	Energy Loss Factor		1.1001	1.1001	1.1001	1.0690	1.1001	1.1001	1.1001	1.0690	1.1001	1.1001	1.0690	1.1001	1.0690	1.1001	1.0690	1.0453	1.1001
14	Energy - Annual MWh	@ Generator	5,917,848	648,411	561,446	1,226	481,048	729,008	961,768	19,856	224,734	1,146,121	97,922	576,628	499,998	56,727	1,135,069	867,465	262,045
15																			
16	Customer																		
17	Annual Customers		485,586	63,644	10,200	43	4,489	3,455	1,925	56	200	515	47	102	61	2	32	9	8,046
18	Average Customers																		3,920
19																			
20	Unit Costs																		
21																			
22	Generation	$ / System Peak kW	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30	$100.30
23	Transmission	$ / System Peak kW	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04
24	Poles, Cond., Subst.	$ / Dist. kW	$100.65	$112.55	$112.55	$112.55	$88.78	$88.78	$88.78	$88.78	$78.07	$78.07	$78.07	$67.03	$67.03	$36.72	$35.12	$0.00	$191.32
25	Transformers	$ / Xfmr kW	$2.80	$2.80	$2.80	$0.00	$2.80	$2.80	$2.80	$0.00	$2.80	$2.80	$0.00	$2.80	$0.00	$2.80	$0.00	$0.00	$2.80
26																			
27	Energy - @ Generator																		
28	Generation	$ / kWh	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337
29	Transmission	$ / kWh	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304
30																			
31	Poles	$ / Cust / Year	$126.83	$154.72	$154.72	$154.72	$96.86	$96.86	$96.86	$96.86	$70.81	$70.81	$70.81	$46.08	$46.08	$0.00	$0.00	$0.00	$350.44
32	Conductor	$ / Cust / Year	$61.26	$74.72	$74.72	$74.72	$46.77	$46.77	$46.77	$46.77	$34.19	$34.19	$34.19	$22.26	$22.26	$0.00	$0.00	$0.00	$169.25
33	Transformers	$ / Cust / Year	$116.05	$164.88	$243.34	$0.00	$723.23	$824.73	$886.16	$0.00	$1,110.75	$1,113.40	$0.00	$1,132.09	$0.00	$1,132.09	$0.00	$0.00	$883.68
34	Service Drop	$ / Cust / Year	$98.36	$127.15	$265.42	$0.00	267.61	278.79	536.10	-	535.87	1,034.04	-	$3,498.63	$0.00	$3,498.63	$0.00	$0.00	$0.00
35	Meters	$ / Cust / Year	$18.48	$19.74	$34.25	$2,089.04	33.59	36.36	231.67	2,089.04	232.62	232.87	2,089.04	$300.67	$2,089.04	$300.67	$2,089.04	$52,630	$33.93
36	Meter Reading	$ / Cust / Year	$16.74	$23.78	$23.78	$23.78	41.36	41.36	41.36	41.36	71.00	71.00	71.00	185.03	$185.03	$185.03	$185.03	$185.03	$52.41
37	Billing & Collections	$ / Cust / Year	$34.18	$32.47	$32.47	$32.47	35.20	35.20	35.20	35.20	35.20	35.20	35.20	130.21	$130.21	$130.21	$130.21	$130.21	$32.47
38	Uncollectables	$ / Cust / Year	$10.36	$1.87	$1.87	$1.87	20.25	20.25	20.25	20.25	141.35	141.35	141.35	613.26	$613.26	$613.26	$613.26	$613.26	$1.71
39	Customer Service / Other	$ / Cust / Year	$8.95	$8.86	$8.86	$8.86	9.94	9.94	9.94	9.94	14.14	14.14	14.14	33.10	$33.10	$33.10	$33.10	$33.10	$9.66
40	Total Commitment & Billing	$ / Cust / Year	$491.21	$608.19	$839.43	$2,385.46	$1,274.83	$1,390.27	$1,904.32	$2,339.43	$2,245.93	$2,747.00	$2,455.73	$5,961.33	$3,118.97	$5,892.99	$3,050.64	$53,591	$1,533.55

Sources:
Lines 1 - 3 Tab 17.4 (Cust Data 4:) `Customer Loads12 Months Ended December 2014'
Lines 5 & 13 Tab 16.1 (Losses:) `Energy Loss Factors'
Lines 12 & 17 Tab 17.2 (Cust Data 2:) `Customers and MWh's12 Months Ended December 2014 - Normalized'
Line 22 Tab 3.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
Line 23 Tab 5.1 (Transm1:) `Marginal Transmission Investment and O&M Expenses'
Line 24 Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'
Line 28 Tab 4.1 (Energy:) `Marginal Generation Energy Costs'
Line 29 Tab 2.6 (Table 6.) `Marginal Cost of Transmission Investment and Associated Expenses'
Lines 31 - 39 Tab 2.7 (Table 7.) `Marginal Distribution & Billing Costs By Load Size'

Table 4

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2014 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	Sch 41	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Marginal Cost																			
1	Generation	$215,252	$94,605	$10,187	$8,758	$17	$8,171	$11,251	$14,790	$285	$3,092	$16,990	$1,508	$8,647	$7,079	$806	$16,371	$9,779	$2,916	
2	Transmission	$354,191	$155,669	$16,763	$14,411	$28	$13,445	$18,514	$24,337	$469	$5,088	$27,956	$2,481	$14,229	$11,649	$1,326	$26,937	$16,091	$4,798	
3	Distribution																			
4	Poles	$52,618	$30,387	$3,377	$2,742	$7	$1,897	$2,667	$3,417	$78	$548	$3,030	$268	$1,006	$798	$11	$191	$0	$2,196	
5	Conductor	$79,429	$44,324	$4,603	$3,738	$9	$3,017	$4,239	$5,433	$125	$986	$5,452	$481	$2,294	$1,819	$23	$364	$0	$2,523	
6	Substations	$70,546	$34,339	$3,128	$2,540	$6	$2,728	$3,834	$4,913	$113	$1,048	$5,796	$511	$2,960	$2,347	$218	$5,126	$0	$937	
7	Subtotal: Pole, Cond, Subs	$202,593	$109,050	$11,109	$9,021	$22	$7,642	$10,740	$13,762	$317	$2,582	$14,277	$1,260	$6,260	$4,964	$252	$5,681	$0	$5,656	
8	Transformers	$14,967	$10,359	$573	$394	$0	$441	$589	$727	$0	$152	$808	$0	$411	$0	$43	$0	$0	$468	
9	Distribution subtotal	$217,560	$119,409	$11,682	$9,415	$22	$8,083	$11,329	$14,489	$317	$2,734	$15,085	$1,260	$6,671	$4,964	$295	$5,681	$0	$6,124	
10																				
11	Total Demand Related	$787,003	$369,683	$38,632	$32,584	$67	$29,699	$41,094	$53,616	$1,071	$10,914	$60,031	$5,249	$29,547	$23,692	$2,427	$48,989	$25,870	$13,838	
12	(Lines 1+2+9)																			
13																				
14	Energy Related Marginal Cost																			
15	Generation Energy Related	$616,337	$256,657	$28,122	$24,350	$53	$20,863	$31,617	$41,712	$861	$9,747	$49,707	$4,247	$25,008	$21,685	$2,460	$49,228	$37,622	$11,365	$1,033
16	Transmission Energy Related	$43,168	$17,976	$1,970	$1,705	$4	$1,461	$2,214	$2,921	$60	$683	$3,481	$297	$1,752	$1,519	$172	$3,448	$2,635	$796	$72
17	Total Energy	$659,505	$274,633	$30,091	$26,055	$57	$22,324	$33,831	$44,633	$921	$10,429	$53,189	$4,544	$26,760	$23,204	$2,633	$52,676	$40,257	$12,161	$1,106
18																				
19	Customer Related Marginal Cost																			
20	Poles	$80,224	$61,587	$9,847	$1,578	$7	$435	$334	$186	$6	$14	$37	$3	$4	$3	$0	$0	$0	$2,819	$3,362
21	Conductor	$37,186	$29,746	$4,756	$763	$3	$211	$162	$90	$3	$7	$17	$1	$3	$1	$0	$0	$0	$1,362	$61
22	Transformers	$85,223	$56,351	$10,495	$2,482	$0	$3,247	$2,849	$1,706	$0	$222	$573	$0	$115	$0	$3	$0	$0	$7,111	$69
23	Service Drops	$62,761	$47,762	$8,093	$2,708	$0	$1,201	$963	$1,032	$0	$107	$532	$0	$357	$0	$7	$0	$0	$0	
24	Meters	$12,746	$8,972	$1,256	$349	$90	$151	$126	$446	$117	$47	$120	$98	$31	$127	$1	$67	$474	$273	$2
25	Meter Reading	$10,598	$8,131	$1,513	$243	$1	$186	$143	$80	$2	$14	$37	$3	$19	$11	$0	$6	$2	$205	$2
26	Billing & Collections	$19,550	$16,596	$2,066	$331	$1	$158	$122	$68	$2	$7	$18	$2	$13	$8	$0	$4	$1	$127	$25
27	Uncollectables	$5,608	$5,029	$119	$19	$0	$91	$70	$39	$1	$28	$73	$7	$63	$37	$1	$20	$6	$7	$0
28	Customer Service / Other	$5,163	$4,347	$564	$90	$0	$45	$34	$19	$1	$3	$7	$1	$3	$2	$0	$1	$0	$38	$7
29	Total Commitment & Billing Rel.	$319,060	$238,521	$38,709	$8,563	$103	$5,724	$4,803	$3,665	$132	$449	$1,414	$115	$608	$190	$12	$98	$482	$11,942	$3,529
30																				
31	Total Revenue @ Full MC																			
32	Generation	$831,589	$351,262	$38,309	$33,108	$70	$29,034	$42,868	$56,502	$1,146	$12,839	$66,697	$5,755	$33,655	$28,764	$3,266	$65,599	$47,401	$14,281	$1,033
33	Transmission	$397,359	$173,645	$18,733	$16,116	$32	$14,906	$20,728	$27,258	$529	$5,771	$31,437	$2,778	$15,981	$13,168	$1,498	$30,385	$18,726	$5,594	$72
34	Distribution	$482,954	$314,855	$44,872	$16,945	$32	$13,177	$15,638	$17,503	$325	$3,084	$16,245	$1,264	$7,150	$4,969	$305	$5,681	$0	$17,415	$3,493
35	Customer - Billing	$19,550	$16,596	$2,066	$331	$1	$158	$122	$68	$2	$7	$18	$2	$13	$8	$0	$4	$1	$127	$25
36	Customer - Metering	$23,344	$17,103	$2,769	$592	$91	$336	$269	$526	$119	$61	$156	$102	$50	$139	$1	$73	$475	$478	$5
37	Customer - Other	$5,163	$4,347	$564	$90	$0	$45	$34	$19	$1	$3	$7	$1	$3	$2	$0	$1	$0	$38	$7
38	Revenue (less Uncollectables)	$1,759,960	$877,808	$107,313	$67,183	$226	$57,657	$79,659	$101,876	$2,123	$21,764	$114,562	$9,901	$56,853	$47,049	$5,071	$101,742	$66,604	$37,934	$4,635
39																				
40	Customer - Uncollectables	$5,608	$5,029	$119	$19	$0	$91	$70	$39	$1	$28	$73	$7	$63	$37	$1	$20	$6	$7	$0
41	Total Revenue	$1,765,568	$882,837	$107,432	$67,202	$226	$57,748	$79,729	$101,915	$2,124	$21,792	$114,635	$9,908	$56,915	$47,086	$5,072	$101,762	$66,609	$37,940	$4,635

Source: Tab 2.3 (Table 3:) '20 Year Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

Line 1 Generation (Table 3, Row 7) x (Table 3, Row 22)/1000
Line 2 Transmission (Table 3, Row 7) x (Table 3, Row 23)/1000
Lines 4-6 Poles, Cond., Subst. (Table 3, Row 8) x (Table 7, Row 1 - 3) x (1 + .423) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 9) x (Table 7, Row 7) x (1 + .423) (Dist OM, Row 32)
Lines 15-16 Energy Related (Table 3, Row 14) x (Table 3, Row 28 - 29)
Lines 20-29 Commitment Related (Table 3, Row 17) x (Table 7, Row 13 - 27) including O&M Adders

Table 5

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs
In Nominal Dollars

Year			(A) Resource Cost (Mills / kWh) (B) + (C)	(B) Energy Only (Mills / kWh)	(C) Capacity Only (Mills / kWh)	(D) Capacity Only ($ / kW)
2014			56.96	34.28	22.68	$100.34
2015			61.41	38.28	23.13	$102.34
2016			63.66	40.09	23.57	$104.29
2017			66.21	42.19	24.02	$106.28
2018			69.38	44.90	24.48	$108.30
2019			72.39	47.47	24.92	$110.25
2020			73.17	47.83	25.34	$112.12
2021			75.74	49.94	25.80	$114.14
2022			79.59	53.33	26.26	$116.19
2023			81.91	55.17	26.74	$118.28
2024			82.01	54.79	27.22	$120.41
2025			84.78	57.07	27.71	$122.58
2026			87.40	59.20	28.20	$124.77
2027			89.89	61.15	28.74	$127.15
2028			92.03	62.74	29.29	$129.57
2029			93.96	64.12	29.84	$132.02
2030			95.40	64.99	30.41	$134.54
2031			97.07	66.05	31.02	$137.24
2032			98.91	67.30	31.61	$139.84
2033			100.78	68.57	32.21	$142.50
2014	**1 year -**					
|	Sum of PV Costs	@ 7.66%	56.96	34.28	22.68	$100.34
2014 - 2018	**5 year -**					
|	Sum of PV Costs	@ 7.66%	273.65	171.67	101.98	$451.17
|	Annual Cost	@ 22.27%	60.94	38.23	22.71	$100.48
2014 - 2023	**10 years -**					
|	Sum of PV Costs	@ 7.66%	502.17	322.97	179.20	$792.80
|	Annual Cost	@ 12.66%	63.58	40.89	22.69	$100.37
2014 - 2033	**20 years -**					
|	Sum of PV Costs	@ 7.66%	821.46	539.47	281.99	$1,247.49
|	Annual Cost	@ 8.04%	66.04	43.37	22.67	$100.30

Footnotes:
(B) Tab 4.1 (Energy:) `Marginal Generation Energy Costs'
(C) Tab 3.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
(D) Tab 3.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

Line	Item		$'s	
1	Growth Related Investments - (2014 to 2018 in $000's)		$632,039	
2				
3	System Growth MW's from 2014 to 2018		364	MW
4				
5	Marginal Investment	(growth invest / kW)	$1,736.37	/ kW
6				
7	Annualized Investment	x 8.00%	138.91	/ kW
8	Admin. & General Factor	x 1.33%	23.09	
9	Annual O&M Expenses	x 1.415%	24.57	/ kW
10	Annualized Marginal Cost		$186.57	/ kW
11				
12	Marginal Cost of Demand-Related Transmission		$165.04	/ kW
13				
14	Marginal Cost of Energy-Related Transmission	(Line 10 - Line 12)	$21.52	/ kW
15	Marginal Cost of Energy-Related Transmission		$0.00304	/ kWh
16	$21.52 / (8760 x 80.87% LF))			

Sources:
Tab 5.2 (Transm2:) `2014-2018 Forecasted Transmission'
Tab 5.1 (Transm1:) `Marginal Transmission Investment and O&M Expenses'

Table 7

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs By Load Size
2014 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
	Demand Related Costs ($/kW)																		
1	Poles		19.71	24.04	24.04	24.04	15.49	15.49	15.49	15.49	11.64	11.64	11.64	7.57	7.57	1.22	0.83	NA	52.20
2	Conductors		28.75	32.78	32.78	32.78	$24.63	24.63	24.63	24.63	20.95	20.95	20.95	17.26	17.26	2.31	1.58	NA	59.98
3	Substation		22.27	22.27	22.27	22.27	22.27	22.27	22.27	22.27	22.27	22.27	22.27	22.27	22.27	22.27	22.27	NA	22.27
4	Dist. O&M @ of Total Investment	42.30%	29.92	33.46	33.46	33.46	26.39	26.39	26.39	26.39	23.21	23.21	23.21	19.93	19.93	10.92	10.44	NA	56.87
5	Total $/ Dist. kW		$100.65	$112.55	$112.55	$112.55	$88.78	$88.78	$88.78	$88.78	$78.07	$78.07	$78.07	$67.03	$67.03	$36.72	$35.12	-	$191.32
6																			
7	Transformers		1.97	1.97	1.97	NA	1.97	1.97	1.97	NA	1.97	1.97	NA	1.97	NA	1.97	NA	NA	1.97
8	Dist. O&M @ of Total Investment	42.30%	0.83	0.83	0.83	NA	0.83	0.83	0.83	NA	0.83	0.83	NA	0.83	NA	0.83	NA	NA	0.83
9	Total $/ Transformer kW		$2.80	$2.80	$2.80	$0.00	$2.80	$2.80	$2.80	$0.00	$2.80	$2.80	$0.00	$2.80	$0.00	$2.80	-	-	$2.80
10																			
11																			
12	Commitment Related Costs ($/Customer)																		
13	Poles		89.13	108.73	108.73	108.73	68.07	68.07	68.07	68.07	49.76	49.76	49.76	32.38	32.38	-	-	NA	246.27
14	Conductors		43.05	52.51	52.51	52.51	32.87	32.87	32.87	32.87	24.03	24.03	24.03	15.64	15.64	-	-	NA	118.94
15	Transformers		81.55	115.87	171.01	NA	508.24	579.57	622.74	NA	780.57	782.43	NA	795.57	NA	795.57	NA	NA	621.00
16	Dist. O&M @ of Total Investment	42.30%	90.41	117.22	140.54	68.20	257.68	287.86	306.12	42.70	361.39	362.18	31.21	356.84	20.31	336.53	-	NA	417.17
17	Total Commitment Related		$304.14	$394.33	$472.79	$229.44	$866.86	$968.37	$1,029.80	$143.64	$1,215.75	$1,218.40	$105.00	$1,200.43	$68.33	$1,132.10	-	-	$1,403.38
18																			
19	Billing Related Costs ($/Customer/Yr)																		
20	Service Drop		69.12	89.35	186.52	NA	188.06	195.92	376.74	NA	376.58	726.66	NA	$2,458.63	NA	$2,458.63	NA	NA	NA
21	Service Drop O&M @	42.30%	29.24	37.80	78.90	NA	79.55	82.87	159.36	NA	159.29	307.38	NA	1,040.00	NA	1,040.00	NA	NA	NA
22	Meter		11.14	11.90	20.65	$1,259.52	20.25	21.92	139.68	1,259.52	140.25	140.40	1,259.52	$181.28	$1,259.52	$181.28	$1,259.52	$31,731.44	20.46
23	Meter O&M at	65.86%	7.34	7.84	13.60	829.52	13.34	14.44	91.99	829.52	92.37	92.47	829.52	119.39	829.52	119.39	829.52	20,898.33	13.47
24	Meter Reading		16.74	23.78	23.78	23.78	41.36	41.36	41.36	41.36	$71.00	$71.00	$71.00	185.03	185.03	185.03	185.03	185.03	52.41
25	Billing & Collections		34.18	32.47	32.47	32.47	35.20	35.20	35.20	35.20	$35.20	$35.20	$35.20	130.21	130.21	130.21	130.21	130.21	32.47
26	Uncollectables		10.36	1.87	1.87	1.87	20.25	20.25	20.25	20.25	$141.35	$141.35	$141.35	613.26	613.26	613.26	613.26	613.26	1.71
27	Customer Service / Other		8.95	8.86	8.86	8.86	9.94	9.94	9.94	9.94	14.14	14.14	14.14	33.10	33.10	33.10	33.10	33.10	9.66
28	Total Billing Related		$187.07	$213.87	$366.65	$2,156.02	$407.96	$421.91	$874.53	$2,195.80	$1,030.18	$1,528.60	$2,350.73	$4,760.90	$3,050.64	$4,760.90	$3,050.64	$53,591.37	$130.18
29																			
30																			
31	Monthly Billing Related (Line 28 / 12)		$15.59	$17.82	$30.55	$179.67	$34.00	$35.16	$72.88	$182.98	$85.85	$127.38	$195.89	$396.74	$254.22	$396.74	$254.22	$4,465.95	$10.85
32																			
33	Total Distribution (Comm & Billing Costs)		$491.21	$608.20	$839.43	$2,385.46	$1,274.82	$1,390.28	$1,904.33	$2,339.44	$2,245.93	$2,747.00	$2,455.73	$5,961.33	$3,118.97	$5,893.00	$3,050.64	$53,591.37	$1,533.55
34	Line 17 + Line 28																		
35	Monthly Commitment & Bill (Line 33 / 12)		$40.93	$50.68	$69.95	$198.79	$106.24	$115.86	$158.69	$194.95	$187.16	$228.92	$204.64	$496.78	$259.91	$491.08	$254.22	$4,465.95	$127.80

Sources: Lines
Line 1 - 2 Tab 7.1 (PC 1:) `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 3 Tab 6.1 (Dist Sub 1:) `Distribution Substation Costs / kW'
Line 4 Sum of lines 1 to 3 multiplied by 42.30%
Tab 9.1 (Dist OM:) `Distribution O&M Expense Loading Factor as a Percent of Dist. Plant' (for 42.30% Factor)
Line 7 Tab 8.2 (XFMR 2:) `Transformer Demand Costs'
Line 13 - 14 Tab 7.1 (PC 1:) `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 15 Tab 8.1 (XFMR 1:) `Transformer Commitment Costs'
Line 20 Tab 10.1 (Services 1:) `Weighted Average Installed Service Drop Costs'
Line 22 Tab 11.1 (Meters 1:) `Weighted Average Installed Meter Costs'
Line 23 Tab 11.5 (Meters 5:) `Distribution Meters Expense Loading Factor' (for 65.86% Factor)
Line 24 -27 Tab 13.1 (Cust Exp Sum:) `Summary of Customer Accounting Expense By Schedule'

PacifiCorp
Oregon Marginal Cost Study
Total 20 Year Demand Costs Divided by Billing kW
December 2014 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans	
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
	Demand Related Marginal Cost																		
1	Generation -	$215,252	$94,605	$10,187	$8,758	$17	$8,171	$11,251	$14,790	$285	$3,092	$16,990	$1,508	$8,647	$7,079	$806	$16,371	$9,779	$2,916
2	Transmission -	$354,191	$155,669	$16,763	$14,411	$28	$13,445	$18,514	$24,337	$469	$5,088	$27,956	$2,481	$14,229	$11,649	$1,326	$26,937	$16,091	$4,798
3																			
4	Distribution -																		
5	Poles, Wire, Sub	$202,593	$109,050	$11,109	$9,021	$22	$7,642	$10,740	$13,762	$317	$2,582	$14,277	$1,260	$6,260	$4,964	$252	$5,681	$0	$5,656
6	Transformers	$14,967	$10,359	$573	$394	$0	$441	$589	$727	$0	$152	$808	$0	$411	$0	$43	$0	$0	$468
7	Distribution Subtotal	$217,560	$119,409	$11,682	$9,415	$22	$8,083	$11,329	$14,489	$317	$2,734	$15,085	$1,260	$6,671	$4,964	$295	$5,681	$0	$6,124
8																			
9	Total Demand Related	$787,003	$369,683	$38,632	$32,584	$67	$29,699	$41,094	$53,616	$1,071	$10,914	$60,031	$5,249	$29,547	$23,692	$2,427	$48,989	$25,870	$13,838
10																			
11	Average Billing kW	7,114,825	4,966,196	263,233	180,731	1,550	141,470	189,067	233,629	18,698	48,729	259,445	21,716	132,222	102,469	13,624	227,830	164,031	150,187
12																			
13	Generation -		$19.05	$38.70	$48.46	$10.97	$57.76	$59.51	$63.31	$15.24	$63.45	$65.49	$69.44	65.40	69.08	59.16	71.86	59.62	19.42
14	Transmission -		$31.35	$63.68	$79.74	$18.06	$95.04	$97.92	$104.17	$25.08	$104.42	$107.75	$114.25	107.61	113.68	97.33	118.23	98.10	31.95
15																			
16	Distribution -																		
17	Poles, Wire, Sub		$21.96	$42.20	$49.91	$14.01	$54.02	$56.81	$58.91	$16.94	$52.99	$55.03	$58.01	47.34	48.45	18.51	24.93	0.00	37.66
18	Transformers		$2.09	$2.18	$2.18	$0.00	$3.12	$3.12	$3.11	$0.00	$3.12	$3.12	$0.00	3.11	0.00	3.13	0.00	0.00	3.12
19	Distribution subtotal		$24.04	$44.38	$52.09	$14.01	$57.14	$59.92	$62.02	$16.94	$56.11	$58.14	$58.01	50.45	48.45	21.64	24.93	0.00	40.77
20																			
21																			
22																			
23																			
24	Total Demand Related		$74.44	$146.76	$180.29	$43.04	$209.93	$217.35	$229.49	$57.27	$223.98	$231.38	$241.70	$223.47	$231.21	$178.14	$215.02	$157.71	$92.14
25																			
26	Monthly Demand Costs		$6.20	$12.23	$15.02	$3.59	$17.49	$18.11	$19.12	$4.77	$18.66	$19.28	$20.14	$18.62	$19.27	$14.84	$17.92	$13.14	$7.68

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage @ Meter
December 2014 Dollars

Line	Description	(A) Marginal Cost (000)s	(B) Mills / kWh	(C) % of Total
	Demand Related Marginal Cost -			
1	Generation	$215,252	16.55	12.2%
2	Transmission	354,191	27.23	20.1%
3	Dist. Poles, Cond., Subst.	202,593	15.58	11.5%
4	Dist. Transformers	14,967	1.15	0.8%
5	Total Demand Related	$787,003	60.51	44.6%
6				
7	Energy Related Marginal Cost -			
8				
9	Generation	$616,337	47.39	34.9%
10	Transmission	43,168	3.32	2.4%
11	Total Energy Related	$659,505	50.71	37.4%
12				
13	Commitment & Billing -			
14	Commitment	202,633	15.58	11.5%
15	Billing	116,427	8.95	6.6%
16	Total Commitment & Billing	$319,060	24.53	18.1%
17				
18				
19	TOTAL MARGINAL COST	$1,765,568	135.75	100.0%
20				
21				
22	Note: Total MWh = 13,006,121			

PacifiCorp
Oregon Marginal Cost Study
10 Year Run Costing Inputs and Customer Data
Marginal Unit Costs
December 2014 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
	Billing Units																		
	Demand																		
1	Peak MW @ Meter	System	849	91	79	0	73	101	133	3	28	153	14	78	65	7	151	94	26
2		Distribution	976	89	72	0	78	109	140	3	30	165	15	84	69	6	150	0	27
3		Transformer	3,327	184	127	2	141	189	234	19	49	259	22	132	102	14	228	164	150
4	Demand Loss Factor		1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.0792	1.1106	1.0792	1.1106	1.0792	1.0426	1.1106
5	Peak MW @ Generator	System	943	102	87	0	81	112	147	3	31	169	15	86	71	8	163	97	29
6		Distribution	1,083	99	80	0	86	121	155	4	33	183	16	93	74	7	162	-	30
7		Transformer	3,695	205	141	N/A	157	210	259	N/A	54	288	N/A	147	N/A	15	N/A	N/A	167
8																			
9																			
10	Energy																		
11	Energy - Annual MWh	@ Meter	5,379,569	589,432	510,378	1,147	437,292	662,698	874,287	18,574	204,293	1,041,871	91,598	524,179	467,708	51,567	1,061,765	829,896	238,210
12	Energy Loss Factor		1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.06904	1.10006	1.06904	1.10006	1.06904	1.04527	1.10006
13	Energy - Annual MWh	@ Generator	5,917,848	648,411	561,446	1,226	481,048	729,008	961,768	19,856	224,734	1,146,121	97,922	576,628	499,998	56,727	1,135,069	867,465	262,045
14																			
15																			
16	Customer																		
17	Annual Customers		485,586	63,644	10,200	43	4,489	3,455	1,925	56	200	515	47	102	61	2	32	9	8,046
18	Average Customers																		3,920
19																			
20	Unit Costs																		
21																			
22	Generation	$ / System Peak kW	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37	$100.37
23	Transmission	$ / System Peak kW	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04	$165.04
24	Poles, Cond., Subst.	$ / Dist. kW	$100.65	$112.55	$112.55	$112.55	$88.78	$88.78	$88.78	$88.78	$78.07	$78.07	$78.07	$67.03	$67.03	$36.72	$35.12	$0.00	$191.32
25	Transformers	$ / Xfmr kW	$2.80	$2.80	$2.80	$0.00	$2.80	$2.80	$2.80	$0.00	$2.80	$2.80	$0.00	$2.80	$0.00	$2.80	$0.00	$0.00	$2.80
26																			
27																			
28	Energy @ Generator	$ / kWh	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393	$0.04393
29																			
30																			
31	Commitment & Billing	$ / Cust. / Year	$491.21	$608.20	$839.43	2,385.46	$1,274.82	$1,390.28	$1,904.33	$2,339.44	$2,245.93	$2,747.00	$2,455.73	5,961.33	$3,118.97	$5,893.00	$3,050.64	$53,591.37	1,533.55

PacifiCorp
Oregon Marginal Cost Study
10 Year Marginal Cost By Load Class
December 2014 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41
Line		Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
	Demand Related Marginal Cost																		
1	Generation -	$215,402	$94,671	$10,194	$8,764	$17	$8,176	$11,259	$14,801	$285	$3,094	$17,002	$1,509	$8,653	$7,084	$807	$16,382	$9,786	$2,918
2	Transmission -	$354,191	$155,669	$16,763	$14,411	$28	$13,445	$18,514	$24,337	$469	$5,088	$27,956	$2,481	$14,229	$11,649	$1,326	$26,937	$16,091	$4,798
3																			
4	Distribution -																		
5	Poles, Conductor, Substations	$202,592	$109,049	$11,109	$9,021	$22	$7,643	$10,740	$13,761	$317	$2,581	$14,277	$1,259	$6,260	$4,965	$253	$5,680	$0	$5,655
6	Transformers	$14,946	$10,347	$573	$393	$0	$440	$588	$726	$0	$152	$807	$0	$411	$0	$42	$0	$0	$467
7	Distribution subtotal	$217,538	$119,396	$11,682	$9,414	$22	$8,083	$11,328	$14,487	$317	$2,733	$15,084	$1,259	$6,671	$4,965	$295	$5,680	$0	$6,122
8																			
9	Total Demand Related	$787,131	$369,736	$38,639	$32,589	$67	$29,704	$41,101	$53,625	$1,071	$10,915	$60,042	$5,249	$29,553	$23,698	$2,428	$48,999	$25,877	$13,838
10	(Lines 1+2+7)																		
11																			
12																			
13	Energy Related Marginal Cost																		
14																			
15	Total Energy Related	$623,215	$259,957	$28,483	$24,663	$54	$21,131	$32,024	$42,248	$872	$9,872	$50,346	$4,301	$25,330	$21,964	$2,492	$49,861	$38,106	$11,511
16																			
17																			
18	Customer Related Marginal Cost																		
19																			
20	Commitment & Billing Rel.	$315,532	$238,525	$38,708	$8,562	$103	$5,723	$4,803	$3,666	$131	$449	$1,415	$115	$608	$190	$12	$98	$482	$11,942
21																			
22																			
23	Total Revenue @ Full MC	$1,725,878	$868,218	$105,830	$65,814	$224	$56,558	$77,928	$99,539	$2,074	$21,236	$111,803	$9,665	$55,491	$45,852	$4,932	$98,958	$64,465	$37,291

5 Year MC

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Costs by Load Class
December 2014 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41
Line		Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(tm)	(sec)
	Billing Units																		
	Demand																		
1	Peak MW @ Meter	System	849	91	79	0	73	101	133	3	28	153	14	78	65	7	151	94	26
2	Demand Loss Factor		1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.0792	1.1106	1.0792	1.1106	1.0792	1.0426	1.1106
3	Peak MW @ Generator	System	943	102	87	0	81	112	147	3	31	169	15	86	71	8	163	97	29
4																			
5	Energy																		
6	Energy - Annual MWh @ Meter	12,984,464	5,379,569	589,432	510,378	1,147	437,292	662,698	874,287	18,574	204,293	1,041,871	91,598	524,179	467,708	51,567	1,061,765	829,896	238,210
7	Energy Loss Factor		1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.06904	1.10006	1.06904	1.10006	1.06904	1.04527	1.10006
8	Energy - Annual MWh @ Generator	14,187,322	5,917,848	648,411	561,446	1,226	481,048	729,008	961,768	19,856	224,734	1,146,121	97,922	576,628	499,998	56,727	1,135,069	867,465	262,045
9																			
10	Customer																		
11	Average Customers	578,412	485,586	63,644	10,200	43	4,489	3,455	1,925	56	200	515	47	102	61	2	32	9	8,046
12																			3,920
13	Unit Costs																		
14																			
15	Generation - $ / System Peak kW		$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48	$100.48
16	Energy @ Generator $ / kWh		$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823	$0.03823
17	Billing Related Costs		$187.07	$213.87	$366.65	$2,156.02	$407.96	421.91	$874.53	$2,195.80	$1,030.18	$1,528.60	$2,350.73	$4,760.90	$3,050.64	$4,760.90	$3,050.64	$53,591.37	$33.93
18																			
19	Marginal Costs $000																		$96.25
20																			
21	Total Demand Related	$215,639	$94,775	$10,206	$8,774	$17	$8,185	$11,271	$14,817	$286	$3,097	$17,020	$1,511	$8,663	$7,092	$807	$16,400	$9,796	$2,921
22																			
23	Total Energy Related	$542,381	$226,239	$24,789	$21,464	$47	$18,390	$27,870	$36,768	$759	$8,592	$43,816	$3,744	$22,044	$19,115	$2,169	$43,394	$33,163	$10,018
24																			
25	Billing Related Costs	$116,392	$90,838	$13,611	$3,740	$93	$1,831	$1,458	$1,683	$123	$206	$787	$110	$486	$186	$10	$98	$482	$650
26																			
27	Total Revenue @ Full MC	$874,412	$411,852	$48,606	$33,978	$157	$28,406	$40,599	$53,268	$1,168	$11,895	$61,623	$5,365	$31,193	$26,393	$2,986	$59,892	$43,441	$13,589

1 Year MC

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs by Load Class
December 2014 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41
Line		Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
	Billing Units																		
	Energy																		
1	Energy - Annual MWh @ Meter	12,984,464	5,379,569	589,432	510,378	1,147	437,292	662,698	874,287	18,574	204,293	1,041,871	91,598	524,179	467,708	51,567	1,061,765	829,896	238,210
2	Energy Loss Factor		1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.10006	1.06904	1.10006	1.10006	1.06904	1.10006	1.06904	1.10006	1.06904	1.04527	1.10006
3	Energy - Annual MWh @ Generator	14,187,322	5,917,848	648,411	561,446	1,226	481,048	729,008	961,768	19,856	224,734	1,146,121	97,922	576,628	499,998	56,727	1,135,069	867,465	262,045
4																			
5	Customer																		
6	Average Customers	578,412	485,586	63,644	10,200	43	4,489	3,455	1,925	56	200	515	47	102	61	2	32	9	8,046
7																			3,920
8	Unit Costs																		
9																			
10	Energy @ Generator $ / kWh		$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428	$0.03428
11																			
12	Billing Related Costs		$187.07	$213.87	$366.65	2,156.02	$407.96	421.91	$874.53	$2,195.80	$1,030.18	$1,528.60	$2,350.73	$4,760.90	$3,050.64	$4,760.90	$3,050.64	$53,591.37	$33.93
13																			$96.25
14																			
15	Marginal Costs $000																		
16																			
17	Total Energy Related	$486,399	$202,888	$22,230	$19,249	$42	$16,492	$24,993	$32,973	$681	$7,705	$39,294	$3,357	$19,769	$17,142	$1,945	$38,915	$29,740	$8,984
18																			
19	Billing Related Costs	$116,392	$90,838	$13,611	$3,740	$93	$1,831	$1,458	$1,683	$123	$206	$787	$110	$486	$186	$10	$98	$482	$650
20																			
21																			
22	Total Revenue @ Full MC	$602,791	$293,726	$35,841	$22,989	$135	$18,323	$26,451	$34,656	$804	$7,911	$40,081	$3,467	$20,255	$17,328	$1,955	$39,013	$30,222	$9,634

Capacity

PacifiCorp
Oregon Marginal Cost Study
Marginal Capacity Costs
Based on Avoided Capacity Costs

	(A)	(B)	(C)	(D)	(E)
Calendar Year (12 Mo Ended Dec)	Projected Capacity $/kW	Present Value Factors	PV of Capacity $/kW	Capacity Mills/kWh	PV of Capacity Mills/kWh
		@ 7.66%	(A) x (B)	(A) / 0.505 / 8,760	(B) * (D)
2014	$100.34	1.0000	100.34	22.68	22.68
2015	$102.34	0.9289	95.06	23.13	21.49
2016	$104.29	0.8628	89.98	23.57	20.34
2017	$106.28	0.8014	85.17	24.02	19.25
2018	$108.30	0.7444	80.62	24.48	18.22
2019	$110.25	0.6915	76.24	24.92	17.23
2020	$112.12	0.6423	72.01	25.34	16.28
2021	$114.14	0.5966	68.10	25.80	15.39
2022	$116.19	0.5542	64.39	26.26	14.55
2023	$118.28	0.5148	60.89	26.74	13.77
2024	$120.41	0.4782	57.58	27.22	13.02
2025	$122.58	0.4442	54.45	27.71	12.31
2026	$124.77	0.4126	51.48	28.20	11.64
2027	$127.15	0.3833	48.74	28.74	11.02
2028	$129.57	0.3560	46.13	29.29	10.43
2029	$132.02	0.3307	43.66	29.84	9.87
2030	$134.54	0.3072	41.33	30.41	9.34
2031	$137.24	0.2854	39.17	31.02	8.85
2032	$139.84	0.2651	37.07	31.61	8.38
2033	$142.50	0.2462	35.08	32.21	7.93

			$/kW	mills / kWh
2014	1 Year -	Sum of PV Costs @ 7.66%	100.34	22.68
2014 - 2018	5 Year -	Short Run -		
		Sum of PV Costs @ 7.66%	$451.17	$101.98
		Annual Cost of Capacity @ 22.27%	100.48	22.71
2014 - 2023	10 Years -	Medium Run -		
		Sum of PV Costs @ 7.66%	$792.80	179.20
		Annual Cost of Capacity @ 12.66%	100.37	22.69
2014 - 2033	20 Years -	Long Run -		
		Sum of PV Costs @ 7.66%	$1,247.49	281.99
		Annual Cost of Capacity @ 8.04%	100.30	22.67

Footnote:

Column A: Oregon Approved Avoided Cost Study, Total Cost of SCCT - Table 8, page 1, column (f)

Energy

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Energy Costs
Nominal Mills / kWh

Calendar Year (12 Mo Ended Dec)	(A) SCCT Fixed Costs ($/kW-yr)	(B) SCCT Fixed Costs ($/kW-mo)	(C) CCCT Fixed Costs ($/kW-yr)	(D) CCCT Fixed Costs ($/kW-mo)	(E) Capitalized Energy Cost ($/kW-mo)	(F) Capitalized Energy Cost 50.5% CF ($/MWh)	(G) Purchase Cost ($/MWh)	(H) Updated Gas Price ($/MMBtu)	(I) CCCT Energy Costs 6,960 Btu/kWh ($/MWh)	(J) Variable Avoided Energy Cost ($/MWh) (G) + (I) =(J)	(K) Capitalized Energy Cost 50.5% CF ($/MWh) (F)=(K)	(L) Total Avoided Energy Cost ($/MWh) (J) + (K) =(L)	(M) Wind Cost ($/MWh)	(N) Oregon RPS %	(O) Total Avoided Energy Cost (Wgt) ($/MWh) (M) * (N) + ((L)*(1 - N)) = (O)	(P) Present Value Factors @ 7.66%	(Q) Present Value of Energy (O)*(P) = (Q)
2014	100.34	8.36	112.36	9.36	1.00	2.72	0.00	4.37	30.42	30.42	2.72	33.13	56.17	5%	34.28	1.0000	34.28
2015	102.34	8.53	114.62	9.55	1.02	2.78	0.00	4.62	32.16	32.16	2.78	34.93	57.29	15%	38.28	0.9289	35.56
2016	104.29	8.69	116.78	9.73	1.04	2.82	0.00	4.89	34.03	34.03	2.82	36.86	58.38	15%	40.09	0.8628	34.59
2017	106.28	8.86	119.02	9.92	1.06	2.88	0.00	5.21	36.26	36.26	2.88	39.14	59.49	15%	42.19	0.8014	33.81
2018	108.30	9.03	121.29	10.11	1.08	2.94	0.00	5.63	39.18	39.18	2.94	42.12	60.62	15%	44.90	0.7444	33.42
2019	110.25	9.19	123.46	10.29	1.10	2.99	0.00	6.03	41.97	41.97	2.99	44.95	61.72	15%	47.47	0.6915	32.83
2020	112.12	9.34	125.54	10.46	1.12	3.03	0.00	5.90	41.06	41.06	3.03	44.10	62.76	20%	47.83	0.6423	30.72
2021	114.14	9.51	127.81	10.65	1.14	3.09	0.00	6.23	43.36	43.36	3.09	46.45	63.89	20%	49.94	0.5966	29.79
2022	116.19	9.68	130.12	10.84	1.16	3.15	0.00	6.79	47.26	47.26	3.15	50.41	65.03	20%	53.33	0.5542	29.56
2023	118.28	9.86	132.47	11.04	1.18	3.21	0.00	7.07	49.21	49.21	3.21	52.41	66.21	20%	55.17	0.5148	28.40
2024	120.41	10.03	134.85	11.24	1.20	3.26	0.00	6.95	48.37	48.37	3.26	51.64	67.41	20%	54.79	0.4782	26.20
2025	122.58	10.22	137.28	11.44	1.23	3.32	0.00	7.17	49.90	49.90	3.32	53.23	68.62	25%	57.07	0.4442	25.35
2026	124.77	10.40	139.74	11.65	1.25	3.38	0.00	7.51	52.27	52.27	3.38	55.65	69.86	25%	59.20	0.4126	24.43
2027	127.15	10.60	142.41	11.87	1.27	3.45	0.00	7.81	54.36	54.36	3.45	57.81	71.18	25%	61.15	0.3833	23.44
2028	129.57	10.80	145.12	12.09	1.30	3.52	0.00	8.04	55.96	55.96	3.52	59.47	72.53	25%	62.74	0.3560	22.33
2029	132.02	11.00	147.87	12.32	1.32	3.58	0.00	8.23	57.28	57.28	3.58	60.86	73.90	25%	64.12	0.3307	21.21
2030	134.54	11.21	150.67	12.56	1.34	3.65	0.00	8.32	57.91	57.91	3.65	61.55	75.31	25%	64.99	0.3072	19.97
2031	137.24	11.44	153.69	12.81	1.37	3.72	0.00	8.44	58.74	58.74	3.72	62.46	76.81	25%	66.05	0.2854	18.85
2032	139.84	11.65	156.62	13.05	1.40	3.79	0.00	8.60	59.86	59.86	3.79	63.65	78.27	25%	67.30	0.2651	17.84
2033	142.50	11.88	159.61	13.30	1.43	3.87	0.00	8.76	60.97	60.97	3.87	64.84	79.76	25%	68.57	0.2462	16.88

				Mills / kWh
2014	1 Year -	Sum of PV Costs		34.28
2014 - 2018	5 Year -	Short Run -		
		Sum of PV Costs	@ 7.66% =	171.67
		Annual Cost of Energy	@ 22.27% =	38.23
2014 - 2023	10 Years -	Medium Run -		
		Sum of PV Costs	@ 7.66% =	322.97
		Annual Cost of Energy	@ 12.66% =	40.89
2014 - 2033	20 Years -	Long Run -		
		Sum of PV Costs	@ 7.66% =	539.47
		Annual Cost of Energy	@ 8.04% =	43.37

Footnote:

Column A: Oregon Approved Avoided Cost Study, Total Cost of SCCT - Table 8, page 1, column (f)
Column C: Oregon Approved Avoided Cost Study, Total Cost of CCCT - Table 8, page 2, column (f)
Column H: Oregon Approved Avoided Cost Study, Gas Price - Table 9, column (b)
Column I: Oregon Approved Avoided Cost Study, Heat Rate for CCCT - Table 8, page 3

PacifiCorp
Marginal Generation Costs
Filed

	12 Months Ended December			12 Months Ended December			
Calendar Year	Avoided Simple Cycle CT Fixed Costs ($/kW-yr)	Avoided Combined Cycle CT Fixed Costs ($/kW-yr)	Gas Price ($/MMBtu)	Avoided Firm Capacity Costs ($/kW-yr)	Combined Cycle CT Fixed Cost ($/kW-yr)	Gas Price ($/MMBtu)	QF Avoided Costs ($/kW-yr)
2014	100.34	112.36	4.37	100.34	112.36	4.37	56.17
2015	102.34	114.62	4.62	102.34	114.62	4.62	57.29
2016	104.29	116.78	4.89	104.29	116.78	4.89	58.38
2017	106.28	119.02	5.21	106.28	119.02	5.21	59.49
2018	108.30	121.29	5.63	108.30	121.29	5.63	60.62
2019	110.25	123.46	6.03	110.25	123.46	6.03	61.72
2020	112.12	125.54	5.90	112.12	125.54	5.90	62.76
2021	114.14	127.81	6.23	114.14	127.81	6.23	63.89
2022	116.19	130.12	6.79	116.19	130.12	6.79	65.03
2023	118.28	132.47	7.07	118.28	132.47	7.07	66.21
2024	120.41	134.85	6.95	120.41	134.85	6.95	67.41
2025	122.58	137.28	7.17	122.58	137.28	7.17	68.62
2026	124.77	139.74	7.51	124.77	139.74	7.51	69.86
2027	127.15	142.41	7.81	127.15	142.41	7.81	71.18
2028	129.57	145.12	8.04	129.57	145.12	8.04	72.53
2029	132.02	147.87	8.23	132.02	147.87	8.23	73.90
2030	134.54	150.67	8.32	134.54	150.67	8.32	75.31
2031	137.24	153.69	8.44	137.24	153.69	8.44	76.81
2032	139.84	156.62	8.60	139.84	156.62	8.60	78.27
2033	142.50	159.61	8.76	142.50	159.61	8.76	79.76

CCCT Capacity Factor	50.5%
CCCT Heat Rate (Btu/kWh)	6,960

Source:
- Oregon Approved Avoided Cost Study, Total Cost of SCCT - Table 8, page 1, column (f)
- Oregon Approved Avoided Cost Study, Total Cost of CCCT - Table 8, page 2, column (f)
- Oregon Approved Avoided Cost Study, Gas Price - Table 9, column (b)
- Oregon AC Study (Renewable Only), column (f)

(Fiscal Year):
(Previous Year * 75%)+(Current Year * 25%)

(Calendar Year):
(Previous Year * 0%)+(Current Year * 100%)

Previous Yr = 0%
Current Yr = 100%

Transm1

PacifiCorp
Oregon Marginal Cost Study
Marginal Transmission Investment and O&M Expenses
2014 Dollars

Line	Item	(A) Total	(B) Demand Related	(C) Energy Related	
		(B) + (C)			
1	2014 Forecasted	172,399	131,867	40,532	
2	2015 Forecasted	149,716	132,795	16,921	
3	2016 Forecasted	115,297	103,438	11,859	
4	2017 Forecasted	104,037	103,368	669	
5	2018 Forecasted	90,590	87,647	2,943	
6					
7	Growth Related Investments - (2014 to 2018 in $000's)	$632,039	$559,115	$72,924	
8					
9	System Growth MW's from 2014-2018	364			MW
10					
11	Marginal Investment (7) / (9)	$1,736.37	$1,536.03	$200.34	/kW
12					
13	Annualized Investment (11) x 8.00%	$138.91	$122.88	$16.03	/kW
14	Admin. & General Factor (11) x 1.33%	$23.09	$20.43	$2.66	/kW
15	Annual O&M Expenses (11) x 1.415%	$24.57	$21.73	$2.83	/kW
16					
17	Annualized Marginal Cost Sum (13) to (15)	$186.57	$165.04	$21.52	/kW
18					
19	Marginal Cost of Energy-Related Transmission			$0.00304	/kWh
20	$21.52 / 8760 hours / 80.87% Load Factor))				

Footnote:

Lines 1-7	Tab 5.2 (Transm2:) `2014-2018 Forecasted Transmission'
Line 9	Peak Load Forecast Detail, Dec. 16, 2009 - Forecasting Dept.
Line 13	Tab 15.1 (Charge 1:) `Calculation of Annual Charges' (for 8.00% factor)
Line 14	Tab 15.1 (Charge 1:) `Calculation of Annual Charges' (for 1.33% factor)
Line 15	Tab 5.3 (Tran_OM:) `Transmission O & M Expenses' (for 1.415% factor)
Line 20	See Tab "TransLF"

Transm2

PacifiCorp
Oregon Marginal Cost Study
2014-2018 Forecasted Transmission
December 2014 Dollars(in 000's)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				Forecast			Total
Line	Description	2014	2015	2016	2017	2018	
1	Bulk Power Lines (grid)	60,589	25,295	17,728	1,000	4,400	
2	price adjustment factor	1.019	1.019	1.019	1.019	1.019	
3	Adjusted Bulk Power Lines (grid)	61,720	25,767	18,058	1,019	4,482	111,046
4							
5	Growth Related Major Projects (local)	108,651	121,678	95,458	101,130	84,531	
6	price adjustment factor	1.0187	1.0187	1.0187	1.0187	1.0187	
7	Adjusted Growth Related Major Projects (local)	110,679	123,949	97,239	103,018	86,108	520,993
8							
9	Bulk Power Lines - Demand Related	21,188	8,846	6,199	350	1,539	
10	Line (3) x Demand Factor 34.33%						
11							
12	Bulk Power Lines - Energy Related	40,532	16,921	11,859	669	2,943	72,924
13	Line (3) - Line (9)						
14							
15	Total Growth Demand Related	131,867	132,795	103,438	103,368	87,647	559,115
16	Line (7) + Line (9)						
17							
18	$ Demand Related	$131,867	$132,795	$103,438	$103,368	$87,647	$559,115
19	$ Energy Related	$40,532	$16,921	$11,859	$669	$2,943	$72,924
20							
21	Total Marginal Transmission Investment	$172,399	$149,716	$115,297	$104,037	$90,590	$632,039

Footnotes:

Line 1 & 5 Bulk power line & growth related projects data provided in 2012 dollars for each year
Line 10 Demand Portion of Transmission = 22.67 / (22.67+43.37) = 34.33%

Index		Escalation Factor
2013	2014	2013 - 2014
1.0180	1.0370	1.0187

PacifiCorp
Transmission O & M Expenses
(Dollars in 000's)

Line	Description	(A) 2002	(B) 2003	(C) 2004	(D) 2005	(E) 2006	(F) 2007	(G) 2008	(H) 2009	(I) 2010	(J) 2011	
1	Transmission O&M Exp.	102,419	105,962	105,324	115,283	136,930	154,195	174,010	172,875	195,628	204,716	
2	Wheeling	76,949	77,497	76,944	83,360	94,111	106,592	121,167	117,161	136,855	138,235	
3	Net Transmission O&M Line (1) - (2)	25,469	28,465	28,379	31,922	42,820	47,603	52,843	55,713	58,774	66,481	
4	Transmission Plant	2,299,173	2,396,665	2,487,677	2,578,317	2,688,839	2,874,659	3,054,529	3,342,914	4,339,114	4,500,418	
5	Tran. O&M Loading Line (3) / (4)	1.108%	1.188%	1.141%	1.238%	1.593%	1.656%	1.730%	1.667%	1.355%	1.477%	1.415%

Source:
PacifiCorp FERC Form 1
(1) page 321, line 112
(2) page 321, line 96

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
2014 Dollars

Line		
1	Incremental Substation Cost - $ / kW	$228.69
2		
3	Annual Distribution Carrying Charge	9.74%
4		
5	Substation Marginal Cost - $ / kW	$22.27 / kW

Dist Sub 2

PacifiCorp
Marginal Cost Study
Substation Investment

In Service Year	Substation Capacity Project	State	Capacity Increase (MVA)	Installed Cost (Dollars in 000's)	Cost Per MVA (Dollars in 000's)
2012	Riddle	OR	61.0	$7,166	$117
2012	Deschutes	OR	12.5	$2,085	$167
2013	Canyonville	OR	10.1	$4,914	$487
2016	Dodge Bridge	OR	12.5	$2,000	$160
2013	Knott	OR	10.0	$4,291	$429
2014	Selah	WA	25.0	$5,989	$240
2016	Independence	OR	5.0	$2,461	$492
2016	Vine Street	OR	10.0	$3,313	$331
			146.1	**$32,219**	

Index		Escalation Factor
2012	2014	2012 - 2014
1.0000	1.0370	1.0370

PacifiCorp
Oregon Marginal Cost Study
Hypothetical Circuit Study Results
Annual Demand and Commitment Costs
December 2014 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Demand				Commitment			
			Investment $ / kW **		Annual $ / kW **		Investment $ / Customer		Annual $ / Customer	
Line	Load Class		Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
					(A) x 9.74%	(B) x 9.74%			(E) x 9.74%	(F) x 9.74%
1	Res - Schedule 4	(sec)	$202.41	$295.16	$19.71	$28.75	$915.10	$441.96	$89.13	$43.05
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$246.83	$336.58	$24.04	$32.78	$1,116.31	$539.14	$108.73	$52.51
5	15+ kW	(sec)	$246.83	$336.58	$24.04	$32.78	$1,116.31	$539.14	$108.73	$52.51
6	Primary	(pri)	$246.83	$336.58	$24.04	$32.78	$1,116.31	$539.14	$108.73	$52.51
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$159.02	$252.85	$15.49	$24.63	$698.82	$337.50	$68.07	$32.87
10	51-100 kW	(sec)	$159.02	$252.85	$15.49	$24.63	$698.82	$337.50	$68.07	$32.87
11	> 101kW	(sec)	$159.02	$252.85	$15.49	$24.63	$698.82	$337.50	$68.07	$32.87
12	Primary	(pri)	$159.02	$252.85	$15.49	$24.63	$698.82	$337.50	$68.07	$32.87
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$119.47	$215.14	$11.64	$20.95	$510.85	$246.72	$49.76	$24.03
16	301+ kW	(sec)	$119.47	$215.14	$11.64	$20.95	$510.85	$246.72	$49.76	$24.03
17	Primary	(pri)	$119.47	$215.14	$11.64	$20.95	$510.85	$246.72	$49.76	$24.03
18										
19	LPS - Schedule 48T									
20	1 - 4 MW	(sec)	$77.77	$177.24	$7.57	$17.26	$332.41	$160.54	$32.38	$15.64
21	1 - 4 MW	(pri)	$77.77	$177.24	$7.57	$17.26	$332.41	$160.54	$32.38	$15.64
22	> 4 MW	(sec)	$12.50	$23.74	$1.22	$2.31	$0.00	$0.00	$0.00	$0.00
23	> 4 MW	(pri)	$8.54	$16.22	$0.83	$1.58	$0.00	$0.00	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$535.96	$615.78	$52.20	$59.98	$2,528.49	$1,221.16	$246.27	$118.94

Footnotes:
**$ / kW are in terms of Distribution kW.

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor
Three Phase Costs as Demand

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Demand		Commitment		2014 Demand		2014 Commitment	
Line	Poles Cost	Conductor Cost	Poles Cost	Conductor Cost	Poles Cost	Conductor Cost	Poles Cost	Conductor Cost
					(D) x 1.0370	(C) x 1.0370	(B) x 1.0370	(A) x 1.0370
1	Res - Schedule 4							
2	$195.19	$284.63	$882.45	$426.19	$202.41	$295.16	$915.10	$441.96
3								
4	GS - Schedule 23							
5	$238.03	$324.57	$1,076.48	$519.90	$246.83	$336.58	$1,116.31	$539.14
6	$238.03	$324.57	$1,076.48	$519.90	$246.83	$336.58	$1,116.31	$539.14
7	$238.03	$324.57	$1,076.48	$519.90	$246.83	$336.58	$1,116.31	$539.14
8								
9	GS - Schedule 28							
10	$153.35	$243.83	$673.89	$325.46	$159.02	$252.85	$698.82	$337.50
11	$153.35	$243.83	$673.89	$325.46	$159.02	$252.85	$698.82	$337.50
12	$153.35	$243.83	$673.89	$325.46	$159.02	$252.85	$698.82	$337.50
13	$153.35	$243.83	$673.89	$325.46	$159.02	$252.85	$698.82	$337.50
14	$153.35	$243.83	$673.89	$325.46	$159.02	$252.85	$698.82	$337.50
15								
16	GS - Schedule 30							
17	$115.21	$207.47	$492.62	$237.92	$119.47	$215.14	$510.85	$246.72
18	$115.21	$207.47	$492.62	$237.92	$119.47	$215.14	$510.85	$246.72
19	$115.21	$207.47	$492.62	$237.92	$119.47	$215.14	$510.85	$246.72
20								
21	LPS - Schedule 48T							
22	$75.00	$170.91	$320.55	$154.81	$77.77	$177.24	$332.41	$160.54
23	$75.00	$170.91	$320.55	$154.81	$77.77	$177.24	$332.41	$160.54
24	$12.05	$22.89	$0.00	$0.00	$12.50	$23.74	$0.00	$0.00
25	$8.23	$15.64	$0.00	$0.00	$8.54	$16.22	$0.00	$0.00
26								
27	Irrigation - Schedule 41							
28	$516.84	$593.81	$2,438.27	$1,177.59	$535.96	$615.78	$2,528.49	$1,221.16
29								

Index		Escalation Factor
2012	2014	2012 - 2014
1.0000	1.0370	1.0370

Footnotes:
Escalation Factors: Cost Trends of Electric Utility Construction, Table A14
Pole and conductor costs from Distribution Circuit Model.

PacifiCorp
Oregon Marginal Cost Study
Circuit Distribution Model
Inputs & Calculations

Line	Class		(A) Annual MWh	(B) Number of Customers	(C) Average MWh per Customer (A) / (B)	(D) Distribution Peak MW	(E) Average kW per customer (D)/(B) * 1,000	(F) Percent Single Phase
1	Res - Schedule 4	(sec)	5,408,536	474,231	11.40	976	2.06	100.00%
2	GS - Schedule 23 - 0-15 kW	(sec)	604,893	66,169	9.14	89	1.34	82.15%
3	GS - Schedule 23 - 15+ kW	(sec)	523,765	10,605	49.39	72	6.81	45.12%
4	GS - Schedule 23 - Primary	(pri)	1,163	44	26.15	0	3.98	-
5	GS - Schedule 28 - 0-50 kW	(sec)	444,385	4,487	99.04	78	17.27	29.81%
6	GS - Schedule 28 - 51-100 kW	(sec)	673,448	3,453	195.01	109	31.54	12.44%
7	GS - Schedule 28 - > 101kW	(sec)	888,469	1,924	461.70	140	72.52	1.93%
8	GS - Schedule 28 - Primary	(pri)	18,661	57	329.16	3	58.43	-
9	GS - Schedule 30 - 0-300 kW	(sec)	202,011	215	939.23	30	138.41	0.39%
10	GS - Schedule 30 - 301+ kW	(sec)	1,030,233	553	1,863.67	165	297.86	-
11	GS - Schedule 30 - Primary	(pri)	90,666	51	1,791.92	15	295.37	-
12	Irrigation - Sch 41	(sec)	217,837	7,211	30.21	27	3.69	14.57%
13	LPS - Schedule 48T - 1 - 4 MW	(sec)	531,189	107	4,961.68	84	785.38	-
14	LPS - Schedule 48T - 1 - 4 MW	(pri)	492,307	64	7,690.63	69	1,072.05	-
15	LPS - Schedule 48T - > 4 MW	(sec)	52,257	2	26,128.40	6	3,096.54	-
16	LPS - Schedule 48T - > 4 MW	(pri)	1,117,609	33	33,801.48	150	4,531.91	-
17	Total -		12,297,428	569,206		2,011		

Customer Distribution on the Hypothetical Circuit Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
		1	2	3	4	5	6	7	Total
18	Res - Schedule 4 (sec)	0.90%	0.90%	0.90%	3.62%	3.62%	3.62%	86.45%	100.00%
19	GS - Schedule 23 - 0-15 kW (sec)	1.30%	1.30%	1.30%	3.92%	3.92%	3.92%	84.34%	100.00%
20	GS - Schedule 23 - 15+ kW (sec)	1.30%	1.30%	1.30%	3.92%	3.92%	3.92%	84.34%	100.00%
21	GS - Schedule 23 - Primary (pri)	1.30%	1.30%	1.30%	3.92%	3.92%	3.92%	84.34%	100.00%
22	GS - Schedule 28 - 0-50 kW (sec)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
23	GS - Schedule 28 - 51-100 kW (sec)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
24	GS - Schedule 28 - > 101kW (sec)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
25	GS - Schedule 28 - Primary (pri)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
26	GS - Schedule 30 - 0-300 kW (sec)	0.52%	0.52%	0.52%	1.26%	1.26%	1.26%	94.65%	100.00%
27	GS - Schedule 30 - 301+ kW (sec)	0.52%	0.52%	0.52%	1.26%	1.26%	1.26%	94.65%	100.00%
28	GS - Schedule 30 - Primary (pri)	0.52%	0.52%	0.52%	1.26%	1.26%	1.26%	94.65%	100.00%
29	Irrigation - Sch 41	2.56%	2.56%	2.56%	12.34%	12.34%	12.34%	55.31%	100.00%
30	LPS - Schedule 48T - 1 - 4 MW (sec)	-	-	-	1.65%	1.65%	1.65%	95.05%	100.00%
31	LPS - Schedule 48T - 1 - 4 MW (pri)	-	-	-	1.65%	1.65%	1.65%	95.05%	100.00%
32	LPS - Schedule 48T - > 4 MW (sec)		Large Customers are on dedicated circuits and are not included here						
33	LPS - Schedule 48T - > 4 MW (pri)		Large Customers are on dedicated circuits and are not included here						

34	System property records & engineering information			
35	Number of pole feet in Oregon	75,818,501	Poles per mile	25.86
36	Number of pole miles in Oregon	14,360	Customers per mile	29.25
37	Number of trench feet in Oregon	26,922,011	MWh per customer	21.60
38	Number of trench miles in Oregon	5,099	MWh per circuit	23,379
39	Total miles in Oregon	19,458	Branches per circuit	7
40			Distance per circuit	36.99
41	Number of circuits in Oregon	526	Distance per branch	5.28
42	Number of poles in Oregon	371,373		
43				

44 12 kV circuit 12 miles long has approx. 3 miles of single phase.
45 which is approx. 25 percent of circuit distance.
46 9.25 = 25 percent of typical Oregon circuit
47
48 5 divide by outer branches
49 1.850 distance of single phase on outer branch
50 35.00% equals percentage of single phase outer branch Segments
51

PacifiCorp
Oregon Circuit Model Study
Customer Distribution on the Hypothetical Circuit Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
		1	2	3	4	5	6	7	Total
1	Residential	0.90%	0.90%	0.90%	3.62%	3.62%	3.62%	86.45%	100.00%
2	GS 0-15 kW (sec) (23)	1.30%	1.30%	1.30%	3.92%	3.92%	3.92%	84.34%	100.00%
3	GS >15 kW (sec) (23)	1.30%	1.30%	1.30%	3.92%	3.92%	3.92%	84.34%	100.00%
4	GS (pri) (23)	1.30%	1.30%	1.30%	3.92%	3.92%	3.92%	84.34%	100.00%
5	GS < 50 kW (sec) (28)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
6	GS 51-100 kW (sec) (28)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
7	GS > 100 kW (sec) (28)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
8	GS (pri) (28)	0.76%	0.76%	0.76%	2.08%	2.08%	2.08%	91.45%	100.00%
9	GS 0-300 kW (sec) (30)	0.52%	0.52%	0.52%	1.26%	1.26%	1.26%	94.65%	100.00%
10	GS >300 kW (sec) (30)	0.52%	0.52%	0.52%	1.26%	1.26%	1.26%	94.65%	100.00%
11	GS (pri) (30)	0.52%	0.52%	0.52%	1.26%	1.26%	1.26%	94.65%	100.00%
12	Irrigation	2.56%	2.56%	2.56%	12.34%	12.34%	12.34%	55.31%	100.00%
13	Large GS 1 - 4 MW (sec)	-	-	-	1.65%	1.65%	1.65%	95.05%	100.00%
14	Large GS 1 - 4 MW (pri)	-	-	-	1.65%	1.65%	1.65%	95.05%	100.00%
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-

Except where customers own their own transformers.

PacifiCorp
Oregon Circuit Model Study
Average Customers by Hypothetical Circuit Branch

Average Customers

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							
		1	2	3	4	5	6	7	Total
1	Residential	8.07	8.07	8.07	32.66	32.66	32.66	779.38	901.58
2	GS 0-15 kW (sec) (23)	1.64	1.64	1.64	4.93	4.93	4.93	106.10	125.80
3	GS >15 kW (sec) (23)	0.26	0.26	0.26	0.79	0.79	0.79	17.00	20.16
4	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.08
5	GS < 50 kW (sec) (28)	0.07	0.07	0.07	0.18	0.18	0.18	7.80	8.53
6	GS 51-100 kW (sec) (28)	0.05	0.05	0.05	0.14	0.14	0.14	6.00	6.57
7	GS > 100 kW (sec) (28)	0.03	0.03	0.03	0.08	0.08	0.08	3.35	3.66
8	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
9	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	0.39	0.41
10	GS >300 kW (sec) (30)	0.01	0.01	0.01	0.01	0.01	0.01	0.99	1.05
11	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10
12	Irrigation	0.35	0.35	0.35	1.69	1.69	1.69	7.58	13.71
13	Large GS 1 - 4 MW (sec)	-	-	-	0.00	0.00	0.00	0.19	0.20
14	Large GS 1 - 4 MW (pri)	-	-	-	0.00	0.00	0.00	0.12	0.12
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	10.48	10.48	10.48	40.49	40.49	40.49	929.17	1,082.07

Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3) Tab 7.3
Source - 'Customer Distribution on the Hypothetical Circuit Branch' (PC 4) Tab 7.4
Customers multiplied by Customer Distribution on the Hypothetical Circuit Branch divided by circuits in the state.
For Example 8.07 is 474,231 Residential Customers X .895% customers on Branch 1 divided by 526 circuits.

Percent of Customers

1	Residential	77.05%	77.05%	77.05%	80.66%	80.66%	80.66%	83.88%	83.32%
2	GS 0-15 kW (sec) (23)	15.63%	15.63%	15.63%	12.17%	12.17%	12.17%	11.42%	11.63%
3	GS >15 kW (sec) (23)	2.50%	2.50%	2.50%	1.95%	1.95%	1.95%	1.83%	1.86%
4	GS (pri) (23)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	0.62%	0.62%	0.62%	0.44%	0.44%	0.44%	0.84%	0.79%
6	GS 51-100 kW (sec) (28)	0.48%	0.48%	0.48%	0.34%	0.34%	0.34%	0.65%	0.61%
7	GS > 100 kW (sec) (28)	0.27%	0.27%	0.27%	0.19%	0.19%	0.19%	0.36%	0.34%
8	GS (pri) (28)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
9	GS 0-300 kW (sec) (30)	0.02%	0.02%	0.02%	0.01%	0.01%	0.01%	0.04%	0.04%
10	GS >300 kW (sec) (30)	0.05%	0.05%	0.05%	0.03%	0.03%	0.03%	0.11%	0.10%
11	GS (pri) (30)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%
12	Irrigation	3.35%	3.35%	3.35%	4.18%	4.18%	4.18%	0.82%	1.27%
13	Large GS 1 - 4 MW (sec)	-	-	-	0.01%	0.01%	0.01%	0.02%	0.02%
14	Large GS 1 - 4 MW (pri)	-	-	-	0.00%	0.00%	0.00%	0.01%	0.01%
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Sum of Branch Customers

18	1,2,3,6	10.5	10.5	10.5			40.5		71.9
19	1,2,3,4,5,6,7	10.5	10.5	10.5	40.5	40.5	40.5	929.2	1,082.1
20									
21	1,2,3,6	14.6%	14.6%	14.6%			56.3%		100.0%
22	1,2,3,4,5,6,7	1.0%	1.0%	1.0%	3.7%	3.7%	3.7%	85.9%	100.0%

PacifiCorp
Oregon Circuit Model Study
Circuit kW Load by Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							
		1	2	3	4	5	6	7	Total
	Circuit kW Loads								
1	Residential	16.6	16.6	16.6	67.2	67.2	67.2	1,603.2	1,854.6
2	GS 0-15 kW (sec) (23)	2.2	2.2	2.2	6.6	6.6	6.6	142.5	169.0
3	GS >15 kW (sec) (23)	1.8	1.8	1.8	5.4	5.4	5.4	115.7	137.2
4	GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3
5	GS < 50 kW (sec) (28)	1.1	1.1	1.1	3.1	3.1	3.1	134.8	147.4
6	GS 51-100 kW (sec) (28)	1.6	1.6	1.6	4.3	4.3	4.3	189.4	207.1
7	GS > 100 kW (sec) (28)	2.0	2.0	2.0	5.5	5.5	5.5	242.7	265.3
8	GS (pri) (28)	0.0	0.0	0.0	0.1	0.1	0.1	5.8	6.3
9	GS 0-300 kW (sec) (30)	0.3	0.3	0.3	0.7	0.7	0.7	53.6	56.6
10	GS >300 kW (sec) (30)	1.6	1.6	1.6	4.0	4.0	4.0	296.3	313.0
11	GS (pri) (30)	0.1	0.1	0.1	0.4	0.4	0.4	26.9	28.4
12	Irrigation	1.3	1.3	1.3	6.2	6.2	6.2	28.0	50.6
13	Large GS 1 - 4 MW (sec)	-	-	-	2.6	2.6	2.6	151.9	159.9
14	Large GS 1 - 4 MW (pri)	-	-	-	2.2	2.2	2.2	124.0	130.5
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	28.8	28.8	28.8	108.3	108.3	108.3	3,115.0	3,526.2

Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3) Tab 7.3
Source - 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5
Customers multiplied by circuit kW per customer.
For Example 16.6 is 8.07 Residential Customers multiplied by 2.06 average Dist. kW per Customer.

Percent of Branch Load

	Class	1	2	3	4	5	6	7	Total
1	Residential	57.74%	57.74%	57.74%	62.04%	62.04%	62.04%	51.47%	52.60%
2	GS 0-15 kW (sec) (23)	7.65%	7.65%	7.65%	6.11%	6.11%	6.11%	4.57%	4.79%
3	GS >15 kW (sec) (23)	6.21%	6.21%	6.21%	4.96%	4.96%	4.96%	3.72%	3.89%
4	GS (pri) (23)	0.02%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	3.92%	3.92%	3.92%	2.84%	2.84%	2.84%	4.33%	4.18%
6	GS 51-100 kW (sec) (28)	5.51%	5.51%	5.51%	3.98%	3.98%	3.98%	6.08%	5.87%
7	GS > 100 kW (sec) (28)	7.06%	7.06%	7.06%	5.10%	5.10%	5.10%	7.79%	7.52%
8	GS (pri) (28)	0.17%	0.17%	0.17%	0.12%	0.12%	0.12%	0.18%	0.18%
9	GS 0-300 kW (sec) (30)	1.03%	1.03%	1.03%	0.66%	0.66%	0.66%	1.72%	1.61%
10	GS >300 kW (sec) (30)	5.68%	5.68%	5.68%	3.65%	3.65%	3.65%	9.51%	8.88%
11	GS (pri) (30)	0.52%	0.52%	0.52%	0.33%	0.33%	0.33%	0.86%	0.81%
12	Irrigation	4.51%	4.51%	4.51%	5.76%	5.76%	5.76%	0.90%	1.43%
13	Large GS 1 - 4 MW (sec)	-	-	-	2.43%	2.43%	2.43%	4.88%	4.53%
14	Large GS 1 - 4 MW (pri)	-	-	-	1.99%	1.99%	1.99%	3.98%	3.70%
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Sum of Branch Loads

	1	2	3	4	5	6	7	Total
1,2,3,6	28.8	28.8	28.8			108.3		194.6
1,2,3,4,5,6,7	28.8	28.8	28.8	108.3	108.3	108.3	3,115.0	3,526.2

1,2,3,6	14.8%	14.8%	14.8%			55.7%		100.0%
1,2,3,4,5,6,7	0.8%	0.8%	0.8%	3.1%	3.1%	3.1%	88.3%	100.0%

PacifiCorp
Oregon Circuit Model Study
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

Wire Sizes	Account 364 Pole Cost per Mile: Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1 Phase -1/0 ACSR	$ 27,300	0.990	$ 27,027	$ 13,053	$ 40,080
3 Phase - 1/0 ACSR	$ 47,186	0.990	$ 46,714	$ 28,680	$ 75,394
3 Phase - 447 AAC & 4\0 AAC	$ 53,129	0.990	$ 52,598	$ 47,812	$ 100,410
3 Phase -795 AAC & 477 AAC	$ 56,254	0.990	$ 55,691	$ 105,804	$ 161,495

	State Specific Account 364 Pole Statistics				Adjustment
State	**Poles**	**Pole Feet**	**Pole Miles**	**Poles / Mile**	**Factor**
California	55,887	12,430,368	2,354	23.74	0.908
Idaho	99,188	22,947,921	4,346	22.82	0.873
Oregon	371,373	75,818,501	14,360	25.86	0.990
Utah	350,610	60,059,546	11,375	30.82	1.180
Washington	98,696	18,879,273	3,576	27.60	1.056
Wyoming	155,389	38,426,986	7,278	21.35	0.817
Total	1,131,143	228,562,595	43,288	26.13	1.000

	Costs for Branches 1,2,3,4,5			
Wire Size	1 Phase -1/0 ACSR	3 Phase - 1/0 ACSR	Total	
Poles	$ 49,991	$ 160,467	$ 210,458	
Conductors	$ 24,144	$ 98,518	$ 122,662	
Total	$ 74,134	$ 258,985	$ 333,120	
	Costs for Branch 6		**Cost for Branch 7**	
Wire Size	3 Phase - 447 AAC & 4\0 AAC		3 Phase -795 AAC & 477 AAC	
Poles	$ 277,965		$ 294,315	
Conductors	$ 252,674		$ 559,147	
Total	$ 530,640		$ 853,462	

Miles per Branch	5.28
Single Phase Miles Per Branch	1.85
Three Phase Miles Per Branch	3.44

Source: Input Tab

Commitment and Demand Costs Per Branch

	Poles			Conductor		
Wire Sizes	**Total Cost**	**Commitment**	**Demand**	**Total Cost**	**Commitment**	**Demand**
Branches 1,2,3,4,5						
1 Phase -1/0 ACSR	$ 49,991	$ 49,991	$ -	$ 24,144	$ 24,144	$ -
3 Phase - 1/0 ACSR	$ 160,467	$ 92,840	$ 67,627	$ 98,518	$ 44,838	$ 53,680
Total Branches 1,2,3,4,5	$ 210,458	$ 142,831	$ 67,627	$ 122,662	$ 68,982	$ 53,680
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 277,965	$ 142,831	$ 135,135	$ 252,674	$ 68,982	$ 183,692
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 294,315	$ 142,831	$ 151,484	$ 559,147	$ 68,982	$ 490,165
Total All Branches	$ 1,624,570	$ 999,816	$ 624,754	$ 1,425,131	$ 482,872	$ 942,258

PacifiCorp
Oregon Circuit Model Study
Calculation of Hypothetical Circuit Model Branch Cost

Conductors Type	(A)	(B)	(C)	(D)	(E)	(F)
	Total Cost		Commitment Cost		Demand Cost	
	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total segment	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 2						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total Segments	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 3						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total Segments	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 4						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total Segments	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 5						
1 Phase -1/0 ACSR	$ 49,991	$ 24,144	$ 49,991	$ 24,144	NA	NA
3 Phase - 1/0 ACSR	$ 160,467	$ 98,518	$ 92,840	$ 44,838	$ 67,627	$ 53,680
Total Segments	$ 210,458	$ 122,662	$ 142,831	$ 68,982	$ 67,627	$ 53,680
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 277,965	$ 252,674	$ 142,831	$ 68,982	$ 135,135	$ 183,692
Total Segments	$ 277,965	$ 252,674	$ 142,831	$ 68,982	$ 135,135	$ 183,692
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 294,315	$ 559,147	$ 142,831	$ 68,982	$ 151,484	$ 490,165
Total segment	$ 294,315	$ 559,147	$ 142,831	$ 68,982	$ 151,484	$ 490,165
$3,049,700	**$1,624,570**	**$1,425,131**	**$999,816**	**$482,872**	**$624,754**	**$942,258**

Source - 'System-wide Pole and Conductor Costs' (PC 7) Tab 7.7

PacifiCorp
Oregon Circuit Model Study
Pole Demand Calculations

	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	14.78%	14.78%	14.78%	NA	NA	55.66%	NA	100.00%	
2	Branch 6 Cost	$ 19,973	$ 19,973	$ 19,973	NA	NA	$ 75,215	NA	$ 135,135	$ / kW
3	% Demand	0.82%	0.82%	0.82%	3.07%	3.07%	3.07%	88.34%	100.00%	
4	Branch 7 Cost	$ 1,235	$ 1,235	$ 1,235	$ 4,652	$ 4,652	$ 4,652	$ 133,822	$ 151,484	
5	Branch Demand Cost	$ 67,627	$ 67,627	$ 67,627	$ 67,627	$ 67,627	NA	NA		Average
6	Total	$ 88,835	$ 88,835	$ 88,835	$ 72,279	$ 72,279	$ 79,868	$ 133,822	$ 624,754	$ 177.18
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 51,297	$ 51,297	$ 51,297	$ 44,845	$ 44,845	$ 49,553	$ 68,876	$ 362,008	$ 195.19
11	GS 0-15 kW (sec) (23)	$ 6,792	$ 6,792	$ 6,792	$ 4,418	$ 4,418	$ 4,882	$ 6,122	$ 40,217	$ 238.03
12	GS >15 kW (sec) (23)	$ 5,516	$ 5,516	$ 5,516	$ 3,588	$ 3,588	$ 3,965	$ 4,972	$ 32,659	$ 238.03
13	GS (pri) (23)	$ 14	$ 14	$ 14	$ 9	$ 9	$ 10	$ 12	$ 80	$ 238.03
14	GS < 50 kW (sec) (28)	$ 3,482	$ 3,482	$ 3,482	$ 2,049	$ 2,049	$ 2,264	$ 5,790	$ 22,597	$ 153.35
15	GS 51-100 kW (sec) (28)	$ 4,893	$ 4,893	$ 4,893	$ 2,880	$ 2,880	$ 3,182	$ 8,136	$ 31,756	$ 153.35
16	GS > 100 kW (sec) (28)	$ 6,269	$ 6,269	$ 6,269	$ 3,690	$ 3,690	$ 4,077	$ 10,425	$ 40,688	$ 153.35
17	GS (pri) (28)	$ 149	$ 149	$ 149	$ 88	$ 88	$ 97	$ 247	$ 966	$ 153.35
18	GS 0-300 kW (sec) (30)	$ 913	$ 913	$ 913	$ 477	$ 477	$ 527	$ 2,301	$ 6,520	$ 115.21
19	GS >300 kW (sec) (30)	$ 5,050	$ 5,050	$ 5,050	$ 2,637	$ 2,637	$ 2,914	$ 12,728	$ 36,065	$ 115.21
20	GS (pri) (30)	$ 458	$ 458	$ 458	$ 239	$ 239	$ 264	$ 1,155	$ 3,273	$ 115.21
21	Irrigation	$ 4,004	$ 4,004	$ 4,004	$ 4,166	$ 4,166	$ 4,604	$ 1,202	$ 26,151	$ 516.84
22	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 1,759	$ 1,759	$ 1,943	$ 6,528	$ 11,988	$ 75.00
23	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 1,435	$ 1,435	$ 1,586	$ 5,328	$ 9,785	$ 75.00
24	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Check Total	$ 88,835	$ 88,835	$ 88,835	$ 72,279	$ 72,279	$ 79,868	$ 133,822	$ 624,754	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 6) Tab 7.6
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $135,135
Line 1 X $135,135
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $151,484
Line 3 X $151,484
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 6) Tab 7.6

PacifiCorp
Oregon Circuit Model Study
Conductor Demand Calculations

Line	**Conductors**	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	14.78%	14.78%	14.78%	NA	NA	55.66%	NA	100.00%	
2	Branch 6 Cost	$ 27,150	$ 27,150	$ 27,150	NA	NA	$ 102,243	NA	$ 183,692	**$ / kW**
3	% Demand	0.82%	0.82%	0.82%	3.07%	3.07%	3.07%	88.34%	100.00%	
4	Branch 7 Cost	$ 3,997	$ 3,997	$ 3,997	$ 15,053	$ 15,053	$ 15,053	$ 433,013	$ 490,165	
5	Branch Demand Cost	$ 53,680	$ 53,680	$ 53,680	$ 53,680	$ 53,680	NA	NA		average
6	Total	$ 84,827	$ 84,827	$ 84,827	$ 68,734	$ 68,734	$ 117,296	$ 433,013	$ 942,258	$ 267.22
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 48,982	$ 48,982	$ 48,982	$ 42,645	$ 42,645	$ 72,775	$ 222,865	$ 527,877	$ 284.63
11	GS 0-15 kW (sec) (23)	$ 6,486	$ 6,486	$ 6,486	$ 4,202	$ 4,202	$ 7,170	$ 19,810	$ 54,840	$ 324.57
12	GS >15 kW (sec) (23)	$ 5,267	$ 5,267	$ 5,267	$ 3,412	$ 3,412	$ 5,823	$ 16,087	$ 44,533	$ 324.57
13	GS (pri) (23)	$ 13	$ 13	$ 13	$ 8	$ 8	$ 14	$ 39	$ 109	$ 324.57
14	GS < 50 kW (sec) (28)	$ 3,324	$ 3,324	$ 3,324	$ 1,949	$ 1,949	$ 3,326	$ 18,733	$ 35,930	$ 243.83
15	GS 51-100 kW (sec) (28)	$ 4,672	$ 4,672	$ 4,672	$ 2,739	$ 2,739	$ 4,673	$ 26,326	$ 50,492	$ 243.83
16	GS > 100 kW (sec) (28)	$ 5,986	$ 5,986	$ 5,986	$ 3,509	$ 3,509	$ 5,988	$ 33,731	$ 64,695	$ 243.83
17	GS (pri) (28)	$ 142	$ 142	$ 142	$ 83	$ 83	$ 142	$ 801	$ 1,535	$ 243.83
18	GS 0-300 kW (sec) (30)	$ 872	$ 872	$ 872	$ 453	$ 453	$ 774	$ 7,446	$ 11,742	$ 207.47
19	GS >300 kW (sec) (30)	$ 4,822	$ 4,822	$ 4,822	$ 2,507	$ 2,507	$ 4,279	$ 41,186	$ 64,945	$ 207.47
20	GS (pri) (30)	$ 438	$ 438	$ 438	$ 228	$ 228	$ 388	$ 3,738	$ 5,895	$ 207.47
21	Irrigation	$ 3,824	$ 3,824	$ 3,824	$ 3,962	$ 3,962	$ 6,761	$ 3,890	$ 30,046	$ 593.81
22	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 1,672	$ 1,672	$ 2,854	$ 21,122	$ 27,321	$ 170.91
23	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 1,365	$ 1,365	$ 2,329	$ 17,239	$ 22,299	$ 170.91
24	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Check Total	$ 84,827	$ 84,827	$ 84,827	$ 68,734	$ 68,734	$ 117,296	$ 433,013	$ 942,258	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 6) Tab 7.6
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $183,692
Line 1 X $183,692
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $490,165
Line 3 X $490,165
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 6) Tab 7.6

PacifiCorp
Oregon Circuit Model Study
Pole Commitment Calculations

	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% customer	14.57%	14.57%	14.57%	NA	NA	56.30%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	**$ Per**
3	% customer	0.97%	0.97%	0.97%	3.74%	3.74%	3.74%	85.87%	100.00%	**Customer**
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 142,831		average
6	Total	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 999,816	$ 923.98
7										
8									Total	**$ Per**
9									Commitment	**Customer**
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 110,055	$ 110,055	$ 110,055	$ 115,209	$ 115,209	$ 115,209	$ 119,805	$ 795,597	$ 882.45
12	GS 0-15 kW (sec) (23)	$ 22,318	$ 22,318	$ 22,318	$ 17,384	$ 17,384	$ 17,384	$ 16,310	$ 135,417	$ 1,076.48
13	GS >15 kW (sec) (23)	$ 3,577	$ 3,577	$ 3,577	$ 2,786	$ 2,786	$ 2,786	$ 2,614	$ 21,704	$ 1,076.48
14	GS (pri) (23)	$ 15	$ 15	$ 15	$ 12	$ 12	$ 12	$ 11	$ 91	$ 1,076.48
15	GS < 50 kW (sec) (28)	$ 890	$ 890	$ 890	$ 627	$ 627	$ 627	$ 1,199	$ 5,749	$ 673.89
16	GS 51-100 kW (sec) (28)	$ 685	$ 685	$ 685	$ 483	$ 483	$ 483	$ 923	$ 4,424	$ 673.89
17	GS > 100 kW (sec) (28)	$ 381	$ 381	$ 381	$ 269	$ 269	$ 269	$ 514	$ 2,465	$ 673.89
18	GS (pri) (28)	$ 11	$ 11	$ 11	$ 8	$ 8	$ 8	$ 15	$ 73	$ 673.89
19	GS 0-300 kW (sec) (30)	$ 29	$ 29	$ 29	$ 18	$ 18	$ 18	$ 59	$ 201	$ 492.62
20	GS >300 kW (sec) (30)	$ 75	$ 75	$ 75	$ 47	$ 47	$ 47	$ 153	$ 518	$ 492.62
21	GS (pri) (30)	$ 7	$ 7	$ 7	$ 4	$ 4	$ 4	$ 14	$ 47	$ 492.62
22	Irrigation	$ 4,788	$ 4,788	$ 4,788	$ 5,965	$ 5,965	$ 5,965	$ 1,165	$ 33,425	$ 2,438.27
23	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 12	$ 12	$ 12	$ 30	$ 65	$ 320.55
24	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 7	$ 7	$ 7	$ 18	$ 39	$ 320.55
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 142,831	$ 999,816	

Sources: Line 1 & 3 - 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $ 0
Line 1 X $ 0
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $ 0
Line 3 X $ 0
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8
Line 7 to 18 - Line 6 X Percent of Customers 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5

PacifiCorp
Oregon Circuit Model Study
Conductor Commitment Calculations

	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% customer	14.57%	14.57%	14.57%	NA	NA	56.30%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	$ Per
3	% customer	0.97%	0.97%	0.97%	3.74%	3.74%	3.74%	85.87%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 68,982		average
6	Total	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 482,872	$ 446.25
7										
8									Total	$ Per
9									Commitment	Customer
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 53,152	$ 53,152	$ 53,152	$ 55,641	$ 55,641	$ 55,641	$ 57,861	$ 384,243	$ 426.19
12	GS 0-15 kW (sec) (23)	$ 10,779	$ 10,779	$ 10,779	$ 8,396	$ 8,396	$ 8,396	$ 7,877	$ 65,401	$ 519.90
13	GS >15 kW (sec) (23)	$ 1,728	$ 1,728	$ 1,728	$ 1,346	$ 1,346	$ 1,346	$ 1,262	$ 10,482	$ 519.90
14	GS (pri) (23)	$ 7	$ 7	$ 7	$ 6	$ 6	$ 6	$ 5	$ 44	$ 519.90
15	GS < 50 kW (sec) (28)	$ 430	$ 430	$ 430	$ 303	$ 303	$ 303	$ 579	$ 2,776	$ 325.46
16	GS 51-100 kW (sec) (28)	$ 331	$ 331	$ 331	$ 233	$ 233	$ 233	$ 446	$ 2,137	$ 325.46
17	GS > 100 kW (sec) (28)	$ 184	$ 184	$ 184	$ 130	$ 130	$ 130	$ 248	$ 1,191	$ 325.46
18	GS (pri) (28)	$ 5	$ 5	$ 5	$ 4	$ 4	$ 4	$ 7	$ 35	$ 325.46
19	GS 0-300 kW (sec) (30)	$ 14	$ 14	$ 14	$ 9	$ 9	$ 9	$ 29	$ 97	$ 237.92
20	GS >300 kW (sec) (30)	$ 36	$ 36	$ 36	$ 23	$ 23	$ 23	$ 74	$ 250	$ 237.92
21	GS (pri) (30)	$ 3	$ 3	$ 3	$ 2	$ 2	$ 2	$ 7	$ 23	$ 237.92
22	Irrigation	$ 2,312	$ 2,312	$ 2,312	$ 2,881	$ 2,881	$ 2,881	$ 563	$ 16,143	$ 1,177.59
23	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 6	$ 6	$ 6	$ 14	$ 32	$ 154.81
24	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 3	$ 3	$ 3	$ 9	$ 19	$ 154.81
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 68,982	$ 482,872	

Sources: Line 1 & 3 - 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $ 0
Line 1 X $ 0
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8 For $ 0
Line 3 X $ 0
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 7.8
Line 7 to 18 - Line 6 X Percent of Customers 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5

PacifiCorp
Oregon Circuit Model Study
Dedicated Circuit Trunk Costs
For Large Customers

	Voltage Delivery			
	Large GS + 4 MW (pri)		Large GS + 4 MW (sec)	
	Poles	Conductor	Poles	Conductor
1 Construction Cost Per Mile	$ 55,691	$ 105,804	$ 55,691	$ 105,804
2 Average Trunk Length	0.67 miles		0.67 miles	
3 Total Construction Cost	$ 37,313	$ 70,889	$ 37,313	$ 70,889
4 Customer Peak Demand	4,532 kW		3,097 kW	
5 Demand Cost $/kW	$8.23	$15.64	$12.05	$22.89

Construction Costs for Distribution Line type - 3 Phase -795 AAC & 477 AAC.

Line 1 - 'System-wide Pole and Conductor Costs' (PC 7) Tab 7.7
Line 2 - Distribution Engineering Studies
Line 3 - Line 1 multiplied by Line 2
Line 4 - 'Circuit Distribution Model Inputs & Calculations' (PC 3) Tab 7.3
Line 5 - Line 3 divided by Line 4

PacifiCorp
Oregon Circuit Model Study
Trunk All Demand Costs
Outer Branches Commitment & Demand
Three Phase As Needed

	(A)	(B)	(C)	(D)	(E)	(F)		
	Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
Residential	$ 882.45	$ 426.19	$ 195.19	$ 284.63	901.6	1,854.63	$ 362,008	$ 527,877
GS 0-15 kW (sec) (23)	$ 1,076.48	$ 519.90	$ 238.03	$ 324.57	125.8	168.96	$ 40,217	$ 54,840
GS >15 kW (sec) (23)	$ 1,076.48	$ 519.90	$ 238.03	$ 324.57	20.2	137.21	$ 32,659	$ 44,533
GS (pri) (23)	$ 1,076.48	$ 519.90	$ 238.03	$ 324.57	0.1	0.34	$ 80	$ 109
GS < 50 kW (sec) (28)	$ 673.89	$ 325.46	$ 153.35	$ 243.83	8.5	147.36	$ 22,597	$ 35,930
GS 51-100 kW (sec) (28)	$ 673.89	$ 325.46	$ 153.35	$ 243.83	6.6	207.08	$ 31,756	$ 50,492
GS > 100 kW (sec) (28)	$ 673.89	$ 325.46	$ 153.35	$ 243.83	3.7	265.33	$ 40,688	$ 64,695
GS (pri) (28)	$ 673.89	$ 325.46	$ 153.35	$ 243.83	0.1	6.30	$ 966	$ 1,535
GS 0-300 kW (sec) (30)	$ 492.62	$ 237.92	$ 115.21	$ 207.47	0.4	56.60	$ 6,520	$ 11,742
GS >300 kW (sec) (30)	$ 492.62	$ 237.92	$ 115.21	$ 207.47	1.1	313.04	$ 36,065	$ 64,945
GS (pri) (30)	$ 492.62	$ 237.92	$ 115.21	$ 207.47	0.1	28.41	$ 3,273	$ 5,895
Irrigation	$ 2,438.27	$ 1,177.59	$ 516.84	$ 593.81	13.7	50.60	$ 26,151	$ 30,046
Large GS 1 - 4 MW (sec)	$ 320.55	$ 154.81	$ 75.00	$ 170.91	0.2	159.85	$ 11,988	$ 27,321
Large GS 1 - 4 MW (pri)	$ 320.55	$ 154.81	$ 75.00	$ 170.91	0.1	130.47	$ 9,785	$ 22,299
Total -	$ 923.98	$ 446.25	$ 177.18	$ 267.22	1,082.1	3,526.2	$ 624,754	$ 942,258
Large GS + 4 MW (sec)	$ -	$ -	$ 12.05	$ 22.89	-	3,096.54	$ 37,313	$ 70,889
Large GS + 4 MW (pri)	$ -	$ -	$ 8.23	$ 15.64	-	4,531.91	$ 37,313	$ 70,889
							$ 699,380	$ 1,084,035

	Commitment	Demand	Total
Poles	$ 999,816	$ 699,380	$ 1,699,196
Conductor	$ 482,872	$ 1,084,035	$ 1,566,908
Total	$ 1,482,688	$ 1,783,416	$ 3,266,104

Source : Column (A) - Pole Commitment Calculations' (PC 11) Tab 7.11
Column (B) - Conductor Commitment Calculations' (PC 12) Tab 7.12
Column (C) - Pole Demand Calculations' (PC 9) Tab 7.9
Column (D) - Conductor Demand Calculations' (PC 10) Tab 8.10
Column (E) - Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 7.5
Column (F) - Circuit kW Load by Branch' (PC 6) Tab 7.6

XFMR 1

PacifiCorp
Oregon Marginal Cost Study
Transformer Commitment Costs

Line	Customer Type	(A) Percent of Customers	(B) Dollars / Tran.	(C) Weighted $ / Tran. (A) x (B)	(D) # Cust. / Tran.	(E) Transformer $ / Cust. (C) / (D)	(F) Average Customers	(G) Tot. Trans. Commitment $ (E) x (F)
1	Res - Schedule 4	100.00%	300.92	300.92	3.69	$81.55	485,586	$39,599,538
2								
3	GS - Schedule 23							
4	1 Phase	82.15%	300.92	247.20	3.37	$73.35		
5	3 Phase	17.85%	855.06	152.64	3.59	$42.52		
6	0-15 kW	100.00%				$115.87	63,644	$7,374,508
7								
8	1 Phase	45.12%	300.92	135.76	3.37	$40.28		
9	3 Phase	54.88%	855.06	469.29	3.59	$130.72		
10	15+ kW	100.00%				$171.01	10,200	$1,744,264
11								
12	Primary	100.00%	-	-	-	0	43	$0
13								
14	GS - Schedule 28							
15	1 Phase	29.81%	300.92	89.71	1.37	$65.60		
16	3 Phase	70.19%	855.06	600.16	1.36	$442.65		
17	0-50 kW	100.00%				$508.24	4,489	$2,281,505.21
18								
19	1 Phase	12.44%	300.92	37.44	1.37	$27.38		
20	3 Phase	87.56%	855.06	748.69	1.36	$552.19		
21	51-100 kW	100.00%				$579.57	3,455	$2,002,414
22								
23	1 Phase	1.93%	300.92	5.79	1.37	$4.23		
24	3 Phase	98.07%	855.06	838.60	1.36	$618.51		
25	> 101kW	100.00%				$622.74	1,925	$1,198,773
26								
27	Primary	100.00%	-	-	-	0	56	$0
28								
29	GS - Schedule 30							
30	1 Phase	0.39%	300.92	1.17	1.00	$1.17		
31	3 Phase	99.61%	855.06	851.75	1.09	$779.40		
32	0-300 kW	100.00%				$780.57	200	$156,114
33								
34	1 Phase	0.00%	300.92	-	1.00	$0.00		
35	3 Phase	100.00%	855.06	855.06	1.09	$782.43		
36	301+ kW	100.00%				$782.43	515	$402,951
37								
38	Primary	100.00%	-	-	0.00	0	47	$0
39								
40	LPS - Schedule 48T							
41	1 - 4 MW (sec)	100.00%	855.06	855.06	1.07	795.57	102	$81,148
42	1 - 4 MW (pri)	100.00%	-	-	0.00	0	61	$0
43	> 4 MW (sec)	100.00%	855.06	855.06	1.07	795.57	2	$1,591
44	> 4 MW (pri)	100.00%	-	-	0.00	0	32	$0
45	Trans (trn)	100.00%	-	-	0.00	0	9	$0
46								
47	Schedule 41- Irrigation							
48	1 Phase	14.57%	300.92	43.84	1.50	$29.13		
49	3 Phase	85.43%	855.06	730.49	1.23	$591.86		
50	Total	100.00%				$621.00	8,046	$4,996,533

XFMR 2

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand Costs

Line	Customer Type		(A) Weighted $ / kW	(B) Transformer Peak kW's	(C) Tot. Trans. Demand $ (A) x (B)
1	Res - Schedule 4	(sec)	$1.97	3,327,351	$6,554,882
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	$1.97	184,263	$362,999
5	15+ kW	(sec)	$1.97	126,512	$249,228
6	Primary	(pri)	$0.00	0	$0
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	$1.97	141,470	$278,696
10	51-100 kW	(sec)	$1.97	189,067	$372,462
11	> 101kW	(sec)	$1.97	233,629	$460,249
12	Primary	(pri)	$0.00	0	$0
13					
14	GS - Schedule 30				
15	0-300 kW	(sec)	$1.97	48,729	$95,995
16	301+ kW	(sec)	$1.97	259,445	$511,107
17	Primary	(pri)	$0.00	0	$0
18					
19					
20	LPS - Schedule 48T				
21	1 - 4 MW	(sec)	$1.97	132,222	$260,477
22	1 - 4 MW	(pri)	$0.00	0	$0
23	> 4 MW	(sec)	$1.97	13,624	$26,838
24	> 4 MW	(pri)	$0.00	0	$0
25	Trans	(trn)	$0.00	0	$0
26					
27	Irrigation - Schedule 41 (Average)				
28	Secondary	(sec)	$1.97	150,187	$295,868
29					
30	Totals			4,806,498	$9,468,801

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors for Transformers
(Regression weighted by number of transformer banks)

Line	Description	(A) Demand Related	(B) Adjusted for System Power Factor of 0.95	(C) Commitment Related	(D) Indexed to 2014	(E) Annualized $ @ 9.74%
			(A) / 0.95		(B) or (C) x 1.0370	(D) x 9.74%
1	1 Phase $/kW	$18.53	$19.51		$20.23	$1.97
2						
3	3 Phase $/kW	$18.53	$19.51		$20.23	$1.97
4						
5	1 Phase			$2,979.28	$3,089.52	$300.92
6	$/Transformer					
7						
8	3 Phase			$5,486.32		
9	Dummy Variable					
10						
11	3 Phase			$8,465.60	$8,778.83	$855.06
12	$/Transformer					

Index		Escalation Factor
2012	2014	2012 - 2014
1.0000	1.0370	1.0370

PacifiCorp
Oregon Marginal Cost Study
Distribution O&M Expense
Loading Factor as a Percent of Dist. Plant
(Excluding Meters and St Ltg)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Description	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
	Distribution O & M Expenses										
1	Total Distribution O & M Expense	48,559,856	48,811,823	71,993,550	67,011,911	68,781,531	71,602,482	73,614,647	71,075,634	69,087,864	66,557,786
2	Less:										
3	585 St Ltg & Signal Systems	-	13,067	89,965	45,553	48,057	75,549	64,882	59,174	58,882	63,875
4	586 Meter Expense	1,800,451	2,010,097	1,892,897	2,122,259	2,058,440	2,206,057	2,848,811	2,878,301	2,873,361	3,548,094
5	587 Customer Installation Expense	9,542	90,751	62,896	-	-	3,636,287	3,568,921	4,456,390	4,466,370	4,633,258
6	596 Main. of St Ltg & Signal Systems	814,491	756,545	885,374	843,436	851,273	945,804	910,118	1,008,869	1,065,645	1,251,031
7	597 Main. of Meters	825,166	1,190,462	1,237,234	1,348,150	1,669,096	1,560,945	1,433,131	1,465,615	1,360,896	1,386,968
8											
9	Total Adjusted Distribution O & M Expense	45,110,206	44,750,901	67,825,184	62,652,513	64,154,665	63,177,840	64,788,784	61,207,285	59,262,711	55,674,560
10	Line 1 - (Lines 3 through 7)										
11											
12											
13	Distribution Plant										
14	Total Distribution Plant	1,303,063,520	1,341,098,219	1,384,196,236	1,431,636,624	1,476,365,173	1,530,307,351	1,590,201,846	1,645,851,699	1,694,776,599	1,733,406,361
15	Less:										
16	370 Meters	57,067,003	56,828,689	56,705,794	58,095,163	58,456,991	59,168,811	59,791,712	60,319,849	60,008,209	59,771,898
17	373 Street Lighting	16,135,274	16,827,066	17,637,977	18,351,472	19,120,699	20,208,050	21,082,794	21,494,031	21,743,089	21,961,746
18											
19	Adjusted Distribution Plant	1,229,861,243	1,267,442,464	1,309,852,465	1,355,189,989	1,398,787,483	1,450,930,490	1,509,327,340	1,564,037,819	1,613,025,300	1,651,672,717
20	Line 14 - Line 16 - Line 17										
21											
22											
23	O & M Expense Loading Factor										
24	Distribution O & M Loading	3.67%	3.53%	5.18%	4.62%	4.59%	4.35%	4.29%	3.91%	3.67%	3.37%
25	Line 9 / Line 19										
26											
27	Average Distribution O & M Loading	4.12%									
28	Average of Line 24										
29											
30	Distribution Annual Charge	9.74%									
31											
32	Annualized Distribution O & M Loading Factor	42.30%									
33	Line 27 / Line 30										

Footnotes:
Source: FERC Form 1 (State of Oregon) & Results of Operations

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			% of Customers			Overhead	Underground			Weighted	Weighted Service Drop Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Service Drop Cost	Service Drop Cost	Overhead %	Underground %	Service Drop Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø						(B) x (E)	(C) x (E)	(D) x (E)
1	Res - Schedule 4	474,231	100.00%	100.00%						$710	$709.69	$709.69	
2	Annualized - Line 1 x 9.74%										$69.12	$69.12	
3													
4	GS - Schedule 23												
5	0-15 kW												
6	kW = 0, 1 Phase	47,268	71.44%	86.96%		$914	$737	67.2%	32.8%	$856	$611.26	$744.10	
7	kW = 0, 3 Phase	2,367	3.58%		20.04%	$1,121	$1,021	67.2%	32.8%	$1,088	$38.93		$218.05
8	kW > 1, 1 Phase	7,089	10.71%	13.04%		$1,022	$780	67.2%	32.8%	$943	$101.00	$122.95	
9	kW > 1, 3 Phase	9,446	14.28%		79.96%	$1,207	$1,076	67.2%	32.8%	$1,164	$166.18		$930.90
10	Total 0-15 kW	66,169	100.00%	100.00%	100.00%						$917.37	$867.05	$1,148.95
11	Annualized - Line 10 x 9.74%										$89.35	$84.45	$111.91
12													
13	15+ kW												
14	1 Phase	4,785	45.12%	100.00%		$1,835	$1,376	67.2%	32.8%	$1,685	$760.02	$1,684.59	
15	3 Phase	5,820	54.88%		100.00%	$2,170	$1,969	67.2%	32.8%	$2,104	$1,154.96		$2,104.36
16	Total 15+ kW	10,605	100.00%	100.00%	100.00%						$1,914.98	$1,684.59	$2,104.36
17	Annualized - Line 16 x 9.74%										$186.52	$164.08	$204.96
18													
19	Primary												
20	12.47 KV 4-wire Wye	44	100.00%		100.00%					$0		$0.00	$0.00
21	Annualized - (Line 20) x 9.74%									$0.00	$0.00	$0.00	$0.00
22													
23	GS - Schedule 28												
24	0-50 kW												
25	1 Phase	1,338	29.81%	100.00%		$1,835	$1,376	49.8%	50.2%	$1,605	$478.36	$1,604.66	
26	3 Phase	3,149	70.19%		100.00%	$2,170	$1,969	49.8%	50.2%	$2,069	$1,452.47		$2,069.36
27	Total 0-50 kW	4,487	100.00%	100.00%	100.00%						$1,930.83	$1,604.66	$2,069.36
28	Annualized - Line 27 x 9.74%										$188.06	$156.29	$201.56
29													
30	51-100 kW												
31	1 Phase	430	12.44%	100.00%		$1,835	$1,376	49.8%	50.2%	$1,605	$199.62	$1,604.66	
32	3 Phase	3,024	87.56%		100.00%	$2,170	$1,969	49.8%	50.2%	$2,069	$1,811.92		$2,069.36
33	Total 51-100 kW	3,453	100.00%	100.00%	100.00%						$2,011.54	$1,604.66	$2,069.36
34	Annualized - Line 33 x 9.74%										$195.92	$156.29	$201.56
35													
36	> 101kW												
37	1 Phase	37	1.93%	100.00%		$3,311	$4,153	49.8%	50.2%	$3,734	$71.89	$3,734.24	
38	3 Phase	1,887	98.07%		100.00%	$3,880	$3,861	49.8%	50.2%	$3,871	$3,796.04		$3,870.55
39	Total > 101kW	1,924	100.00%	100.00%	100.00%						$3,867.93	$3,734.24	$3,870.55
40	Annualized - Line 39 x 9.74%										$376.74	$363.71	$376.99
41													
42	Primary												
43	12.47 KV 4-wire Wye	57	100.00%		100.00%					$0	$0.00		$0.00
44	Annualized - (Line 43) x 9.74%										$0.00	$0.00	$0.00

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2012.

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
GS - Schedule 30 / LPS - Schedule 48T

		(A)	(B)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Load Class	Customers	% of Customers 1 & 3 Phase	Overhead Service Drop Cost	Underground Service Drop Cost	Overhead %	Underground %	Weighted Service Drop Cost	Weighted Service Drop Cost 1 & 3 Phase
			(A) / (A,Ttl)						(B) x (E)
1	GS - Schedule 30								
2									
3	0-300 kW								
4	1 Phase	1	0.39%	$3,311	$4,153	26.9%	73.1%	$3,927	$15.22
5	3 Phase	214	99.61%	$3,880	$3,861	26.9%	73.1%	$3,866	$3,851.06
6	Total 0-300 kW	215	100.00%						$3,866.28
7	Annualized - Line 6 x 9.74%								$376.58
8									
9	301+ kW								
10	1 Phase	0	0.00%	$8,171	$7,200	26.9%	73.1%	$7,461	$0.00
11	3 Phase	553	100.00%	$8,171	$7,200	26.9%	73.1%	$7,461	$7,460.56
12	Total 301+ kW	553	100.00%						$7,460.56
13	Annualized - Line 12 x 9.74%								$726.66
14									
15	Primary								
16	12.47 KV 4-wire Wye	51	100.00%					$0	$0.00
17	Annualized - Line 16 x 9.74%								$0.00
18									
19	LPS - Schedule 48T								
20	1 - 4 MW (sec)	107	100.00%		$25,243	0.0%	100.0%	$25,243	$25,242.65
21	Annualized - Line 20 x 9.74%								$2,458.63
22									
23	1 - 4 MW (pri)	64	100.00%					$0	$0.00
24	Annualized - Line 23 x 9.74%								$0.00
25									
26	> 4 MW (sec)	2	100.00%		$25,243	0.0%	100.0%	$25,243	$25,242.65
27	Annualized - Line 26 x 9.74%								$2,458.63
28									
29	> 4 MW (pri)	33	100.00%					$0	$0.00
30	Annualized - Line 29 x 9.74%								$0.00
31									
32	Trans (trn)	6	100.00%					$0	$0.00
33	Annualized - Line 32 x 9.74%								$0.00

Footnote:
Columns (E) & (F) - see Tab 10.3 (Services 3:) `Summary of Average Installed Costs Service Drops'

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Service Drops

Line	Load Class	(A) Service Conductor	(B) Cost	(C) Indexed to 2014 (B) x 1.0370	(D) Percent Use	(E) Total Cost per Service
	Residential					
1	OH - small load	#2 Triplex*	$612	$635	33.6%	$212.94
2	OH - all electric	1/0 Triplex	$703	$729	29.0%	$211.45
3	UG - small load	1/0 Triplex	$711	$737	15.7%	$115.94
4	UG - all electric	4/0 Triplex	$752	$780	21.7%	$169.35
5						$709.69
6	0 - 15 kW					
7	kW = 0, 1 Phase	OH - 1/0 Triplex	$881	$914		
8		UG - 1/0 Triplex	$711	$737		
9						
10						
11	kW = 0, 3 Phase	OH - 1/0 Quadruplex	$1,081	$1,121		
12		UG - 1/0 Quadruplex	$985	$1,021		
13						
14						
15	kW > 1, 1 Phase	OH - 4/0 Triplex	$986	$1,022		
16		UG - 4/0 Triplex	$752	$780		
17						
18						
19	kW > 1, 3 Phase	OH - 4/0 Quadruplex	$1,164	$1,207		
20		UG - 4/0 Quadruplex	$1,038	$1,076		
21						
22	16 - 100 kW					
23	1 Phase	OH - 2-4/0 Triplex	$1,770	$1,835		
24		UG - 2-4/0 Triplex	$1,327	$1,376		
25						
26						
27	3 Phase	OH - 2-4/0 Quadruplex	$2,093	$2,170		
28		UG - 2-4/0 Quadruplex	$1,899	$1,969		
29						
30	101 - 300 kW					
31	1 Phase	3-500 & 350N	$3,193	$3,311		
32		3- 750 & 500 N	$4,005	$4,153		
33						
34						
35	3 Phase	OH - 3-4/0 Quadruplex	$3,742	$3,880		
36		4-350 Quad	$3,723	$3,861		
37						
38	301 - 1000 kW					
39	3 Phase	3-750 kcmil Quad.	$7,879	$8,171		
40		4-750 kcmil Quad.	$6,943	$7,200		
41						
42						
43	1000 kW and Over					
44	Secondary Volt(1)	12-1000 kcmil Quad.	$24,342	$25,243		
45						
46						
47	Primary Volt	---	---	---		---

Index 2012	Index 2014	Escalation Factor 2012 - 2014
1.0000	1.0370	1.0370

		Weighted %
Residential Overhead % =	62.6%	
% of Overhead Which Are Small Load=	53.6%	33.6%
% of Overhead Which Are All Electric=	46.4%	29.0%
Residential Underground % =	37.4%	
% of Underground Which Are Small Load=	42.0%	15.7%
% of Underground Which Are All Electric=	58.0%	21.7%
Total OH & UG		100.0%

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers				Weighted Metering Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E)
1	Res - Schedule 4	474,231	100.00%	100.00%		$114	$114.39	$114.39	
2	Annualized - (Line 1) x 9.74%						$11.14	$11.14	
3									
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	47,268	71.44%	86.96%		$94	$66.95	$81.50	
7	kW = 0, 3 Phase	2,367	3.58%		20.04%	$209	$7.47		$41.84
8	kW > 1, 1 Phase	7,089	10.71%	13.04%		$167	$17.90	$21.79	
9	kW > 1, 3 Phase	9,446	14.28%		79.96%	$209	$29.81		$166.99
10	Total 0-15 kW	66,169	100.00%	100.00%	100.00%		$122.13	$103.29	$208.83
11	Annualized - (Line 10) x 9.74%						$11.90	$10.06	$20.34
12									
13	15+ kW								
14	1 Phase	4,785	45.12%	100.00%		$206	$92.84	$205.78	
15	3 Phase W/O KVAR	4,536	42.77%		77.93%	$209	$89.32		$162.75
16	3 Phase With KVAR	1,284	12.11%		22.07%	$247	$29.86		$54.40
17	Total 15+ kW	10,605	100.00%	100.00%	100.00%		$212.02	$205.78	$217.15
18	Annualized - (Line 17) x 9.74%						$20.65	$20.04	$21.15
19									
20	Primary								
21	12.47 KV 4-wire Wye	44	100.00%		100.00%	$12,931	$12,931.38		$12,931.38
22	Annualized - (Line 21) x 9.74%						$1,259.52	$0.00	$1,259.52
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	0	0.01%	0.03%		$206	$0.02	$0.06	
27	kW = 0, 3 Phase	5	0.11%		0.15%	$209	$0.22		$0.32
28	kW > 1, 1 Phase	1,337	29.80%	99.97%		$206	$61.33	$205.72	
29	kW > 1, 3 Phase	3,145	70.08%		99.85%	$209	$146.36		$208.52
30	Total 0-50 kW	4,487	100.00%	100.00%	100.00%		$207.93	$205.78	$208.84
31	Annualized - (Line 30) x 9.74%						$20.25	$20.04	$20.34
32									
33	51-100 kW								
34	1 Phase	430	12.44%	100.00%		$206	$25.60	$205.78	
35	3 Phase W/O KVAR	1,508	43.67%		49.87%	$209	$91.19		$104.15
36	3 Phase With KVAR	1,516	43.89%		50.13%	$247	$108.21		$123.58
37	Total 51-100 kW	3,453	100.00%	100.00%	100.00%		$225.00	$205.78	$227.73
38	Annualized - (Line 37) x 9.74%						$21.92	$20.04	$22.18
39									
40	> 101kW								
41	1 Phase	37	1.93%	100.00%		$1,057	$20.36	$1,057.41	
42	3 Phase W/O KVAR	716	37.20%		37.93%	$1,441	$536.20		$546.72
43	3 Phase With KVAR	1,171	60.88%		62.07%	$1,441	$877.51		$894.74
44	Total > 101kW	1,924	100.00%	100.00%	100.00%		$1,434.07	$1,057.41	$1,441.46
45	Annualized - (Line 44) x 9.74%						$139.68	$102.99	$140.40
46									
47	Primary								
48	12.47 KV 4-wire Wye	57	100.00%		100.00%	$12,931	$12,931.38		$12,931.38
49	Annualized - (Line 48) x 9.74%						$1,259.52	$0.00	$1,259.52

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2012.

Meters 2

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
GS - Schedule 30 / LPS - Schedule 48T / Irrigation - Schedule 41 (Annual)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers				Weighted Metering Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E) (F) x 9.74%
1	GS - Schedule 30								
2	0-300 kW								
3	1 Phase	1	0.39%	100.00%		$1,057	$4.10	$1,057.41	
4	3 Phase W/O KVAR	39	18.09%		18.16%	$1,441	$260.76		$261.78
5	3 Phase With KVAR	175	81.52%		81.84%	$1,441	$1,175.11		$1,179.68
6	Total 0-300 kW	215	100.00%	100.00%	100.00%		$1,439.97	$1,057.41	$1,441.46
7	Annualized - (Line 6) x 9.74%						$140.25	$102.99	$140.40
8									
9	301+ kW								
10	1 Phase	0	0.00%	100.00%		$1,194	$0.00	$1,193.92	
11	3 Phase W/O KVAR	87	15.70%		15.70%	$1,441	$226.35		$226.35
12	3 Phase With KVAR	466	84.30%		84.30%	$1,441	$1,215.11		$1,215.11
13	301+ kW	553	100.00%	100.00%	100.00%		$1,441.46	$1,193.92	$1,441.46
14	Annualized - (Line 13) x 9.74%						$140.40	$116.29	$140.40
15									
16	Primary								
17	12.47 KV 4-wire Wye	51	100.00%		100.00%	$12,931	$12,931.38		$12,931.38
18	Annualized - (Line 17) x 9.74%						$1,259.52		$1,259.52
19									
20	LPS - Schedule 48T								
21	1 - 4 MW (sec)	107	100.00%		100.00%	$1,861	$1,861.16		$1,861.16
22	Annualized - (Line 21) x 9.74%						$181.28		$181.28
23									
24	1 - 4 MW (pri)	64	100.00%		100.00%	$12,931	$12,931.38		$12,931.38
25	Annualized - (Line 24) x 9.74%						$1,259.52		$1,259.52
26									
27	> 4 MW (sec)	2	100.00%		100.00%	$1,861	$1,861.16		$1,861.16
28	Annualized - (Line 27) x 9.74%						$181.28		$181.28
29									
30	> 4 MW (pri)	33	100.00%		100.00%	$12,931	$12,931.38		$12,931.38
31	Annualized - (Line 30) x 9.74%						$1,259.52		$1,259.52
32									
33	Trans (trn)	6	100.00%		100.00%	$325,785	$325,784.84		$325,784.84
34	Annualized - (Line 33) x 9.74%						$31,731.44		$31,731.44
35									
36									
37	Irrigation - Schedule 41 (Annual)								
38	0 - 50 kW								
39	kW = 0, 1 Phase	52	0.72%	4.95%		$94	$0.68	$4.64	
40	kW = 0, 3 Phase	187	2.59%		3.04%	$209	$5.42		$6.34
41	kW > 1, 1 Phase	997	13.83%	94.95%		$167	$23.11	$158.64	
42	kW > 1, 3 Phase	4,865	67.47%		78.97%	$209	$140.89		$164.92
43									
44	51 - 300 kW								
45	1 Phase	1	0.01%	0.10%		$206	$0.03	$0.20	
46	3 Phase W/O KVAR	311	4.31%		5.05%	$209	$9.01		$10.54
47	3 Phase With KVAR	776	10.76%		12.59%	$247	$26.52		$31.04
48									
49	> 300 kW								
50	1 Phase	-	0.00%	0.00%		$1,194	$0.00	$0.00	
51	3 Phase W/O KVAR	1	0.01%		0.02%	$1,441	$0.20		$0.23
52	3 Phase With KVAR	21	0.29%		0.34%	$1,441	$4.16		$4.87
53	Total Irrigation	7,211	100.00%	100.00%	100.00%		$210.02	$163.48	$217.94
54							$20.46	$15.92	$21.23
55									
56	Primary	-	100.00%		100.00%	$0	$0.00		$0.00
57							$0.00	$0.00	$0.00

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2012.

PacifiCorp
Oregon Marginal Cost Study
Incremental Three Phase
Meter and Services Costs

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Meters				Service Drops			
Line	Load Class	Single Phase	Three Phase	Difference	Annualized Difference	Single Phase	Three Phase	Difference	Annualized Difference
				(B) - (A)	(C) x 9.74%			(F) - (E)	(G) x 9.74%
1	Residential	$114.39	$208.83	$94.44	$9.20	$709.69	$1,083.72	$374.04	$36.43
2									
3	0-15 kW	$93.72	$208.83	$115.11	$11.21	$942.77	$1,164.15	$221.38	$21.56
4									
5	16-100 kW	$205.78	$208.83	$3.06	$0.30	$1,684.59	$2,104.36	$419.77	$40.89
6									
7	101-1000 kW	$1,193.92	$1,441.46	$247.54	$24.11	$3,734.24	$3,870.55	$136.31	$13.28
8									
9	1 - 4 MW	N.A.	$1,861.16	N.A.	N.A.	N.A.	$25,242.65	N.A.	N.A.

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Meters

Line	Load Class	(A) Metering Standard	(B) Meter Cost in 2013 Dollars	(C) Indexed to 2014	(D) Percent Use	(E) Total Installed Cost per Meter
	Residential					
1	Small Load	DM221A	$92.00	$93.72	49.28%	$46.18
2	All Electric)	DM221D	$132.00	$134.47	50.72%	$68.20
3					100.00%	$114.39
4						
5	0 - 15 kW					
6	kW = 0, 1 Phase	DM221A	$92.00	$93.72	100.00%	$93.72
7						
8	kW = 0, 3 Phase	DM241A	$205.00	$208.83	100.00%	$208.83
9						
10	kW > 1, 1 Phase	DM221B	$164.00	$167.07	100.00%	$167.07
11						
12	kW > 1, 3 Phase	DM241A	$205.00	$208.83	100.00%	$208.83
13						
14						
15	15 - 100 kW					
16	1 Phase	DM221C	$202.00	$205.78	100.00%	$205.78
17						
18	3 Phase wo / KVAR	DM241A	$205.00	$208.83	100.00%	$208.83
19						
20	3 Phase with KVAR	DM241B	$242.00	$246.53	100.00%	$246.53
21						
22						
23	100 - 300 kW					
24	1 Phase	DM231ABB	$1,038.00	$1,057.41	100.00%	$1,057.41
25						
26	3 Phase wo / KVAR	DM271AEC	$1,415.00	$1,441.46	100.00%	$1,441.46
27						
28	3 Phase with KVAR	DM271AEC	$1,415.00	$1,441.46	100.00%	$1,441.46
29						
30						
31	300-1000 kW					
32	W/O KVAR, 1 Phase	DM231AFE	$1,172.00	$1,193.92	100.00%	$1,193.92
33						
34	W/O KVAR, 3 Phase	DM271AEC	$1,415.00	$1,441.46	100.00%	$1,441.46
35						
36	W/KVAR, 3 Phase	DM271AEC	$1,415.00	$1,441.46	100.00%	$1,441.46
37						
38						
39	1000 kW and over					
40	Secondary Volt	DM271AEG	$1,827.00	$1,861.16	100.00%	$1,861.16
41						
42	Primary Metering					
43	13.8 KV 3-wire	DM101ACBI	$7,872.00	$8,019.21		$8,019.21
44	12.47 KV 4-wire Wye	DM121DBBI	$12,694.00	$12,931.38		$12,931.38
45	24.9 KV 4-wire Wye	DM121DGBI	$15,232.00	$15,516.84		$15,516.84
46	35 KV 4-wire Wye	DM131DBH	$30,170.00	$30,734.18		$30,734.18

Index		Escalation Factor
2013	2014	2013 - 2014
1.0180	1.0370	1.0187

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Description	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
	Distribution Meters Expenses										
1	586 Meter Expense	1,800,451	2,010,097	1,892,897	2,122,259	2,058,440	2,206,057	2,848,811	2,878,301	2,873,361	3,548,094
2	597 Main. of Meters	825,166	1,190,462	1,237,234	1,348,150	1,669,096	1,560,945	1,433,131	1,465,615	1,360,896	1,386,968
3											
4	Total Adjusted Distribution Meters Expens	2,625,617	3,200,559	3,130,131	3,470,409	3,727,536	3,767,002	4,281,942	4,343,916	4,234,257	4,935,062
5	Line 1 + Line 2										
6											
7											
8											
9	Distribution Meters										
10	370 Meters	57,067,003	56,828,689	56,705,794	58,095,163	58,456,991	59,168,811	59,791,712	60,319,849	60,008,209	59,771,898
11											
12											
13											
14	Meters Expense Loading Factor										
15	Meter O&M Loading	4.60%	5.63%	5.52%	5.97%	6.38%	6.37%	7.16%	7.20%	7.06%	8.26%
16	Line 3 / Line 4										
17											
18	Average Meter O&M Loading	6.41%									
19	Average of Line 5										
20											
21	Distribution Annual Charge	9.74%									
22											
23	Annualized Meter O&M Loading Factor	$\boxed{65.86\%}$									
24	Line 6 / Line 7										

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Commitment & Billing Related Cost per Customer

Line	Description	100 Watt HPSV	150 Watt HPSV	250 Watt HPSV	400 Watt HPSV	Schedule 53 Customer Owned	Schedule 54 Customer Owned
1	Light Installation Cost - per lamp	$180.40	$194.70	$217.82	$291.28	N. A.	N. A.
2							
3	Distribution Commitment Costs - per customer						
4	Acct. 364 Poles	$108.73	$108.73	$108.73	$108.73	$108.73	$108.73
5	Acct. 365 Conductors	$52.51	$52.51	$52.51	$52.51	$52.51	$52.51
6	Acct. 368 Transformers	N. A.	N. A.	N. A.	N. A.	115.87	171.01
7	Dist O&M at 42.3% of Annual Charge	$68.20	$68.20	$68.20	$68.20	$117.22	$140.54
8	Acct. 370 Meters	N. A.	N. A.	N. A.	N. A.	N. A.	$11.90
9	Meter O&M at 65.86% of Annual Charge	N. A.	N. A.	N. A.	N. A.	N. A.	$7.84
10	Total Commitment Related	$229.44	$229.44	$229.44	$229.44	$394.33	$492.52
11							
12	Billing Costs per Customer	$39.36	$39.36	$39.36	$39.36	$39.36	$63.13
13							
14	Total Marginal Commitment & Billing Cost per Cust.	$268.80	$268.80	$268.80	$268.80	$433.69	$555.66

Sources:
Line 1 "Distribution Cost Development For Street Lighting"
Line 4 `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 5 `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 6 `Transformer Commitment Costs By Customer Load Class'
Line 7 Sum of lines 4 to 6 multiplied by
Distribution O&M Expense Loading Factor as a Percent of Dist. Plant'
Line 14 Sum of Commitment & Billing Costs per Customer

Streetlight 2

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Full Marginal Cost by Schedule

Line	Description	Units	Schedule 51 High Pressure Sodium Vapor				Schedule 53 Customer Owned	Schedule 54 Customer Owned	Total Streetlighting
			9,500 Lumen 100 Watt	16,000 Lumen 150 Watt	27,500 Lumen 250 Watt	50,000 Lumen 400 Watt			
	Energy								
1	Generation Energy $/kWh @ Generator	$/kWh	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	$0.04337	
2	Transmission Energy $/kWh @ Generator	$/kWh	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	$0.00304	
3									
4	Energy @ Meter 2012	kWh	7,622,922	245,348	678,794	2,460,628	9,668,960	1,205,229	
5	Energy @ Meter 2014		7,923,559	255,024	705,565	2,557,672	8,966,764	1,249,347	21,657,931
6	Losses		1.10006	1.10006	1.10006	1.10006	1.10006	1.10006	
7	Energy @ Generator - (5)*(6)	kWh	8,716,390	280,542	776,164	2,813,593	9,863,978	1,374,357	23,825,024
8									
9	Generation Energy Related Marginal Costs - (1)*(7)	$	$378,030	$12,167	$33,662	$122,026	$427,801	$59,606	$1,033,291
10	Transmission Energy Related Marginal Costs - (2)*(7)	$	$26,477	$852	$2,358	$8,547	$29,963	$4,175	$72,371
11									
12	Commitment								
13	Total of Monthly Lamp Billing Units 2014	#	180,082	3,985	6,136	14,532			
14	Number of Lamps 2014 - (13) / 12	#	15,007	332	511	1,211			
15	Light Installation Cost	$/Lamp	$180.40	$194.70	$217.82	$291.28			
16	Light Installation Related		$2,707,181	$64,655	$111,378	$352,741			$3,235,955
17									
18	Average customers - 2014 (from blocking)	#	272	43	62	70	266	104	817
19									
20									
21	Acct. 364 Poles		$108.73	$108.73	$108.73	$108.73	$108.73	$108.73	
22	Acct. 365 Conductors		$52.51	$52.51	$52.51	$52.51	$52.51	$52.51	
23	Acct. 368 Transformers		N. A.	N. A.	N. A.	N. A.	$115.87	$171.01	
24	Acct. 370 Meters							$11.90	
25									
26	Acct. 364 Poles with O&M		$42,062	$6,653	$9,593	$10,831	$41,173	$16,091	$126,403
27	Acct. 365 Conductors with O&M		$20,313	$3,213	$4,633	$5,231	$19,884	$7,771	$61,045
28	Acct. 368 Transformers with O&M		N.A.	N.A.	N.A.	N.A.	$43,877	$25,308	$69,185
29	Acct. 370 Meter with O&M		N.A.	N.A.	N.A.	N.A.	N.A.	$2,053	$2,053
30	Total Poles, Conductors, Transfomers		$62,375	$9,866	$14,226	$16,061	$104,935	$51,222	$258,685
31									
32	Total Commitment Marginal Cost		$2,769,556	$74,522	$125,603	$368,802	$104,935	$51,222	$3,494,640
33									
34	Billing / Customer								
35	Billing Related	$/Customer	$31.10	$31.10	$31.10	$31.10	$31.10	$31.10	
36	Meter Reading	$/Customer	-	-	-	-	-	$23.78	
37	Customer Other	$/Customer	$8.26	$8.26	$8.26	$8.26	$8.26	$8.26	
38									
39	Billing Related	$	8,455	1,337	1,928	2,177	8,276	3,234	$25,408
40	Meter Reading	$	-	-	-	-	-	2,473	$2,473
41	Customer Other	$	2,245	355	512	578	2,197	859	$6,745
42	Total Billing Related Marginal Cost		$10,699	$1,692	$2,440	$2,755	$10,473	$6,566	$34,626
43									
44	Total Marginal Cost		$3,184,762	$89,233	$164,063	$502,129	$573,172	$121,569	$4,634,928

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$545,885	$427,801	$59,606	$1,033,291
Transmission	$38,233	$29,963	$4,175	$72,371
Distribution	$3,338,482	$104,935	$51,222	$3,494,640
Customer - Billing	$13,897	8,276	3,234	$25,408
Customer - Metering	-	-	2,473	$2,473
Customer - Other	3,690	2,197	859	$6,745
	$3,940,187	$573,172	$121,569	$4,634,928

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$545.88	$427.80	$59.61	$1,033.29
Transmission	$38.23	$29.96	$4.17	$72.37
Distribution	$3,338.48	$104.93	$51.22	$3,494.64
Customer - Billing	$13.90	$8.28	$3.23	$25.41
Customer - Metering	$0.00	$0.00	$2.47	$2.47
Customer - Other	$3.69	$2.20	$0.86	$6.75

Streetlight 3

PacifiCorp
Oregon Marginal Cost Study
Distribution Cost Development
For Street Lighting Service
Fully-Loaded Overheads
Wood Pole Installations
Schedule 51

Line No.	Description		High Pressure Sodium Vapor			
			9,500 Lumen 100 Watt	16,000 Lumen 150 Watt	27,500 Lumen 250 Watt	50,000 Lumen 400 Watt
1	Installed Cost Per Unit					
2	Lamp Cost per unit including pole, luminaire,					
3	p.e.control, mast arm and wiring					
4	Without Pole (Functional)		$741.00	$756.00	$926.00	$1,339.00
5	Wood Pole Cost		$816.00	$940.00	$885.00	$884.00
6	Percent of Wood Pole Utilized (see footnote)		16.67%	20.00%	20.00%	50.00%
7	Adjusted Wood Pole Cost		$136.00	$188.00	$177.00	$442.00
8						
9	Installed Lamp Cost for Analysis	2013' $	$877.00	$944.00	$1,103.00	$1,781.00
10	Index		1.0187	1.0187	1.0187	1.0187
11	Revised Lamp Cost	2014' $	$893.37	$961.62	$1,123.59	$1,814.24
12						
13						
14	Transformer Cost	2012' $	$13.55	$19.81	$35.33	$54.21
15	Index		1.0370	1.0370	1.0370	1.0370
16	Revised Transformer Cost	2014' $	$14.05	$20.54	$36.64	$56.22
17						
18	Total Installed Cost		$907.42	$982.16	$1,160.22	$1,870.46
19						
20	Annual Cost @	9.74%	$88.38	$95.66	$113.01	$182.18
21						
22						
23	Operation & Maintenance					
24	Annual Maintenance Per Unit	2013' $	$90.33	$97.22	$102.89	$107.10
25	Index		1.0187	1.0187	1.0187	1.0187
26		2014' $	$92.01	$99.03	$104.81	$109.10
27						
28						
29	Total Cost per Unit	2014' $	$180.40	$194.70	$217.82	$291.28
30						
31						

32 Assumptions:
33 Annual Maintenance Per Unit - Percentage of installed cost from 11/99 study.
34 100 Watt It is assumed, one new wood pole is to be installed per six new lights, therefore, 1/6 X unit cost of wood pole will be utilized here as a component.
35 200 Watt It is assumed, one new wood pole is to be installed per five new lights, therefore, 1/5 X unit cost of wood pole will be utilized here as a component.
36 400 Watt It is assumed, one new wood pole is to be installed per two new lights, therefore, 1/2 X unit cost of wood pole will be utilized here as a component.

Streetlight 4

PacifiCorp
Oregon Marginal Cost Study
Cost of Streetlighting Transformer

Transformer Cost Per Light - 100 Watt

Assume Installed Cost* 25 KVA Transformer is $ 2,896

Lamp Line Watts = 117 watts

Transformer Cost = Total Watts/25,000 X Installed Cost
117 / 25000 X $2896 = $ 13.55

Transformer Cost Per Light - 150 Watt

Assume Installed Cost* 25 KVA Transformer is $ 2,896

Lamp Line Watts = 171 watts

Transformer Cost = Total Watts/25,000 X Installed Cost
171 / 25000 X $2896 = $ 19.81

Transformer Cost Per Light - 250 Watt

Assume Installed Cost* 25 KVA Transformer is $ 2,896

Lamp Line Watts = 305 watts

Transformer Cost = Total Watts/25,000 X Installed Cost
305 / 25000 X $2896 = $ 35.33

Transformer Cost Per Light - 400 Watt

Assume Installed Cost* 25 KVA Transformer is $ 2,896

Lamp Line Watts = 468 watts

Transformer Cost = Total Watts/25,000 X Installed Cost
468 / 25000 X $2896 = $ 54.21

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2014 Dollars

Line	FERC Account	Description	(A) Sch. 4 Residential	(B) Sch. 23 General Service	(C) Sch. 28 General Service	(D) Sch. 30 General Service	(E) Sch. 48T General Service	(F) Sch. 41 Irrigation	(G) Streetlighting	(H) Total
1		Average Number of Customers	485,586	73,887	9,924	762	206	3,920	817	575,102
2										
3		Write-offs By Schedule	5,322,978	145,937	212,760	114,009	133,722	7,103	-	5,936,510
4										
5	901									
6	Supervision	Account 902 + 903 + 904	$29,755,314	$4,293,634	$960,790	$188,631	$191,271	$339,418	$29,649	$35,758,707
7		% of Total 902 + 903 +904	83.21%	12.01%	2.69%	0.53%	0.53%	0.95%	0.08%	100.00%
8		Total 901 $	$752,909	$108,643	$24,311	$4,773	$4,840	$8,588	$750	$904,815
9		Dollars Per Customer	$1.55	$1.47	$2.45	$6.26	$23.49	$2.19	$0.92	$1.57
10	902									
11	Meter Reading Expense	902 Weighting Factor	1.00	1.42	2.47	4.24	11.05	3.13	0.31	
12		Weighted Customers	485,586	104,920	24,512	3,231	2,276	12,269	253	633,047
13		% of Total $	76.71%	16.57%	3.87%	0.51%	0.36%	1.94%	0.04%	100.00%
14		Total 902 $	$8,130,885	$1,756,823	$410,445	$54,099	$38,115	$205,439	$4,241	$10,600,048
15		Dollars Per Customer	$16.74	$23.78	$41.36	$71.00	$185.03	$52.41	$5.19	$18.43
16	903									
17	Cust. Receipts & Collect.	903 Weighting Factor	1.00	0.95	1.03	1.03	3.81	0.95	0.91	
18		Weighted Customers	485,586	70,193	10,222	785	785	3,724	743	572,037
19		% of Total $	84.89%	12.27%	1.79%	0.14%	0.14%	0.65%	0.13%	100.00%
20		Total 903 $	$16,595,627	$2,398,939	$349,343	$26,824	$26,824	$127,268	$25,408	$19,550,232
21		Dollars Per Customer	$34.18	$32.47	$35.20	$35.20	$130.21	$32.47	$31.10	$33.99
22	904									
23	Uncollectibles	Total 904 $	$5,028,802	$137,872	$201,002	$107,708	$126,332	$6,711	$0	$5,608,427
24		% of Write-offs	89.67%	2.46%	3.58%	1.92%	2.25%	0.12%	0.00%	
25		Dollars Per Customer	$10.36	$1.87	$20.25	$141.35	$613.26	$1.71	$0.00	$9.75
26	905									
27	Misc Cust Acct Expense	Account 902 + 903 + 904	$29,755,314	$4,293,634	$960,790	$188,631	$191,271	$339,418	$29,649	$35,758,707
28		% of Total 902 + 903 +904	83.21%	12.01%	2.69%	0.53%	0.53%	0.95%	0.08%	100.00%
29		Total 905 $	$75,687	$10,921	$2,444	$480	$487	$863	$75	$90,957
30		Dollars Per Customer	$0.16	$0.15	$0.25	$0.63	$2.36	$0.22	$0.09	$0.16
31	907-910									
32	Supervision, Cust. Assist.	Average Number of customers	485,586	73,887	9,924	762	206	3,920	817	575,102
33	Info & Instructional Exp.,	% of Total	84.43%	12.85%	1.73%	0.13%	0.04%	0.68%	0.14%	100.00%
34	Misc Cust Svc & Info Exp.		$3,518,623	$535,395	$71,911	$5,522	$1,493	$28,404	$5,920	$4,167,267
35		Dollars Per Customer	$7.25	$7.25	$7.25	$7.25	$7.25	$7.25	$7.25	$7.25
36										
37	Total 901 - 910	Total 901 - 910 $	$34,102,533	$4,948,594	$1,059,456	$199,406	$198,090	$377,273	$36,394	$40,921,746
38										
39		Dollars Per Customer	$70.23	$66.98	$106.76	$261.69	$961.60	$96.25	$44.55	$71.16

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer and Metering Expenses
December 2014 Dollars

Line	Description	(A) Actual 2007 Dollars	(B) Actual 2008 Dollars	(C) Actual 2009 Dollars	(D) Actual 2010 Dollars	(E) Actual 2011 Dollars	(F) Adjusted 2014 Dollars
							[(A) x 1.1381+ (B) x 1.1172+ (C) x 1.0968+ (D) x 1.0767+ (E) x 1.0570] / 5
	Customer Accounting						
1	901 Supervision	900,404	768,055	788,080	769,087	897,646	$904,815
2	902 Meter Reading Expense	9,563,375	9,190,112	9,195,750	9,874,311	10,531,128	$10,600,048
3	903 Cust Records & Collection	17,918,701	18,662,255	18,060,493	17,281,809	17,116,692	$19,550,232
4	904 Uncollectible Accounts	3,555,170	6,272,907	4,220,604	4,470,369	7,138,600	$5,608,427
5	905 Misc Cust Acct Expense	124,686	77,974	87,564	55,759	65,934	$90,957
6	Total	32,062,336	34,971,303	32,352,491	32,451,335	35,750,000	$36,754,479
7							
8	Customer Service & Info Expense						
9	907 Supervision	138,616	77,577	88,905	81,203	92,542	$105,437
10	908 Cust Assistance Expense	2,488,601	1,998,956	2,164,154	2,165,667	2,441,612	$2,470,343
11	909 Info & Instructional Expense	1,248,551	1,236,009	1,706,781	1,433,382	1,491,095	$1,558,651
12	910 Misc Cust Svc & Info Expense	1,429	19,976	46,577	27,745	56,083	$32,836
13	Total	3,877,197	3,332,518	4,006,417	3,707,997	4,081,332	$4,167,267
14							$40,921,746
15	Distribution Expenses						
16	586 Meter Expenses	$2,206,057	$2,848,811	$2,878,301	$2,873,361	$3,548,094	$3,138,882
17	597 Meter Maintenance	$1,560,945	$1,433,131	$1,465,615	$1,360,896	$1,386,968	$1,583,279
18		$3,767,002	$4,281,942	$4,343,916	$4,234,257	$4,935,062	$4,722,161
19							
20							
21	(1) Inflation Adjustment -	1.1381	1.1172	1.0968	1.0767	1.0570	

Source:
Source: State of Oregon results of operations

AG Expenses

PacifiCorp
Oregon Marginal Cost Study
Administrative & General Expense
Loading Factor

Year	(A) Administrative and General Expenses (000)	(B) Electric Plant in Service (000)	(C) Admin. & General to Electric Plant In Service Loading Factor (A) / (B)
2002	$277,395	$12,690,449	2.19%
2003	$251,357	$13,208,159	1.90%
2004	$244,893	$13,688,398	1.79%
2005	$236,709	$14,335,797	1.65%
2006	$238,645	$15,317,103	1.56%
2007	$180,356	$16,417,338	1.10%
2008	$170,044	$18,224,943	0.93%
2009	$162,620	$19,645,569	0.83%
2010	$146,076	$21,775,587	0.67%
2011	$152,657	$22,769,524	0.67%
10 Year Average A&G to EPIS Loading Factor			1.33%

Footnotes:
(A) FERC Form 1 Page 322-323
(B) FERC Form 1 Page 206-207

Charge 1

PacifiCorp
Oregon Marginal Cost Study
Calculation of Annual Charges

		(A)	(B)	(C)	(D)	(E)
Line	Description	20 years - Generation	10 years - Generation	5 years - Generation	System Transmission	Distribution
1	Levelized Income Taxes *	NA	NA	NA	1.93%	1.94%
2	Levelized Property Tax *	NA	NA	NA	1.14%	1.16%
3	Total	NA	NA	NA	3.07%	3.10%
4						
5	Levelized Income & Property Taxes	NA	NA	NA	$30.70	$31.00
6	(per $1,000 of Investment)					
7						
8	Expected Life	20	10	5	58	50
9						
10	Nominal Interest Rate *	7.66%	7.66%	7.66%	7.66%	7.66%
11						
12	Present Value: Income **	NA	NA	NA	$395.47	$394.82
13	Taxes & Property Taxes per				(PV of $30.70 per year	(PV of $31.00 per year
14	$1,000 of Investment				for 58 years at 7.66%)	for 50 years at 7.66%)
15						
16	Removal Cost Per $1,000 Investment				$204.38	$463.24
17						
18	Present Value: Removal Cost				$2.83	$11.59
19	at End of Useful Life				(PV of $204.38 in	(PV of $463.24 in
20					58 years at 7.66%)	50 years at 7.66%)
21						
22	Investment and Taxes	$1,000.00	$1,000.00	$1,000.00	$1,398.30	$1,406.41
23	w/o PVCD (Line 12 + Line 18 + $1000)					
24						
25	PVCD Factor	NA	NA	NA	0.020533	0.041839
26						
27	PVCD $ (Line 22 x Line 25)	NA	NA	NA	$28.71	$58.84
28						
29	Total (Line 22 + Line 27)	$1,000.00	$1,000.00	$1,000.00	$1,427.01	$1,465.25
30						
31	EOY Annual Charge ***	$80.39	$126.64	$222.70	$79.99	$84.11
32						
33	Annual Economic Carrying	8.04%	12.66%	22.27%	8.00%	8.41%
34	Adm &Gen Expense Loading Factor	0.00%	0.00%	0.00%	1.33%	1.33%
35						
36	Annual Econ Carrying + A&G Loading	8.04%	12.66%	22.27%	9.33%	9.74%

Footnotes:

From Financial Analysis -

** PV = Ln(5) x [1/r - (1/r)/(1+r)^a]

30.70*(1/0.0766-(1/0.0766)/(1+0.0766)^58)
31.00*(1/0.0766-(1/0.0766)/(1+0.0766)^50)

Where:
r = Nominal Interest Rate
a = Expected Investment Life

*** The Annual Charge Formula:

AC% = Ln(11) x k x {1/[1 - 1/(1+k)^a]}/(1+k)

Where:
k = real interest rate = (1 + r) / (1 + i) - 1
i = inflation rate = 1.9%
a = expected investment life
r = nominal interest rate

PacifiCorp
Oregon Marginal Cost Study
Financial Inputs to the Economic Carrying Charge Calculation

	(A)	(B)	(C)	(D)
	Financial Inputs		Levelized	
1	Weighted Cost of Capital	7.66%	Income Taxes	
2	Borrowing Rate	7.66%	Transmission	1.93%
3	Inflation	1.87%	Distribution	1.94%
4			Property Taxes	
5	Real Cost of Capital		Transmission	1.14%
6	(1+0.0766)/(1+0.0187)-1 =	5.68%	Distribution	1.16%

Source:
Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)
Income & Property Taxes: Financial Analysis, Use of Facilities Charges 12/31/11 Basis (prepared 7/20/12)
Inflation Rate, 2012 Avoided Cost, Table 8

Charge 3

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 3.0 & 58 Year Average Life
Page 1 of 2

Real Cost of Capital = 5.68%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.5
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0568 ^Year	(C) / (D)	(B)	1.0568 ^58	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000144	1.59%	0.0159	1.056843	0.015009	0.0159	24.695459	0.000642	0.014367	99.9841
2	0.000415	3.17%	0.0317	1.116918	0.028403	0.0317	24.695459	0.001285	0.027119	99.9524
3	0.000671	3.17%	0.0317	1.180407	0.026876	0.0317	24.695459	0.001285	0.025591	99.9207
4	0.000982	4.08%	0.0408	1.247506	0.032727	0.0408	24.695459	0.001653	0.031074	99.8799
5	0.001318	4.69%	0.0469	1.318418	0.035570	0.0469	24.695459	0.001899	0.033671	99.8330
6	0.001636	4.69%	0.0469	1.393362	0.033657	0.0469	24.695459	0.001899	0.031758	99.7861
7	0.002029	6.16%	0.0616	1.472565	0.041846	0.0616	24.695459	0.002495	0.039351	99.7244
8	0.002438	6.79%	0.0679	1.556271	0.043650	0.0679	24.695459	0.002751	0.040899	99.6565
9	0.002824	6.79%	0.0679	1.644734	0.041302	0.0679	24.695459	0.002751	0.038551	99.5886
10	0.003304	8.97%	0.0897	1.738227	0.051618	0.0897	24.695459	0.003633	0.047985	99.4989
11	0.003783	9.52%	0.0952	1.837033	0.051808	0.0952	24.695459	0.003854	0.047954	99.4037
12	0.004235	9.52%	0.0952	1.941457	0.049021	0.0952	24.695459	0.003854	0.045167	99.3085
13	0.004802	12.68%	0.1268	2.051816	0.061812	0.1268	24.695459	0.005136	0.056677	99.1817
14	0.005350	13.03%	0.1303	2.168448	0.060110	0.1303	24.695459	0.005278	0.054832	99.0513
15	0.005866	13.03%	0.1303	2.291710	0.056877	0.1303	24.695459	0.005278	0.051599	98.9210
16	0.006516	17.45%	0.1745	2.421978	0.072041	0.1745	24.695459	0.007065	0.064976	98.7465
17	0.007127	17.45%	0.1745	2.559652	0.068167	0.1745	24.695459	0.007065	0.061101	98.5720
18	0.007719	17.99%	0.1799	2.705151	0.066514	0.1799	24.695459	0.007286	0.059228	98.3921
19	0.008427	22.90%	0.2290	2.858921	0.080088	0.2290	24.695459	0.009272	0.070817	98.1631
20	0.009092	22.90%	0.2290	3.021432	0.075780	0.2290	24.695459	0.009272	0.066509	97.9342
21	0.009752	24.21%	0.2421	3.193180	0.075830	0.2421	24.695459	0.009805	0.066025	97.6920
22	0.010507	29.48%	0.2948	3.374691	0.087364	0.2948	24.695459	0.011939	0.075426	97.3972
23	0.011214	29.48%	0.2948	3.566520	0.082665	0.2948	24.695459	0.011939	0.070727	97.1024
24	0.011930	31.83%	0.3183	3.769254	0.084449	0.3183	24.695459	0.012889	0.071560	96.7841
25	0.012715	37.31%	0.3731	3.983511	0.093662	0.3731	24.695459	0.015108	0.078554	96.4110
26	0.013450	37.31%	0.3731	4.209947	0.088624	0.3731	24.695459	0.015108	0.073516	96.0379
27	0.014205	40.98%	0.4098	4.449255	0.092104	0.4098	24.695459	0.016594	0.075510	95.6281
28	0.015006	46.48%	0.4648	4.702166	0.098854	0.4648	24.695459	0.018822	0.080032	95.1632
29	0.015753	46.48%	0.4648	4.969453	0.093537	0.4648	24.695459	0.018822	0.074715	94.6984
30	0.016529	51.79%	0.5179	5.251933	0.098617	0.5179	24.695459	0.020973	0.077644	94.1805
31	0.017327	57.10%	0.5710	5.550471	0.102880	0.5710	24.695459	0.023123	0.079757	93.6094
32	0.018069	57.10%	0.5710	5.865979	0.097347	0.5710	24.695459	0.023123	0.074224	93.0384
33	0.018848	64.45%	0.6445	6.199421	0.103959	0.6445	24.695459	0.026097	0.077861	92.3939
34	0.019625	69.34%	0.6934	6.551817	0.105841	0.6934	24.695459	0.028080	0.077761	91.7005
35	0.020346	69.34%	0.6934	6.924244	0.100148	0.6934	24.695459	0.028080	0.072068	91.0070
36	0.021107	79.17%	0.7917	7.317842	0.108186	0.7917	24.695459	0.032058	0.076128	90.2153
37	0.021848	83.38%	0.8338	7.733813	0.107811	0.8338	24.695459	0.033763	0.074048	89.3816
38	0.022530	83.38%	0.8338	8.173429	0.102013	0.8338	24.695459	0.033763	0.068250	88.5478
39	0.023256	96.34%	0.9634	8.638035	0.111536	0.9634	24.695459	0.039013	0.072522	87.5843
40	0.023943	99.59%	0.9959	9.129050	0.109087	0.9959	24.695459	0.040326	0.068761	86.5884
41	0.024572	99.59%	0.9959	9.647976	0.103220	0.9959	24.695459	0.040326	0.062894	85.5926
42	0.025242	116.28%	1.1628	10.196400	0.114043	1.1628	24.695459	0.047087	0.066956	84.4298
43	0.025860	118.14%	1.1814	10.775998	0.109631	1.1814	24.695459	0.047838	0.061793	83.2484
44	0.026419	118.14%	1.1814	11.388543	0.103734	1.1814	24.695459	0.047838	0.055896	82.0670
45	0.027012	139.28%	1.3928	12.035906	0.115717	1.3928	24.695459	0.056397	0.059320	80.6742
46	0.027543	139.28%	1.3928	12.720068	0.109493	1.3928	24.695459	0.056397	0.053096	79.2815
47	0.028023	141.63%	1.4163	13.443120	0.105358	1.4163	24.695459	0.057352	0.048006	77.8651
48	0.028510	162.86%	1.6286	14.207273	0.114633	1.6286	24.695459	0.065948	0.048685	76.2365
49	0.028935	162.86%	1.6286	15.014862	0.108467	1.6286	24.695459	0.065948	0.042519	74.6079
50	0.029313	167.95%	1.6795	15.868358	0.105841	1.6795	24.695459	0.068009	0.037831	72.9284
51	0.029673	188.31%	1.8831	16.770369	0.112288	1.8831	24.695459	0.076253	0.036035	71.0453
52	0.029973	188.31%	1.8831	17.723654	0.106248	1.8831	24.695459	0.076253	0.029995	69.1622
53	0.030226	196.04%	1.9604	18.731127	0.104659	1.9604	24.695459	0.079382	0.025277	67.2018
54	0.030441	214.07%	2.1407	19.795868	0.108138	2.1407	24.695459	0.086684	0.021455	65.0611
55	0.030597	214.07%	2.1407	20.921132	0.102322	2.1407	24.695459	0.086684	0.015638	62.9204
56	0.030703	223.53%	2.2353	22.110361	0.101098	2.2353	24.695459	0.090515	0.010583	60.6851
57	0.030758	237.72%	2.3772	23.367189	0.101734	2.3772	24.695459	0.096262	0.005472	58.3079
58	0.030758	237.72%	2.3772	24.695459	0.096262	2.3772	24.695459	0.096262	0.000000	55.9306
59	0.030704	246.88%	2.4688	26.099233	0.094593	2.4688	24.695459	0.099970	-0.005377	53.4618
60	0.030595	256.03%	2.5603	27.582802	0.092824	2.5603	24.695459	0.103677	-0.010853	50.9015

Charge 4

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 3.0 & 58 Year Average Life

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.5
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0568 ^Year	(C) / (D)	(B)	1.0568 ^58	(F) / (G)	(E) - (H)	(Given)
61	0.030437	256.03%	2.5603	29.150703	0.087831	2.5603	24.695459	0.103677	-0.015845	48.3411
62	0.030227	261.70%	2.6170	30.807728	0.084947	2.6170	24.695459	0.105972	-0.021025	45.7241
63	0.029967	265.48%	2.6548	32.558944	0.081539	2.6548	24.695459	0.107503	-0.025964	43.0693
64	0.029663	265.48%	2.6548	34.409705	0.077153	2.6548	24.695459	0.107503	-0.030349	40.4144
65	0.029320	263.96%	2.6396	36.365670	0.072586	2.6396	24.695459	0.106887	-0.034301	37.7748
66	0.028939	263.31%	2.6331	38.432818	0.068512	2.6331	24.695459	0.106623	-0.038111	35.1417
67	0.028521	263.31%	2.6331	40.617470	0.064827	2.6331	24.695459	0.106623	-0.041796	32.5086
68	0.028089	251.34%	2.5134	42.926305	0.058551	2.5134	24.695459	0.101775	-0.043224	29.9952
69	0.027631	248.34%	2.4834	45.366382	0.054742	2.4834	24.695459	0.100563	-0.045821	27.5118
70	0.027143	248.34%	2.4834	47.945162	0.051798	2.4834	24.695459	0.100563	-0.048765	25.0283
71	0.026678	224.39%	2.2439	50.670528	0.044283	2.2439	24.695459	0.090861	-0.046578	22.7845
72	0.026194	221.72%	2.2172	53.550813	0.041404	2.2172	24.695459	0.089783	-0.048379	20.5672
73	0.025688	221.72%	2.2172	56.594823	0.039177	2.2172	24.695459	0.089783	-0.050606	18.3500
74	0.025243	187.10%	1.8710	59.811865	0.031282	1.8710	24.695459	0.075764	-0.044482	16.4790
75	0.024781	187.10%	1.8710	63.211775	0.029599	1.8710	24.695459	0.075764	-0.046165	14.6079
76	0.024313	183.31%	1.8331	66.804947	0.027440	1.8331	24.695459	0.074228	-0.046789	12.7748
77	0.023921	149.17%	1.4917	70.602368	0.021129	1.4917	24.695459	0.060405	-0.039276	11.2831
78	0.023516	149.17%	1.4917	74.615646	0.019992	1.4917	24.695459	0.060405	-0.040413	9.7914
79	0.023122	141.86%	1.4186	78.857053	0.017989	1.4186	24.695459	0.057442	-0.039453	8.3728
80	0.022801	112.59%	1.1259	83.339556	0.013509	1.1259	24.695459	0.045590	-0.032081	7.2470
81	0.022473	112.59%	1.1259	88.076860	0.012783	1.1259	24.695459	0.045590	-0.032807	6.1211
82	0.022167	102.87%	1.0287	93.083449	0.011052	1.0287	24.695459	0.041656	-0.030605	5.0924
83	0.021924	80.21%	0.8021	98.374628	0.008153	0.8021	24.695459	0.032478	-0.024325	4.2903
84	0.021676	80.21%	0.8021	103.966577	0.007715	0.8021	24.695459	0.032478	-0.024764	3.4882
85	0.021458	69.35%	0.6935	109.876390	0.006312	0.6935	24.695459	0.028083	-0.021771	2.7947
86	0.021289	53.07%	0.5307	116.122138	0.004570	0.5307	24.695459	0.021489	-0.016919	2.2640
87	0.021118	53.07%	0.5307	122.722915	0.004324	0.5307	24.695459	0.021489	-0.017165	1.7333
88	0.020979	42.14%	0.4214	129.698903	0.003249	0.4214	24.695459	0.017063	-0.013814	1.3120
89	0.020876	31.21%	0.3121	137.071430	0.002277	0.3121	24.695459	0.012637	-0.010360	0.9999
90	0.020771	31.21%	0.3121	144.863036	0.002154	0.3121	24.695459	0.012637	-0.010482	0.6878
91	0.020699	21.32%	0.2132	153.097544	0.001392	0.2132	24.695459	0.008632	-0.007240	0.4747
92	0.020648	14.72%	0.1472	161.800129	0.000910	0.1472	24.695459	0.005962	-0.005052	0.3274
93	0.020597	14.72%	0.1472	170.997398	0.000861	0.1472	24.695459	0.005962	-0.005101	0.1802
94	0.020571	7.46%	0.0746	180.717472	0.000413	0.0746	24.695459	0.003020	-0.002608	0.1056
95	0.020556	4.34%	0.0434	190.990067	0.000227	0.0434	24.695459	0.001759	-0.001532	0.0621
96	0.020540	4.34%	0.0434	201.846592	0.000215	0.0434	24.695459	0.001759	-0.001544	0.0187
97	0.020536	1.14%	0.0114	213.320239	0.000054	0.0114	24.695459	0.000464	-0.000410	0.0072
98	0.020535	0.34%	0.0034	225.446087	0.000015	0.0034	24.695459	0.000140	-0.000124	0.0038
99	0.020534	0.34%	0.0034	238.261209	0.000014	0.0034	24.695459	0.000140	-0.000125	0.0003
100	0.020533	0.03%	0.0003	251.804786	0.000001	0.0003	24.695459	0.000014	-0.000013	0.0000
101	0.020533	0.00%	0.0000	266.118227	0.000000	0.0000	24.695459	0.000000	0.000000	0.0000
102	0.020533	0.00%	0.0000	281.245292	0.000000	0.0000	24.695459	0.000000	0.000000	0.0000
103	0.020533	0.00%	0.0000	297.232231	0.000000	0.0000	24.695459	0.000000	0.000000	0.0000
104	0.020533	0.00%	0.0000	314.127921	0.000000	0.0000	24.695459	0.000000	0.000000	0.0000
		100.0000	100.0000							

**Source: Iowa Curves (09-17-2008)

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2.0 & 50 Year Average Life

Real Cost of Capital = 5.68%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 1.5
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0568 ^Year	(C) / (D)	(B)	1.0568 ^50	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000897	10.16%	0.1016	1.056843	0.096135	0.1016	15.868358	0.006403	0.089733	99.8984
2	0.002589	20.32%	0.2032	1.116918	0.181929	0.2032	15.868358	0.012805	0.169124	99.6952
3	0.004182	20.32%	0.2032	1.180407	0.172144	0.2032	15.868358	0.012805	0.159339	99.4920
4	0.005949	23.92%	0.2392	1.247506	0.191743	0.2392	15.868358	0.015074	0.176669	99.2528
5	0.007612	23.92%	0.2392	1.318418	0.181430	0.2392	15.868358	0.015074	0.166356	99.0136
6	0.009314	26.00%	0.2600	1.393362	0.186599	0.2600	15.868358	0.016385	0.170214	98.7536
7	0.011044	28.08%	0.2808	1.472565	0.190688	0.2808	15.868358	0.017696	0.172992	98.4728
8	0.012672	28.08%	0.2808	1.556271	0.180431	0.2808	15.868358	0.017696	0.162736	98.1920
9	0.014455	32.72%	0.3272	1.644734	0.198938	0.3272	15.868358	0.020620	0.178318	97.8648
10	0.016131	32.72%	0.3272	1.738227	0.188238	0.3272	15.868358	0.020620	0.167618	97.5376
11	0.017832	35.34%	0.3534	1.837033	0.192375	0.3534	15.868358	0.022271	0.170105	97.1842
12	0.019548	37.96%	0.3796	1.941457	0.195523	0.3796	15.868358	0.023922	0.171601	96.8046
13	0.021159	37.96%	0.3796	2.051816	0.185007	0.3796	15.868358	0.023922	0.161085	96.4250
14	0.022904	43.84%	0.4384	2.168448	0.202172	0.4384	15.868358	0.027627	0.174545	95.9866
15	0.024541	43.84%	0.4384	2.291710	0.191298	0.4384	15.868358	0.027627	0.163671	95.5482
16	0.026188	47.08%	0.4708	2.421978	0.194387	0.4708	15.868358	0.029669	0.164717	95.0774
17	0.027837	50.32%	0.5032	2.559652	0.196589	0.5032	15.868358	0.031711	0.164878	94.5742
18	0.029380	50.32%	0.5032	2.705151	0.186015	0.5032	15.868358	0.031711	0.154305	94.0710
19	0.031032	57.60%	0.5760	2.858921	0.201475	0.5760	15.868358	0.036299	0.165176	93.4950
20	0.032575	57.60%	0.5760	3.021432	0.190638	0.5760	15.868358	0.036299	0.154339	92.9190
21	0.034117	61.62%	0.6162	3.193180	0.192974	0.6162	15.868358	0.038832	0.154142	92.3028
22	0.035648	65.64%	0.6564	3.374691	0.194507	0.6564	15.868358	0.041365	0.153141	91.6464
23	0.037075	65.64%	0.6564	3.566520	0.184045	0.6564	15.868358	0.041365	0.142680	90.9900
24	0.038582	74.52%	0.7452	3.769254	0.197705	0.7452	15.868358	0.046961	0.150744	90.2448
25	0.039983	74.52%	0.7452	3.983511	0.187071	0.7452	15.868358	0.046961	0.140110	89.4996
26	0.041369	79.40%	0.7940	4.209947	0.188601	0.7940	15.868358	0.050037	0.138564	88.7056
27	0.042732	84.28%	0.8428	4.449255	0.189425	0.8428	15.868358	0.053112	0.136313	87.8628
28	0.043993	84.28%	0.8428	4.702166	0.179237	0.8428	15.868358	0.053112	0.126125	87.0200
29	0.045305	94.92%	0.9492	4.969453	0.191007	0.9492	15.868358	0.059817	0.131190	86.0708
30	0.046514	94.92%	0.9492	5.251933	0.180733	0.9492	15.868358	0.059817	0.120916	85.1216
31	0.047694	100.70%	1.0070	5.550471	0.181426	1.0070	15.868358	0.063460	0.117966	84.1146
32	0.048838	106.48%	1.0648	5.865979	0.181521	1.0648	15.868358	0.067102	0.114419	83.0498
33	0.049885	106.48%	1.0648	6.199421	0.171758	1.0648	15.868358	0.067102	0.104656	81.9850
34	0.050951	118.96%	1.1896	6.551817	0.181568	1.1896	15.868358	0.074967	0.106601	80.7954
35	0.051919	118.96%	1.1896	6.924244	0.171802	1.1896	15.868358	0.074967	0.096835	79.6058
36	0.052844	125.56%	1.2556	7.317842	0.171581	1.2556	15.868358	0.079126	0.092455	78.3502
37	0.053720	132.16%	1.3216	7.733813	0.170886	1.3216	15.868358	0.083285	0.087601	77.0286
38	0.054504	132.16%	1.3216	8.173429	0.161695	1.3216	15.868358	0.083285	0.078409	75.7070
39	0.055274	146.00%	1.4600	8.638035	0.169020	1.4600	15.868358	0.092007	0.077013	74.2470
40	0.055953	146.00%	1.4600	9.129050	0.159929	1.4600	15.868358	0.092007	0.067922	72.7870
41	0.056575	153.06%	1.5306	9.647976	0.158645	1.5306	15.868358	0.096456	0.062189	71.2564
42	0.057136	160.12%	1.6012	10.196400	0.157036	1.6012	15.868358	0.100905	0.056131	69.6552
43	0.057613	160.12%	1.6012	10.775998	0.148589	1.6012	15.868358	0.100905	0.047684	68.0540
44	0.058045	174.16%	1.7416	11.388543	0.152926	1.7416	15.868358	0.109753	0.043173	66.3124
45	0.058394	174.16%	1.7416	12.035906	0.144700	1.7416	15.868358	0.109753	0.034947	64.5708
46	0.058677	180.84%	1.8084	12.720068	0.142169	1.8084	15.868358	0.113963	0.028206	62.7624

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2.0 & 50 Year Average Life

Real Cost of Capital = 5.68%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 1.5
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0568 ^Year	(C) / (D)	(B)	1.0568 ^50	(F) / (G)	(E) - (H)	(Given)
47	0.058890	187.52%	1.8752	13.443120	0.139491	1.8752	15.868358	0.118172	0.021319	60.8872
48	0.059028	187.52%	1.8752	14.207273	0.131989	1.8752	15.868358	0.118172	0.013816	59.0120
49	0.059099	199.48%	1.9948	15.014862	0.132855	1.9948	15.868358	0.125709	0.007146	57.0172
50	0.059099	199.48%	1.9948	15.868358	0.125709	1.9948	15.868358	0.125709	0.000000	55.0224
51	0.059030	204.36%	2.0436	16.770369	0.121858	2.0436	15.868358	0.128785	-0.006927	52.9788
52	0.058892	209.24%	2.0924	17.723654	0.118057	2.0924	15.868358	0.131860	-0.013803	50.8864
53	0.058691	209.24%	2.0924	18.731127	0.111707	2.0924	15.868358	0.131860	-0.020153	48.7940
54	0.058421	215.92%	2.1592	19.795868	0.109073	2.1592	15.868358	0.136070	-0.026996	46.6348
55	0.058092	215.92%	2.1592	20.921132	0.103207	2.1592	15.868358	0.136070	-0.032863	44.4756
56	0.057705	217.28%	2.1728	22.110361	0.098271	2.1728	15.868358	0.136927	-0.038656	42.3028
57	0.057263	218.64%	2.1864	23.367189	0.093567	2.1864	15.868358	0.137784	-0.044217	40.1164
58	0.056771	218.64%	2.1864	24.695459	0.088534	2.1864	15.868358	0.137784	-0.049249	37.9300
59	0.056235	216.76%	2.1676	26.099233	0.083052	2.1676	15.868358	0.136599	-0.053547	35.7624
60	0.055655	216.76%	2.1676	27.582802	0.078585	2.1676	15.868358	0.136599	-0.058014	33.5948
61	0.055043	213.28%	2.1328	29.150703	0.073165	2.1328	15.868358	0.134406	-0.061241	31.4620
62	0.054402	209.80%	2.0980	30.807728	0.068100	2.0980	15.868358	0.132213	-0.064113	29.3640
63	0.053724	209.80%	2.0980	32.558944	0.064437	2.0980	15.868358	0.132213	-0.067776	27.2660
64	0.053052	197.88%	1.9788	34.409705	0.057507	1.9788	15.868358	0.124701	-0.067194	25.2872
65	0.052349	197.88%	1.9788	36.365670	0.054414	1.9788	15.868358	0.124701	-0.070287	23.3084
66	0.051647	189.68%	1.8968	38.432818	0.049354	1.8968	15.868358	0.119533	-0.070180	21.4116
67	0.050950	181.48%	1.8148	40.617470	0.044680	1.8148	15.868358	0.114366	-0.069686	19.5968
68	0.050229	181.48%	1.8148	42.926305	0.042277	1.8148	15.868358	0.114366	-0.072089	17.7820
69	0.049567	161.60%	1.6160	45.366382	0.035621	1.6160	15.868358	0.101838	-0.066217	16.1660
70	0.048886	161.60%	1.6160	47.945162	0.033705	1.6160	15.868358	0.101838	-0.068133	14.5500
71	0.048234	150.60%	1.5060	50.670528	0.029721	1.5060	15.868358	0.094906	-0.065184	13.0440
72	0.047615	139.60%	1.3960	53.550813	0.026069	1.3960	15.868358	0.087974	-0.061905	11.6480
73	0.046982	139.60%	1.3960	56.594823	0.024667	1.3960	15.868358	0.087974	-0.063307	10.2520
74	0.046441	116.92%	1.1692	59.811865	0.019548	1.1692	15.868358	0.073681	-0.054133	9.0828
75	0.045889	116.92%	1.1692	63.211775	0.018497	1.1692	15.868358	0.073681	-0.055185	7.9136
76	0.045380	105.82%	1.0582	66.804947	0.015840	1.0582	15.868358	0.066686	-0.050846	6.8554
77	0.044918	94.72%	0.9472	70.602368	0.013416	0.9472	15.868358	0.059691	-0.046275	5.9082
78	0.044448	94.72%	0.9472	74.615646	0.012694	0.9472	15.868358	0.059691	-0.046997	4.9610
79	0.044076	73.88%	0.7388	78.857053	0.009369	0.7388	15.868358	0.046558	-0.037189	4.2222
80	0.043699	73.88%	0.7388	83.339556	0.008865	0.7388	15.868358	0.046558	-0.037693	3.4834
81	0.043367	64.24%	0.6424	88.076860	0.007294	0.6424	15.868358	0.040483	-0.033189	2.8410
82	0.043081	54.60%	0.5460	93.083449	0.005866	0.5460	15.868358	0.034408	-0.028542	2.2950
83	0.042793	54.60%	0.5460	98.374628	0.005550	0.5460	15.868358	0.034408	-0.028858	1.7490
84	0.042595	37.08%	0.3708	103.966577	0.003567	0.3708	15.868358	0.023367	-0.019801	1.3782
85	0.042395	37.08%	0.3708	109.876390	0.003375	0.3708	15.868358	0.023367	-0.019993	1.0074
86	0.042235	29.38%	0.2938	116.122138	0.002530	0.2938	15.868358	0.018515	-0.015985	0.7136
87	0.042116	21.68%	0.2168	122.722915	0.001767	0.2168	15.868358	0.013662	-0.011896	0.4968
88	0.041996	21.68%	0.2168	129.698903	0.001672	0.2168	15.868358	0.013662	-0.011991	0.2800
89	0.041944	9.36%	0.0936	137.071430	0.000683	0.0936	15.868358	0.005899	-0.005216	0.1864
90	0.041892	9.36%	0.0936	144.863036	0.000646	0.0936	15.868358	0.005899	-0.005252	0.0928
91	0.041860	5.60%	0.0560	153.097544	0.000366	0.0560	15.868358	0.003529	-0.003163	0.0368
92	0.041849	1.84%	0.0184	161.800129	0.000114	0.0184	15.868358	0.001160	-0.001046	0.0184
93	0.041839	1.84%	0.0184	170.997398	0.000108	0.0184	15.868358	0.001160	-0.001052	0.0000
94	0.041839	0.00%	0.0000	180.717472	0.000000	0.0000	15.868358	0.000000	0.000000	0.0000
			99.9816	50.9667						

CHARGE 6

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 12/31/2006 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount
		$		Yrs	%	$
	TRANSMISSION PLANT					
350.20	Land Rights	61,181,203	R5	70.00	0.00%	-
352.00	Structures & Improvements	55,260,234	S1	75.00	-1.00%	(552,602)
353.00	Station Equipment	907,682,638	R1.5	58.00	-4.00%	(36,307,306)
353.70	Supervisory Equipment	55,509,184	R2	25.00	0.00%	-
354.00	Towers & Fixtures	380,678,705	R5	65.00	-7.00%	(26,647,509)
355.00	Poles & Fixtures	508,938,637	R2.5	52.00	-42.00%	(213,754,228)
356.00	OH Conductors & Devices	630,352,557	R4	60.00	-42.00%	(264,748,074)
356.20	Clearing	30,355,853	S6	65.00	0.00%	-
357.00	UG Conduit	3,277,188	R2	60.00	0.00%	-
358.00	UG Conductors & Devices	7,274,658	R2	60.00	0.00%	-
359.00	Roads & Trails	11,494,522	R5	70.00	0.00%	-
	Total Transmission Plant	2,652,005,379		58.41	-20.44%	(542,009,719)
				Use 58 Years		

[1] Account Number	[2] Description	[3] 12/31/2006 Balance				
	TRANSMISSION PLANT excludes land accounts					
352.00	Structures & Improvements	55,260,234	-	2.13%	-	
353.00	Station Equipment	907,682,638	1.50	35.03%	0.5255	
353.70	Supervisory Equipment	55,509,184	2.00	2.14%	0.0429	
354.00	Towers & Fixtures	380,678,705	5.00	14.69%	0.7347	
355.00	Poles & Fixtures	508,938,637	2.50	19.64%	0.4911	
356.00	OH Conductors & Devices	630,352,557	4.00	24.33%	0.9732	
356.20	Clearing	30,355,853	-	1.17%	-	
357.00	UG Conduit	3,277,188	2.00	0.13%	0.0025	
358.00	UG Conductors & Devices	7,274,658	2.00	0.28%	0.0056	
359.00	Roads & Trails	11,494,522	5.00	0.44%	0.0222	
	Total Transmission Plant	2,590,824,176		100.00%	2.7977	**Use R 3**

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 12/31/2006 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount
		$		Yrs	%	$
	DISTRIBUTION PLANT (OREGON)					
360.20	Land Rights	3,556,253	R4	53.00	0.00%	-
361.00	Structures & Improvements	12,345,312	R1.5	65.00	-5.00%	(617,266)
362.00	Station Equipment	160,587,683	R1	52.00	-10.00%	(16,058,768)
362.70	Supervisory & Alarm Equipment	2,779,659	R2.5	23.00	0.00%	-
364.00	Poles, Towers & Fixtures	282,793,465	R2	49.00	-100.00%	(282,793,465)
365.00	OH Conductors & Devices	210,301,551	R1.5	58.00	-80.00%	(168,241,241)
366.00	UG Conduit	75,474,348	R2.5	60.00	-60.00%	(45,284,609)
367.00	UG Conductors & Devices	133,175,353	R2.5	58.00	-45.00%	(59,928,909)
368.00	Line Transformers	340,095,762	R1.5	40.00	-20.00%	(68,019,152)
369.10	Overhead Services	60,741,141	R2	65.00	-25.00%	(15,185,285)
369.20	Underground Services	122,060,821	R4	55.00	-20.00%	(24,412,164)
370.00	Meters	58,792,161	R2.5	26.00	-2.00%	(1,175,843)
371.00	I.O.C.P.	2,433,995	S1	25.00	-40.00%	(973,598)
373.00	Street Lighting & Signal Systems	19,600,663	R1	40.00	-26.00%	(5,096,172)
	Total OREGON Distribution Plant	1,484,738,167		50.08	-46.32%	(687,786,473)
				Use 50 years		

	DISTRIBUTION PLANT excludes land accounts (OREGON)					
361.00	Structures & Improvements	12,345,312	1.5	0.83%	0.01	
362.00	Station Equipment	160,587,683	1	10.84%	0.11	
362.70	Supervisory & Alarm Equipment	2,779,659	2.5	0.19%	0.00	
364.00	Poles, Towers & Fixtures	282,793,465	2	19.09%	0.38	
365.00	OH Conductors & Devices	210,301,551	1.5	14.20%	0.21	
366.00	UG Conduit	75,474,348	2.5	5.10%	0.13	
367.00	UG Conductors & Devices	133,175,353	2.5	8.99%	0.22	
368.00	Line Transformers	340,095,762	1.5	22.96%	0.34	
369.10	Overhead Services	60,741,141	2	4.10%	0.08	
369.20	Underground Services	122,060,821	4	8.24%	0.33	
370.00	Meters	58,792,161	2.5	3.97%	0.10	
371.00	I.O.C.P.	2,433,995	0	0.16%	0.00	
373.00	Street Lighting & Signal Systems	19,600,663	1	1.32%	0.01	
	Total OREGON Distribution Plant	1,481,181,914		100.00%	1.94	**Use R 2**

**Source: Depreciation Rates.xls

Losses

PacifiCorp
Oregon Marginal Cost Study
Energy Loss Factors

Line	(A) Voltage Level	(B) Energy Factor	(C) Energy Loss Percent	(D) Demand Factor	(E) Demand Loss Percent
1	Transmission	1.04527	4.53%	1.04259	4.26%
2					
3					
4					
5					
6	Primary	1.06904	6.90%	1.07920	7.92%
7					
8					
9					
10					
11	Secondary	1.10006	10.01%	1.11057	11.06%
12					

**Source: 2009 Analysis of System Losses

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended June 30, 2012 - Actual

Line	Description	(A) Del. Volt	(B) Average Customers	(C) % Total Class	(D) Annual MWh's	(E) % Total Class	(F) Average Billing kW	(G) % Total Class
1	Res - Schedule 4	(sec)	474,231	100.0%	5,408,536	100.0%	4,966,196	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	66,169	86.2%	604,893	53.6%	263,233	59.3%
5	15+ kW	(sec)	10,605	13.8%	523,765	46.4%	180,731	40.7%
6	Sec Subtotal		76,774	100.0%	1,128,658	100.0%	443,964	100.0%
7	Primary	(pri)	44		1,163		1,550	
8	Total		76,818		1,129,820		445,514	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,487	45.5%	444,385	22.1%	141,470	7.0%
12	51-100 kW	(sec)	3,453	35.0%	673,448	33.6%	189,067	9.4%
13	> 101kW	(sec)	1,924	19.5%	888,469	44.3%	233,629	11.6%
14	Sec Subtotal		9,865	100.0%	2,006,302	100.0%	2,016,169	28.0%
15	Primary	(pri)	57		18,661		18,698	
16	Total		9,922		2,024,963		2,034,866	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	215	28.0%	202,011	16.4%	48,729	15.8%
20	301+ kW	(sec)	553	72.0%	1,030,233	83.6%	259,445	84.2%
21	Sec Subtotal		768	100.0%	1,232,244	100.0%	308,174	100.0%
22	Primary	(pri)	51		90,666		21,716	
23	Total		818		1,322,910		329,890	
24								
25	LPS - Schedule 48T							
26	1 - 4 MW	(sec)	107	98.2%	531,189	91.0%	132,222	90.7%
27	> 4 MW	(sec)	2	1.8%	52,257	9.0%	13,624	9.3%
28	Sec Subtotal		109	100.0%	583,446	100.0%	145,845	100.0%
29	1 - 4 MW	(pri)	64	65.9%	492,307	30.6%	102,469	31.0%
30	> 4 MW	(pri)	33	34.1%	1,117,609	69.4%	227,830	69.0%
31	Pri Subtotal		97	100.0%	1,609,916	100.0%	330,299	100.0%
32	Trans	(trn)	6		528,557		164,031	
33	Total		212		2,721,919		640,175	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	3,444	100.0%	217,837	100.0%	150,187	100.0%
36								
37	Irrigation - Schedule 41 (Annual)	(sec)	7,211					

Source:
Columns B & D - PacifiCorp, Pricing Department

Cust Data 2

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended December 2014 - Normalized

Line	Description	(A) Del. Volt	(B) Average Customers	(C) % Total Class	(D) Annual MWh's	(E) % Total Class	(F) Average Billing kW	(G) % Total Class
1	Res - Schedule 4	(sec)	485,586	100.0%	5,379,569	100.0%	4,966,196	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	63,644	86.2%	589,432	53.6%	263,233	59.3%
5	15+ kW	(sec)	10,200	13.8%	510,378	46.4%	180,731	40.7%
6	Sec Subtotal		73,844	100.0%	1,099,810	100.0%	443,964	100.0%
7	Primary	(pri)	43		1,147		1,550	
8	Total		73,887		1,100,957		445,514	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,489	45.5%	437,292	22.1%	141,470	7.0%
12	51-100 kW	(sec)	3,455	35.0%	662,698	33.6%	189,067	9.4%
13	> 101kW	(sec)	1,925	19.5%	874,287	44.3%	233,629	11.6%
14	Sec Subtotal		9,868	100.0%	1,974,277	100.0%	564,166	28.0%
15	Primary	(pri)	56		18,574		18,698	
16	Total		9,924		1,992,851		582,863	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	200	28.0%	204,293	16.4%	48,729	15.8%
20	301+ kW	(sec)	515	72.0%	1,041,871	83.6%	259,445	84.2%
21	Sec Subtotal		715	100.0%	1,246,164	100.0%	308,174	100.0%
22	Primary	(pri)	47		91,598		21,716	
23	Total		762		1,337,762		329,890	
24								
25	LPS - Schedule 48T							
26	1 - 4 MW	(sec)	102	98.2%	524,179	91.0%	132,222	90.7%
27	> 4 MW	(sec)	2	1.8%	51,567	9.0%	13,624	9.3%
28	Sec Subtotal		104	100.0%	575,746	100.0%	145,845	100.0%
29	1 - 4 MW	(pri)	61	65.9%	467,708	30.6%	102,469	31.0%
30	> 4 MW	(pri)	32	34.1%	1,061,765	69.4%	227,830	69.0%
31	Pri Subtotal		93	100.0%	1,529,473	100.0%	330,299	100.0%
32	Trans	(trn)	9		829,896		164,031	
33	Total		206		2,935,115		640,175	
34								
35								
36	Irrigation - Schedule 41 (Average)	(sec)	3,920	100.0%	238,210	100.0%	150,187	100.0%
37								
38								
39	Irrigation - Schedule 41 (Annual)	(sec)	8,046	100.0%	238,210	100.0%	150,187	100.0%

Source:
Columns B & D - PacifiCorp, Pricing Department

Cust Data 3

PacifiCorp
Oregon Marginal Cost Study
Customer Class Split between
Three Phase / Single Phase

Line	Customer Class		(A) Voltage Level	(B) Three Phase	(C) Total Customers	(D) Three Phase % of Customers	(E) Single Phase % of Customers
						(A) / (B)	100% - (C)
1	Res - Schedule 4		(sec)	-	474,231	0.0000%	100.0000%
2							
3	GS - Schedule 23						
4	0-15 kW		(sec)	11,812	66,169	17.8518%	82.1482%
5	15+ kW		(sec)	5,820	10,605	54.8840%	45.1160%
6		Sec Subtotal		17,633	76,774		
7	Primary		(pri)	44	44	100.0000%	0.0000%
8		Total		17,677	76,818	23.0118%	76.9882%
9							
10	GS - Schedule 28						
11	0-50 kW		(sec)	3,149	4,487	70.1895%	29.8105%
12	51-100 kW		(sec)	3,024	3,453	87.5598%	12.4402%
13	> 101kW		(sec)	1,887	1,924	98.0750%	1.9250%
14		Sec Subtotal		8,061	9,865		
15	Primary		(pri)	57	57	100.0000%	0.0000%
16		Total		8,117	9,922	81.8146%	18.1854%
17							
18	GS - Schedule 30						
19	0-300 kW			214	215	99.6125%	0.3875%
20	301+ kW			553	553	100.0000%	0.0000%
21		Sec Subtotal		767	768		
22	Primary			51	51	100.0000%	0.0000%
23		Total		818	818	99.8982%	0.1018%
24							
25	LPS - Schedule 48T						
26	1 - 4 MW		(sec)	107	107	100.0000%	0.0000%
27	1 - 4 MW		(pri)	64	64	100.0000%	0.0000%
28	> 4 MW		(sec)	2	2	100.0000%	0.0000%
29	> 4 MW		(pri)	33	33	100.0000%	0.0000%
30	Trans		(trn)	6	6	100.0000%	0.0000%
31	Total			212	212	100.0000%	0.0000%
32							
33	Irrigation - Schedule 41 (Annual)		(sec)	6,160	7,211	85.4313%	14.5687%
34							
35							
36	TOTAL			32,984	569,212	5.7948%	94.2052%

Cust Data 4

PacifiCorp
Oregon Marginal Cost Study
Customer Loads
12 Months Ended December 2014

	(A)	(B)	(C)	(D)	(E)
			MW @ Sales		
Line	Description	Del. Volt	System	Distribution	Transformer
1	Res - Schedule 4	(sec)	849	976	3,327
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	91	89	184
5	15+ kW	(sec)	79	72	127
6	Primary	(pri)	0	0	2
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	73	78	141
10	51-100 kW	(sec)	101	109	189
11	> 101kW	(sec)	133	140	234
12					
13	Primary	(pri)	3	3	19
14					
15	GS - Schedule 30				
16	0-300 kW	(sec)	28	30	49
17	301+ kW	(sec)	153	165	259
18	Primary	(pri)	14	15	22
19					
20	LPS - Schedule 48T				
21	1 - 4 MW	(sec)	78	84	132
22	1 - 4 MW	(pri)	65	69	102
23	> 4 MW	(sec)	7	6	14
24	> 4 MW	(pri)	151	150	228
25	Trans	(trn)	94	0	164
26					
27	Irrigation - Sch 41	(sec)	26	27	150

Source:
Columns C, D & F - PacifiCorp, Load Research Dept.
Column E - Column F x Column H
Column H - PacifiCorp Distribution Construction Standard, DA 411

Cust Data 5

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2014

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				Revenues		Percent of				
			Del.	December 2014		Total Revenues		Allocated Net Uncollectible		
Line	Description		Volt	Commercial	Industrial	Commercial	Industrial	Commercial	Industrial	Total
1	Res - Schedule 4		(sec)	-	-	0.00%	0.00%	-	-	5,322,978
2										
3	GS - Schedule 23									
4			(sec)	111,580,331	2,282,796	25.39%	1.61%	145,265	552	145,817
5			(pri)	87,942	22,422	0.02%	0.02%	114	5	120
6		Total		$111,668,273	$2,305,218	25.41%	1.63%	145,380	557	145,937
7										
8	GS - Schedule 28									
9			(sec)	160,691,885	8,297,935	36.56%	5.86%	209,203	2,007	211,210
10			(pri)	1,108,427	443,089	0.25%	0.31%	1,443	107	1,550
11		Total		$161,800,312	$8,741,024	36.81%	6.17%	210,646	2,114	212,760
12										
13	GS - Schedule 30									
14			(sec)	78,702,779	15,724,276	17.91%	11.10%	102,462	3,803	106,265
15			(pri)	5,748,192	1,076,582	1.31%	0.76%	7,484	260	7,744
16		Total		$84,450,971	$16,800,858	19.22%	11.87%	109,946	4,063	114,009
17										
18	LPS - Schedule 48T									
19			(sec)	25,582,615	17,278,450	5.82%	12.20%	33,306	4,178	37,484
20			(pri)	29,532,712	73,545,828	6.72%	51.94%	38,448	17,786	56,234
21			(trn)	26,468,477	22,928,332	6.02%	16.19%	34,459	5,545	40,004
22		Total		$81,583,804	$113,752,610	18.56%	80.33%	106,213	27,509	133,722
23										
24	Irrigation - Schedule 41		(sec)	-	$25,360,982	0.00%	100.00%	-	7,103	7,103
25				-	$25,360,982	0.00%	100.00%	-	7,103	7,103
26										
27	Total			$439,503,360	$166,960,692			572,186	41,346	5,936,510

Docket No. UE 263
Exhibit PAC/1200
Witness: Joelle R. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Joelle R. Steward

March 2013

DIRECT TESTIMONY OF JOELLE R. STEWARD

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/1201 – Proposed Tariffs

Exhibit PAC/1202 – Target Functionalized Revenues and Billing Determinants

Exhibit PAC/1203 – Estimated Effect of Proposed Rates

Exhibit PAC/1204 – Generation Investment Adjustment Proposed Rate Spread and Illustrative Tariff

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Joelle R. Steward. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing, Cost of Service, and Regulatory Operations.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Arts degree in Political Science from the University of Oregon and a Masters of Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as the Regulatory Manager responsible for all regulatory filings and proceedings in Oregon. I assumed my current position in February 2012, in which I direct the work of the cost of service, pricing, and regulatory operations groups.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What are your responsibilities in these proceedings?

A. I am responsible for the design of the Company's proposed prices in this proceeding. The proposed tariffs incorporate the Company's proposed price increase and are designed consistent with the Commission's rules under OAR 860-038-0200. I am sponsoring the Company's Oregon electric tariff schedules submitted for approval in this filing. Exhibit PAC/1201 contains the proposed tariffs.

Q. Please summarize your testimony.

A. The overall rate increase proposed by the Company in this case, including the effect of rebalancing the Rate Mitigation Adjustment (RMA) (discussed later in my testimony), is $56.2 million. However, after reflecting the effect of the implementation of Schedule 80, Transmission Investment Adjustment, for the Mona-to-Oquirrh transmission project in 2013, the overall proposed increase to customer bills as a result of this general rate case will be $44.8 million or 3.7 percent effective January 1, 2014. The Company is proposing a base rate spread that is consistent with the cost of service study in this case. Including the effect of all tariff riders, the Company's proposed net rate spread proposes continued use of the RMA to achieve a rate increase on January 1, 2014, where no customer rate class will see a rate increase more than 6.5 percent.

For rate design, in compliance with Order No. 12-500 the Company has included a new unbundled rate element in all non-direct access delivery service rate schedules—the System Usage Charge—to identify the franchise fee costs that would be avoided by any customer taking direct access. For residential rates, the Company is proposing a monthly basic charge of $10, which is a $1 increase to the current charge. For commercial and industrial rates, the Company is proposing increases to demand charges in Schedule 200 to better reflect cost of service results. Lastly, the Company is proposing separate treatment for the collection of the Lake Side 2 natural gas-fired generating plant (Lake Side 2) investment, which would take effect when the plant goes into service in the second quarter of 2014.

ALLOCATION OF THE FUNCTIONALIZED REVENUE REQUIREMENT

Q. How is the Company proposing to allocate the functionalized revenue requirement across classes of customers in this proceeding?

A. The Company is allocating the functionalized revenue requirement to classes consistent with the Commission's rules for Direct Access Regulation in OAR 860, Division 38. The rules indicate that rates are to be based on cost. As stated in OAR 860-038-0240(3)(b), "rates for any class of consumer must be based on the unbundled costs to serve that class." In this filing, the Company has allocated the revenue requirement to each rate schedule based on the results of the functionalized class cost of service study sponsored by Mr. C. Craig Paice. The proposed rates for each rate schedule included in the cost of service study are targeted to collect the cost of service for that rate schedule in the test period. Therefore, the proposed base rates for each class are based on the unbundled costs to serve that class.

Q. Do you have an exhibit that summarizes the functionalized results of the cost of service study presented by Mr. Paice?

A. Yes. Exhibit PAC/1202, Steward/1-2, summarizes the functionalized results of the cost of service study in column (4). This summary is provided at the level used to design rates. The cost of service for each rate schedule has been summarized into the following components: Transmission & Ancillary Services, System Usage, Distribution, Generation Energy Other (Non-NPC), and Generation Energy NPC.

Q. What is the purpose of including this summary of cost components for the target functionalized revenue requirement?

A. The summary level for revenue requirement shown in Exhibit PAC/1202, Steward/1-2, summarizes the cost of service results into the target revenue requirement components used in rate design.

The process of unbundling the Company's proposed prices is consistent with the method the Company first implemented in docket UE 116. For each rate schedule, the functionalized costs developed by Mr. Paice are applied to rates as follows: distribution, billing, metering, and customer costs are included in each proposed delivery service schedule's Distribution rates; the Federal Energy Regulatory Commission (FERC) regulated transmission and ancillary services are included in each proposed delivery service schedule's Transmission & Ancillary Services rates; non-net power cost generation costs are included in Schedule 200, Base Supply Service rates; and net power costs are included in Schedule 201, Net Power Costs, Cost-Based Supply Service rates.

Q. Please explain the System Usage costs shown in exhibit PAC/1202 and how those costs are proposed to be recovered in rates.

A. In Order No. 12-500, the Commission directed the Company to develop a volumetric rate element for franchise fees that could be avoided by customers taking direct access. The amounts shown as System Usage costs in Exhibit PAC/1202 are a portion of the Oregon Franchise Tax and Oregon Energy

Supplier Assessment from FERC Account 408 in the results of operations.[1] The System Usage costs have been calculated as the portion of the franchise and energy supplier taxes associated with revenues not paid by direct access customers: net power costs and transmission and ancillary services. As discussed later, a separate volumetric rate element has been developed to recover these costs, which will not be paid by direct access customers.

Q. Have any adjustments been made to the functionalized revenue requirement by rate schedule resulting from the cost of service study sponsored by Mr. Paice?

A. Yes, consistent with past cases the Company has made one adjustment. The functionalized revenue requirement has been adjusted to remove the proposed changes to net power costs (NPC) collected through Schedule 201. Changes to Schedule 201 are implemented through the Transition Adjustment Mechanism (TAM), which is a separate proceeding from this general rate case, and the Schedule 201 changes will be addressed in that proceeding. The modified cost of service results reflecting this adjustment that removes the NPC increase from the functionalized revenue requirement is shown in Exhibit PAC/1202, Steward/1-2, column (5). This column displays the target functionalized revenue requirement used in the design of rates proposed in this general rate case.

[1]The Oregon Energy Supplier Assessment is a fee paid to the Oregon Department of Energy under ORS 469.421(8). While this treatment for this assessment was not reflected in Order No. 12-500, the Company has included it in the System Usage Charge because it is assessed in the same manner (a percent of revenue) as franchise taxes in FERC Account 408. The Company is therefore proposing parallel treatment.

Q. Do the Company's proposed rates collect the target functionalized revenues?

A. Yes. The revenues calculated by multiplying the test period billing determinants by the proposed rates are summarized in column (6) of Exhibit PAC/1202, Steward/1-2. A direct comparison to the target functionalized revenues shown in column (5) of this exhibit shows that the calculated revenues equal the target revenues with the exception of small differences due to the rounding of rates. The detailed calculation of proposed revenues based on billing determinants and proposed rates is shown in Exhibit PAC/1202, Steward/3-12.

Q. Have you prepared an exhibit showing the estimated effects of the prices proposed in this general rate case?

A. Yes. Exhibit PAC/1203 shows the estimated effect of the Company's proposed prices. It contains two summary tables: Table 1203-1 shows the effect of the proposed prices by delivery service rate schedule for the proposed net rate increase on January 1, 2014 of $44.8 million; Table 1203-2 shows the effect of the proposed prices by delivery service rate schedule for the revenue requirement change requested in this case of $56.2 million. The expected January 1, 2014 rate increase shown in Table 1203-1 includes the effect following the implementation in early 2013 of Schedule 80, Transmission Investment Adjustment for the Mona-to-Oquirrh transmission project, applied to the 2014 forecast billing determinants. The Transmission Investment Adjustment is currently estimated to be $11.4 million and is expected to become effective during May 2013, as authorized by the Commission in Order No. 12-493. The estimated increase for the Transmission Investment Adjustment, shown in column (6) of Table 1203-1, reduces the net increase that will go into effect on January 1, 2014, from $56.2 million to $44.8 million. These tables show the effect of the price changes on both base revenues and net revenues. Base revenues show the effect before the impacts of any adjustment tariffs. Net revenues include the effect of adjustment tariffs (discussed directly below) and the impact of the $0.2 million RMA rebalancing (discussed later in my testimony).

The adder columns in Tables 1203-1 and 1203-2 show revenues from present adjustment tariff schedules (Schedules 96, 204, and 299). The adder revenue is added to base revenue to calculate net revenue including adjustment schedules. Table 1203-3 shows the calculation of the adjustment revenue included in the adders columns in Tables 1203-1 and 1203-2. Table 1203-4 shows the present and proposed rates for these adjustment schedules. These tables exclude the effects of pass-through adjustment schedules for Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Beginning on page 5 of Exhibit PAC/1203 are the monthly billing comparisons for each of the major delivery service rate schedules showing the customer bill impacts of the proposed prices at various levels of usage. The monthly billing comparisons in Exhibit PAC/1203 show the expected rate increases for January 1, 2014, as they include the effect of the estimated Transmission Investment Adjustment in present rates. The monthly billing comparisons also include the effects of all adjustment schedules, including the pass-through adjustment schedules listed above.

Q. What are the Company's rate spread objectives in this case?

A. The Company's rate spread objectives in this case are to minimize price impacts on our customers while fairly reflecting cost of service and sending proper signals about increasing costs.

Q. What is the Company's rate spread proposal in this case?

A. Based on the cost of service results and in order to achieve the Company's rate spread objectives in this case, Table 1 below summarizes the Company's proposed net percentage price changes for the major rate schedule classes.

TABLE 1

Residential Schedule 4	**2.9%**
General Service	
Schedule 23/723 (0-30kW)	**4.1%**
Schedule 28/728 (31-200kW)	**1.7%**
Schedule 30/730 (201-999kW)	**5.2%**
Large General Service	
Schedules 47/747, 48/748 (≥1,000kW)	**6.5%**
Agricultural Pumping Service Schedule 41/741	**3.7%**
Lighting Schedules	**6.5%**
Overall	**3.7%**

Under the Company's proposal, the rate change that takes effect January 1, 2014, will result in no customer rate schedule class receiving an increase greater than 6.5 percent. The Company's proposed rate spread strikes a balance between moderating rate impacts on customers, while sending proper price signals about increasing costs and minimizing subsidization across rate schedule classes. As a result, the Company proposes revisions to the RMA to achieve these goals.

Q. Please describe the Rate Mitigation Adjustment.

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the functionalized revenue requirement on net rates across rate schedules. Net rates are the rates that customers pay once all tariff riders (including the RMA) are taken into account. The RMA is designed to be revenue neutral overall at the time a general rate case price change is implemented, resulting in RMA credits for some rate schedule classes requiring rate mitigation with offsetting RMA charges for others. The RMA was first implemented in docket UE 116 to transition to cost of service rates under SB 1149. The Schedule 299 RMA tariff rider is included in customers' rates for delivery services in order to minimize the effect of the price change allocation across customer classes.

Q. Besides mitigation of rate changes across rate schedules, what other factors contribute to the adjustment of the RMA in a general rate case?

A. In each general rate case, the RMA must be rebalanced in order to achieve revenue neutrality so that the revenues from the RMA charges and the RMA credits are in balance. The present Schedule 299 RMA rates were designed to be revenue neutral in the calendar year 2013 test period from the Company's last general rate case, docket UE 246 (2012 Rate Case); however, due to changes in rate schedule loads, present Schedule 299 RMA rates are not projected to produce revenue neutrality in the calendar year 2014 test period of this case. The present RMA rates result in RMA credits that exceed RMA charges by $0.2 million for the 2014 test period loads (see Exhibit PAC/1203, Table 1203-3, Column 5, Row 17). Consistent with prior RMA revisions, the proposed RMA rates have been designed to be revenue neutral for the 2014 test period. As a result of this realignment, the proposed net rate increase in this case is $0.2 million higher than the base revenue requirement increase (Exhibit PAC/1203, Table 1203-1 and Table 1203-2).

Q. Has the RMA required rebalancing in prior general rate cases?

A. Yes. For example, in the 2012 Rate Case the RMA required a rebalancing adjustment of $2.8 million.

Q. What are the present and proposed RMA revenues and rates in this case?

A. The present and proposed RMA revenues are shown in Exhibit PAC/1203, Table 1203-3, columns (5) and (6). Present and proposed RMA rates are shown in Exhibit PAC/1203, Table 1203-4, columns (5) through (10).

Q. What is the Company's RMA objective in this case?

A. The Company's RMA objective in this case is to minimize rate schedule subsidization through the RMA while minimizing impacts on customers. As a result, the Company has limited RMA charges and credits as much as possible. The Company proposes no increase to present RMA credit rates. In addition, the Company proposes to reduce RMA credit rates if the continuation of the present RMA credit rates would result in a percentage increase lower than the overall net percentage increase. As a result, the Company is proposing to reduce the RMA credit to Schedule 41/741, Agricultural Pumping Service by approximately $0.9 million in order to achieve a January 1 net rate impact for Schedule 41/741 equal to the overall net percentage increase of 3.7 percent.

For Large General Service Schedules 47/747 and 48/748, the Company proposes no change to the present RMA credit rates in order to minimize rate impacts to these customers. The proposed January 1 net increase for Schedules 47/747 and 48/748 is 6.5 percent. Eliminating or reducing the RMA credit rates would result in a larger increase for these schedules. With this proposal, Schedule 47/747 and 48/748 will continue to receive the largest RMA credit rates of any rate schedule class, ranging from 0.267 cents per kWh to 0.413 cents per kWh, depending on voltage level, and will produce over $10.1 million of annual credits to these rate schedules. Nonetheless, the Company believes the proposed RMA credits for Schedule 47/747 and 48/748 are reasonable in light of the overall percentage increase proposed for these customers.

Residential Schedule 4 and General Service Schedules 23/723, 28/728, and 30/730 will see a slight reduction in their RMA surcharge rates as a result of the decrease in the credit to Schedule 41/741. Lighting schedules continue to pay an RMA surcharge rate; however, the Company has reduced the RMA rate so the January 1 net increase for this rate class is capped at 6.5 percent, which is consistent with Schedules 48/748 and 47/747.

Overall, the Company believes that these proposals are fair and will minimize rate impacts while reducing subsidization through the RMA.

RATE DESIGN

Q. Please generally describe the process for designing rates to collect the proposed revenue requirement.

A. Proposed rates are designed to collect the target functionalized revenue requirement based on customer billing determinants including number of monthly bills, kilowatts, and kilowatt-hours consumed for the rate case test period. The billing determinants used in this case reflect the forecast test period for the 12 months ending December 2014.

Q. How are the forecast billing determinants developed?

A. Forecast test period billing determinants are developed based on the Company's forecast test period bills and energy forecasts along with the historical test period billing determinants.

A three-step process occurs in developing test period billing determinants. First, monthly forecast test period bills and energy by class and by rate schedule are prepared by the Company as described by Ms. Kelcey A. Brown.

Second, a full set of billing determinants, including all rate elements such as kW demand, load size, reactive power quantities and kilowatt-hours by rate block, are retrieved at the customer invoice level from the Company's billing system for the base period—in this case, the 12 months ended June 2012. These historical billing determinants are summarized by class, rate schedule, and voltage level.

Finally, a full set of forecast billing determinants is developed using the historical base period data and the test period forecast. The forecast billing determinants are calculated based upon the ratio of historical bills and energy (temperature normalized) in the base period to the forecast bills and energy provided in the sales forecast.

Q. Have you provided an exhibit showing proposed rates and the billing determinants used to design rates?

A. Yes. Exhibit PAC/1202, Steward/3-13, contains historical and forecast billing determinants along with present and proposed base rates.

Q. Please summarize the rate design changes proposed by the Company.

A. The basic structure of the Company's current tariffs, broken out into Delivery Service and Supply Service tariffs as first approved in docket UE 116, is proposed to remain in effect. In compliance with Order No. 12-500, the Company has included a new rate element—the System Usage Charge—to unbundle the franchise fee costs that would be avoided by a customer taking direct access. Additionally, the Company is proposing separate treatment for the collection of the Lake Side 2 generation investment.

Q. Please explain how the System Usage Charge was designed and how it will be applied to customers.

A. As previously noted, the System Usage Charge is calculated as a per kilowatt-hour rate to unbundle the portion of each rate schedule's allocation of the franchise and energy supplier taxes related to costs that customers taking direct access would not pay to the utility—specifically, net power costs and transmission and ancillary services. Previously, these costs were collected through the distribution rates of each rate schedule for all customers. Consistent with Order No. 12-500, the Company proposes that the System Usage Charge will not be applied to direct access service customers. However, direct access customers will continue to pay the portion of those fees attributed to distribution and non-net power cost generation components. Because the System Usage Charge will not apply to the direct access delivery service schedules, it has not been included in the proposed Direct Access Delivery Service rate schedules in this case. Effective January 1, 2014, when a customer takes service under a direct access delivery service schedule, the customer will pay only the portion of the franchise and energy supplier taxes attributable to direct access delivery service from the Company, as required by Order No. 12-500. The System Usage Charge has been added as a separate section to all cost based delivery service schedules proposed in this filing and included in Exhibit PAC/1201. All cost based delivery service customers will pay the System Usage Charge.

Q. Please explain the proposed tariffs for residential customers.

A. Residential customers are served on Delivery Service Schedule 4. For the Basic Charge, the Company proposes to increase the current Basic Charge by $1.00 per month. This results in a proposed Basic Charge of $10.00 per month. This change will better reflect the fixed costs of serving residential customers while, in conjunction with the proposed energy charges, keeping customer impacts in line with the overall rate change for smaller users. Even with this change the Company's Basic Charge will remain at or below the basic/minimum charges of more than half of 24 electric utilities surveyed by the Company in Oregon. The 24 utilities include the major investor-owned and municipally-owned utilities along with people's utility districts and electric cooperatives in Oregon.

For residential customers, as well as for all classes of customers, Schedule 200, Base Supply Service, is proposed to reflect changes in the non-net power cost generation revenue requirement as indicated in Exhibit PAC/1202, Steward/1-2. The Company proposes to keep the same rate blocks and ratio between the rates for each block as in the currently effective rates. The portfolio options (Schedules 210 through 213) do not require changes since they are adders to customers' Schedule 200 rates.

Q. Please explain the proposed tariffs for general service customers.

A. The proposed general service tariffs are Schedule 23/723 for small (less than 31 kW) nonresidential general service customers, Schedule 28/728 for general service customers between 31 and 200 kW, and Schedule 30/730 for general service customers over 200 kW but less than 1,000 kW. The Company automatically migrates these customers to the appropriate rate schedule once they meet its applicability criteria. The Company has proposed to modify base delivery and Schedule 200 Base Supply Service prices, at different voltage levels, to collect the target functionalized revenue requirement. For Schedule 30/730 the Company proposes to increase the Schedule 200 demand charges by $0.07 per kW, a percentage increase for that rate approximately equal to the overall base percentage increase for the rate schedule. This increase continues movement toward cost of service while minimizing rate impacts to customers.

Q. Please explain the proposed tariffs for irrigation customers.

A. In line with the changes for general service customers, Schedule 41/741, Agricultural Pumping Service rates have been modified to collect the target revenue requirement and to track functionalized costs.

Q. How has the Company treated Schedule 33 Klamath Basin Irrigation and Drainage Pumping customers in this general rate case?

A. In accordance with the law and with Order No. 06-172, as clarified in Order No. 06-440, the seven-year rate mitigation transition period for the Klamath Basin irrigation and drainage pumping customers served under the Company's Schedule 33 will conclude on April 16, 2013, before the test year for this case. At that time, these customers will be migrated to standard tariff, Schedule 41, Agricultural Pumping Service. Therefore, for the 2014 test year in this case, the Company has included Schedule 33 customers under standard irrigation tariff Schedule 41 for all rates, revenues and billing determinants.

Q. Please explain the proposed tariffs for large general service customers.

A. For Schedules 48/748, Large General Service, the Company has proposed to modify base prices, at different voltage levels, to collect the target functionalized revenue requirement. For partial requirements customers served on Schedule 47/747, most prices are linked to changes in Schedule 48/748 prices. Changes to Schedule 48/748 continue to flow through to Schedule 47/747. The Company proposes to maintain the current Schedule 48/748 rate structure, including an on-peak period demand charge only and the current on-peak/off-peak time of use energy charge differential. As with Schedule 30/730, the Company proposes to increase Schedule 47/747 and 48/748 Schedule 200 demand charges by $0.07 per kW, a percentage increase for that rate approximately equal to the overall base percentage increase for the rate schedule, to better reflect the cost of service while minimizing customer impacts.

Q. Please explain the proposed tariffs for lighting customers.

A. For lighting (Schedules 15, 50, 51/55/751, 52/752, 53/753, and 54/754) the proposed revisions are designed to collect the overall functionalized target revenue requirement.

GENERATION INVESTMENT ADJUSTMENT

Q. Please explain the proposed rate treatment of the Lake Side 2 generation investment in this general rate case.

A. As discussed in the testimony of Mr. Gary W. Tawwater, the Company proposes to place in rates the generation investment for the Lake Side 2 generating plant following a prudence review in this case and once the investment becomes used and useful. The in-service date is expected to occur in the second quarter of 2014. Exhibit PAC/1204 presents the proposed rate spread and rates for this adjustment along with an illustrative version of the Generation Investment Adjustment tariff. Following a prudence review in this case, the Company proposes to submit an advice filing in 2014 for approval of the proposed Generation Investment Adjustment tariff no less than 30 days before the in-service date of Lake Side 2.

Q. How are the proposed generation investment adjustment rates calculated?

A. The generation investment adjustment costs are allocated to customer classes based on the generation allocation factors from the cost of service study. The proposed tariff rider rates have been designed to collect these costs through energy charges.

Q. Why has the Company proposed separate treatment of the costs for this generation investment project?

A. As discussed by Mr. Richard P. Reiten, the Company has proposed this treatment for Lake Side 2 so the prudence of this project may be reviewed in this general rate case and the project may be properly reflected in rates in a timely manner once it becomes used and useful. This is consistent with the treatment of the Mona-to-Oquirrh transmission investment approved by the Commission in Order No. 12-493.

Q. Are the rates for the Generation Investment Adjustment tariff reflected in the proposed rate spread, rate design and rate impact Exhibits PAC/1202 and PAC/1203?

A. No. Since this investment is anticipated to become used and useful following the January 1, 2014 effective date of proposed rates in this case, the effects of this proposed adjustment are not included in the rate comparisons or rate impacts in these exhibits.

Q. What will be the rate change attributable to the Generation Investment Adjustment tariff proposed to become effective in May 2014?

A. As shown in Exhibit PAC/1204, the annualized effect of the Generation Investment Adjustment tariff is approximately $22.7 million, equal to an increase of approximately 1.8 percent.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 263
Exhibit PAC/1201
Witness: Joelle R. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Joelle R. Steward

Proposed Tariffs

March 2013

Available

In all territory served by the Company in the State of Oregon.

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements when all service is supplied at one point of delivery. Three-phase service will be supplied only when service is available from Company's presently existing facilities, or where such facilities can be installed under Company's Line Extension Rules, and, in any event, only when deliveries can be made by using one service for Consumer's single-phase and three-phase requirements.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge		
Basic Charge, per month	$10.00	(I)
Three Phase Demand Charge, per kW demand	$ 2.20	
Three Phase Minimum Demand Charge, per month	$ 3.80	
Distribution Energy Charge, per kWh	3.821¢	(R)
Transmission & Ancillary Services Charge		
Per kWh	0.372¢	(R)
System Usage Charge		(N)
Per kWh	0.077¢	(N)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 210, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

Special Conditions

Consumer shall so arrange his wiring as to make possible the separate metering of the three-phase demand at a location adjacent to the kWh meter. If, on November 25, 1975, any present Consumer's wiring was arranged only for combined single and three-phase demand measurement, and continues to be so arranged, such demands will be metered and billed hereunder except that the first 10 kW of such combined demand will be deducted before applying demand charges for three phase service. No new combined demand installations will be allowed such a demand deduction.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from minimum monthly charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

SEPARATELY METERED ELECTRIC VEHICLE SERVICE FOR RESIDENTIAL CONSUMERS
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements supplied to electric vehicle charging installations where such service is supplied at a point of delivery separately metered from other residential service. Three-phase service will be supplied only when service is available from Company's presently existing facilities.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge		
Basic Charge, per month	$10.00	(I)
Three Phase Demand Charge, per kW demand	$2.20	
Three Phase Minimum Demand Charge, per month	$3.80	
Distribution Energy Charge, per kWh	3.821¢	(R)
Transmission & Ancillary Services Charge		
Per kWh	0.372¢	(R)
System Usage Charge		(N)
Per kWh	0.077¢	(N)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 210, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from minimum monthly charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Consumers for outdoor area lighting service furnished from dusk to dawn by means of presently-installed Company-owned mercury vapor or high-pressure sodium luminaires which may be served by secondary voltage circuits from the Company's existing overhead distribution system. Luminaires shall be mounted on Company-owned wood poles and served in accordance with the Company's specifications as to equipment and installation.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Type of Luminaire	Nominal Rating	Monthly kWh	Rate Per Luminaire	
Mercury Vapor	7,000	76	$6.52	(I)
Mercury Vapor	21,000	172	$11.73	(I)
Mercury Vapor	55,000	412	$23.19	(I)
High Pressure Sodium	5,800	31	$9.09	(I)
High Pressure Sodium	22,000	85	$12.36	(I)
High Pressure Sodium	50,000	176	$19.05	(I)

Pole Charge

A monthly charge of $1.00 per pole shall be made for each additional pole required in excess of the number of luminaires installed.

Supply Service Option

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Supply Service shall be provided by Supply Service Schedule 201.

Special Conditions

1. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.

2. The Company reserves the right to contract for the maintenance of lighting service provided hereunder.

3. Temporary disconnection and subsequent reconnection of electrical service requested by the Consumer shall be at the Consumer's expense. The Consumer may request temporary suspension of power for lighting by written notice. During such periods, the monthly rate will be reduced by the Company's estimated average monthly relamping and energy costs for the luminaire. The facilities may be considered idle and may be removed after 12 months of inactivity. The Company will not be required to reestablish such service under this rate schedule if service has been permanently discontinued by the Consumer.

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers whose entire electric service requirements are supplied hereunder and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
Distribution Charge	**Secondary**	**Primary**	
Basic Charge			
Single Charge, per month	$18.45	$18.45	(I)
Three Phase, per month	$27.60	$27.60	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW Load Size	$1.30	$1.30	(I)
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$4.29	$4.17	(I)
Distribution Energy Charge, per kWh	2.699¢	2.623¢	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.365¢	0.355¢	(I)
System Usage Charge			(N)
Per kWh	0.075¢	0.073¢	(N)

kW Load Size

For determination of the Basic Charge and Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

(continued)

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW to 200 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

	Delivery Voltage Secondary	Delivery Voltage Primary	
Distribution Charge			
Basic Charge			
Load Size ≤50 kW, per month	$ 20.00	$ 26.00	(I)
Load Size 51-100 kW, per month	$ 36.00	$ 44.00	(R),(I)
Load Size 101 - 300 kW, per month	$ 86.00	$ 104.00	(R),(I)
Load Size > 300 kW, per month	$123.00	$ 150.00	(R),(I)
Load Size Charge			
≤50 kW, per kW Load Size	$ 1.25	$ 1.45	(I)
51 - 100 kW, per kW Load Size	$ 1.00	$ 1.20	(I)
101 – 300 kW, per kW Load Size	$ 0.60	$ 0.70	(I)
> 300 kW, per kW Load Size	$ 0.40	$ 0.40	(I)
Demand Charge, per kW	$ 4.25	$ 5.08	(R),(I)
Distribution Energy Charge, per kWh	0.407¢	0.083¢	(R),(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kW	$ 1.10	$ 0.89	(R)
System Usage Charge			(N)
Per kWh	0.078¢	0.072¢	(N)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage** Secondary	Primary	
Basic Charge			
Load Size ≤200 kW, per month	$529.00	$514.00	(I)
Load Size 201 - 300 kW, per month	$159.00	$164.00	(I)
Load Size > 300 kW, per month	$417.00	$424.00	(I)
Load Size Charge			
≤200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$1.85	$1.75	(I)
> 300 kW, per kW Load Size	$0.90	$0.90	(I)
Demand Charge, per kW	$4.75	$4.74	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kW	$1.26	$1.21	(I)
System Usage Charge			(N)
Per kWh	0.073¢	0.071¢	(N)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 47 or 48. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the monthly billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$310.00	$300.00	(R)
Three Phase Load Size > 300 kW	$1,220.00	$1,190.00	(R)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$15.00	$15.00	
Three Phase 51 - 300 kW, per kW Load Size	$10.00	$10.00	
Three Phase > 300 kW, per kW Load Size	$6.00	$6.00	
Single Phase, Minimum Charge	$55.00	$55.00	
Three Phase, Minimum Charge	$95.00	$90.00	
Distribution Energy Charge, per kWh	3.579¢	3.478¢	(R)
Reactive Power Charge, per kVar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.286¢	0.278¢	(R)
System Usage Charge			(N)
Per kWh	0.074¢	0.072¢	(N)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of the Company's meter, or by appropriate test, for the 15-minute period of the Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 747, Direct Access Delivery Service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$490.00	$560.00	$990.00	(I)
Facility Capacity > 4,000 kW, per month	$920.00	$1,000.00	$1,830.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$1.05	$0.55	$0.80	(R)
> 4,000 kW, per kW Facility Capacity	$1.00	$0.50	$0.80	(R)
On-Peak Demand Charge, per kW	$4.88	$5.24	$4.99	(I)
Reactive Power Charges				
Per kvar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Reserves Charges				
Spinning Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company approved Self-Supply Agreement)				
Per kW of Spinning Reserves Level	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved Load Reduction Plan or Self-Supply Agreement)				
Per kW of Supplemental Reserves Level	($0.27)	($0.27)	($0.27)	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$0.78	$0.89	$1.18	(I),(I),(R)
System Usage Charge				(N)
Per kWh	0.073¢	0.069¢	0.064¢	(N)

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until the Consumer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 47.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**			
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$490.00	$560.00	$ 990.00	(I)
Facility Capacity > 4,000 kW, per month	$920.00	$1,000.00	$1,830.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$1.05	$0.55	$0.80	(R)
> 4,000 kW, per kW Facility Capacity	$1.00	$0.50	$0.80	(R)
On-Peak Demand Charge, per kW	$4.88	$5.24	$4.99	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$1.32	$1.43	$1.72	(I),(I),(R)
System Usage Charge				(N)
Per kWh	0.073¢	0.069¢	0.064¢	(N)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

(continued)

MERCURY VAPOR STREET LIGHTING SERVICE
NO NEW SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

To service furnished from dusk to dawn for the lighting of public streets, highways, alleys and parks by means of presently-installed mercury vapor lights. Street lights will be served by either series or multiple circuits as the Company may determine. The type and kind of fixtures and supports will be in accordance with the Company's specifications. Service includes installation, maintenance, energy, lamp and glassware renewals.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

A. Company-owned Overhead System

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
Horizontal, per lamp	$6.10	$10.58	$20.53	(I)
Vertical, per lamp	$5.61	$9.71		

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$8.35		
On 26-foot poles, vertical, per lamp	$7.80		
On 30-foot poles, horizontal , per lamp		$13.23	
On 30-foot poles, vertical, per lamp		$12.36	
On 33-foot poles, horizontal , per lamp			$23.15

B. Company-owned Underground System

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$8.35			
On 26-foot poles, vertical, per lamp	$7.80			
On 30-foot poles, horizontal , per lamp		$12.67		
On 30-foot poles, vertical, per lamp		$11.87		
On 33-foot poles, horizontal , per lamp			$22.59	(I)
plus rate per foot of underground cable:				
In paved area	$0.05	$0.05	$0.05	
in unpaved area	$0.03	$0.03	$0.03	

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor							
Lumen Rating	5,800*	9,500	16,000	22,000*	27,500	50,000	
Watts	70	100	150	200	250	400	
Monthly kWh	31	44	64	85	115	176	
Functional Lighting	$ 5.46	$ 6.08	$ 7.39	$ 8.67	$ 11.18	$ 13.70	(I)
Decorative - Series 1	N/A	$ 20.56	$ 20.51	N/A	N/A	N/A	(I)
Decorative - Series 2	N/A	$ 17.64	$ 17.54	N/A	N/A	N/A	(I)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	
Watts	100	175	250	400	
Monthly kWh	39	68	94	149	
Functional Lighting	N/A	$ 14.37	$ 16.14	$ 15.60	(I)
Decorative - Series 1	$ 20.68	$ 22.08	N/A	N/A	(I)
Decorative - Series 2	$ 19.04	$ 19.08	N/A	N/A	(I)

*Existing fixtures only. Service is not available under this schedule to new 5,800 or 22,000 lumen High Pressure Sodium Vapor fixtures or to Metal Halide fixtures of any size.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 751, Direct Access Delivery Service.

(continued)

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

To service furnished by means of the Company-owned installations, for the lighting of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. The Company may not be required to furnish service hereunder to other than municipal Consumers. This schedule is closed to new service beginning November 8, 2006.

Monthly Billing

The Monthly Billing shall be the Rate Per kWh below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

A flat rate equal to one-twelfth of the Company's estimated annual cost for operation, maintenance, fixed charges and depreciation applicable to the street lighting system, including Distribution Charge as follows:

For dusk to dawn operation, per kWh	2.200¢	(I)
For dusk to midnight operation, per kWh	2.614¢	(I)

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 752, Direct Access Delivery Service.

Term of Contract

Not less than five years for service to an overhead, or ten years to an underground, Company-owned system by written contract when unusual conditions prevail.

Provisions

1. Installation, daily operation, repair and maintenance of lights on this rate schedule will be performed by the Company, providing that the facilities furnished remain readily accessible for maintenance purposes.
2. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.
3. Existing fixtures and facilities that are deemed irreparable will be replaced with comparable fixtures and facilities from the Company's Construction Standards.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor							
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000	
Watts	70	100	150	200	250	400	
Monthly kWh	31	44	64	85	115	176	
Energy Only Service	$ 1.36	$ 1.93	$ 2.81	$ 3.73	$ 5.05	$ 7.73	(I)

Metal Halide – No New Service						
Lumen Rating	9,000*	12,000*	19,500*	32,000*	107,800*	
Watts	100	175	250	400	1,000	
Monthly kWh	39	68	94	149	354	
Energy Only Service	$ 1.71	$ 2.99	$ 4.13	$ 6.54	$ 15.55	(I)

*Existing fixtures only. Service is not available under this Schedule to new Metal Halide fixtures of any size.

For non-listed luminaires the cost will be calculated for 3940 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh	
Energy Only Service	4.392	(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At the Consumer's option, service for recreational field lighting may be taken under the Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge		
Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.360¢	(I)
Transmission & Ancillary Services Charge		
per kWh	0.061¢	(I)
System Usage Charge		(N)
per kWh	0.049¢	(N)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 754, Direct Access Delivery Service.

Special Conditions

The Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control.

Monthly Billing

The Monthly Billing shall be the sum of the rates per luminaire as specified in the rate tables below plus the applicable rate for Schedule 51 shown in Schedule 80 and all adjustments that are applicable for Schedule 51 as specified in Schedule 90.

Light-Emitting Diode (LED)		
Compares to HPSV lamp size of (Watts)	100	150
Monthly kWh	29	41
LED Luminaire Rate	$ 5.18	$ 7.23

(I)

Supply Service Option:

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Supply Service shall be provided by Supply Service Schedule 201.

Provisions

1. Installation, daily operation, repair and maintenance of lights on this rate schedule will be performed by the Company, providing that the facilities furnished remain readily accessible for maintenance purposes.
2. Company will install only Company approved street lighting equipment at locations acceptable to Company.
3. Where provided by this tariff, and following notification by the Consumer, inoperable lights will be repaired as soon as possible, during regular business hours or as allowed by Company's operating schedule and requirements.
4. Existing fixtures and facilities that are deemed irreparable will be replaced with comparable fixtures and facilities from the Company's Construction Standards.

(continued)

Purpose

To provide Consumers served on Schedule 47 with the opportunity of purchasing Energy from the Company to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement power except as explicitly agreed to between Company and Consumer.

Applicable

To Large Nonresidential Consumers receiving Delivery Service under Schedule 47.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 47 plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90:

	Delivery Voltage			
	Secondary	**Primary**	**Transmission**	
Transmission & Ancillary Services Charge				
Per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.030	$0.035	$0.046	(I),(R)
Daily ERP Demand Charge				
Per kW of Daily ERP On-Peak Demand	$0.190	$0.204	$0.194	(I)

Supply Service

A Consumer taking Delivery Service under this Schedule shall be served under the terms of Supply Service Schedule 276R.

ERP and ENF

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Power Agreement (ERPA). ERP, ENF and ERPA are more fully described in Schedule 276R.

Daily ERP On-Peak Demand

Daily ERP On-Peak Demand shall not be less than the maximum ERP On-Peak Demand scheduled per day and shall not be greater than the difference between the Facility Capacity and the Baseline Demand. Daily ERP On-Peak Demand will be billed for each day in the month that the Company supplies ERP to the Consumer.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Residential Consumers and Nonresidential Consumers. This service may be taken only in conjunction with the applicable Delivery Service Schedule or Direct Access Delivery Service Schedule. Not applicable to energy usage under Delivery Service Schedule 76 which is billed at Economic Replacement Power rates under Schedule 276 or energy usage under Delivery Service Schedule 47 which is billed at Unscheduled Energy rates under Schedule 247.

Monthly Billing

The Monthly Billing shall be the Energy Charge and/or Demand Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage** Secondary	Primary	Transmission	
4	Per kWh	0 – 1000 kWh	2.784¢			(I)
		> 1000 kWh	3.802¢			(I)
5	Per kWh	0 – 1000 kWh	2.784¢			(I)
		> 1000 kWh	3.802¢			(I)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

Schedule		Secondary	Primary	Transmission	
23, 723	First 3,000 kWh, per kWh	3.218¢	3.127¢		(I)
	All additional kWh, per kWh	2.388¢	2.321¢		(I)
28, 728	First 20,000 kWh, per kWh	3.061¢	2.920¢		(I)
	All additional kWh, per kWh	2.980¢	2.841¢		(I)
30, 730	Demand Charge, per kW	$1.35	$1.35		(I)
	First 20,000 kWh, per kWh	2.951¢	2.880¢		(I)
	All additional kWh, per kWh	2.559¢	2.489¢		(I)

Demand shall be as defined in the Delivery Service Schedule

Schedule		Secondary	Primary	Transmission	
41, 741	Winter, first 100 kWh/kW, per kWh	4.205¢	4.086¢		(I)
	Winter, all additional kWh, per kWh	2.866¢	2.785¢		(I)
	Summer, all kWh, per kWh	2.866¢	2.785¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission	
47/48, 747/748	Demand Charge, per kW of On-Peak Demand	$1.24	$1.25	$1.26	(I)
	Per kWh, On-Peak	2.682¢	2.609¢	2.493¢	(I)
	Per kWh, Off-Peak	2.632¢	2.559¢	2.443¢	(I)

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

On-Peak Demand shall be as defined in the Delivery Service Schedule.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

52, 752	For dusk to dawn operation, per kWh	2.455¢	(I)
	For dusk to midnight operation, per kWh	2.455¢	(I)
54, 754	Per kWh	1.803¢	(I)

15	**Type of Luminaire**	**Nominal Rating**	**Monthly kWh**	**Rate Per Luminaire**	
	Mercury Vapor	7,000	76	$1.71	(I)
	Mercury Vapor	21,000	172	$3.87	(I)
	Mercury Vapor	55,000	412	$9.27	(I)
	High Pressure Sodium	5,800	31	$0.70	(I)
	High Pressure Sodium	22,000	85	$1.91	(I)
	High Pressure Sodium	50,000	176	$3.96	(I)

50 **A. Company-owned Overhead System**

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
Horizontal, per lamp	$1.54	$3.49	$8.36	(I)
Vertical, per lamp	$1.54	$3.49		(I)

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.54			(I)
On 26-foot poles, vertical, per lamp	$1.54			(I)
On 30-foot poles, horizontal, per lamp		$3.49		(I)
On 30-foot poles, vertical, per lamp		$3.49		(I)
On 33-foot poles, horizontal, per lamp			$8.36	(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.54			(I)
On 26-foot poles, vertical, per lamp	$1.54			(I)
On 30-foot poles, horizontal, per lamp		$3.49		(I)
On 30-foot poles, vertical, per lamp		$3.49		(I)
On 33-foot poles, horizontal, per lamp			$8.36	(I)

51, 751

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
High Pressure Sodium	5,800	70	31	$0.99	(I)
High Pressure Sodium	9,500	100	44	$1.41	
High Pressure Sodium	16,000	150	64	$2.05	
High Pressure Sodium	22,000	200	85	$2.72	
High Pressure Sodium	27,500	250	115	$3.68	
High Pressure Sodium	50,000	400	176	$5.64	
Metal Halide	9,000	100	39	$1.25	
Metal Halide	12,000	175	68	$2.18	
Metal Halide	19,500	250	94	$3.01	
Metal Halide	32,000	400	149	$4.77	(I)

53, 753

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
High Pressure Sodium	5,800	70	31	$0.32	(I)
High Pressure Sodium	9,500	100	44	$0.46	
High Pressure Sodium	16,000	150	64	$0.67	
High Pressure Sodium	22,000	200	85	$0.89	
High Pressure Sodium	27,500	250	115	$1.21	
High Pressure Sodium	50,000	400	176	$1.84	
Metal Halide	9,000	100	39	$0.41	
Metal Halide	12,000	175	68	$0.71	
Metal Halide	19,500	250	94	$0.99	
Metal Halide	32,000	400	149	$1.56	
Metal Halide	107,800	1,000	354	$3.71	(I)

Non-Listed Luminaire, per kWh 1.048¢ (I)

55

Types of Luminaire	**Compares to HPSV Lamp Size of (Watts)**	**Monthly kWh**	**Rate Per Luminaire**	
Light Emitting Diode	100	29	$0.93	(I)
Light Emitting Diode	150	41	$1.31	(I)

OREGON
SCHEDULE 299

RATE MITIGATION ADJUSTMENT

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No. 36 shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt hour.

	Secondary	Primary	Transmission	
Schedule 4	0.052¢			(C)
Schedule 5	0.052¢			
Schedule 15	2.193¢			
Schedule 23, 723	0.411¢	0.411¢		
Schedule 28, 728	0.108¢	0.108¢		
Schedule 30, 730	0.033¢	0.033¢		
Schedule 41, 741	(0.221¢)	(0.221¢)		(C)
Schedule 47, 747	(0.267¢)	(0.334¢)	(0.413¢)	
Schedule 48, 748	(0.267¢)	(0.334¢)	(0.413¢)	
Schedule 50	2.052¢			(C)
Schedule 51, 751	3.404¢			
Schedule 52, 752	2.008¢			
Schedule 53, 753	1.155¢			
Schedule 54, 754	1.482¢			(C)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers who have chosen to receive electricity from an ESS, and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Single Phase, per month	$18.45	$18.45	(I)
Three Phase, per month	$27.60	$27.60	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW, Load Size	$ 1.30	$ 1.30	(I)
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$ 4.29	$ 4.17	(I)
Distribution Energy Charge, per kWh	2.699¢	2.623¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage** Secondary	Primary	
Basic Charge			
Load Size ≤ 50 kW, per month	$ 20.00	$ 26.00	(I)
Load Size 51-100 kW, per month	$ 36.00	$ 44.00	(R),(I)
Load Size 101 - 300 kW, per month	$ 86.00	$104.00	(R),(I)
Load Size > 300 kW, per month	$123.00	$150.00	(R),(I)
Load Size Charge			
≤ 50 kW, per kW Load Size	$ 1.25	$ 1.45	(I)
51-100 kW, per kW Load Size	$ 1.00	$ 1.20	(I)
101 – 300 kW, per kW Load Size	$ 0.60	$ 0.70	(I)
> 300 kW, per kW Load Size	$ 0.40	$ 0.40	(I)
Demand Charge, per kW	$ 4.25	$ 5.08	(R),(I)
Distribution Energy Charge, per kWh	0.407¢	0.083¢	(R),(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 200 kW, per month	$529.00	$514.00	(I)
Load Size 201 - 300 kW, per month	$159.00	$164.00	(I)
Load Size > 300 kW, per month	$417.00	$424.00	(I)
Load Size Charge			
≤ 200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 1.85	$ 1.75	(I)
> 300 kW, per kW Load Size	$ 0.90	$ 0.90	(I)
Demand Charge, per kW	$ 4.75	$ 4.74	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW, but not less than 100 kW.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers who have chosen to receive electricity from an ESS and desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the Monthly Billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge	Delivery Voltage		
Basic Charge (November billing only)	**Secondary**	**Primary**	
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$ 310.00	$ 300.00	(R)
Three Phase Load Size > 300 kW	$1,220.00	$1,190.00	(R)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$ 15.00	$ 15.00	
Three Phase 51 - 300 kW, per kW Load Size	$ 10.00	$ 10.00	
Three Phase > 300 kW, per kW Load Size	$ 6.00	$ 6.00	
Single Phase, Minimum Charge	$ 55.00	$ 55.00	
Three Phase, Minimum Charge	$ 95.00	$ 90.00	
Distribution Energy Charge, per kWh	3.579¢	3.478¢	(R)
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of Company's meter, or by appropriate test, for the 15-minute period of Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

If Motor Size Is:	Monthly kW is:
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Reserves Charges plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$490.00	$560.00	$990.00	(I)
Facility Capacity > 4,000 kW, per month	$920.00	$1,000.00	$1,830.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$1.05	$0.55	$0.80	(R)
> 4,000 kW, per kW Facility Capacity	$1.00	$0.50	$0.80	(R)
On-Peak Demand Charge, per kW	$4.88	$5.24	$4.99	(I)
Reactive Power Charges				
Per kVar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Reserves Charges				
Spinning Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company-approved Self-Supply Agreement)				
per kW of Self-Supplied Spinning Reserves	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved load reduction plan or Self-Supply Agreement)				
per kW of approved load reduction kW	($0.27)	($0.27)	($0.27)	

(continued)

LARGE GENERAL SERVICE 1,000 KW AND OVER DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS, to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 747.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

Distribution Charge		**Delivery Voltage**		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$490.00	$560.00	$990.00	(I)
Facility Capacity > 4000 kW, per month	$920.00	$1,000.00	$1,830.00	(I)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$1.05	$0.55	$0.80	(R)
> 4000 kW, per kW Facility Capacity	$1.00	$0.50	$0.80	(R)
On-Peak Demand Charge, per kW	$4.88	$5.24	$4.99	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor							
Lumen Rating	5,800*	9,500	16,000	22,000*	27,500	50,000	
Watts	70	100	150	200	250	400	
Monthly kWh	31	44	64	85	115	176	
Functional Lighting	$ 5.42	$ 6.03	$ 7.32	$ 8.58	$ 11.05	$ 13.50	(I)
Decorative - Series 1	N/A	$ 20.51	$ 20.44	N/A	N/A	N/A	(I)
Decorative - Series 2	N/A	$ 17.59	$ 17.47	N/A	N/A	N/A	(I)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	
Watts	100	175	250	400	
Monthly kWh	39	68	94	149	
Functional Lighting	N/A	$ 14.30	$ 16.03	$ 15.44	(I)
Decorative - Series 1	$ 20.64	$ 22.01	N/A	N/A	(I)
Decorative - Series 2	$ 19.00	$ 19.01	N/A	N/A	(I)

*Existing fixtures only. Service is not available under this schedule to new 5,800 or 22,000 lumen High Pressure Sodium Vapor fixtures or Metal Halide fixtures of any size.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this Schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

(continued)

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To service furnished by means of Company-owned installations, for the lighting of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. Company may not be required to furnish service hereunder to other than municipal Consumers. This schedule is closed to new service beginning November 8, 2006.

Monthly Billing

For systems owned, operated and maintained by Company. The Monthly Billing shall be the Rate Per kWh below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

A flat rate equal to one-twelfth of Company's estimated annual cost for operation, maintenance, fixed charges and depreciation applicable to the street lighting system, including energy costs as follows:

For dusk to dawn operation, per kWh	2.090¢	(I)
For dusk to midnight operation, per kWh	2.504¢	(I)

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Term of Contract

Not less than five years for service to an overhead, or ten years to an underground, Company-owned system by written contract when unusual conditions prevail.

Suspension of Service

The Consumer may request temporary suspension of power for lighting by written notice. During such periods, the monthly rate will be reduced by Company's estimated average monthly relamping and energy costs for the luminaire. Company will not be required to reestablish such service under this rate schedule if service has been permanently discontinued by Consumer.

Termination of Service

Service furnished hereunder by means of incandescent and mercury-vapor lights is subject to termination by not less than sixty (60) days written notice given by Company to Consumer.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.33	$ 1.88	$ 2.74	$ 3.64	$ 4.92	$ 7.54

(I)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	107,800*
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.67	$ 2.91	$ 4.03	$ 6.38	$ 15.16

(I)

*Existing fixtures only. Service is not available under this schedule to new Metal Halide fixtures of any size.

For non-listed luminaires the cost will be calculated for 3940 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.282

(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At Consumer's option, service for recreational field lighting may be taken under Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

<u>**Distribution Charge**</u>

Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.360¢	(I)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Special Conditions

Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery. Company will supply one transformer, or transformer bank, for each athletic or recreational field; any additional transformers required shall be supplied and owned by Consumer. All transformers owned by Consumer must be properly fused and of such types and characteristics as conform to Company's standards. When service is supplied to more than one transformer or transformer bank, Company may meter such an installation at primary voltage.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

LARGE GENERAL SERVICE - PARTIAL REQUIREMENTS
SERVICE-ECONOMIC REPLACEMENT SERVICE RIDER
DIRECT ACCESS DELIVERY SERVICE

Purpose

To provide Consumers served on Schedule 747 with the opportunity of purchasing Energy from an ESS to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement service except as explicitly agreed to between Company and Consumer.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers receiving Delivery Service under Schedule 747.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 747 plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90:

		Delivery Voltage		
	Secondary	Primary	Transmission	
Daily ERS Demand Charge				
per kW of Daily ERS On-Peak Demand	$0.190	$0.204	$0.194	(I)

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

ERS and ENF

Economic Replacement Service (ERS) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Service Agreement (ERSA).

(continued)

Docket No. UE 263
Exhibit PAC/1202
Witness: Joelle R. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Joelle R. Steward

Target functionalized Revenues and Billing Determinants

March 2013

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenue
Forecast 12 Months Ended December 31, 2014

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 4, Residential					
	Transmission & Ancillary Services[1]	$20,335	$20,000	$20,000	$20,012
	System Usage[2]		$4,149	$4,149	$4,142
	Distribution	$258,310	$263,862	$263,862	$263,868
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$150,780	$164,052	$164,052	$164,048
	Generation Energy - Net Power Costs (Sch 201)	$153,561	$151,532	$153,561	$153,561
	Total	$582,985	$603,595	$605,623	$605,631
Schedule 23, Small General Service					
	Transmission & Ancillary Services[1]	$3,974	$4,023	$4,023	$4,018
	System Usage[2]		$827	$827	$826
	Distribution	$49,749	$51,195	$51,195	$51,203
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$29,852	$33,387	$33,387	$33,390
	Generation Energy - Net Power Costs (Sch 201)	$30,398	$30,839	$30,398	$30,398
	Total	$113,973	$120,271	$119,830	$119,836
Schedule 28, General Service 31-200kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$7,401	$7,250	$7,250	$7,269
	System Usage[2]		$1,536	$1,536	$1,540
	Distribution	$49,364	$48,513	$48,513	$48,480
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$55,601	$59,969	$59,969	$59,969
	Generation Energy - Net Power Costs (Sch 201)	$56,624	$55,393	$56,624	$56,624
	Total	$168,990	$172,660	$173,892	$173,882
Primary Voltage					
	Transmission & Ancillary Services[1]	$69	$61	$61	$61
	System Usage[2]		$13	$13	$13
	Distribution	$470	$506	$506	$506
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$502	$535	$535	$535
	Generation Energy - Net Power Costs (Sch 201)	$511	$494	$511	$511
	Total	$1,552	$1,610	$1,627	$1,627
Schedule 30, General Service 201-999kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$4,238	$4,309	$4,309	$4,306
	System Usage[2]		$908	$908	$910
	Distribution	$22,408	$23,881	$23,881	$23,816
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$33,594	$37,146	$37,146	$37,209
	Generation Energy - Net Power Costs (Sch 201)	$34,187	$34,311	$34,187	$34,187
	Total	$94,427	$100,556	$100,431	$100,429
Primary Voltage					
	Transmission & Ancillary Services[1]	$307	$321	$321	$321
	System Usage[2]		$65	$65	$65
	Distribution	$1,616	$1,789	$1,789	$1,791
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$2,425	$2,688	$2,688	$2,685
	Generation Energy - Net Power Costs (Sch 201)	$2,477	$2,483	$2,477	$2,477
	Total	$6,825	$7,346	$7,340	$7,340
Schedule 41, Agricultural Pumping Service					
	Transmission & Ancillary Services[1]	$678	$661	$661	$662
	System Usage[2]		$171	$171	$171
	Distribution	$11,957	$11,650	$11,650	$11,647
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$6,305	$6,670	$6,670	$6,670
	Generation Energy - Net Power Costs (Sch 201)	$6,421	$6,161	$6,421	$6,421
	Total	$25,361	$25,312	$25,572	$25,571

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenue
Forecast 12 Months Ended December 31, 2014

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$1,997	$2,022	$2,022	$2,028
	System Usage[2]		$419	$419	$420
	Distribution	$9,885	$10,326	$10,326	$10,315
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$15,363	$17,244	$17,244	$17,244
	Generation Energy - Net Power Costs (Sch 201)	$15,615	$15,928	$15,615	$15,615
	Total	$42,861	$45,938	$45,626	$45,623
Primary Voltage					
	Transmission & Ancillary Services[1]	$4,796	$5,051	$5,051	$5,043
	System Usage[2]		$1,048	$1,048	$1,055
	Distribution	$19,794	$21,832	$21,832	$21,890
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$38,878	$44,071	$44,071	$44,019
	Generation Energy - Net Power Costs (Sch 201)	$39,611	$40,708	$39,611	$39,611
	Total	$103,079	$112,709	$111,613	$111,618
Transmission Voltage					
	Transmission & Ancillary Services[1]	$2,275	$2,210	$2,210	$2,211
	System Usage[2]		$529	$529	$531
	Distribution	$7,475	$7,679	$7,679	$7,682
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$19,667	$22,138	$22,138	$22,130
	Generation Energy - Net Power Costs (Sch 201)	$19,980	$20,448	$19,980	$19,980
	Total	$49,397	$53,004	$52,535	$52,534
Schedules 51, 53, 54, Lighting[3]					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$14	$13	$13	$14
	System Usage[2]		$11	$11	$10
	Distribution	$1,654	$1,834	$1,834	$1,833
	Other Adjustments	$0	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$439	$483	$483	$483
	Generation Energy - Net Power Costs (Sch 201)	$448	$446	$448	$448
	Total	$2,555	$2,786	$2,788	$2,789
TOTAL		**$1,192,004**	**$1,245,787**	**$1,246,878**	**$1,246,878**
Additional Rate Schedules					
	Schedule 47	$11,332		$12,134	$12,134
	Lighting 15, 50, 51[3], 52	$3,402		$3,712	$3,712
Total Oregon		**$1,206,738**		**$1,262,725**	**$1,262,725**
			Revenue Increase	**$55,987**	**$55,987**

[1]Includes only FERC transmission plus ancillary services revenues. Non-FERC transmission revenues are recovered through distribution charges.
[2]Includes the portion of Franchise & Energy Supplier Taxes which are associated with rates not paid by Direct Access consumers. The remainder of these fees are recovered through distribution charges.
[3]Cost of Service study includes only certain lamp types under Schedule 51.

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2012
Forecast 12 Months Ended December 31, 2014

Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,473,577,108	5,408,535,590	5,379,568,669	kWh	0.378 ¢	$20,334,770	0.372 ¢	$20,011,995
System Usage Charge								
per kWh	5,473,577,108	5,408,535,590	5,379,568,669	kWh			0.077 ¢	$4,142,268
Distribution Charge								
Basic Charge, per month	5,690,777	5,690,777	5,827,029	bill	$9.00	$52,443,260	$10.00	$58,270,289
Three Phase Demand Charge, per kW demand	17,530	17,530	17,436	kW	$2.20	$38,359	$2.20	$38,359
Three Phase Minimum Demand Charge, per month	1,506	1,506	1,542	bill	$3.80	$5,860	$3.80	$5,860
Distribution Energy Charge, per kWh	5,473,577,108	5,408,535,590	5,379,568,669	kWh	3.826 ¢	$205,822,297	3.821 ¢	$205,553,319
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	4,046,215,827	3,998,134,827	3,976,721,700	kWh	2.559 ¢	$101,764,308	2.784 ¢	$110,711,932
Second Block kWh (> 1,000)	1,427,361,281	1,410,400,763	1,402,846,969	kWh	3.494 ¢	$49,015,473	3.802 ¢	$53,336,242
Subtotal	5,473,577,108	5,408,535,590	5,379,568,669	kWh		$429,424,327		$452,070,264
Schedule 201								
First Block kWh (0-1,000)	4,046,215,827	3,998,134,827	3,976,721,700	kWh	2.606 ¢	$103,633,368	2.606 ¢	$103,633,368
Second Block kWh (> 1,000)	1,427,361,281	1,410,400,763	1,402,846,969	kWh	3.559 ¢	$49,927,324	3.559 ¢	$49,927,324
Total	5,473,577,108	5,408,535,590	5,379,568,669	kWh		$582,985,019		$605,630,956
							Change	$22,645,937
Schedule No. 23/723 - Composite								
General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,128,657,655	1,123,360,093	1,099,810,037	kWh	0.361 ¢	$3,970,314	0.365 ¢	$4,014,307
System Usage Charge								
per kWh	1,128,657,655	1,123,360,093	1,099,810,037	kWh			0.075 ¢	$824,858
Distribution Charge								
Basic Charge								
Single Phase, per month	709,691	709,691	682,389	bill	$17.95	$12,248,883	$18.45	$12,590,077
Three Phase, per month	211,594	211,594	203,734	bill	$26.80	$5,460,071	$27.60	$5,623,058
Load Size Charge								
≤ 15 kW				kW	No Charge		No Charge	
per kW for all kW in excess of 15 kW	920,009	920,009	901,120	kW	$1.25	$1,126,400	$1.30	$1,171,456
Demand Charge, the first 15 kW of demand				kW	No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	483,146	483,146	473,196	kW	$4.17	$1,973,227	$4.29	$2,030,011
Reactive Power Charge, per kvar	88,406	88,406	86,927	kvar	65.00 ¢	$56,503	65.00 ¢	$56,503
Distribution Energy Charge, per kWh	1,128,657,655	1,123,360,093	1,099,810,037	kWh	2.622 ¢	$28,837,019	2.699 ¢	$29,683,873
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	877,038,849	872,921,849	854,629,409	kWh	2.877 ¢	$24,587,688	3.218 ¢	$27,501,974
All additional kWh, per kWh	251,618,806	250,438,244	245,180,628	kWh	2.135 ¢	$5,234,606	2.388 ¢	$5,854,913
Subtotal	1,128,657,655	1,123,360,093	1,099,810,037	kWh		$83,494,711		$89,351,030
Schedule 201								
1st 3,000 kWh, per kWh	877,038,849	872,921,849	854,629,409	kWh	2.930 ¢	$25,040,642	2.930 ¢	$25,040,642
All additional kWh, per kWh	251,618,806	250,438,244	245,180,628	kWh	2.173 ¢	$5,327,775	2.173 ¢	$5,327,775
Total	1,128,657,655	1,123,360,093	1,099,810,037	kWh	0.000 0	$113,863,128		$119,719,447
							Change	$5,856,319
Schedule No. 23/723 - Composite								
General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	1,162,587	1,162,587	1,147,117	kWh	0.351 ¢	$4,026	0.355 ¢	$4,072
System Usage Charge								
per kWh	1,162,587	1,162,587	1,147,117	kWh			0.073 ¢	$837
Distribution Charge								
Basic Charge								
Single Phase, per month	302	302	290	bill	$17.95	$5,206	$18.45	$5,351
Three Phase, per month	232	232	225	bill	$26.80	$6,030	$27.60	$6,210
Load Size Charge								
≤ 15 kW				kW	No Charge		No Charge	
per kW for all kW in excess of 15 kW	1,943	1,943	1,917	kW	$1.25	$2,396	$1.30	$2,492
Demand Charge, the first 15 kW of demand				kW	No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	819	819	806	kW	$4.05	$3,264	$4.17	$3,361
Reactive Power Charge, per kvar	1,215	1,215	1,229	kvar	60.00 ¢	$737	60.00 ¢	$737
Distribution Energy Charge, per kWh	1,162,587	1,162,587	1,147,117	kWh	2.548 ¢	$29,229	2.623 ¢	$30,089
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	805,814	805,814	792,413	kWh	2.796 ¢	$22,156	3.127 ¢	$24,779
All additional kWh, per kWh	356,773	356,773	354,704	kWh	2.075 ¢	$7,360	2.321 ¢	$8,233
Subtotal	1,162,587	1,162,587	1,147,117	kWh		$80,404		$86,161
Schedule 201								
1st 3,000 kWh, per kWh	805,814	805,814	792,413	kWh	2.838 ¢	$22,489	2.838 ¢	$22,489
All additional kWh, per kWh	356,773	356,773	354,704	kWh	2.106 ¢	$7,470	2.106 ¢	$7,470
Total	1,162,587	1,162,587	1,147,117	kWh	0.000 0	$110,363		$116,120
							Change	$5,757

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2012
Forecast 12 Months Ended December 31, 2014

Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	6,695,021	6,695,021	6,608,093	kW	$1.12	$7,401,064	$1.10	$7,268,902
System Usage Charge								
per kW	2,006,302,002	2,001,326,623	1,974,277,099	kWh			0.078 ¢	$1,539,936
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	55,003	55,003	55,062	bill	$20.00	$1,101,240	$20.00	$1,101,240
Load Size 51-100 kW, per month	40,921	40,921	40,932	bill	$37.00	$1,514,484	$36.00	$1,473,552
Load Size 101-300 kW, per month	22,017	22,017	21,983	bill	$88.00	$1,934,504	$86.00	$1,890,538
Load Size > 300 kW, per month	437	437	437	bill	$125.00	$54,625	$123.00	$53,751
Load Size Charge								
≤ 50 kW, per kW	2,115,606	2,115,606	2,086,427	kW	$1.25	$2,608,034	$1.25	$2,608,034
51-100 kW, per kW	2,849,026	2,849,026	2,811,094	kW	$1.00	$2,811,094	$1.00	$2,811,094
101-300 kW, per kW	3,305,777	3,305,777	3,265,179	kW	$0.60	$1,959,107	$0.60	$1,959,107
>300 kW, per kW	180,987	180,987	178,647	kW	$0.40	$71,459	$0.40	$71,459
Demand Charge, per kW	6,695,021	6,695,021	6,608,093	kW	$4.32	$28,546,962	$4.25	$28,084,395
Reactive Power Charge, per kvar	606,594	606,594	601,896	kvar	65.00 ¢	$391,232	65.00 ¢	$391,232
Distribution Energy Charge, per kWh	2,006,302,002	2,001,326,623	1,974,277,099	kWh	0.424 ¢	$8,370,935	0.407 ¢	$8,035,308
Energy Charge - Schedule 200								
1st 20,000 kWh, per kWh	1,424,748,123	1,421,217,123	1,402,035,556	kWh	2.838 ¢	$39,789,769	3.061 ¢	$42,916,308
All additional kWh, per kWh	581,553,879	580,109,500	572,241,543	kWh	2.763 ¢	$15,811,034	2.980 ¢	$17,052,798
Subtotal	2,006,302,002	2,001,326,623	1,974,277,099	kWh		$112,365,543		$117,257,654
Schedule 201								
1st 20,000 kWh, per kWh	1,424,748,123	1,421,217,123	1,402,035,556	kWh	2.891 ¢	$40,532,848	2.891 ¢	$40,532,848
All additional kWh, per kWh	581,553,879	580,109,500	572,241,543	kWh	2.812 ¢	$16,091,432	2.812 ¢	$16,091,432
Total	2,006,302,002	2,001,326,623	1,974,277,099	kWh		$168,989,823		$173,881,934
							Change	$4,892,111
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	68,909	68,909	68,711	kW	$1.00	$68,711	$0.89	$61,153
System Usage Charge								
per kWh	18,660,769	18,660,769	18,573,773	kWh			0.072 ¢	$13,373
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	105	105	104	bill	$24.00	$2,496	$26.00	$2,704
Load Size 51-100 kW, per month	185	185	183	bill	$41.00	$7,503	$44.00	$8,052
Load Size 101-300 kW, per month	343	343	336	bill	$97.00	$32,592	$104.00	$34,944
Load Size > 300 kW, per month	48	48	47	bill	$139.00	$6,533	$150.00	$7,050
Load Size Charge								
≤ 50 kW, per kW	3,479	3,479	3,447	kW	$1.35	$4,653	$1.45	$4,998
51-100 kW, per kW	13,359	13,359	13,278	kW	$1.10	$14,606	$1.20	$15,934
101-300 kW, per kW	61,154	61,154	60,933	kW	$0.65	$39,606	$0.70	$42,653
>300 kW, per kW	25,040	25,040	24,994	kW	$0.35	$8,748	$0.40	$9,998
Demand Charge, per kW	68,909	68,909	68,711	kW	$4.72	$324,316	$5.08	$349,052
Reactive Power Charge, per kvar	25,327	25,327	25,239	kvar	60.00 ¢	$15,143	60.00 ¢	$15,143
Distribution Energy Charge, per kWh	18,660,769	18,660,769	18,573,773	kWh	0.074 ¢	$13,745	0.083 ¢	$15,416
Energy Charge - Schedule 200								
1st 20,000 kWh, per kWh	9,767,910	9,767,910	9,746,389	kWh	2.737 ¢	$266,759	2.920 ¢	$284,595
All additional kWh, per kWh	8,892,859	8,892,859	8,827,384	kWh	2.663 ¢	$235,073	2.841 ¢	$250,786
Subtotal	18,660,769	18,660,769	18,573,773	kWh		$1,040,484		$1,115,851
Schedule 201								
1st 20,000 kWh, per kWh	9,767,910	9,767,910	9,746,389	kWh	2.787 ¢	$271,632	2.787 ¢	$271,632
All additional kWh, per kWh	8,892,859	8,892,859	8,827,384	kWh	2.712 ¢	$239,399	2.712 ¢	$239,399
Total	18,660,769	18,660,769	18,573,773	kWh		$1,551,515		$1,626,882
							Change	$75,367

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2012
Forecast 12 Months Ended December 31, 2014

Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 30/730 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	3,392,832	3,392,832	3,417,800	kW	$1.24	$4,238,072	$1.26	$4,306,428
System Usage Charge								
per kWh	1,232,243,636	1,233,760,487	1,246,164,161	kWh			0.073 ¢	$909,700
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	102	102	96	bill	$499.00	$47,904	$529.00	$50,784
Load Size 201-300 kW, per month	2,564	2,564	2,390	bill	$149.00	$356,110	$159.00	$380,010
Load Size > 300 kW, per month	6,548	6,548	6,094	bill	$391.00	$2,382,754	$417.00	$2,541,198
Load Size Charge								
≤ 200 Kw, per kW					No Charge		No Charge	
201-300 kW, per kW	665,480	665,480	671,613	kW	$1.75	$1,175,323	$1.85	$1,242,484
>300 kW, per kW	3,265,363	3,265,363	3,289,504	kW	$0.85	$2,796,078	$0.90	$2,960,554
Demand Charge, per kW	3,392,832	3,392,832	3,417,800	kW	$4.46	$15,243,388	$4.75	$16,234,550
Reactive Power Charge, per kvar	626,808	626,808	625,839	kvar	65.00 ¢	$406,795	65.00 ¢	$406,795
Energy Charge - Schedule 200								
Demand Charge, per kW	3,392,832	3,392,832	3,417,800	kW	$1.28	$4,374,784	$1.35	$4,614,030
1st 20,000 kWh, per kWh	178,281,743	178,493,743	180,025,326	kWh	2.645 ¢	$4,761,670	2.951 ¢	$5,312,547
All additional kWh, per kWh	1,053,961,893	1,055,266,744	1,066,138,835	kWh	2.294 ¢	$24,457,225	2.559 ¢	$27,282,493
Subtotal	1,232,243,636	1,233,760,487	1,246,164,161	kWh		$60,240,103		$66,241,573
Schedule 201								
1st 20,000 kWh, per kWh	178,281,743	178,493,743	180,025,326	kWh	3.095 ¢	$5,571,784	3.095 ¢	$5,571,784
All additional kWh, per kWh	1,053,961,893	1,055,266,744	1,066,138,835	kWh	2.684 ¢	$28,615,166	2.684 ¢	$28,615,166
Total	1,232,243,636	1,233,760,487	1,246,164,161	kWh		$94,427,053		$100,428,523
							Change	$6,001,470
Schedule No. 30/730 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	262,752	262,752	264,892	kW	$1.16	$307,275	$1.21	$320,519
System Usage Charge								
per kWh	90,666,396	90,666,396	91,598,045	kWh			0.071 ¢	$65,035
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	0	0	0	bill	$468.00	$0	$514.00	$0.00
Load Size 201-300 kW, per month	71	71	67	bill	$148.00	$9,916	$164.00	$10,988.00
Load Size > 300 kW, per month	536	536	499	bill	$383.00	$191,117	$424.00	$211,576.00
Load Size Charge								
≤ 200 Kw, per kW					No Charge		No Charge	
201-300 kW, per kW	18,536	18,536	18,859	kW	$1.60	$30,174	$1.75	$33,003
>300 kW, per kW	293,828	293,828	296,226	kW	$0.80	$236,981	$0.90	$266,603
Demand Charge, per kW	262,752	262,752	264,892	kW	$4.28	$1,133,738	$4.74	$1,255,588
Reactive Power Charge, per kvar	22,988	22,988	22,791	kvar	60.00 ¢	$13,675	60.00 ¢	$13,675
Energy Charge - Schedule 200								
Demand Charge, per kW	262,752	262,752	264,892	kW	$1.28	$339,062	$1.35	$357,604
1st 20,000 kWh, per kWh	12,140,233	12,140,233	12,257,555	kWh	2.580 ¢	$316,245	2.880 ¢	$353,018
All additional kWh, per kWh	78,526,163	78,526,163	79,340,490	kWh	2.230 ¢	$1,769,293	2.489 ¢	$1,974,785
Subtotal	90,666,396	90,666,396	91,598,045	kWh		$4,347,476		$4,862,394
Schedule 201								
1st 20,000 kWh, per kWh	12,140,233	12,140,233	12,257,555	kWh	3.064 ¢	$375,571	3.064 ¢	$375,571
All additional kWh, per kWh	78,526,163	78,526,163	79,340,490	kWh	2.649 ¢	$2,101,730	2.649 ¢	$2,101,730
Total	90,666,396	90,666,396	91,598,045	kWh		$6,824,777		$7,339,695
							Change	$514,918

PACIFIC POWER
State of Oregon
Billing Determinants
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Forecast 12 Months Ended December 31, 2014

Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Composite								
Agricultural Pumping Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	217,448,274	221,662,849	230,988,811	kWh	0.293 ¢	$676,797	0.286 ¢	$660,628
System Usage Charge								
per kWh	217,448,274	221,662,849	230,988,811	kWh			0.074 ¢	$170,932
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	6,116	6,116	6,912	bill	No Charge		No Charge	
Three Phase Load Size 51 - 300 kW, per customer	1,071	1,071	1,109	bill	$320.00	$354,880	$310.00	$343,790
Three Phase Load Size > 300 kW, per customer	21	21	23	bill	$1,250.00	$28,750	$1,220.00	$28,060
Total Customers	7,208	7,208	8,044	bill				
Monthly Bills	41,294	41,294	47,005					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase≤ 50 kW	106,062	106,062	111,212	kW	$15.00	$1,668,180	$15.00	$1,668,180
Three Phase Load Size 51-300 kW, per kW	95,183	95,183	98,529	kW	$10.00	$985,290	$10.00	$985,290
Three Phase Load Size > 300 kW, per kW	11,823	11,823	12,295	kW	$6.00	$73,770	$6.00	$73,770
Single Phase, Minimum Charge	386	386	451	bill	$55.00	$24,805	$55.00	$24,805
Three Phase, Minimum Charge	1,314	1,314	1,505	bill	$95.00	$142,975	$95.00	$142,975
Distribution Energy Charge, per kWh	217,448,274	221,662,849	230,988,811	kWh	3.708 ¢	$8,565,065	3.579 ¢	$8,267,090
Reactive Power Charge, per kvar	140,668	140,668	144,328	kvar	65.00 ¢	$93,813	65.00 ¢	$93,813
Energy Charge - Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	1,619,361	2,722,361	2,861,725	kWh	3.975 ¢	$113,754	4.205 ¢	$120,336
Winter, All additional kWh, per kWh	1,368,676	2,336,220	2,445,439	kWh	2.709 ¢	$66,247	2.866 ¢	$70,086
Summer, All kWh, per kWh	214,460,237	216,604,268	225,681,647	kWh	2.709 ¢	$6,113,716	2.866 ¢	$6,468,036
Subtotal	217,448,274	221,662,849	230,988,811	kWh		$18,908,042		$19,117,791
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	1,619,361	2,722,361	2,861,725	kWh	4.050 ¢	$115,900	4.050 ¢	$115,900
Winter, All additional kWh, per kWh	1,368,676	2,336,220	2,445,439	kWh	2.759 ¢	$67,470	2.759 ¢	$67,470
Summer, All kWh, per kWh	214,460,237	216,604,268	225,681,647	kWh	2.759 ¢	$6,226,557	2.759 ¢	$6,226,557
Total	217,448,274	221,662,849	230,988,811	kWh		$25,317,969		$25,527,718
							Change	$209,749
Schedule No. 41/741								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	388,834	388,834	414,701	kWh	0.285 ¢	$1,182	0.278 ¢	$1,153
System Usage Charge								
per kWh	388,834	388,834	414,701	kWh			0.072 ¢	$299
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	1	1	1	bill	No Charge		No Charge	
Three Phase Load Size 51 - 300 kW, per customer	0	0	0	bill	$310.00	$0	$300.00	$0
Three Phase Load Size > 300 kW, per customer	1	1	1	bill	$1,210.00	$1,210	$1,190.00	$1,190
Total Customers	2	2	2	bill				
Monthly Bills	33	33	33					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase≤ 50 kW	12	12	13	kW	$15.00	$195	$15.00	$195
Three Phase Load Size 51-300 kW, per kW	0	0	0	kW	$10.00	$0	$10.00	$0
Three Phase Load Size > 300 kW, per kW	371	371	396	kW	$6.00	$2,376	$6.00	$2,376
Single Phase, Minimum Charge	0	0	0	bill	$55.00	$0	$55.00	$0
Three Phase, Minimum Charge	1	1	1	bill	$90.00	$90	$90.00	$90
Distribution Energy Charge, per kWh	388,834	388,834	414,701	kWh	3.603 ¢	$14,942	3.478 ¢	$14,423
Reactive Power Charge, per kvar	1,212	1,212	1,293	kvar	60.00 ¢	$776	60.00 ¢	$776
Energy Charge - Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	9,199	9,199	9,811	kWh	3.863 ¢	$379	4.086 ¢	$401
Winter, All additional kWh, per kWh	52,614	52,614	56,114	kWh	2.633 ¢	$1,477	2.785 ¢	$1,563
Summer, All kWh, per kWh	327,021	327,021	348,776	kWh	2.633 ¢	$9,183	2.785 ¢	$9,713
Subtotal	388,834	388,834	414,701	kWh		$31,810		$32,179
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	9,199	9,199	9,811	kWh	3.922 ¢	$385	3.922 ¢	$385
Winter, All additional kWh, per kWh	52,614	52,614	56,114	kWh	2.672 ¢	$1,499	2.672 ¢	$1,499
Summer, All kWh, per kWh	327,021	327,021	348,776	kWh	2.672 ¢	$9,319	2.672 ¢	$9,319
Total	388,834	388,834	414,701	kWh		$43,013		$43,382
							Change	$369

PACIFIC POWER
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Forecast 12 Months Ended December 31, 2014

Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	158,378	158,378	405,068	kW	$0.82	$332,156	$0.89	$360,511
credit per kW of on-peak demand (OATT)	0	0	0	kW	($0.82)	$0	($0.89)	$0
System Usage Charge								
per kWh	38,170,609	38,170,609	123,942,339	kWh			0.069 ¢	$85,520
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$510.00	$0	$560.00	$0
Facility Capacity > 4,000 kW, per month	24	24	35	bill	$910.00	$31,850	$1,000.00	$35,000
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$0.75	$0	$0.55	$0
Facility Capacity > 4,000 kW, per kW	180,861	180,861	440,578	kW	$0.70	$308,405	$0.50	$220,289
Demand Charge, per kW of on-peak demand	158,378	158,378	405,068	kW	$4.43	$1,794,451	$5.24	$2,122,556
Reactive Power Charge, per kvar	22,401	22,401	90,707	kvar	60.00 ¢	$54,424	60.00 ¢	$54,424
Reactive Hours, per kvarh	12,477,400	12,477,400	10,608,504	kvarh	0.080 ¢	$8,487	0.080 ¢	$8,487
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	180,861	180,861	440,578	kW	$0.27	$118,956	$0.27	$118,956
Supplemental Reserves, per kW of Facility Cap.	180,861	180,861	440,578	kW	$0.27	$118,956	$0.27	$118,956
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	158,378	158,378	405,068	kW	$1.18	$477,980	$1.25	$506,335
On-Peak, per on-peak kWh	27,208,072	27,208,072	84,413,283	kWh	2.289 ¢	$1,932,220	2.609 ¢	$2,202,343
Off-Peak, per off-peak kWh	10,962,537	10,962,537	39,529,056	kWh	2.239 ¢	$885,056	2.559 ¢	$1,011,549
Unscheduled Energy, per kWh	1,062,391	1,062,391	860,411	kWh		$21,726		$21,726
Subtotal	39,233,000	39,233,000	124,802,750	kWh		$6,084,667		$6,866,652
Schedule 201								
On-Peak, per on-peak kWh	27,208,072	27,208,072	84,413,283	kWh	2.609 ¢	$2,202,343	2.609 ¢	$2,202,343
Off-Peak, per off-peak kWh	10,962,537	10,962,537	39,529,056	kWh	2.559 ¢	$1,011,549	2.559 ¢	$1,011,549
Total	39,233,000	39,233,000	124,802,750	kWh		$9,298,559		$10,080,544
							Change	$781,985

Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	119,885	119,885	92,839	kW	$1.23	$114,192	$1.18	$109,550
credit per kW of on-peak demand (OATT)	0	0	0	kW	($1.23)	$0	($1.18)	$0
System Usage Charge								
per kWh	24,773,671	24,773,671	18,535,048	kWh			0.064 ¢	$11,862
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	16	16	14	bill	$960.00	$13,440	$990.00	$13,860
Facility Capacity > 4,000 kW, per month	25	25	23	bill	$1,780.00	$40,940	$1,830.00	$42,090
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	33,612	33,612	27,220	kW	$1.15	$31,303	$0.80	$21,776
Facility Capacity > 4,000 kW, per kW	330,580	330,580	248,448	kW	$1.15	$285,715	$0.80	$198,758
Demand Charge, per kW of on-peak demand	119,885	119,885	92,839	kW	$4.47	$414,990	$4.99	$463,267
Reactive Power Charge, per kvar	26,149	26,149	20,113	kvar	55.00 ¢	$11,062	55.00 ¢	$11,062
Reactive Hours, per kvarh	3,625,600	3,625,600	2,744,624	kvarh	0.080 ¢	$2,196	0.08 ¢	$2,196
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	364,192	364,192	275,668	kW	$0.27	$74,430	$0.27	$74,430
Supplemental Reserves, per kW of Facility Cap.	364,192	364,192	275,668	kW	$0.27	$74,430	$0.27	$74,430
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	119,885	119,885	92,839	kW	$1.19	$110,478	$1.26	$116,977
On-Peak, per on-peak kWh	14,171,254	14,171,254	10,531,685	kWh	2.207 ¢	$232,434	2.493 ¢	$262,555
Off-Peak, per off-peak kWh	10,602,417	10,602,417	8,003,363	kWh	2.157 ¢	$172,633	2.443 ¢	$195,522
Unscheduled Energy, per kWh	660,984	660,984	514,338	kWh		$9,377		$9,377
Subtotal	25,434,655	25,434,655	19,049,386	kWh		$1,587,620		$1,607,712
Schedule 201								
On-Peak, per on-peak kWh	14,171,254	14,171,254	10,531,685	kWh	2.429 ¢	$255,815	2.429 ¢	$255,815
Off-Peak, per off-peak kWh	10,602,417	10,602,417	8,003,363	kWh	2.379 ¢	$190,400	2.379 ¢	$190,400
Total	25,434,655	25,434,655	19,049,386	kWh		$2,033,835		$2,053,927
							Change	$20,092

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Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 76R/776R								
Large General Service/Partial Requirements Service - Economic Replacement Power Rider								
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.030	$0	$0.030	$0
Primary	0	0	0	kW	$0.032	$0	$0.035	$0
Transmission	0	0	0	kW	$0.048	$0	$0.046	$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.166	$0	$0.190	$0
Primary	0	0	0	kW	$0.173	$0	$0.204	$0
Transmission	0	0	0	kW	$0.174	$0	$0.194	$0
Schedule No. 48/748 - Composite								
Large General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,575,031	1,575,031	1,536,500	kW	$1.30	$1,997,450	$1.32	$2,028,180
System Usage Charge								
per kWh	583,446,236	587,561,075	575,745,854	kWh			0.073 ¢	$420,294
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	1,295	1,295	1,237	bill	$470.00	$581,390	$490.00	$606,130
Facility Capacity > 4,000 kW, per month	14	14	14	bill	$880.00	$12,320	$920.00	$12,880
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,753,444	1,753,444	1,709,811	kW	$1.35	$2,308,245	$1.05	$1,795,302
Facility Capacity > 4,000 kW, per kW	137,846	137,846	140,089	kW	$1.25	$175,111	$1.00	$140,089
Demand Charge, per kW of on-peak demand	1,575,031	1,575,031	1,536,500	kW	$4.26	$6,545,490	$4.88	$7,498,120
Reactive Power Charge, per kvar	423,134	423,134	404,234	kvar	65.00 ¢	$262,752	65.00 ¢	$262,752
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,575,031	1,575,031	1,536,500	kW	$1.17	$1,797,705	$1.24	$1,905,260
On-Peak, per on-peak kWh	375,591,468	378,198,468	370,279,657	kWh	2.374 ¢	$8,790,439	2.682 ¢	$9,930,900
Off-Peak, per off-peak kWh	207,854,768	209,362,607	205,466,197	kWh	2.324 ¢	$4,775,034	2.632 ¢	$5,407,870
Subtotal	583,446,236	587,561,075	575,745,854	kWh		$27,245,936		$30,007,777
Schedule 201								
On-Peak, per on-peak kWh	375,591,468	378,198,468	370,279,657	kWh	2.730 ¢	$10,108,635	2.730 ¢	$10,108,635
Off-Peak, per off-peak kWh	207,854,768	209,362,607	205,466,197	kWh	2.680 ¢	$5,506,494	2.680 ¢	$5,506,494
Total	583,446,236	587,561,075	575,745,854	kWh	0.000	$42,861,065		$45,622,906
							Change	$2,761,841
Schedule No. 48/748 - Composite								
Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	3,713,601	3,713,601	3,526,702	kW	$1.36	$4,796,315	$1.43	$5,043,184
System Usage Charge								
per kWh	1,609,915,537	1,609,915,537	1,529,472,682	kWh			0.069 ¢	$1,055,336
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	783	783	754	bill	$510.00	$384,540	$560.00	$422,240
Facility Capacity > 4,000 kW, per month	382	382	356	bill	$910.00	$323,960	$1,000.00	$356,000
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,451,090	1,451,090	1,405,660	kW	$0.75	$1,054,245	$0.55	$773,113
Facility Capacity > 4,000 kW, per kW	2,908,840	2,908,840	2,744,263	kW	$0.70	$1,920,984	$0.50	$1,372,132
Demand Charge, per kW of on-peak demand	3,713,601	3,713,601	3,526,702	kW	$4.43	$15,623,290	$5.24	$18,479,918
Reactive Power Charge, per kvar	862,110	862,110	810,849	kvar	60.00 ¢	$486,509	60.00 ¢	$486,509
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	3,713,601	3,713,601	3,526,702	kW	$1.18	$4,161,508	$1.25	$4,408,378
On-Peak, per on-peak kWh	992,785,405	992,785,405	943,087,671	kWh	2.289 ¢	$21,587,277	2.609 ¢	$24,605,157
Off-Peak, per off-peak kWh	617,130,132	617,130,132	586,385,011	kWh	2.239 ¢	$13,129,160	2.559 ¢	$15,005,592
Subtotal	1,609,915,537	1,609,915,537	1,529,472,682	kWh		$63,467,788		$72,007,559
Schedule 201								
On-Peak, per on-peak kWh	992,785,405	992,785,405	943,087,671	kWh	2.609 ¢	$24,605,157	2.609 ¢	$24,605,157
Off-Peak, per off-peak kWh	617,130,132	617,130,132	586,385,011	kWh	2.559 ¢	$15,005,592	2.559 ¢	$15,005,592
Total	1,609,915,537	1,609,915,537	1,529,472,682	kWh		$103,078,537		$111,618,308
							Change	$8,539,771

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Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 - Composite								
Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	832,525	832,525	1,285,292	kW	$1.77	$2,274,967	$1.72	$2,210,702
System Usage Charge								
per kWh	528,557,000	528,557,000	829,896,081	kWh			0.064 ¢	$531,133
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	36	36	36	bill	$960.00	$34,560	$990.00	$35,640
Facility Capacity > 4,000 kW, per month	36	36	58	bill	$1,780.00	$103,240	$1,830.00	$106,140
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	49,400	49,400	50,204	kW	$1.15	$57,735	$0.80	$40,163
Facility Capacity > 4,000 kW, per kW	826,354	826,354	1,280,310	kW	$1.15	$1,472,357	$0.80	$1,024,248
Demand Charge, per kW of on-peak demand	832,525	832,525	1,285,292	kW	$4.47	$5,745,255	$4.99	$6,413,607
Reactive Power Charge, per kvar	122,144	122,144	113,276	kvar	55.00 ¢	$62,302	55.00 ¢	$62,302
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	832,525	832,525	1,285,292	kW	$1.19	$1,529,497	$1.26	$1,619,468
On-Peak, per on-peak kWh	296,805,000	296,805,000	472,809,887	kWh	2.207 ¢	$10,434,914	2.493 ¢	$11,787,150
Off-Peak, per off-peak kWh	231,752,000	231,752,000	357,086,194	kWh	2.157 ¢	$7,702,349	2.443 ¢	$8,723,616
Subtotal	528,557,000	528,557,000	829,896,081	kWh		$29,417,176		$32,554,169
Schedule 201								
On-Peak, per on-peak kWh	296,805,000	296,805,000	472,809,887	kWh	2.429 ¢	$11,484,552	2.429 ¢	$11,484,552
Off-Peak, per off-peak kWh	231,752,000	231,752,000	357,086,194	kWh	2.379 ¢	$8,495,081	2.379 ¢	$8,495,081
Total	528,557,000	528,557,000	829,896,081	kWh		$49,396,809		$52,533,802
							Change	$3,136,993

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2012
Forecast 12 Months Ended December 31, 2014

Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 15 - Composite										
Outdoor Area Lighting Service										
No. of Customers	7,040	7,040	6,769							
Transmission & Ancillary Services Charge										
per kWh	10,107,088	10,107,088	9,286,499	kWh	0.060	¢	$5,842	0.061	¢	$5,842
System Usage Charge										
per kWh	10,107,088	10,107,088	9,286,499	kWh				0.049	¢	$4,721
Distribution Charge										
Distribution Charge, per kWh	10,107,088	10,107,088	9,286,499	kWh	7.880	¢	$732,292	8.751	¢	$812,708
Energy Charge - Schedule 200										
per kWh	10,107,088	10,107,088	9,286,499	kWh	2.046	¢	$189,638	2.249	¢	$208,959
Subtotal	10,107,088	10,107,088	9,286,499	kWh			$927,773			$1,032,230
Schedule 201										
per kWh	10,107,088	10,107,088	9,286,499	kWh	2.287	¢	$212,447	2.287	¢	$212,447
Total	10,107,088	10,107,088	9,286,499	kWh			$1,140,219			$1,244,677
								Change		$104,458
Schedule No. 50										
Mercury Vapor Street Lighting Service										
No. of Customers	246	246	251							
Transmission & Ancillary Services Charge										
per kWh	8,902,125	8,902,125	7,823,337	kWh	0.060	¢	$5,006	0.061	¢	$5,006
System Usage Charge										
per kWh	8,902,125	8,902,125	7,823,337	kWh				0.049	¢	$4,005
Distribution Charge										
Distribution Charge, per kWh	8,902,125	8,902,125	7,823,337	kWh	6.799	¢	$531,907	7.528	¢	$588,942
Energy Charge - Schedule 200										
per kWh	8,902,125	8,902,125	7,823,337	kWh	1.845	¢	$144,128	2.028	¢	$158,572
Subtotal	8,902,125	8,902,125	7,823,337	kWh			$681,041			$756,525
Schedule 201										
per kWh	8,902,125	8,902,125	7,823,337	kWh	1.880	¢	$147,131	1.880	¢	$147,131
Total	8,902,125	8,902,125	7,823,337	kWh			$828,172			$903,657
								Change		$75,485
Schedule No. 51/751, 55										
Street Lighting Service, Company-Owned System										
No. of Customers	702	702	747							
Transmission & Ancillary Services Charge										
per kWh	18,868,176	18,868,176	19,612,310	kWh	0.060	¢	$12,504	0.061	¢	$12,506
System Usage Charge										
per kWh	18,868,176	18,868,176	19,612,310	kWh				0.049	¢	$9,551
Distribution Charge										
Distribution Charge, per kWh	18,868,176	18,868,176	19,612,310	kWh	10.833	¢	$2,124,598	12.028	¢	$2,359,047
Energy Charge - Schedule 200										
per kWh	18,868,176	18,868,176	19,612,310	kWh	2.914	¢	$571,142	3.204	¢	$627,973
Subtotal	18,868,176	18,868,176	19,612,310	kWh			$2,708,245			$3,009,077
Schedule 201										
per kWh	18,868,176	18,868,176	19,612,310	kWh	2.967	¢	$582,552	2.967	¢	$582,552
Total	18,868,176	18,868,176	19,612,310	kWh			$3,290,797			$3,591,628
								Change		$300,832

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2012
Forecast 12 Months Ended December 31, 2014

Schedule	Actual 7/11-6/12 Units	Normalized 7/11-6/12 Units	Forecast 1/14 - 12/14 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 52/752								
Street Lighting Service, Company-Owned System								
No. of Customers	48	48	44					
Transmission & Ancillary Services Charge								
per kWh	566,839	566,839	523,143	kWh	0.060 ¢	$314	0.061 ¢	$319
System Usage Charge								
per kWh	566,839	566,839	523,143	kWh			0.049 ¢	$256
Distribution Charge								
Distribution Charge, per kWh	566,839	566,839	523,143	kWh	7.904 ¢	$41,339	8.770 ¢	$45,880
Energy Charge - Schedule 200								
per kWh	566,839	566,839	523,143	kWh	2.233 ¢	$11,682	2.455 ¢	$12,843
Subtotal	566,839	566,839	523,143	kWh		$53,335		$59,299
Schedule 201								
per kWh	566,839	566,839	523,143	kWh	2.273 ¢	$11,891	2.273 ¢	$11,891
Total	566,839	566,839	523,143	kWh		$65,226		$71,190
							Change	$5,964
Schedule No. 53/753								
Street Lighting Service, Consumer-Owned System								
No. of Customers	253	253	266					
Transmission & Ancillary Services Charge								
per kWh	9,668,960	9,668,960	8,966,764	kWh	0.060 ¢	$5,380	0.061 ¢	$5,470
System Usage Charge								
per kWh	9,668,960	9,668,960	8,966,764	kWh			0.049 ¢	$4,394
Distribution Charge								
Distribution Charge, per kWh	9,668,960	9,668,960	8,966,764	kWh	3.960 ¢	$355,093	4.358 ¢	$390,781
Energy Charge - Schedule 200								
per kWh	9,668,960	9,668,960	8,966,764	kWh	0.953 ¢	$85,453	1.048 ¢	$93,972
Subtotal	9,668,960	9,668,960	8,966,764	kWh		$445,926		$494,616
Schedule 201								
per kWh	9,668,960	9,668,960	8,966,764	kWh	0.970 ¢	$86,978	0.970 ¢	$86,978
Total	9,668,960	9,668,960	8,966,764	kWh		$532,904		$581,593
							Change	$48,690
Schedule No. 54/754								
Recreational Field Lighting								
Transmission & Ancillary Services Charge								
per kWh	1,205,229	1,205,229	1,249,347	kWh	0.060 ¢	$750	0.061 ¢	$762
System Usage Charge								
per kWh	1,205,229	1,205,229	1,249,347	kWh			0.049 ¢	$612
Distribution Charge								
Basic Charge, Single Phase, per month	806	806	815	bill	$6.00	$4,890	$6.00	$4,890
Basic Charge, Three Phase, per month	430	430	435	bill	$9.00	$3,915	$9.00	$3,915
Distribution Energy Charge, per kWh	1,205,229	1,205,229	1,249,347	kWh	3.849 ¢	$48,087	4.360 ¢	$54,472
Energy Charge - Schedule 200								
per kWh	1,205,229	1,205,229	1,249,347	kWh	1.640 ¢	$20,489	1.803 ¢	$22,526
Subtotal	1,205,229	1,205,229	1,249,347	kWh		$78,131		$87,177
Schedule 201								
per kWh	1,205,229	1,205,229	1,249,347	kWh	1.672 ¢	$20,889	1.672 ¢	$20,889
Total	1,205,229	1,205,229	1,249,347	kWh		$99,020		$108,066
							Change	$9,046
TOTAL OREGON	13,005,012,106	12,939,543,912	13,168,970,566			$1,206,737,803		$1,262,724,955

Docket No. UE 263
Exhibit PAC/1203
Witness: Joelle R. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Joelle R. Steward

Estimated Effect of Proposed Rates

March 2013

GRC Price Change - with Estimated Transmission Investment Adjustment 1203-1

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2014

					Present Revenues ($000)					Proposed Revenues ($000)			Change				
													Base + TIA		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Estimated TIA	Base + TIA	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	
							(5) + (6)		(7) + (8)			(10) + (11)	(10) - (7)	(13)/(7)	(12) - (9)	(15)/(9)	
	Residential																
1	Residential	4	485,586	5,379,569	$582,985	$5,003	$587,988	$2,529	$590,517	$605,631	$2,206	$607,837	$17,643	3.0%	$17,320	2.9%	1
2	**Total Residential**		485,586	5,379,569	$582,985	$5,003	$587,988	$2,529	$590,517	$605,631	$2,206	$607,837	$17,643	3.0%	$17,320	2.9%	2
	Commercial & Industrial																
3	Gen. Svc. < 31 kW	23	73,886	1,100,957	$113,973	$958	$114,931	$4,460	$119,391	$119,835	$4,404	$124,239	$4,904	4.3%	$4,848	4.1%	3
4	Gen. Svc. 31 - 200 kW	28	9,924	1,992,850	$170,542	$1,867	$172,409	$2,033	$174,442	$175,508	$1,933	$177,441	$3,099	1.8%	$2,999	1.7%	4
5	Gen. Svc. 201 - 999 kW	30	762	1,337,763	$101,252	$1,100	$102,352	$360	$102,712	$107,768	$280	$108,048	$5,416	5.3%	$5,336	5.2%	5
6	Large General Service >= 1,000 kW	48	205	2,935,115	$195,337	$2,145	$197,482	($10,456)	$187,026	$209,776	($10,456)	$199,320	$12,294	6.2%	$12,294	6.5%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	143,852	$11,333	$169	$11,502	($514)	$10,988	$12,135	($514)	$11,621	$633	6.2%	$633	6.5%	7
8	Agricultural Pumping Service	41	8,046	231,404	$25,361	$174	$25,535	($1,402)	$24,133	$25,571	($536)	$25,035	$36	0.1%	$902	3.7%	8
9	**Total Commercial & Industrial**		92,829	7,741,941	$617,798	$6,412	$624,210	($5,519)	$618,691	$650,593	($4,889)	$645,704	$26,383	4.2%	$27,013	4.4%	9
	Lighting																
10	Outdoor Area Lighting Service	15	6,768	9,286	$1,140	$1	$1,141	$218	$1,359	$1,245	$202	$1,447	$104	9.1%	$88	6.5%	10
11	Street Lighting Service	50	251	7,823	$828	$1	$829	$170	$999	$904	$160	$1,064	$75	9.1%	$65	6.5%	11
12	Street Lighting Service HPS	51	747	19,612	$3,291	$2	$3,293	$706	$3,999	$3,592	$666	$4,258	$299	9.1%	$259	6.5%	12
13	Street Lighting Service	52	44	523	$65	$0	$65	$12	$77	$71	$11	$82	$6	9.1%	$5	6.4%	13
14	Street Lighting Service	53	266	8,967	$533	$1	$534	$108	$642	$582	$102	$684	$48	9.0%	$42	6.5%	14
15	Recreational Field Lighting	54	104	1,249	$99	$0	$99	$20	$119	$108	$19	$127	$9	8.9%	$8	6.6%	15
16	**Total Public Street Lighting**		8,180	47,460	$5,956	$6	$5,962	$1,234	$7,196	$6,502	$1,160	$7,662	$540	9.1%	$466	6.5%	16
17	**Total Sales to Ultimate Consumers**		586,595	13,168,970	$1,206,739	$11,420	$1,218,159	($1,756)	$1,216,403	$1,262,726	($1,523)	$1,261,203	$44,567	3.7%	$44,800	3.7%	17
18	AGA Revenue				$2,439		$2,439		$2,439	$2,439		$2,439	$0		$0		18
19	**Total Sales with AGA**		586,595	13,168,970	$1,209,178	$11,420	$1,220,598	($1,756)	$1,218,842	$1,265,165	($1,523)	$1,263,642	$44,567	3.7%	$44,800	3.7%	19

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Table 1203-2

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2014

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	485,586	5,379,569	$582,985	$2,529	$585,514	$605,631	$2,206	$607,837	$22,646	3.9%	$22,323	3.8%	1
2	**Total Residential**		485,586	5,379,569	$582,985	$2,529	$585,514	$605,631	$2,206	$607,837	$22,646	3.9%	$22,323	3.8%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	73,886	1,100,957	$113,973	$4,460	$118,433	$119,835	$4,404	$124,239	$5,862	5.1%	$5,806	4.9%	3
4	Gen. Svc. 31 - 200 kW	28	9,924	1,992,850	$170,542	$2,033	$172,575	$175,508	$1,933	$177,441	$4,966	2.9%	$4,866	2.8%	4
5	Gen. Svc. 201 - 999 kW	30	762	1,337,763	$101,252	$360	$101,612	$107,768	$280	$108,048	$6,516	6.4%	$6,436	6.3%	5
6	Large General Service >= 1,000 kW	48	205	2,935,115	$195,337	($10,456)	$184,881	$209,776	($10,456)	$199,320	$14,439	7.4%	$14,439	7.8%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	143,852	$11,333	($514)	$10,819	$12,135	($514)	$11,621	$802	7.4%	$802	7.8%	7
8	Agricultural Pumping Service	41	8,046	231,404	$25,361	($1,402)	$23,959	$25,571	($536)	$25,035	$210	0.8%	$1,076	4.5%	8
9	**Total Commercial & Industrial**		92,829	7,741,941	$617,798	($5,519)	$612,279	$650,593	($4,889)	$645,704	$32,795	5.3%	$33,425	5.5%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,768	9,286	$1,140	$218	$1,358	$1,245	$202	$1,447	$105	9.2%	$89	6.6%	10
11	Street Lighting Service	50	251	7,823	$828	$170	$998	$904	$160	$1,064	$76	9.2%	$66	6.6%	11
12	Street Lighting Service HPS	51	747	19,612	$3,291	$706	$3,997	$3,592	$666	$4,258	$301	9.2%	$261	6.5%	12
13	Street Lighting Service	52	44	523	$65	$12	$77	$71	$11	$82	$6	9.2%	$5	6.5%	13
14	Street Lighting Service	53	266	8,967	$533	$108	$641	$582	$102	$684	$49	9.2%	$43	6.7%	14
15	Recreational Field Lighting	54	104	1,249	$99	$20	$119	$108	$19	$127	$9	9.1%	$8	6.7%	15
16	**Total Public Street Lighting**		8,180	47,460	$5,956	$1,234	$7,190	$6,502	$1,160	$7,662	$546	9.2%	$472	6.6%	16
17	**Total Sales to Ultimate Consumers**		586,595	13,168,970	$1,206,739	($1,756)	$1,204,983	$1,262,726	($1,523)	$1,261,203	$55,987	4.6%	$56,220	4.7%	17
18	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		18
19	**Total Sales with AGA**		586,595	13,168,970	$1,209,178	($1,756)	$1,207,422	$1,265,165	($1,523)	$1,263,642	$55,987	4.6%	$56,220	4.7%	19

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Table 1203-3
PACIFIC POWER
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2014

Line No.	Description	Sch No.	Prop. Sales 96 ($000)	Sol. Inctv. 204 ($000)	RMA 299 ($000)	RMA 299 ($000)	Total ($000)	Total ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
					PRE	PRO	PRE	PRO
	Residential							
1	Residential	4	($1,452)	$861	$3,120	$2,797	$2,529	$2,206
2	**Total Residential**		($1,452)	$861	$3,120	$2,797	$2,529	$2,206
	Commercial & Industrial							
3	Gen. Svc. < 31 kW	23	($297)	$177	$4,580	$4,524	$4,460	$4,404
4	Gen. Svc. 31 - 200 kW	28	($538)	$319	$2,252	$2,152	$2,033	$1,933
5	Gen. Svc. 201 - 999 kW	30	($362)	$201	$521	$441	$360	$280
6	Large General Service >= 1,000 kW	48	($793)	$411	($10,074)	($10,074)	($10,456)	($10,456)
7	Partial Req. Svc. >= 1,000 kW	47	($39)	$20	($495)	($495)	($514)	($514)
8	Agricultural Pumping Service	41	($62)	$37	($1,377)	($511)	($1,402)	($536)
9	**Total Commercial & Industrial**		($2,091)	$1,165	($4,593)	($3,963)	($5,519)	($4,889)
	Lighting							
10	Outdoor Area Lighting Service	15	($3)	$1	$220	$204	$218	$202
11	Street Lighting Service	50	($2)	$1	$171	$161	$170	$160
12	Street Lighting Service HPS	51	($5)	$3	$708	$668	$706	$666
13	Street Lighting Service	52	$0	$0	$12	$11	$12	$11
14	Street Lighting Service	53	($2)	$0	$110	$104	$108	$102
15	Recreational Field Lighting	54	$0	$0	$20	$19	$20	$19
16	**Total Public Street Lighting**		($12)	$5	$1,241	$1,167	$1,234	$1,160
17	**Total**		($3,555)	$2,031	($232)	$1	($1,756)	($1,523)

Table 1203-4
PACIFIC POWER
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2014

Line No.	Description	Sch No.	Prop. Sales 96 ¢/kWh	Sol. Inctv. 204 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					PRE	PRE	PRE	PRO	PRO	PRO
	Residential									
1	Residential	4	(0.027)	0.016	0.058			0.052		
	Commercial & Industrial									
2	Gen. Svc. < 31 kW	23	(0.027)	0.016	0.416	0.416		0.411	0.411	
3	Gen. Svc. 31 - 200 kW	28	(0.027)	0.016	0.113	0.113		0.108	0.108	
4	Gen. Svc. 201 - 999 kW	30	(0.027)	0.015	0.039	0.039		0.033	0.033	
5	Large General Service >= 1,000 kW	48	(0.027)	0.014	(0.267)	(0.334)	(0.413)	(0.267)	(0.334)	(0.413)
6	Partial Req. Svc. >= 1,000 kW	47	(0.027)	0.014	(0.267)	(0.334)	(0.413)	(0.267)	(0.334)	(0.413)
7	Agricultural Pumping Service	41	(0.027)	0.016	(0.595)	(0.595)		(0.221)	(0.221)	
	Lighting									
8	Outdoor Area Lighting Service	15	(0.027)	0.013	2.365			2.193		
9	Street Lighting Service	50	(0.027)	0.011	2.183			2.052		
10	Street Lighting Service HPS	51	(0.027)	0.017	3.609			3.404		
11	Street Lighting Service	52	(0.027)	0.013	2.240			2.008		
12	Street Lighting Service	53	(0.027)	0.005	1.230			1.155		
13	Recreational Field Lighting	54	(0.027)	0.009	1.590			1.482		

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price**	Proposed Price	Difference	Difference
100	$19.80	$21.02	$1.22	6.16%
200	$29.48	$30.90	$1.42	4.82%
300	$39.17	$40.78	$1.61	4.11%
400	$48.85	$50.66	$1.81	3.71%
500	$58.53	$60.55	$2.02	3.45%
600	$68.18	$70.41	$2.23	3.27%
700	$77.87	$80.29	$2.42	3.11%
800	$87.55	$90.17	$2.62	2.99%
900	**$97.24**	**$100.05**	**$2.81**	**2.89%**
950	$102.07	$104.97	$2.90	2.84%
1,000	$106.91	$109.92	$3.01	2.82%
1,100	$119.06	$122.35	$3.29	2.76%
1,200	$131.22	$134.79	$3.57	2.72%
1,300	$143.37	$147.23	$3.86	2.69%
1,400	$155.53	$159.67	$4.14	2.66%
1,500	$167.68	$172.10	$4.42	2.64%
1,600	$179.81	$184.52	$4.71	2.62%
2,000	$228.43	$234.27	$5.84	2.56%
3,000	$349.95	$358.62	$8.67	2.48%
4,000	$471.47	$482.98	$11.51	2.44%
5,000	$592.99	$607.33	$14.34	2.42%

* Net rate including Schedules 91, 98, 199, 290 and 297.

** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price**		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$69	$78	$71	$81	3.79%	3.74%
	750	$94	$103	$97	$107	3.89%	3.84%
	1,000	$119	$128	$124	$133	3.94%	3.90%
	1,500	$169	$178	$176	$185	4.00%	3.97%
10	1,000	$119	$128	$124	$133	3.94%	3.90%
	2,000	$219	$228	$228	$238	4.04%	4.01%
	3,000	$320	$329	$333	$342	4.08%	4.06%
	4,000	$405	$414	$421	$430	4.03%	4.01%
20	4,000	$433	$442	$450	$459	3.97%	3.96%
	6,000	$603	$612	$626	$636	3.93%	3.92%
	8,000	$772	$782	$803	$812	3.91%	3.91%
	10,000	$942	$951	$979	$989	3.90%	3.89%
30	9,000	$913	$922	$948	$958	3.86%	3.85%
	12,000	$1,168	$1,177	$1,213	$1,223	3.86%	3.85%
	15,000	$1,423	$1,432	$1,478	$1,487	3.85%	3.85%
	18,000	$1,678	$1,687	$1,743	$1,752	3.85%	3.85%

* Net rate including Schedules 91, 199, 290 and 297.
** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent	
kW		Present Price**		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$67	$76	$70	$79	3.77%	3.73%
	750	$92	$101	$95	$105	3.87%	3.83%
	1,000	$116	$125	$121	$130	3.92%	3.89%
	1,500	$165	$174	$172	$181	3.99%	3.96%
10	1,000	$116	$125	$121	$130	3.92%	3.89%
	2,000	$214	$223	$223	$232	4.02%	4.00%
	3,000	$312	$321	$324	$334	4.06%	4.04%
	4,000	$394	$404	$410	$420	4.01%	4.00%
20	4,000	$422	$431	$438	$448	3.96%	3.95%
	6,000	$587	$596	$610	$620	3.92%	3.92%
	8,000	$753	$762	$782	$792	3.91%	3.90%
	10,000	$918	$928	$954	$964	3.89%	3.89%
30	9,000	$890	$899	$925	$934	3.86%	3.85%
	12,000	$1,139	$1,148	$1,182	$1,192	3.85%	3.85%
	15,000	$1,387	$1,396	$1,440	$1,450	3.85%	3.84%
	18,000	$1,635	$1,644	$1,698	$1,707	3.84%	3.84%

* Net rate including Schedules 91, 199, 290 and 297.

** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price**	Proposed Price	Difference
15	3,000	$333	$336	0.87%
	4,500	$436	$443	1.66%
	7,500	$641	$657	2.47%
31	6,200	$667	$673	0.90%
	9,300	$879	$894	1.70%
	15,500	$1,303	$1,336	2.51%
40	8,000	$855	$863	0.91%
	12,000	$1,129	$1,148	1.70%
	20,000	$1,676	$1,718	2.52%
60	12,000	$1,274	$1,285	0.83%
	18,000	$1,685	$1,712	1.65%
	30,000	$2,489	$2,551	2.48%
80	16,000	$1,686	$1,701	0.86%
	24,000	$2,227	$2,264	1.67%
	40,000	$3,296	$3,378	2.49%
100	20,000	$2,098	$2,117	0.87%
	30,000	$2,766	$2,813	1.68%
	50,000	$4,103	$4,205	2.50%
200	40,000	$4,097	$4,132	0.86%
	60,000	$5,433	$5,525	1.69%
	100,000	$8,105	$8,309	2.52%

* Net rate including Schedules 91, 199, 290 and 297.

** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price**	Proposed Price	Difference
15	4,500	$420	$435	3.72%
	6,000	$514	$534	3.82%
	7,500	$608	$632	3.89%
31	9,300	$841	$871	3.57%
	12,400	$1,036	$1,074	3.70%
	15,500	$1,230	$1,277	3.79%
40	12,000	$1,078	$1,117	3.54%
	16,000	$1,329	$1,378	3.68%
	20,000	$1,580	$1,639	3.77%
60	18,000	$1,607	$1,665	3.56%
	24,000	$1,977	$2,050	3.70%
	30,000	$2,344	$2,433	3.79%
80	24,000	$2,123	$2,198	3.54%
	32,000	$2,612	$2,708	3.68%
	40,000	$3,101	$3,218	3.77%
100	30,000	$2,635	$2,728	3.53%
	40,000	$3,247	$3,366	3.67%
	50,000	$3,858	$4,004	3.76%
200	60,000	$5,163	$5,339	3.40%
	80,000	$6,386	$6,614	3.57%
	100,000	$7,609	$7,889	3.68%

* Net rate including Schedules 91, 199, 290 and 297.

** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price**	Proposed Price	Difference
100	20,000	$2,527	$2,643	4.59%
	30,000	$3,081	$3,231	4.87%
	50,000	$4,187	$4,406	5.22%
200	40,000	$4,384	$4,576	4.39%
	60,000	$5,491	$5,752	4.75%
	100,000	$7,704	$8,102	5.16%
300	60,000	$6,421	$6,700	4.35%
	90,000	$8,081	$8,463	4.73%
	150,000	$11,400	$11,988	5.15%
400	80,000	$8,336	$8,698	4.35%
	120,000	$10,549	$11,048	4.73%
	200,000	$14,976	$15,748	5.16%
500	100,000	$10,280	$10,724	4.32%
	150,000	$13,046	$13,661	4.71%
	250,000	$18,580	$19,537	5.15%
600	120,000	$12,224	$12,750	4.30%
	180,000	$15,544	$16,275	4.70%
	300,000	$22,183	$23,325	5.15%
800	160,000	$16,112	$16,801	4.28%
	240,000	$20,538	$21,501	4.69%
	400,000	$29,391	$30,902	5.14%
1000	200,000	$20,000	$20,853	4.27%
	300,000	$25,533	$26,728	4.68%
	500,000	$36,599	$38,478	5.13%

* Net rate including Schedules 91, 199, 290 and 297.

** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price**	Proposed Price	Difference
100	30,000	$2,990	$3,177	6.25%
	40,000	$3,533	$3,753	6.23%
	50,000	$4,076	$4,330	6.22%
200	60,000	$5,340	$5,658	5.95%
	80,000	$6,427	$6,811	5.98%
	100,000	$7,513	$7,964	6.01%
300	90,000	$7,855	$8,320	5.91%
	120,000	$9,485	$10,049	5.95%
	150,000	$11,114	$11,779	5.98%
400	120,000	$10,283	$10,899	5.99%
	160,000	$12,456	$13,205	6.02%
	200,000	$14,628	$15,511	6.04%
500	150,000	$12,716	$13,473	5.96%
	200,000	$15,431	$16,356	5.99%
	250,000	$18,147	$19,238	6.01%
600	180,000	$15,149	$16,047	5.93%
	240,000	$18,407	$19,506	5.97%
	300,000	$21,666	$22,965	6.00%
800	240,000	$20,014	$21,195	5.90%
	320,000	$24,359	$25,807	5.95%
	400,000	$28,704	$30,419	5.98%
1000	300,000	$24,880	$26,343	5.88%
	400,000	$30,311	$32,108	5.93%
	500,000	$35,742	$37,873	5.96%

* Net rate including Schedules 91, 199, 290 and 297.

** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill**	December- March Monthly Bill**	Annual Load Size Charge	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$186	$213	$155	$194	$222	$155	4.36%	4.17%	0.00%
	3,000	$280	$306	$155	$292	$319	$155	4.36%	4.23%	0.00%
	5,000	$466	$492	$155	$486	$513	$155	4.35%	4.28%	0.00%
Three Phase										
20	4,000	$373	$425	$309	$389	$443	$309	4.35%	4.17%	0.00%
	6,000	$559	$612	$309	$583	$638	$309	4.36%	4.23%	0.00%
	10,000	$932	$984	$309	$972	$1,027	$309	4.36%	4.27%	0.00%
100	20,000	$1,864	$2,127	$1,360	$1,945	$2,216	$1,349	4.35%	4.17%	-0.76%
	30,000	$2,795	$3,059	$1,360	$2,917	$3,188	$1,349	4.36%	4.23%	-0.76%
	50,000	$4,659	$4,922	$1,360	$4,862	$5,133	$1,349	4.36%	4.27%	-0.76%
300	60,000	$5,591	$6,381	$3,420	$5,834	$6,647	$3,409	4.36%	4.17%	-0.30%
	90,000	$8,386	$9,176	$3,420	$8,752	$9,564	$3,409	4.36%	4.23%	-0.30%
	150,000	$13,977	$14,767	$3,420	$14,586	$15,399	$3,409	4.36%	4.27%	-0.30%

* Net rate including Schedules 91, 98, 199, 290 and 297.
** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill**	December-March Monthly Bill**	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$271	$297	$155	$283	$309	$155	4.48%	4.34%	0.00%
	4,000	$361	$387	$155	$377	$404	$155	4.48%	4.37%	0.00%
	5,000	$452	$477	$155	$472	$498	$155	4.48%	4.40%	0.00%
Three Phase										
20	6,000	$542	$593	$309	$566	$619	$309	4.48%	4.34%	0.00%
	8,000	$723	$774	$309	$755	$807	$309	4.48%	4.38%	0.00%
	10,000	$903	$954	$309	$944	$996	$309	4.48%	4.39%	0.00%
100	30,000	$2,710	$2,965	$1,349	$2,831	$3,094	$1,339	4.48%	4.34%	-0.76%
	40,000	$3,613	$3,868	$1,349	$3,775	$4,037	$1,339	4.48%	4.37%	-0.76%
	50,000	$4,516	$4,771	$1,349	$4,718	$4,981	$1,339	4.48%	4.40%	-0.76%
300	90,000	$8,129	$8,895	$3,409	$8,493	$9,281	$3,399	4.48%	4.34%	-0.30%
	120,000	$10,838	$11,604	$3,409	$11,324	$12,112	$3,399	4.48%	4.37%	-0.30%
	150,000	$13,548	$14,314	$3,409	$14,155	$14,943	$3,399	4.48%	4.40%	-0.30%

* Net rate including Schedules 91, 98, 199, 290 and 297.
** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price**	Proposed Price	Difference
1,000	300,000	$24,924	$26,225	5.22%
	500,000	$35,456	$37,541	5.88%
	700,000	$45,988	$48,858	6.24%
2,000	600,000	$49,363	$51,944	5.23%
	1,000,000	$68,637	$72,788	6.05%
	1,400,000	$88,785	$94,506	6.44%
6,000	1,800,000	$143,304	$151,336	5.60%
	3,000,000	$203,747	$216,489	6.25%
	4,200,000	$264,191	$281,641	6.61%
12,000	3,600,000	$285,201	$301,224	5.62%
	6,000,000	$406,089	$431,530	6.26%
	8,400,000	$526,976	$561,835	6.61%

Notes:

On-Peak kWh	64.31%
Off-Peak kWh	35.69%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price**	Proposed Price	Difference
1,000	300,000	$23,753	$25,449	7.14%
	500,000	$33,717	$36,214	7.41%
	700,000	$43,681	$46,980	7.55%
2,000	600,000	$46,980	$50,321	7.11%
	1,000,000	$65,118	$70,062	7.59%
	1,400,000	$84,130	$90,677	7.78%
6,000	1,800,000	$136,370	$146,332	7.31%
	3,000,000	$193,407	$208,177	7.64%
	4,200,000	$250,443	$270,021	7.82%
12,000	3,600,000	$271,303	$291,135	7.31%
	6,000,000	$385,376	$414,824	7.64%
	8,400,000	$499,449	$538,513	7.82%

Notes:

On-Peak kWh	61.66%
Off-Peak kWh	38.34%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price**	Proposed Price	Difference
1,000	500,000	$33,389	$34,985	4.78%
	700,000	$42,641	$44,958	5.43%
2,000	1,000,000	$63,999	$67,161	4.94%
	1,400,000	$81,587	$86,191	5.64%
6,000	3,000,000	$189,863	$199,308	4.97%
	4,200,000	$242,627	$256,398	5.68%
12,000	6,000,000	$377,392	$396,231	4.99%
	8,400,000	$482,920	$510,411	5.69%

Notes:

On-Peak kWh	56.97%
Off-Peak kWh	43.03%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

** Includes the effect of the estimated Transmission Investment Adjustment expected to become effective in early 2013.

Docket No. UE 263
Exhibit PAC/1204
Witness: Joelle R. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Joelle R. Steward

Generation Investment Adjustment Proposed Rate Spread and Illustrative Tariff

March 2013

PACIFIC POWER
STATE OF OREGON
Functionalized Generation Investment Adjustment Revenue Requirement
Forecast 12 Months Ended December 31, 2014
Dollars in Thousands

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential	**General Service**		**General Service**		**General Service**		**Large Power Service**			**Irrigation**	**Street Lgt.**
		Total		Sch 23		Sch 28		Sch 30		Sch 48T			Sch 41	Sch 51, 53, 54
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	Lakeside 2 Revenue Requirement	$22,671												
2	Collection for Schedules not included in COS Study*	$270												
3	Revenue Requirement for Schedules Included in COS Study	$22,401												
4														
5														
6	Generation Allocation Factors from GRC	100.00%	42.24%	8.59%	0.01%	15.44%	0.14%	9.56%	0.69%	4.44%	11.35%	5.70%	1.72%	0.12%
7														
8														
9	**Functionalized Revenue Requirement- (Target)**	**$22,401**	**$9,462**	**$1,924**	**$2**	**$3,459**	**$31**	**$2,143**	**$155**	**$995**	**$2,542**	**$1,277**	**$385**	**$28**

*Revenues by rate schedule as follows:

Schedule 47 Primary	$207
Schedule 47 Transmission	$29
Schedule 15	$12
Schedule 50	$10
Schedule 51 (partial)	$11
Schedule 52	$1
Total not in study	$270

PACIFIC POWER
STATE OF OREGON
Generation Investment Adjustment Proposed Rates and Rate Spread

Forecast 12 Months Ended December 31, 2014

Rate Schedule	Annual Forecast Energy		Proposed Generation Investment Adjustment Rates		Revenues
Schedule 4, Residential	5,379,568,669	kWh	0.176	¢/kWh	$9,468,041
Secondary Voltage					
Schedule 23, Small General Service					
Secondary Voltage	1,099,810,037	kWh	0.175	¢/kWh	$1,924,668
Primary Voltage	1,147,117	kWh	0.170	¢/kWh	$1,950
Schedule 28, General Service 31-200kW					
Secondary Voltage	1,974,277,099	kWh	0.175	¢/kWh	$3,454,985
Primary Voltage	18,573,773	kWh	0.166	¢/kWh	$30,832
Schedule 30, General Service 201-999kW					
Secondary Voltage	1,246,164,161	kWh	0.172	¢/kWh	$2,143,402
Primary Voltage	91,598,045	kWh	0.169	¢/kWh	$154,801
Schedule 41, Agricultural Pumping Service					
Secondary Voltage	230,988,811	kWh	0.166	¢/kWh	$383,441
Primary Voltage	414,701	kWh	0.161	¢/kWh	$668
Schedule 47, Large General Service, Partial Requirements 1,000kW and over					
Secondary Voltage	0	kWh	0.173	¢/kWh	$0
Primary Voltage	124,802,750	kWh	0.166	¢/kWh	$207,173
Transmission Voltage	19,049,386	kWh	0.154	¢/kWh	$29,336
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage	575,745,854	kWh	0.173	¢/kWh	$996,040
Primary Voltage	1,529,472,682	kWh	0.166	¢/kWh	$2,538,925
Transmission Voltage	829,896,081	kWh	0.154	¢/kWh	$1,278,040
Schedule 15, Outdoor Area Lighting Service					
Secondary Voltage	9,286,499	kWh	0.129	¢/kWh	$11,980
Schedule 50, Mercury Vapor Street Lighting Service					
Secondary Voltage	7,823,337	kWh	0.129	¢/kWh	$10,092
Schedule 51, 55, Street Lighting Service, Company-Owned System					
Secondary Voltage	19,612,310	kWh	0.129	¢/kWh	$25,300
Schedule 52, Street Lighting Service, Company-Owned System					
Secondary Voltage	523,143	kWh	0.129	¢/kWh	$675
Schedule 53, Street Lighting Service, Consumer-Owned System					
Secondary Voltage	8,966,764	kWh	0.129	¢/kWh	$11,567
Schedule 54, Recreational Field Lighting					
Secondary Voltage	1,249,347	kWh	0.129	¢/kWh	$1,612
TOTAL	**13,168,970,566**				**$22,673,528**

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 80

GENERATION INVESTMENT ADJUSTMENT

Purpose
This schedule reflects an adjustment associated with the Lake Side 2 generation investment, consistent with Order No. XXX.

Applicable
To all Residential Consumers and Nonresidential Consumers.

Monthly Billing
All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No. 36 shall have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Delivery Service Schedule	Secondary	Primary	Transmission
Schedule 4, per kWh	0.176¢		
Schedule 5, per kWh	0.176¢		
Schedule 15, per kWh	0.129¢		
Schedule 23, 723, per kWh	0.175¢	0.170¢	
Schedule 28, 728, per kWh	0.175¢	0.166¢	
Schedule 30, 730, per kWh	0.172¢	0.169¢	
Schedule 41, 741, per kWh	0.166¢	0.161¢	
Schedule 47, 747, per On-Peak kWh	0.173¢	0.166¢	0.154¢
Schedule 48, 748, per On-Peak kWh	0.173¢	0.166¢	0.154¢
Schedule 50, per kWh	0.129¢		
Schedule 51, 751, per kWh	0.129¢		
Schedule 52, 752, per kWh	0.129¢		
Schedule 53, 753, per kWh	0.129¢		
Schedule 54, 754, per kWh	0.129¢		