PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 30, 2009

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

Re: Advice Filing 09-007
PacifiCorp's 2010 Transition Adjustment Mechanism
Schedule 200, Cost-Based Supply Service

PacifiCorp (dba Pacific Power) submits for filing an original and five copies of Cost-Based Supply Service Schedule 200 - PacifiCorp's 2010 Transition Adjustment Mechanism ("TAM"). The Company is requesting an effective date of January 1, 2010 for these tariff sheets.

PacifiCorp waives paper service in this docket and requests that communications on this filing be addressed to the parties identified in subsection (C) herein.

A. Description of Filing

Pursuant to Commission Order No. 05-1050 in Docket UE 170, the TAM is filed each year on or about April 1. The purpose of the TAM filing is to update net power costs for 2010 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window.

This tariff filing is supported by testimony and exhibits from Company witnesses addressing overall net power costs and pricing. The testimony and exhibits contained in this filing address the OAR Division 22 requirements for filing tariffs or schedules that change rates.

B. Tariff Sheets

Fourteenth Revision of Sheet No. 200-1	Schedule 200	Cost-Based Supply Service
Fourteenth Revision of Sheet No. 200-2	Schedule 200	Cost-Based Supply Service
Thirteenth Revision of Sheet No. 200-3	Schedule 200	Cost-Based Supply Service

C. Correspondence

It is respectfully requested that all communications related to this filing be addressed to:

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Additionally, PacifiCorp respectfully requests that all data requests regarding this matter 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 Joelle Steward, Regulatory Manager, at (503) 813-5542.

A copy of this filing has been served on all parties to PacifiCorp's last TAM proceeding, UE 199, as indicated on the attached certificate of service.

Very truly yours,

Andrea L. Kelly /JB

Andrea L. Kelly
Vice President, Regulation
Enclosures

cc: UE 199 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 30th of March, 2009, I caused to be served, via E-Mail and overnight delivery (to those parties who have not waived paper service), a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

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Ariel Son
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BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

PACIFICORP

2010 TRANSITION ADJUSTMENT MECHANISM (TAM)

Direct Testimony and Exhibits

March 2009

Docket No. UE-
Exhibit PPL(TAM)/100
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Gregory N. Duvall

March 2009

Q. Please state your name, business address and present position with PacifiCorp, dba Pacific Power ("Company").

A. My name is Gregory N. Duvall, my business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232, and my present title is Director, Long Range Planning and Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a degree in Mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by Pacific Power in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon, was responsible for directing the analytical effort for the Multi-State Process ("MSP"), and currently direct the work of the integrated resource planning group, the load forecasting group, the market assessment group, and the net power cost group in the Company.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I present the Company's proposed 2010 Transition Adjustment Mechanism ("TAM") net power costs. Specifically, my testimony:

- Summarizes the purpose and content of the filing.

- Describes the changes in the Company's net power costs.
- Explains the background and design of the 2010 TAM filing.
- Describes modeling enhancements addressing hydro resources, dispatch of gas-fired units and call option contracts, duct-firing and inclusion of short-term firm transmission.
- Introduces the other witnesses providing testimony on behalf of PacifiCorp.

Summary of PacifiCorp's 2010 TAM Filing

Q. Please provide background on the Company's 2010 TAM filing.

A. The TAM is PacifiCorp's annual filing to update its net variable power costs in rates. The updated power costs are used to set the transition adjustment for direct access and, in this case, become effective in rates on January 1, 2010. This is the Company's fifth TAM filing. The Company is filing the 2010 TAM concurrently with a request for a general rate increase. Because the rate effective date for the general rate case is February 1, 2010, one month later than the TAM, the Company has filed the TAM separately from its general rate case.

Q. What are the forecasted normalized system-wide net power costs for calendar year 2010?

A. The Company's total forecasted normalized system-wide net power costs for the test period of 12 months ending December 31, 2010, are approximately $1.101 billion.

Q. What is the estimated amount of the increase in Oregon-allocated net power costs upon which the Transition Adjustment will be based for calendar year 2010?

A. As shown in Exhibit PPL(TAM)/101, on an Oregon-allocated basis, the Company's forecasted normalized net power costs for calendar year 2010 are approximately $6.1 million, or 0.7 percent, higher than the net power costs currently in Oregon rates. The net power costs currently in rates are the result of a settlement in the Company's 2009 TAM, Docket UE 199. ("UE 199")

Q. Did the Company agree to incorporate a load-change adjustment in future TAM filings in the UE 199 Stipulation?

A, Yes. Staff and ICNU proposed such an adjustment in UE 199. As a part of the Stipulation in that case, the parties incorporated the adjustment into the 2009 TAM. Additionally, the parties agreed that the Company should design future TAM filings "to recover the Company's Oregon-allocated NPC, including calculation of the increased/decreased revenues due to load growth/load loss."

Q. Did the Company include a TAM load-change adjustment in this filing?

A. Yes. The load forecast in this case reflects a decrease in Oregon loads when compared to the 2009 projected loads from UE 199. Company witness Ms. Judith M. Ridenour explains the calculation of the load-change adjustment in this case. Because Oregon loads are decreasing due to the recession, rates have been designed to collect an additional $14.4 million of revenue. The combination of the $6.1 million in increased net power costs and the $14.4 million of decreased revenues results in a total proposed revenue increase of $20.6 million. As explained in Ms. Ridenour's testimony, this is an overall average increase of approximately 2.1 percent.

Changes in Net Power Costs

Q. Please describe the changes in net power costs forecasted in this case.

A. As discussed above, the Company's 2010 net power costs are projected to increase by 0.7 percent as compared against the 2009 net power costs in rates. Although the overall increase is quite moderate, there are certain factors that are driving increases in net power costs and certain factors that are driving decreases in net power costs. The factors that are driving net power costs upward in 2010 include the expiration of existing long-term firm power purchase and sales contracts, increased firm wheeling expenses, addition of natural gas pipeline reservation fees and startup fuel costs, lower hydro generation at Company-owned facilities, and increases in coal costs. The factors that are driving net power costs downward in 2010 include decreases in the forecast load due to the recession, and the addition of new generation resources.

Q. How do expiring power purchase and sales contracts impact net power costs?

A. The cost of the replacement power could be higher or lower, depending on whether the price of the expired power purchase contract was below or above the market prices. Likewise, the revenue credits of additional wholesale sales could be lower or higher, depending on whether the price of the expired power sales contract was above or below the market prices. Beginning in November 2009, the original contract between the Company and the Grant Public Utility District ("Grant PUD") for the generation from the Wanapum project expires. Because this contract was priced at the cost of the Wanapum project, net power costs in the test period are higher due to higher costs of the replacement power. The cost increase from this contract is somewhat mitigated by the increase in revenues from the Reasonable Portion of the contract with Grant PUD. In total, changes to the Mid-Columbia contracts cause net power costs to increase by approximately $10 million from UE 199 on a total Company basis. In addition, this filing reflects the expiration of the sales contract with NV Energy ("Sierra Pacific") and a reduction in the energy take of the sales contract with the Public Service Company of Colorado ("PSCol") per the contract terms. The combined impact of the two contracts increases net power costs by approximately $5 million on a total Company basis.

Q. What are the primary reasons for the increase in firm wheeling expenses?

A. Wheeling expenses increased due to a low priced formula power transfer ("FPT") wheeling contract with the Bonneville Power Administration ("BPA") that expires and will be converted to a higher priced BPA point-to-point ("PTP") contract. BPA is eliminating FPT contracts when they expire. Wheeling expenses also increased to reflect wheeling generation from the newly acquired Chehalis natural gas plant to the Company's load center and market. In addition, the Company has received a verbal notice from Idaho Power Company to modify the wheeling contract associated with delivering generation from the Jim Bridger plant to the Company's load areas. The total changes in wheeling expenses result in an approximate $25 million increase in net power costs from UE 199 on a total Company basis.

Q. Are there other new costs associated with the Chehalis plant included in net power costs?

A. Yes. Net power costs include the cost of transporting natural gas for the Chehalis plant, approximately $13 million, and startup fuel costs of the plant.

Q. Please explain why the Company-owned hydro generation in the current filing is lower than UE 199.

A. The operational flexibility at the Company's Lewis River system has decreased due to changes in the Company's contracts for generation from the Mid Columbia projects. Also, the hydro generation in the current filing reflects the expiration of the operating license of the Condit dam and minimum flow requirements on other facilities from relicensing. The total impact of the reduction in hydro generation from the Company-owned facilities increases net power costs by approximately $19 million from UE 199 on a total Company basis.

Q. Have the Company's coal costs impacted the net power costs in the current proceeding?

A. Yes. Net power costs are higher due to increases in the costs of coal supplied to the coal-fired generating facilities from both the Company's captive mines and contracts with third parties. Further details on coal costs are provided in the testimony of Company witness Mr. A. Robert Lasich.

Q. How does retail load forecast impact the Company's net power costs?

A. This filing reflects a decrease of approximately three percent in the forecast load over loads reflected in UE 199. All else held constant, decreased load reduces net power costs.

Q. Are the net power cost increases also partially offset by the inclusion of additional resources during calendar year 2010?

A. Yes. The generation from the Chehalis plant and the High Plains wind project located in Wyoming are included in net power costs for the current proceeding.

Q. What is the impact of the Chehalis Plant in the current filing?

A. The impact of not running the Chehalis plant would increase net power costs by approximately $14 million

Q. Has the Company updated its wind integration charges?

A. Yes. There are two categories of wind integration charges, one for wind resources located in the Company's control area, and one for the Company's wind resources located in BPA's control area. For the former, the Company continues to use the value from the Company's 2007 Integrated Resource Plan ("IRP") escalated to 2010, which is $1.15 per megawatt hour. For the latter, the charge has been updated from $0.68 per kW-month to $2.72 per kW-month based on the most recent proposals in the current BPA transmission rate case.

TAM Background and Design Issues

Q. Does this filing incorporate an adjustment to include the short-term trading margin from Order No. 07-446 approving the 2008 TAM, Docket UE 191?

A. Yes. To streamline the filing, the Company has included the wholesale trading margin in this filing, despite concerns about incorporating selective, one-sided adjustments based upon actual results into normalized net power costs.

Q. Please explain the short-term wholesale trading margin adjustment.

A. In UE 191, the Commission ordered the Company to include $0.8 million on an

Oregon-allocated basis for margins associated with its short-term trading activities. The amount was based on the Company's average historical differences between revenues and expenses of its trading activities in the last four years. In the current proceeding, the Company used the same methodology and the four-year period through June 2008. The average net revenue during this period is $4.8 million on a total Company basis, and approximately $1.3 million on an Oregon-allocated basis.

Q. Has the Company made changes to its modeling of outages since UE 199?

A. No. The modeling of outages is the subject of an on-going Commission investigation in Docket UM 1355. In this filing, the Company is using the same methodology as in UE 199 for both planned and forced outages, and for thermal and hydro generating units. The proposed schedule in UM 1355 provides for a Commission order resolving issues in mid-August 2009. The Company will incorporate Commission-ordered changes, if necessary, to the outage modeling in the Company's November TAM updates.

Q. Did the Company convene workshops prior to filing this case for the purpose of seeking consensus on the specific elements of future TAM proceedings, as required by the stipulation in UE 199?

A. Yes. Pursuant to the UE 199 Stipulation, the Company convened workshops with interested parties. Commission Staff, the Citizen's Utility Board of Oregon, the Industrial Customers of Northwest Utilities, Sempra and the Company met for three workshops, participated in conference calls and circulated several draft proposals in an effort to reach consensus. While progress was made, the parties were unable to reach a consensus on all issues by the agreed upon date. Therefore, the Company filed on February 5, 2009 to initiate a proceeding, as required by the Stipulation.

Q. Pending resolution in the separate proceeding, does the Company intend to follow the same process for updating net power costs in this case as used in UE 199 and other TAM filings?

A. Yes. As in all previous TAM filings, and consistent with the Commission's Order No. 05-1050 that adopted the TAM, the Company intends to update net power costs concurrently with its rebuttal filing and then again before the direct access window in the fall. In the rebuttal update, the Company will update the forward price curve and will update for new power, fuel and transportation/transmission contracts, both physical and financial, and changes to existing contracts. In early November, prior to the posting of indicative prices, the Company will make these same updates, plus reflect any Commission-ordered changes to net power costs. In mid-November, just prior to the direct access open enrollment window, the Company will produce a final GRID study incorporating its most recent forward price curve. This final GRID study will establish the Transition Adjustment and total Company net power costs for calendar year 2010.

Q. Has the Company made changes to this filing to address issues raised by the parties in the workshops?

A. Yes. The parties asked the Company to provide information on potential contract updates in the initial TAM filing. Based on this request, Exhibit PPL(TAM)/102 contains a list of known contracts that could be included in the Company's TAM updates in this case. The Company will update this list as new information becomes available.

Q. Did the parties ask the Company to include other information in its initial TAM filing in this case?

A. Yes. The parties asked the Company to identify the 48-month historical period used to determine the outage rates and other inputs in the initial filing. The historical base period for the current filing is 48-months ending June 2008 for most of the data, with the exception of short-term firm transmission discussed later in my testimony.

Q. What workpapers did the Company provide with this filing?

A. Pursuant to the UE 199 Stipulation, the Company provided access to the GRID model concurrently with this initial filing. In addition, the Company provided parties with workpapers, specifically the Company's net power cost report workbook and the GRID project report.

Determination of Net Power Costs

Q. Please explain net power costs.

A. Net power costs are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

Q. Please explain how the Company calculates net power costs.

A. Net power costs are calculated for a future test period based on projected data using the GRID model. For each hour in the forecast period, the model simulates the operation of the power supply portion of the Company under a given stream flow condition.

Q. Is the Company's general approach to the calculation of net power costs using the GRID model the same in this case as in previous cases?

A. Yes. The Company has used the GRID model in its last several rate case and TAM filings in Oregon.

Q. Is the Company using the same version of the GRID model as used in UE 199?

A. Yes.

GRID Model Inputs and Outputs

Q. What inputs were updated for this filing?

A. The net system load, wholesale sales and purchase power expenses, wheeling expenses, market prices for natural gas and electricity, fuel expenses, hydro generation, thermal capacity, heat rates, thermal planned maintenance and outages inputs were updated for this filing.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the Net Power Cost report. This is attached to my testimony as Exhibit PPL(TAM)/103. Additional data with more detailed analyses are also available in hourly, daily, monthly and annual formats by heavy load hours and light load hours.

Q. Do you believe that the GRID model appropriately reflects the Company's forecasted net power costs over the test period?

A. Yes. The GRID model reasonably simulates the operation of the Company's system load and resource portfolio consistent with the Company's operation of its system including operating constraints and requirements. Like any model, the simulated result may not match the individual components on actual basis perfectly. And like any model, certain improvements and enhancements are made from time to time.

Enhancements to the GRID Model

Q. Please described the major enhancements to the GRID model that the Company made in the filing.

A. There are several major changes to the inputs of the GRID model: hydro generation, dispatch of thermal resources, duct-firing and inclusion of short-term firm transmission.

Q. How has the Company changed its hydro generation inputs for normalized net power costs?

A. In UE 199, the Company used three equally weighted "exceedence levels" to determine the hydro volumes used in GRID and the dispatch of the resources. In this proceeding, the Company uses a median hydro condition that is created using a single water year input based on a historical water inflow profile and median water volume.

Q. Why did the Company choose to use median hydro?

A. It is transparent and easy to understand and it is consistent with the hydro condition used by the Company for operational planning. This change does not significantly change the net power cost results.

Q. Please describe how the median hydro forecast is created.

A. For run-of-river projects, the single year forecast is simply the median generation of the available historical data. This is not a change from past practice and includes historical outages. For other river systems with reservoirs and the Mid Columbia projects, the single year inflow forecast is created based on the average daily or weekly shapes and median annual volumes of the available historical inflow data, which can range from about ten years to about 70 years depending on the river system.

Q. Is the hydro generation still created by the same model?

A. Yes. Weekly median hydro generation is the created by the Company's VISTA model given one inflow forecast, as well as other information required to simulate the operations of the reservoirs.

Q. Please address how the Company has ensured the prudent dispatch of its thermal units in the GRID model?

A. Similar to the approach used in UE 199, the Company has taken steps to mitigate the uneconomic dispatch of the gas-fired resources in its net power costs model on a monthly basis. Once all other inputs have been set, final net power costs are determined after a series of GRID runs to screen out the uneconomic commitment of gas-fired plants. The screens are set in a manner that blocks the gas-fired plants from being committed to run if they displace less expensive resources after taking start-up costs into consideration. In addition to Currant Creek and Lake Side, the screens are also set for the Gadsby steam units and peakers, and the Chehalis plant.

Q. Could you please give an example of how the Company sets up a screen?

A. The screen is reflected by a change in planned outages to make the plant not available during the periods when it is not economical for it to run. To set up the screen for the Currant Creek plant, for example, the Company made an initial model run including the plant with the normalized planned outages only. The Company then made a second model run excluding the plant from the resource portfolio. Based on hourly comparison of the variable costs between the two model runs, with and without the plant and the additional costs of starting up the plant, the Company determined additional "planned outages." These planned outages are blocks of hours on a monthly basis when it is uneconomical to run the Currant Creek plant.

Q. Did the Company also apply the screens to the Company's call option contracts?

A. Yes. There are two call option contracts in the current test period. Model runs were made to check if they are exercised economically. One of the call options was restricted from being exercised because exercising it would cause the net power costs to increase.

Q. How is the Company modeling duct firing units?

A. The duct firing units of the Currant Creek and Lake Side plants are modeled as separate units from the underlying 2 by 1 combined-cycle combustion turbines consistent with how the Company modeled these units in UE 199. Ideally, the underlying combustion turbine and its duct firing unit would be modeled together as a single unit, since the duct firing unit cannot run until the underlying 2 by1 combined-cycle plant is fully running. They are not, however, because the duct firing unit and the underlying 2 by1 combined-cycle unit have significantly different heat rates.

Q. Has the Company made any improvements in how it models duct firing units in this filing?

A. Yes. The Company has added screens to ensure that the duct firing units do not run when their corresponding underlying combined-cycle unit is not running.

Q. How well does the screen of the duct firing units approximate how the units actually operate?

A. Very well. A duct firing unit comes online only after the underlying unit reaches its maximum capacity. The Company's modeling now recognizes this dependency in that the duct firing units cannot operate independently of the underlying unit.

Q. Has the Company added short-term firm transmission to its net power costs modeling?

A. Yes.

Q. Please explain how the short-term firm transmission is added.

A. In addition to the long-term rights per contract terms on Company-owned transmission lines and lines from third parties, the Company added additional transmission paths based on transmission contracts that the Company has entered into over the four-year period ending December 2007, which is the most recent data available at the time of the study. The size of the additional transmission paths are the average megawatt hour of capacities purchased in the four-year period. The use of a four-year period is appropriate given that the amount of short-term firm transmission can vary year-to-year. However, the addition of short-term firm transmission to the GRID model recognizes that the Company does enter into these contracts and the costs of these contracts are reflected in rates.

Q. Is the Company also proposing to add a transmission path between its Four Corners and SP15 transmission areas?

A. Yes. While the Company has not purchased long-term or short-term transmission on this path for use in 2010, the Company is proposing to add a path to its net power costs model at a zero variable cost, from the Four Corners transmission area to the SP15 market, to meet the requirement of the short physical positions that are created by the short-term firm sales at SP15.

Q. Please explain why the Company enters into transactions that have delivery points in SP15 when it does not have firm transmission rights.

A. Sales at SP15 are made to hedge the Company's long fixed-price position at Four Corners. This occurs when the Company has a desire to hedge its fixed-price exposure but the Four Corners market is illiquid. A portion of the transactions are financial hedges and do not require physical delivery of power. However, if the hedges are physical products, at a time closer to delivery when the Four Corners market becomes more liquid, the Company would sell at Four Corners and buy at SP15. Alternatively, the Company may wheel the power from Four Corners to SP15 to close the SP15 physical positions in the hour-ahead market if transmission were available and it is more economical to do so.

Q. How does the Company size the transmission path from Four Corners to SP15?

A. As described above, the Company utilizes the SP15 market to hedge the exposure at the Four Corners area when the Four Corners market is still illiquid. Since the transactions at SP15 are for system balancing rather than trading, the size of the transfer allowed from the Four Corners to SP15 should not exceed the physical short positions at the SP15 market. That is, the physical short positions at SP15 may be met either with purchases in the SP15 market, or transferred from the Four Corners market on a forward basis in GRID. Since there are no net short term firm sales at the SP15 market at this time for 2010, the link is not present in the current filing. Transfer capability will be added in the July and November update filings to the extent new wholesale power contracts are added at SP15.

Introduction of Witnesses

Q. Please list the other Company witnesses in the 2010 TAM and provide a brief explanation of the witness' testimony.

A. The other Company witnesses filing direct testimony are:

- **A. Robert Lasich**, President, PacifiCorp Energy, who discusses the primary factors for the increases in coal costs, and demonstrates the benefits of affiliated mining interests relative to the coal market.
- **Judith M. Ridenour**, Regulatory Consultant, Pricing & Cost of Service, who presents the Company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL(TAM)/101
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Allocated Net Power Costs to Oregon

March 2009

Net Power Costs for Oregon TAM

2010 TAM Filing

		Total Company					Oregon Allocated	
	ACCOUNT	CY 2009 FINAL UE-199	CY 2010 FILED		CY 2009 FINAL UE-199	CY 2010 FILED	CY 2009 FINAL UE-199	CY2010 FILED
Sales for Resale								
Existing Firm PPL	447	24,281,555	24,656,916	SG	26.411%	26.877%	6,413,106	6,627,011
Existing Firm UPL	447	25,490,590	25,490,589	SG	26.411%	26.877%	6,732,429	6,851,076
Post-Merger Firm	447	882,169,664	696,790,188	SG	26.411%	26.877%	232,993,623	187,275,491
Non-Firm	447	-	-	SE	25.525%	25.002%	-	-
Total Sales for Resale		931,941,809	746,937,693				246,139,158	200,753,578
Purchased Power								
Existing Firm Demand PPL	555	62,711,383	57,671,363	SG	26.411%	26.877%	16,562,973	15,500,265
Existing Firm Demand UPL	555	46,726,726	47,195,846	SG	26.411%	26.877%	12,341,196	12,684,773
Existing Firm Energy	555	66,847,124	55,596,693	SE	25.525%	25.002%	17,062,586	13,900,229
Post-merger Firm	555	707,106,149	376,422,870	SG	26.411%	26.877%	186,756,845	101,170,739
Secondary Purchases	555	-	-	SE	25.525%	25.002%	-	-
Seasonal Contracts	555	7,688,490	-	SSGC	24.488%	0.000%	1,882,756	-
Other Generation Expense	555	5,247,531	11,022,399	SG	26.411%	26.877%	1,385,948	2,962,477
Total Purchased Power		896,327,403	547,909,171				235,992,304	146,218,483
Wheeling Expense								
Existing Firm PPL	565	31,031,711	43,189,893	SG	26.411%	26.877%	8,195,919	11,608,098
Existing Firm UPL	565	172,448	168,268	SG	26.411%	26.877%	45,546	45,225
Post-merger Firm	565	83,334,742	96,107,739	SG	26.411%	26.877%	22,009,897	25,830,766
Non-Firm	565	184,789	282,748	SE	25.525%	25.002%	47,167	70,692
Total Wheeling Expense		114,723,691	139,748,649				30,298,529	37,554,781
Fuel Expense								
Fuel Consumed - Coal	501	568,676,213	604,154,098	SE	25.525%	25.002%	145,153,389	151,049,995
Cholla	501	57,517,646	54,964,906	SSECH	25.897%	25.405%	14,895,507	13,963,575
Fuel Consumed - Gas	501	27,408,356	21,128,538	SE	25.525%	25.002%	6,995,924	5,282,536
Natural Gas Consumed	547	374,811,293	458,583,217	SE	25.525%	25.002%	95,669,782	114,654,511
Simple Cycle Combustion Turbines	547	23,655,228	17,499,425	SSECT	24.286%	23.563%	5,744,981	4,123,302
Steam from Other Sources	503	3,541,671	3,494,899	SE	25.525%	25.002%	904,004	873,791
Total Fuel Expense		1,055,610,407	1,159,825,082				269,363,588	289,947,711
Net Power Cost		1,134,719,692	1,100,545,210				289,515,263	272,967,396
Net Power Costs in Rates from UE-199		**1,043,323,002**					**266,835,529**	
			57,222,208					**6,131,867** Increase Absent Load Change

Oregon-Allocated NPC Baseline in Rates from UE 199	$	266,835,529
2009 MWH (excluding Schedule 33)		14,026,969
$/MWH in Rates		19.02
2010 MWH (excluding Schedule 33)		13,267,901
2010 Recovery of NPC in Rates	**$**	**252,395,751**
		20,571,646 Increase With Load Change

Docket No. UE-
Exhibit PPL(TAM)/102
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

List of Expected Contracts

March 2009

Exhibit PPL/102

Contracts that would have changes during 2009 for 2010:

Sales and Purchases of Electricity and Natural Gas

1. New sales and purchases contracts, physical and financial
2. New sales and purchase contracts for natural gas, physical and financial
3. Sales contract with Black Hills Company
4. Sales contract with Public Service Company of Colorado
5. Purchase contracts for generation from the Mid Columbia projects
6. Purchase contract with Tri-State Generation and Transmission Association Inc
7. Purchase contract with MagCorp for ready reserves
8. Generation incentive contract with Kennecott
9. Contracts whose prices are linked to market indexes and inflation rates

Transportation and Storage of Natural Gas

10. Pipeline changes for transporting natural gas from market to Company's Generating Facilities
11. Contracts whose prices are linked to market indexes and inflation rates

Wheeling Expenses and Transmission

12. Modifications to the transmission agreement with the Idaho Power Company
13. Final wind integration charge by the BPA
14. Wind integration charge for the wind resource in the Company's control area
15. Transmission from the Four Corners market to the SP15 market
16. Contracts whose prices are linked to market indexes and inflation rates

Coal Costs

July 2010 TAM Projected Price Updates

		Captive		Fixed Price Contracts		Escalating Contracts		Transportation Contacts	
Plant	**Supplier/Mine**	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Bridger	Bridger Coal Company	Yes	No						
	Black Butte					Yes	Yes		
	Union Pacific Railway							Yes	Yes
Carbon	Arch - Skyline			Yes	Yes				
	Arch - Dugout			Yes	Yes				
	Utah Trucking							Yes	Yes
Cholla	Peabody Coalsales - Lee Ranch Mine					Yes	Yes		
	BNSF Railway							Yes	Yes
Colstrip	Westmoreland - Rosebud Mine					Yes	Yes		
Craig	Trapper Mine	Yes	No						
	Rio Tinto- - Colowyo Mine					Yes	Yes		
	Union Pacific Railway							Yes	Yes
Hayden	Peabody Coalsales - Twentymile Mine					Yes	Yes		
	Pirate Trucking							Yes	Yes
Hunter	Deer Creek	Yes	No						
	Arch - Sufco			Yes	Yes				
	Arch - Dugout			Yes	Yes				
	Murray Energy - Westridge Mine			Yes	Yes				
	Utah Trucking							Yes	Yes
Huntington	Deer Creek	Yes	No						
	Arch - Sufco			Yes	Yes				
	Utah Trucking							Yes	Yes
D Johnston	Black Hills - Wyodak Mine					Yes	Yes		
	Arch - Coal Creek Mine			Yes	Yes				
	Western Fuels - Dry Fork Mine			Yes	Yes				
	Spot					Yes	Yes		
	BNSF Railway							Yes	Yes
Naughton	Chevron Mining - Kemmerer Mine					Yes	Yes		
Wyodak	Black Hills - Wyodak Mine					Yes	Yes		

Docket No. UE-
Exhibit PPL(TAM)/103
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Net Power Costs Report

March 2009

Exhibit PPL(TAM)/103
Duvall/1

PacifiCorp

_OR GRC CY2010 - NPC Study GOLD _2009 03 17

Net Power Cost Analysis

$

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	11,692,116	979,308	938,959	989,899	968,466	975,400	958,814	995,280	983,916	965,773	979,983	969,368	986,951
BPA Wind	2,748,457	344,454	288,814	279,631	217,271	205,016	166,318	124,735	118,197	155,395	227,090	286,056	335,480
Hurricane Sale	985,499	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125
LADWP (IPP Layoff)	25,490,589	2,164,955	1,955,441	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955
PSCO	32,663,275	2,837,461	2,625,426	2,700,006	2,613,730	2,676,610	2,618,117	2,837,460	2,837,460	2,761,421	2,689,771	2,638,589	2,827,225
SMUD	12,964,800	1,990,600	1,228,400	96,200	81,400	-	-	1,420,800	1,724,200	1,613,200	1,576,200	1,498,500	1,735,300
UMPA II	9,769,272	603,875	571,475	603,875	593,075	603,875	948,920	1,811,625	1,425,145	806,582	603,875	593,075	603,875
Total Long Term Firm Sales	96,314,008	9,002,777	7,690,641	6,916,691	6,651,182	6,707,981	6,869,409	9,436,981	9,335,998	8,479,611	8,323,998	8,162,828	8,735,910
Short Term Firm Sales													
COB	68,026,380	9,530,480	8,487,360	9,360,240	4,305,600	4,140,000	4,305,600	5,114,200	5,114,200	4,917,500	4,305,600	4,140,000	4,305,600
Four Corners	20,391,520	2,957,110	2,475,720	2,682,030	1,285,160	1,454,260	1,285,160	1,386,620	1,386,620	1,352,800	1,386,620	1,352,800	1,386,620
Mid Columbia	18,520,800	3,968,100	3,747,600	4,198,500	1,456,000	1,400,000	1,456,000	774,800	774,800	745,000	-	-	-
Palo Verde	52,506,990	6,733,350	6,076,200	6,725,550	5,730,780	5,888,430	5,730,780	2,706,050	2,706,050	2,626,000	2,552,650	2,478,500	2,552,650
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	4,782,179	398,515	398,515	398,515	398,515	398,515	398,515	398,515	398,515	398,515	398,515	398,515	398,515
Total Short Term Firm Sales	164,227,869	23,587,555	21,185,395	23,364,835	13,176,055	13,281,205	13,176,055	10,380,185	10,380,185	10,039,815	8,643,385	8,369,815	8,643,385
System Balancing Sales													
COB	91,004,073	7,771,255	7,218,538	8,175,094	7,307,110	6,736,239	5,513,480	6,030,231	7,139,657	6,399,923	7,684,687	9,315,860	11,712,000
Four Corners	198,413,073	18,800,170	14,388,469	10,711,266	12,413,333	10,722,070	12,218,646	21,885,870	16,140,305	16,900,306	21,451,408	23,269,484	19,511,746
Mid Columbia	114,131,334	15,865,181	3,837,909	6,336,594	1,240,773	2,126,418	2,509,023	8,763,092	4,700,476	22,509,850	16,218,691	14,356,798	15,666,529
Mona	18,134,800	1,888,045	205,185	1,448,101	1,134,677	1,807,610	1,769,850	1,264,001	2,755,420	2,660,498	1,751,877	1,053,917	395,620
Palo Verde	64,712,536	3,708,057	3,557,331	4,186,273	7,436,657	6,660,500	5,995,014	5,205,923	5,201,005	5,521,456	5,603,076	5,500,424	6,136,823
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	486,395,815	48,032,707	29,207,432	30,857,328	29,532,549	28,052,836	28,006,013	43,149,117	35,936,863	53,992,033	52,709,739	53,496,482	53,422,718
Total Special Sales For Resale	746,937,693	80,623,040	58,083,468	61,138,853	49,359,786	48,042,022	48,051,477	62,966,283	55,653,045	72,511,458	69,677,122	70,029,125	70,802,013

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_OR GRC CY2010 - NPC Study GOLD _2009 03 17

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	10,927,901	177,888	177,991	939,790	1,729,945	1,725,692	2,329,705	1,106,173	435,085	437,121	1,249,682	395,927	222,901
Blanding Purchase	19,725	1,675	1,513	1,675	1,621	1,675	1,621	1,675	1,675	1,621	1,675	1,621	1,675
Combine Hills	3,911,516	374,287	244,282	432,546	304,814	283,008	340,525	326,830	324,299	309,038	331,759	369,943	270,184
Deseret Purchase	32,249,754	2,710,272	2,593,056	2,710,272	2,671,200	2,710,272	2,671,200	2,710,272	2,710,272	2,671,200	2,710,272	2,671,200	2,710,272
Douglas PUD Settlement	1,894,200	95,756	92,645	125,479	174,570	266,088	280,849	221,857	172,811	103,279	125,616	116,398	118,851
Gemstate	2,716,400	222,200	219,500	224,300	215,100	215,100	215,100	215,100	221,500	215,100	265,600	265,600	222,200
Georgia-Pacific Camas	7,280,700	618,361	558,520	618,361	598,414	618,361	598,414	618,361	618,361	598,414	618,361	598,414	618,361
Grant County 10 aMW purchase	6,971,139	571,459	463,808	514,203	534,854	585,061	593,363	750,640	782,483	621,574	488,377	457,778	607,540
Hermiston Purchase	98,888,667	8,928,753	8,370,993	8,660,291	6,352,426	6,963,650	6,577,722	8,624,293	8,667,109	8,585,331	8,807,686	9,059,509	9,290,904
Hurricane Purchase	328,501	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375
Idaho Power RTSA Purchase	2,372,618	206,635	188,554	202,800	75,957	55,235	193,324	303,100	324,019	242,208	176,721	186,850	217,216
IPP Purchase	25,490,589	2,164,955	1,955,441	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955
Kennecott Generation Incentive	8,211,540	-	-	445,008	503,561	498,523	303,486	1,875,336	2,122,795	1,717,515	745,316	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	1,755,360	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280
Morgan Stanley p189046	10,683,600	870,000	835,200	939,600	904,800	870,000	904,800	904,800	904,800	870,000	904,800	870,000	904,800
Morgan Stanley p272153-6-8	1,485,000	-	-	-	-	-	495,000	495,000	495,000	-	-	-	-
Morgan Stanley p272154-7	3,369,600	-	-	-	-	-	524,000	2,321,600	524,000	-	-	-	-
Nucor	4,610,400	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200
P4 Production	16,193,520	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460
PGE Cove	252,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000
Rock River	5,041,688	614,835	485,591	490,707	384,510	367,683	277,559	197,878	239,001	310,441	444,855	605,219	623,409
Roseburg Forest Products	8,767,111	740,873	674,107	747,821	723,250	740,873	723,250	744,347	744,346	719,775	744,347	719,776	744,347
Small Purchases east	570,556	67,645	52,765	46,480	44,319	37,967	35,152	32,262	36,915	32,677	89,197	43,403	51,774
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	10,935,525	-	-	-	-	-	1,183,705	1,054,534	1,080,289	1,421,602	1,785,496	2,005,586	2,404,313
Tri-State Purchase	10,971,155	932,093	906,028	928,005	831,577	865,469	905,148	980,731	995,854	950,926	874,870	887,163	913,291
Wolverine Creek	9,748,726	722,591	570,183	1,135,230	1,093,009	1,065,499	830,533	810,703	760,900	707,747	612,757	801,036	638,537
Long Term Firm Purchases Total	285,647,492	21,948,592	20,318,492	23,255,839	21,167,358	21,963,428	24,007,885	28,388,762	26,254,786	24,538,997	25,070,657	24,078,853	24,653,844
Seasonal Purchased Power													
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

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_OR GRC CY2010 - NPC Study GOLD _2009 03 17

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Qualifying Facilities													
QF California	4,026,592	387,407	465,359	612,482	697,499	700,649	513,945	157,972	74,754	62,334	58,899	87,379	207,914
QF Idaho	4,134,120	284,092	256,470	327,684	360,466	468,529	505,260	390,670	306,588	295,810	322,415	317,409	298,726
QF Oregon	18,594,597	1,791,121	1,688,038	1,883,638	1,967,093	1,866,316	1,560,912	1,259,690	1,159,138	1,201,478	1,229,801	1,337,666	1,649,707
QF Utah	705,089	52,109	59,151	58,425	67,055	70,420	68,201	58,369	54,041	52,715	65,080	56,660	42,865
QF Washington	1,931,867	160,049	147,934	154,519	161,333	184,376	172,564	174,469	162,340	158,197	152,351	156,319	147,416
QF Wyoming	725,034	15,375	14,501	14,044	38,135	109,333	111,447	119,184	118,964	106,725	47,724	15,152	14,451
Biomass	27,250,062	2,309,276	2,111,600	2,309,276	2,243,384	2,309,276	2,243,384	2,309,276	2,309,276	2,243,384	2,309,276	2,243,384	2,309,276
Douglas County Forest Products QF	247,106	47,270	37,911	35,193	35,768	26,161	24,104	40,698	-	-	-	-	-
Evergreen BioPower QF	3,571,338	317,135	286,061	314,752	305,187	245,621	305,188	316,378	315,508	303,003	319,320	303,003	240,182
ExxonMobil QF	31,569,800	4,446,144	3,830,734	3,537,665	1,589,308	1,358,480	1,408,205	1,052,316	2,618,880	2,057,022	2,125,590	3,401,415	4,144,043
Mountain Wind 1 QF	10,554,541	1,462,169	833,144	1,189,703	618,885	654,677	590,656	688,592	991,207	788,374	720,697	992,110	1,024,326
Mountain Wind 2 QF	16,296,914	2,193,392	1,233,591	1,808,707	921,157	966,854	990,160	1,231,594	1,644,434	1,227,738	1,043,794	1,500,671	1,534,822
Oregon Wind Farm QF	7,134,319	410,370	453,099	580,986	712,274	720,080	837,294	852,615	654,967	530,024	538,533	625,998	218,079
Simplot Phosphates	3,796,797	321,520	295,186	321,520	312,742	321,520	312,742	321,520	321,520	312,742	321,520	312,742	321,520
Spanish Fork Wind 2 QF	2,948,260	246,059	193,055	175,077	170,308	154,745	234,248	364,568	374,299	281,621	227,354	233,241	293,685
Sunnyside	25,811,027	2,295,926	2,142,905	1,630,262	2,170,591	2,135,667	2,118,964	2,321,148	2,331,296	2,284,897	1,922,681	2,189,136	2,267,553
Qualifying Facilities Total	159,297,462	16,739,414	14,048,739	14,953,933	12,371,185	12,292,703	11,997,274	11,659,058	13,437,211	11,906,063	11,405,033	13,772,286	14,714,563
Mid-Columbia Contracts													
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Chelan - Rocky Reach	4,257,236	354,770	354,770	354,770	354,770	354,770	354,770	354,770	354,770	354,770	354,770	354,770	354,770
Douglas - Wells	4,830,214	400,757	400,757	400,757	400,757	400,757	400,757	400,757	400,757	406,040	406,040	406,040	406,040
Grant Displacement	12,134,859	872,382	815,628	849,200	1,143,931	1,197,604	999,476	1,170,453	963,543	954,228	990,197	1,049,234	1,128,984
Grant Reasonable	(19,067,850)	(1,588,988)	(1,588,988)	(1,588,988)	(1,588,988)	(1,588,988)	(1,588,988)	(1,588,988)	(1,588,988)	(1,588,988)	(1,588,988)	(1,588,988)	(1,588,988)
Grant Surplus	1,790,608	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	3,945,067	188,138	131,384	164,956	459,687	513,360	315,232	486,209	279,299	275,267	311,237	370,274	450,023
Total Long Term Firm Purchases	448,890,021	38,876,143	34,498,615	38,374,728	33,998,230	34,769,491	36,320,392	40,534,029	39,971,297	36,720,328	36,786,926	38,221,412	39,818,430

Exhibit PPL(TAM)/103
Duvall/4

PacifiCorp

_OR GRC CY2010 - NPC Study GOLD _2009 03 17

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Storage & Exchange													
APGI/Colockum Capacity Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	1,411,140	116,430	116,430	116,430	116,430	116,430	116,430	118,760	118,760	118,760	118,760	118,760	118,760
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Peaking	47,058,000	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500
BPA So. Idaho Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	3,600,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
PSCO FC III Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
TransAlta p371343/s371344	(1,644,000)	(186,000)	(168,000)	(186,000)	-	-	-	(186,000)	(186,000)	(180,000)	(186,000)	(180,000)	(186,000)
Total Storage & Exchange	50,425,140	4,151,930	4,169,930	4,151,930	4,337,930	4,337,930	4,337,930	4,154,260	4,154,260	4,160,260	4,154,260	4,160,260	4,154,260
Short Term Firm Purchases													
COB	1,634,300	595,550	498,600	540,150	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	36,615,272	-	-	-	-	-	-	13,480,136	13,419,536	9,715,600	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	(71,219,083)	(6,002,465)	(7,096,128)	(9,555,260)	(7,863,640)	(10,922,961)	(9,576,170)	(2,932,910)	(1,575,766)	(3,208,560)	(4,450,426)	(4,360,298)	(3,674,499)
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	(32,969,511)	(5,406,915)	(6,597,528)	(9,015,110)	(7,863,640)	(10,922,961)	(9,576,170)	10,547,226	11,843,770	6,507,040	(4,450,426)	(4,360,298)	(3,674,499)
System Balancing Purchases													
COB	7,340,816	593,945	293,627	801,583	230,824	396,564	387,121	1,595,651	912,254	257,725	733,845	176,561	961,116
Four Corners	8,031,120	1,673,908	1,772,921	1,031,064	41,547	15,849	50,711	53,270	817,535	993,819	397,819	95,041	1,087,635
Mid Columbia	31,644,307	693,525	1,654,905	1,281,408	7,066,729	3,783,003	3,938,952	2,257,323	3,501,456	2,217,337	1,557,454	1,653,549	2,038,667
Mona	21,682,451	492,025	4,629,440	1,796,247	1,791,559	264,259	42,106	4,157,161	-	152,523	2,911,794	1,613,819	3,831,518
Palo Verde	1,576,764	738,154	462,387	90,636	22,135	18,761	82,602	9,461	22,588	1,526	41,300	12,766	74,447
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	265,664	-	-	103,219	136,966	25,479	-	-	-	-	-	-	-
Total System Balancing Purchases	70,541,122	4,191,557	8,813,280	5,104,157	9,289,761	4,503,915	4,501,493	8,072,866	5,253,833	3,622,929	5,642,212	3,551,737	7,993,383
Total Purchased Power & Net Inte	536,886,772	41,812,715	40,884,297	38,615,704	39,762,281	32,688,375	35,583,645	63,308,381	61,223,160	51,010,556	42,132,972	41,573,112	48,291,573

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Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Wheeling & U. of F. Expense													
Firm Wheeling	139,465,900	11,987,144	11,295,829	11,779,271	11,489,840	11,745,003	12,092,670	11,312,290	11,393,342	11,131,592	11,739,996	12,045,834	11,453,091
ST Firm & Non-Firm	282,748	6,599	6,690	1,250	13,465	10,673	46,336	73,777	66,168	23,949	14,488	11,061	8,292
Total Wheeling & U. of F. Expense	139,748,649	11,993,742	11,302,520	11,780,521	11,503,305	11,755,676	12,139,006	11,386,068	11,459,510	11,155,541	11,754,484	12,056,895	11,461,383
Coal Fuel Burn Expense													
Carbon	19,446,056	1,816,519	1,659,215	1,656,801	1,746,140	1,598,592	1,633,569	1,722,405	1,743,096	1,598,906	1,551,697	933,075	1,786,040
Cholla	54,964,906	4,799,733	4,369,919	2,504,228	4,786,973	4,855,100	4,671,433	4,873,784	4,913,705	4,757,588	4,888,033	4,711,510	4,832,902
Colstrip	12,395,660	1,090,113	984,618	1,090,113	1,054,948	1,090,113	1,054,948	1,090,113	1,090,113	826,125	879,397	1,054,948	1,090,113
Craig	20,691,191	1,785,914	1,612,874	1,636,866	1,612,416	1,773,579	1,720,231	1,766,623	1,786,111	1,720,855	1,781,325	1,708,202	1,786,194
Dave Johnston	52,590,391	4,588,512	4,144,462	4,587,090	4,440,413	4,557,758	4,410,734	4,557,758	4,557,758	4,136,173	3,586,153	4,435,067	4,588,512
Hayden	11,369,342	993,544	897,395	664,702	961,495	993,544	961,495	993,544	993,544	961,495	993,544	961,495	993,544
Hunter	111,340,062	10,140,159	9,099,942	7,279,739	8,836,520	9,450,489	9,180,344	9,564,870	9,673,680	9,187,889	9,620,444	9,180,072	10,125,915
Huntington	96,354,411	8,541,272	7,712,563	8,535,595	4,928,556	8,183,368	8,124,775	8,418,283	8,573,244	8,215,829	8,429,424	8,121,691	8,569,812
Jim Bridger	180,236,369	16,018,059	14,423,928	15,352,178	11,282,708	12,317,233	15,500,975	16,032,368	16,086,264	15,567,075	16,070,247	15,518,203	16,067,131
Naughton	80,290,581	6,991,618	6,324,656	6,985,647	5,053,125	6,565,159	6,771,802	6,998,943	6,998,943	6,773,170	6,996,549	6,820,529	7,010,440
Wyodak	19,440,034	1,720,831	1,560,707	1,722,900	1,669,103	1,713,320	1,641,476	1,656,236	1,661,943	1,641,476	1,441,767	1,283,882	1,726,392
Total Coal Fuel Burn Expense	659,119,003	58,486,274	52,790,280	52,015,859	46,372,397	53,098,256	55,671,781	57,674,928	58,078,401	55,386,582	56,238,580	54,728,673	58,576,994
Gas Fuel Burn Expense													
Chehalis	76,769,700	12,565,006	-	-	-	-	-	10,487,015	11,204,825	10,795,472	11,725,368	8,597,643	11,394,371
Currant Creek	85,312,984	7,338,782	6,994,606	8,626,805	9,196,894	6,039,186	6,240,251	7,394,748	7,318,517	6,606,507	5,064,768	6,841,961	7,649,959
Gadsby	14,278,311	-	-	-	-	-	1,426,509	3,272,455	3,338,580	2,734,503	2,444,830	1,061,435	-
Gadsby CT	12,699,426	1,352,292	709,578	-	1,240,303	159,498	996,052	1,548,623	1,541,554	1,357,717	1,577,392	1,211,032	1,005,386
Hermiston	62,004,977	5,844,810	5,299,259	5,582,802	3,324,338	3,922,374	3,544,612	5,547,722	5,589,397	5,509,255	5,726,768	5,943,701	6,169,938
Lake Side	114,102,572	10,547,317	8,721,675	9,648,358	10,442,955	7,626,374	7,827,963	10,671,319	10,674,346	9,843,150	6,897,385	10,711,042	10,490,687
Little Mountain	7,762,427	1,120,226	1,007,084	980,935	758,215	720,496	-	97,858	256,801	143,418	734,585	828,572	1,114,235
Total Gas Fuel Burn	372,930,397	38,768,434	22,732,203	24,838,900	24,962,704	18,467,928	20,035,387	39,019,740	39,924,021	36,990,022	34,171,096	35,195,386	37,824,576
Gas Physical	153,409	32,216	28,883	25,912	(2,882)	(4,126)	(2,888)	160	(683)	(2,636)	(7,462)	35,084	51,830
Gas Swaps	85,862,718	4,126,100	3,495,100	5,652,850	7,941,000	8,646,869	7,903,500	10,909,869	11,083,856	10,613,888	6,947,250	6,432,405	2,110,031
Clay Basin Gas Storage	(1,224,841)	(450,597)	(444,246)	(281,755)	52,364	52,364	52,364	52,364	52,364	52,364	52,364	(51,001)	(363,788)
Pipeline Reservation Fees	26,474,459	2,240,920	2,126,411	2,240,920	2,184,634	2,225,534	2,184,634	2,225,534	2,225,534	2,184,634	2,225,534	2,184,634	2,225,534
Additional Fixed Costs	13,015,039	1,616,504	893,848	866,364	16,794	1,005,721	1,184,085	1,232,018	1,231,297	1,227,311	1,102,226	1,069,732	1,569,141
Total Gas Fuel Burn Expense	497,211,180	46,333,576	28,832,198	33,343,191	35,154,615	30,394,290	31,357,081	53,439,684	54,516,389	51,065,583	44,491,008	44,866,241	43,417,323
Other Generation													
Blundell	3,494,899	309,548	279,592	309,548	299,563	309,548	299,563	309,548	309,548	299,563	159,767	299,563	309,548
Wind Integration Charge	11,022,399	1,015,471	906,000	971,417	896,368	874,280	883,397	832,170	854,489	866,206	919,645	990,277	1,012,678
Total Other Generation	14,517,298	1,325,019	1,185,592	1,280,966	1,195,931	1,183,828	1,182,960	1,141,718	1,164,038	1,165,769	1,079,411	1,289,840	1,322,226
Net Power Cost	**1,100,545,210**	79,328,286	76,911,419	75,897,387	84,628,742	81,078,404	87,882,997	123,984,496	130,788,452	97,272,573	86,019,333	84,485,635	92,267,487
Net Power Cost/Net System Load	**18.76**	**15.19**	**16.38**	**16.01**	**18.80**	**17.76**	**18.17**	**23.01**	**24.45**	**20.59**	**18.65**	**17.93**	**17.36**

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Net Power Cost Analysis

MWh

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Adjustments to Load													
MagCorp Curtailment	(38,516)	(5,896)	-	-	-	-	(6,610)	(6,310)	(6,610)	(6,310)	-	-	(6,780)
Monsanto Curtailment	(42,790)	-	-	-	(295)	(589)	(1,620)	(9,817)	(8,802)	(5,169)	(4,787)	(2,652)	(9,059)
Station Service	70,811	4,141	4,619	6,050	6,195	7,218	6,770	5,966	6,951	5,953	6,234	6,492	4,222
Total Adjustments to Load	(10,495)	(1,755)	4,619	6,050	5,900	6,629	(1,460)	(10,161)	(8,461)	(5,526)	1,447	3,840	(11,617)
System Load	58,674,332	5,222,664	4,691,697	4,735,035	4,495,316	4,559,607	4,838,202	5,398,855	5,357,125	4,729,459	4,610,488	4,709,269	5,326,617
Net System Load	58,663,837	5,220,909	4,696,316	4,741,085	4,501,216	4,566,236	4,836,741	5,388,694	5,348,664	4,723,933	4,611,935	4,713,109	5,315,000
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	362,521	30,535	27,893	31,229	29,825	30,279	29,193	31,581	30,837	29,649	30,579	29,884	31,036
BPA Wind	39,096	4,900	4,108	3,978	3,091	2,916	2,366	1,774	1,681	2,210	3,230	4,069	4,772
Hurricane Sale	13,140	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095
LADWP (IPP Layoff)	613,200	52,080	47,040	52,080	50,400	52,080	50,400	52,080	52,080	50,400	52,080	50,400	52,080
PSCO	467,237	41,180	37,062	38,510	36,835	38,056	36,920	41,180	41,180	39,703	38,312	37,318	40,981
SMUD	350,400	53,800	33,200	2,600	2,200	-	-	38,400	46,600	43,600	42,600	40,500	46,900
UMPA II	223,878	13,938	12,588	13,938	13,488	13,938	21,580	41,813	32,893	18,343	13,938	13,488	13,938
Total Long Term Firm Sales	2,069,472	197,527	162,986	143,429	136,933	138,364	141,554	207,923	206,366	185,001	181,834	176,753	190,802
Short Term Firm Sales													
COB	857,200	127,400	112,800	124,200	52,000	50,000	52,000	62,400	62,400	60,000	52,000	50,000	52,000
Four Corners	359,400	51,600	43,200	46,800	22,800	25,800	22,800	24,600	24,600	24,000	24,600	24,000	24,600
Mid Columbia	268,000	58,600	55,200	61,800	20,800	20,000	20,800	10,400	10,400	10,000	-	-	-
Palo Verde	870,800	110,200	98,400	108,600	97,600	101,600	97,600	43,200	43,200	42,000	43,200	42,000	43,200
Total Short Term Firm Sales	2,355,400	347,800	309,600	341,400	193,200	197,400	193,200	140,600	140,600	136,000	119,800	116,000	119,800
System Balancing Sales													
COB	1,576,116	117,192	121,393	146,362	131,804	148,264	129,137	101,956	111,706	103,149	127,460	154,966	182,730
Four Corners	3,507,824	333,649	262,642	204,935	254,236	240,918	238,711	296,580	219,809	265,283	395,153	450,235	345,674
Mid Columbia	1,916,288	249,617	66,674	123,321	30,642	59,503	69,114	153,780	73,713	333,304	273,156	235,943	247,520
Mona	309,330	33,499	3,891	28,152	22,992	39,934	29,402	15,178	32,512	41,329	33,367	21,791	7,282
Palo Verde	1,179,048	68,718	66,241	83,267	148,230	133,027	101,641	79,787	77,481	91,707	107,424	107,931	113,593
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	8,488,607	802,675	520,842	586,038	587,904	621,646	568,005	647,281	515,220	834,772	936,559	970,865	896,798
Total Special Sales For Resale	12,913,478	1,348,003	993,427	1,070,867	918,037	957,410	902,759	995,804	862,186	1,155,773	1,238,193	1,263,619	1,207,400
Total Requirements	71,577,316	6,568,912	5,689,743	5,811,953	5,419,253	5,523,646	5,739,500	6,384,498	6,210,850	5,879,706	5,850,128	5,976,728	6,522,400

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12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	222,600	4,450	4,450	31,650	37,500	37,500	37,500	13,400	4,450	4,450	29,100	12,200	5,950
Blanding Purchase	263	22	20	22	22	22	22	22	22	22	22	22	22
Combine Hills	111,503	10,670	6,964	12,330	8,689	8,068	9,707	9,317	9,245	8,810	9,457	10,546	7,702
Deseret Purchase	785,772	66,737	60,278	66,737	64,584	66,737	64,584	66,737	66,737	64,584	66,737	64,584	66,737
Douglas PUD Settlement	68,696	3,479	3,379	4,577	6,323	9,647	10,240	8,083	6,242	3,712	4,554	4,184	4,276
Gemstate	37,448	-	-	-	-	1,467	10,146	13,379	12,456	-	-	-	-
Georgia-Pacific Camas	97,741	8,301	7,498	8,301	8,034	8,301	8,034	8,301	8,301	8,034	8,301	8,034	8,301
Grant County 10 aMW purchase	87,634	6,400	4,992	5,824	7,410	9,346	9,996	10,280	9,560	7,098	5,904	4,734	6,090
Hurricane Purchase	4,380	365	365	365	365	365	365	365	365	365	365	365	365
Idaho Power RTSA Purchase	40,506	3,247	3,222	3,790	1,661	1,620	3,925	4,441	4,704	4,275	3,021	3,132	3,467
IPP Purchase	613,200	52,080	47,040	52,080	50,400	52,080	50,400	52,080	52,080	50,400	52,080	50,400	52,080
MagCorp Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p189046	245,600	20,000	19,200	21,600	20,800	20,000	20,800	20,800	20,800	20,000	20,800	20,000	20,800
Morgan Stanley p272154-7	16,800	-	-	-	-	-	-	16,800	-	-	-	-	-
PGE Cove	12,000	1,014	942	1,014	990	1,014	990	1,014	1,014	990	1,014	990	1,014
Rock River	142,099	17,329	13,686	13,830	10,837	10,363	7,823	5,577	6,736	8,750	12,538	17,058	17,571
Roseburg Forest Products	153,792	13,062	11,798	13,062	12,640	13,062	12,640	13,062	13,062	12,640	13,062	12,640	13,062
Small Purchases east	8,636	842	652	573	551	472	436	402	458	410	2,655	539	647
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	171,403	-	-	-	-	-	18,553	16,529	16,932	22,282	27,986	31,436	37,685
Tri-State Purchase	170,819	15,086	13,842	14,891	10,290	11,907	13,800	17,406	18,128	15,984	12,356	12,942	14,189
Wolverine Creek	176,896	13,112	10,346	20,599	19,833	19,334	15,070	14,711	13,807	12,842	11,119	14,535	11,587
Long Term Firm Purchases Total	4,900,070	406,357	359,425	431,147	342,286	373,629	384,374	451,147	425,355	403,302	446,423	432,787	443,838
Seasonal Purchased Power													
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

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Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Qualifying Facilities													
QF California	34,066	3,297	4,002	4,561	6,189	6,236	4,473	1,336	587	477	442	706	1,759
QF Idaho	76,135	5,278	4,771	6,072	6,672	8,644	9,315	7,137	5,616	5,425	5,908	5,817	5,481
QF Oregon	216,074	20,782	19,426	21,426	22,490	21,653	18,262	14,921	13,900	14,114	14,311	15,636	19,153
QF Utah	13,466	993	1,081	1,044	1,259	1,416	1,354	1,155	1,091	1,028	1,234	1,013	799
QF Washington	13,136	1,087	999	1,048	1,099	1,268	1,181	1,193	1,103	1,073	1,031	1,060	995
QF Wyoming	11,387	159	147	144	559	1,820	1,834	1,975	1,967	1,741	739	155	148
Biomass	173,449	14,731	13,306	14,731	14,256	14,731	14,256	14,731	14,731	14,256	14,731	14,256	14,731
Douglas County Forest Products QF	5,071	780	684	692	776	734	700	706	-	-	-	-	-
Evergreen BioPower QF	67,072	6,004	5,352	5,867	5,695	4,666	5,695	5,935	5,935	5,695	6,004	5,695	4,529
ExxonMobil QF	648,960	71,424	64,512	71,424	46,080	47,616	46,080	19,968	47,616	46,080	47,616	69,120	71,424
Mountain Wind 1 QF	188,345	24,118	14,287	22,311	12,854	13,268	11,583	10,839	15,113	13,571	13,736	18,868	17,798
Mountain Wind 2 QF	249,558	31,957	18,931	29,562	17,031	17,581	15,347	14,362	20,024	17,982	18,200	25,000	23,582
Oregon Wind Farm QF	111,235	6,333	6,992	8,958	11,025	11,340	13,066	13,435	10,351	8,330	8,407	9,667	3,332
Simplot Phosphates	74,460	6,324	5,712	6,324	6,120	6,324	6,120	6,324	6,324	6,120	6,324	6,120	6,324
Spanish Fork Wind 2 QF	55,562	4,484	3,689	3,500	3,695	3,438	4,611	6,114	6,123	5,203	4,608	4,616	5,480
Sunnyside	385,060	34,700	31,342	19,029	33,581	34,700	33,581	34,700	34,700	33,581	26,865	33,581	34,700
Qualifying Facilities Total	2,323,035	232,450	195,231	216,691	189,379	195,435	187,458	154,832	185,182	174,677	170,156	211,309	210,235
Mid-Columbia Contracts													
Canadian Entitlement	(17,528)	(1,456)	(1,344)	(1,512)	(1,456)	(1,456)	(1,456)	(1,512)	(1,456)	(1,456)	(1,456)	(1,456)	(1,512)
Chelan - Rocky Reach	325,718	33,684	24,357	23,972	29,847	33,505	34,820	33,200	25,159	17,390	20,396	23,035	26,351
Douglas - Wells	253,377	26,087	18,603	18,065	23,297	28,016	27,301	26,469	19,586	13,085	15,393	17,432	20,042
Grant Displacement	439,837	29,411	26,744	29,808	42,693	53,655	51,540	46,501	33,187	30,962	31,597	31,347	32,392
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	87,217	9,821	7,150	6,954	7,518	7,510	8,194	8,235	6,497	5,027	5,895	6,717	7,698
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,088,620	97,547	75,510	77,288	101,900	121,230	120,398	112,893	82,973	65,009	71,826	77,075	84,971
Total Long Term Firm Purchases	8,311,725	736,353	630,165	725,126	633,565	690,295	692,230	718,873	693,510	642,988	688,404	721,171	739,044

Exhibit PPL(TAM)/103
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Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Storage & Exchange													
APGI/Colockum Capacity Exchange	(268,153)	(18,608)	(15,579)	(16,877)	(16,445)	(18,608)	(16,445)	(17,743)	(17,743)	(37,310)	(37,743)	(37,310)	(17,743)
APS Exchange	230	142,785	68,790	-	-	(78,070)	(137,940)	(142,560)	(142,440)	(68,850)	78,240	137,865	142,410
BPA Exchange	0	-	-	(50,000)	-	-	133,333	116,667	-	(66,667)	(66,667)	(66,667)	-
BPA FC II Storage Agreement	239	36	(34)	15	(95)	18	(64)	10	22	117	23	158	32
BPA FC IV Storage Agreement	2,229	340	(316)	141	(886)	168	(597)	95	206	1,095	212	1,473	300
BPA Peaking	1,150	(1,725)	(6,900)	6,650	3,253	(4,660)	(5,874)	9,255	(5,124)	4,000	(5,200)	1,380	6,095
BPA So. Idaho Exchange	39,670	3,921	4,087	3,264	2,979	2,485	3,063	3,170	3,318	2,593	3,034	3,545	4,211
Cowlitz Swift	8,398	1,362	2,204	2,019	3,777	(3,410)	(876)	1,191	(3,159)	3,477	1,715	(4,989)	5,087
EWEB FC I Storage Agreement	1,235	160	53	33	(39)	77	(19)	(53)	66	192	260	284	220
PSCo Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO FC III Storage Agreement	(0)	1,240	(1,767)	(2,146)	(2,224)	(1,922)	(1,334)	(2,580)	(1,075)	1,549	3,550	3,854	2,855
Redding Exchange	-	11,371	10,316	11,536	10,418	(6,704)	(5,864)	(11,642)	(15,062)	(13,693)	(12,861)	10,704	11,481
SCL State Line Storage Agreement	14,486	1,857	(3,516)	10,718	9,052	(7,771)	4,559	(1,603)	(5,140)	(2,481)	1,374	6,949	490
TransAlta p371343/s371344	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	(200,516)	142,739	57,337	(34,647)	9,791	(118,396)	(28,058)	(45,793)	(186,131)	(175,979)	(34,063)	57,246	155,439
Short Term Firm Purchases													
COB	23,600	8,600	7,200	7,800	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	485,200	-	-	-	-	-	-	177,600	176,800	130,800	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	508,800	8,600	7,200	7,800	-	-	-	177,600	176,800	130,800	-	-	-
System Balancing Purchases													
COB	135,485	10,628	5,283	16,617	4,483	12,490	10,829	24,934	10,732	4,435	13,349	3,477	18,229
Four Corners	172,523	37,833	41,041	26,419	952	355	713	592	11,369	17,291	8,762	2,089	25,107
Mid Columbia	734,223	11,843	30,909	24,765	158,398	130,251	130,182	46,805	61,371	42,495	28,698	31,678	36,827
Mona	419,346	11,162	95,605	42,796	43,364	8,789	1,130	54,539	-	2,728	57,623	30,002	71,608
Palo Verde	36,393	16,956	10,448	2,014	523	518	1,889	228	519	26	1,024	316	1,932
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	5,269	-	-	1,867	2,477	926	-	-	-	-	-	-	-
Total System Balancing Purchases	1,503,239	88,422	183,285	114,478	210,198	153,329	144,742	127,099	83,991	66,975	109,456	67,561	153,704
Total Purchased Power & Net Inter	10,123,248	976,114	877,987	812,757	853,554	725,227	808,914	977,779	768,169	664,784	763,797	845,978	1,048,187

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Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Coal Generation													
Carbon	1,147,100	107,766	98,522	97,422	103,372	93,557	96,146	101,524	102,860	93,858	92,122	54,167	105,785
Cholla	2,884,768	251,851	229,346	131,429	251,336	254,793	245,099	255,784	257,940	249,749	256,557	247,262	253,623
Colstrip	1,157,357	101,782	91,932	101,782	98,499	101,782	98,499	101,782	101,782	77,195	82,041	98,499	101,782
Craig	1,345,899	116,190	104,932	106,448	104,947	115,358	111,890	114,851	116,203	111,932	115,874	111,065	116,209
Dave Johnston	5,896,566	514,505	464,714	514,346	497,899	511,030	494,546	511,030	511,030	463,603	402,085	497,273	514,505
Hayden	633,810	55,391	50,030	37,018	53,604	55,391	53,604	55,391	55,391	53,604	55,391	53,604	55,391
Hunter	7,924,287	724,651	650,047	519,323	628,086	670,963	651,907	679,604	688,075	652,389	683,924	651,809	723,510
Huntington	6,628,572	587,836	530,803	587,426	339,176	562,962	558,623	578,749	590,016	565,144	579,648	558,349	589,840
Jim Bridger	10,276,986	913,287	822,177	875,276	642,998	702,239	883,798	914,093	917,517	887,902	916,523	884,845	916,331
Naughton	5,397,148	469,898	425,097	469,463	339,825	441,782	455,129	470,396	470,396	455,222	470,233	458,514	471,192
Wyodak	2,201,838	195,036	176,948	195,290	189,209	194,114	185,818	187,107	187,807	185,818	163,393	145,580	195,718
Total Coal Generation	45,494,329	4,038,191	3,644,548	3,635,222	3,248,951	3,703,972	3,835,059	3,970,310	3,999,017	3,796,417	3,817,791	3,760,967	4,043,885
Gas Generation													
Chehalis	1,443,311	214,765	-	-	-	-	-	215,726	227,681	218,293	234,859	145,542	186,444
Currant Creek	2,330,968	153,195	146,798	205,564	279,612	183,277	188,999	224,307	224,731	210,047	164,858	188,938	160,642
Gadsby	253,018	-	-	-	-	-	22,980	57,406	59,617	49,508	45,431	18,077	-
Gadsby CT	200,399	14,105	7,436	-	19,995	2,418	17,495	27,339	27,615	25,038	31,184	17,230	10,543
Hermiston	1,732,282	170,162	150,750	159,901	81,357	102,325	89,342	158,441	160,256	157,655	165,352	164,447	172,294
Lake Side	3,271,159	231,550	193,064	238,286	336,683	244,785	249,387	336,041	340,776	325,077	234,544	309,971	230,996
Little Mountain	87,083	10,371	9,368	10,371	10,037	9,630	-	1,225	3,385	1,917	10,371	10,037	10,371
Total Gas Generation	9,318,222	794,149	507,415	614,123	727,684	542,434	568,203	1,020,486	1,044,061	987,536	886,599	854,243	771,290
Hydro Generation													
West Hydro	3,624,481	478,846	419,770	454,887	336,995	293,268	275,090	174,407	167,383	215,825	156,783	261,774	389,452
East Hydro	308,123	17,301	17,095	30,231	30,539	37,018	35,738	42,039	36,171	19,642	12,909	13,577	15,861
Total Hydro Generation	3,932,604	496,147	436,865	485,119	367,534	330,286	310,828	216,446	203,555	235,467	169,693	275,352	405,313
Other Generation													
Blundell	181,821	16,104	14,546	16,104	15,585	16,104	15,585	16,104	16,104	15,585	8,312	15,585	16,104
Blundell Bottoming Cycle	86,958	7,702	6,957	7,702	7,454	7,702	7,454	7,702	7,702	7,454	3,975	7,454	7,702
Total Blundell	268,778	23,806	21,502	23,806	23,038	23,806	23,038	23,806	23,806	23,038	12,287	23,038	23,806
Foote Creek I	102,699	12,892	10,506	10,105	7,611	7,605	5,865	4,253	4,466	6,260	9,075	11,269	12,794
Glenrock Wind	332,471	36,809	28,625	30,312	27,213	22,675	22,529	19,189	20,690	24,548	29,268	32,442	38,172
Glenrock III Wind	124,409	13,846	10,745	11,363	10,181	8,432	8,385	7,094	7,676	9,169	10,960	12,182	14,375
Goodnoe Wind	266,887	13,956	18,183	31,076	22,609	24,419	28,225	27,556	23,970	18,281	23,542	20,857	14,214
High Plains Wind	309,370	35,480	27,001	29,176	25,636	26,751	20,556	16,976	17,585	20,555	22,727	31,025	35,902
Leaning Juniper 1	305,473	16,176	17,454	29,577	23,680	31,823	33,873	35,958	30,532	25,784	24,369	18,181	18,066
Marengo I	393,136	32,850	33,648	35,285	35,941	33,338	32,512	31,293	30,373	29,681	32,407	31,668	34,139
Marengo II	187,226	25,913	18,628	19,890	13,929	12,361	15,227	12,975	13,096	12,325	12,202	16,669	14,013
Seven Mile Wind	349,596	43,929	30,606	36,878	26,476	25,496	21,961	17,024	19,928	21,606	29,584	35,802	40,304
Seven Mile II Wind	68,862	8,653	6,029	7,264	5,215	5,022	4,326	3,353	3,925	4,256	5,827	7,052	7,939
Total Wind Generation	2,440,129	240,504	201,425	240,925	198,492	197,921	193,459	175,670	172,242	172,465	199,961	217,147	229,919
Total Other Generation	2,708,907	264,310	222,927	264,731	221,530	221,727	216,497	199,476	196,048	195,504	212,248	240,185	253,725
Total Resources	71,577,310	6,568,911	5,689,743	5,811,952	5,419,252	5,523,647	5,739,500	6,384,497	6,210,850	5,879,707	5,850,128	5,976,726	6,522,398

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_OR GRC CY2010 - NPC Study GOLD _2009 03 17

Net Power Cost Analysis

"The Rack"

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Fuel Burned (MMBtu)													
Carbon	13,271,382	1,239,722	1,132,368	1,130,719	1,191,690	1,090,994	1,114,865	1,175,492	1,189,612	1,091,209	1,058,988	636,800	1,218,922
Cholla	31,175,935	2,722,383	2,478,598	1,420,386	2,715,165	2,753,796	2,649,622	2,764,400	2,787,047	2,698,496	2,772,483	2,672,357	2,741,202
Colstrip	12,493,123	1,098,684	992,359	1,098,684	1,063,242	1,098,684	1,063,242	1,098,684	1,098,684	832,622	886,310	1,063,242	1,098,684
Craig	13,602,522	1,174,071	1,060,315	1,076,087	1,060,013	1,165,962	1,130,891	1,161,389	1,174,200	1,131,301	1,171,054	1,122,983	1,174,255
Dave Johnston	65,552,266	5,719,439	5,165,944	5,717,667	5,534,839	5,681,098	5,497,837	5,681,098	5,681,098	5,155,603	4,470,031	5,528,174	5,719,439
Hayden	6,708,928	586,280	529,544	392,235	567,368	586,280	567,368	586,280	586,280	567,368	586,280	567,368	586,280
Hunter	84,160,185	7,664,778	6,878,498	5,502,647	6,679,386	7,143,473	6,939,275	7,229,937	7,312,186	6,944,981	7,271,940	6,939,072	7,654,012
Huntington	66,425,898	5,888,280	5,316,977	5,884,366	3,397,709	5,641,545	5,601,150	5,803,488	5,910,317	5,663,920	5,811,169	5,599,023	5,907,954
Jim Bridger	107,391,897	9,544,188	8,594,348	9,147,423	6,722,668	7,339,099	9,236,091	9,552,714	9,584,827	9,275,476	9,575,283	9,246,356	9,573,427
Naughton	56,316,944	4,904,020	4,436,195	4,899,833	3,544,329	4,604,896	4,749,837	4,909,161	4,909,161	4,750,797	4,907,483	4,784,011	4,917,221
Wyodak	26,438,831	2,340,347	2,122,599	2,343,186	2,269,997	2,330,141	2,232,441	2,252,525	2,260,272	2,232,441	1,960,838	1,746,110	2,347,935
Chehalis	10,321,491	1,545,646	-	-	-	-	-	1,541,017	1,626,083	1,559,436	1,673,113	1,043,689	1,332,509
Currant Creek	17,207,122	1,141,517	1,093,124	1,533,689	2,050,763	1,369,117	1,391,321	1,647,238	1,649,707	1,534,192	1,205,209	1,394,919	1,196,326
Gadsby	3,129,870	-	-	-	-	-	307,967	705,860	728,644	614,673	563,010	209,716	-
Gadsby CT	2,560,540	204,209	107,657	-	267,796	35,007	215,036	334,034	336,444	305,193	363,251	239,274	152,639
Hermiston	12,521,421	1,225,891	1,087,970	1,159,654	588,686	739,875	644,375	1,150,785	1,161,320	1,141,056	1,196,053	1,185,771	1,239,986
Lake Side	22,904,297	1,629,688	1,353,972	1,703,946	2,313,249	1,717,542	1,733,806	2,361,450	2,390,307	2,270,782	1,630,507	2,169,374	1,629,674
Little Mountain	1,424,406	169,166	152,795	169,166	163,709	158,137	-	21,108	56,047	32,238	169,166	163,709	169,166
Burn Rate (MMBtu/MWh)													
Carbon	11.570	11.504	11.494	11.606	11.528	11.661	11.596	11.578	11.565	11.626	11.496	11.756	11.523
Cholla	10.807	10.810	10.807	10.807	10.803	10.808	10.810	10.808	10.805	10.805	10.806	10.808	10.808
Colstrip	10.795	10.794	10.794	10.794	10.794	10.794	10.794	10.794	10.794	10.786	10.803	10.794	10.794
Craig	10.107	10.105	10.105	10.109	10.100	10.107	10.107	10.112	10.105	10.107	10.106	10.111	10.105
Dave Johnston	11.117	11.116	11.116	11.116	11.116	11.117	11.117	11.117	11.117	11.121	11.117	11.117	11.116
Hayden	10.585	10.584	10.584	10.596	10.584	10.584	10.584	10.584	10.584	10.584	10.584	10.584	10.584
Hunter	10.621	10.577	10.582	10.596	10.635	10.647	10.645	10.638	10.627	10.645	10.633	10.646	10.579
Huntington	10.021	10.017	10.017	10.017	10.018	10.021	10.027	10.028	10.017	10.022	10.025	10.028	10.016
Jim Bridger	10.450	10.450	10.453	10.451	10.455	10.451	10.450	10.450	10.446	10.447	10.447	10.450	10.448
Naughton	10.435	10.436	10.436	10.437	10.430	10.423	10.436	10.436	10.436	10.436	10.436	10.434	10.436
Wyodak	12.008	12.000	11.996	11.999	11.997	12.004	12.014	12.039	12.035	12.014	12.001	11.994	11.996
Chehalis	7.151	7.197	0.000	0.000	0.000	0.000	0.000	7.143	7.142	7.144	7.124	7.171	7.147
Currant Creek	7.382	7.451	7.446	7.461	7.334	7.470	7.362	7.344	7.341	7.304	7.311	7.383	7.447
Gadsby	12.370	0.000	0.000	0.000	0.000	0.000	13.402	12.296	12.222	12.416	12.393	11.601	0.000
Gadsby CT	12.777	14.478	14.478	0.000	13.393	14.478	12.291	12.218	12.183	12.189	11.649	13.887	14.478
Hermiston	7.228	7.204	7.217	7.252	7.236	7.231	7.212	7.263	7.247	7.238	7.233	7.211	7.197
Lake Side	7.002	7.038	7.013	7.151	6.871	7.017	6.952	7.027	7.014	6.985	6.952	6.999	7.055
Little Mountain	16.357	16.311	16.311	16.311	16.311	16.421	0.000	17.232	16.555	16.818	16.311	16.311	16.311
Average Fuel Cost ($/MMBtu)													
Carbon	1.465	1.465	1.465	1.465	1.465	1.465	1.465	1.465	1.465	1.465	1.465	1.465	1.465
Cholla	1.763	1.763	1.763	1.763	1.763	1.763	1.763	1.763	1.763	1.763	1.763	1.763	1.763
Colstrip	0.992	0.992	0.992	0.992	0.992	0.992	0.992	0.992	0.992	0.992	0.992	0.992	0.992
Craig	1.521	1.521	1.521	1.521	1.521	1.521	1.521	1.521	1.521	1.521	1.521	1.521	1.521
Dave Johnston	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802
Hayden	1.695	1.695	1.695	1.695	1.695	1.695	1.695	1.695	1.695	1.695	1.695	1.695	1.695
Hunter	1.323	1.323	1.323	1.323	1.323	1.323	1.323	1.323	1.323	1.323	1.323	1.323	1.323
Huntington	1.451	1.451	1.451	1.451	1.451	1.451	1.451	1.451	1.451	1.451	1.451	1.451	1.451
Jim Bridger	1.678	1.678	1.678	1.678	1.678	1.678	1.678	1.678	1.678	1.678	1.678	1.678	1.678
Naughton	1.426	1.426	1.426	1.426	1.426	1.426	1.426	1.426	1.426	1.426	1.426	1.426	1.426
Wyodak	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735
Chehalis	7.374	8.129	8.135	7.932	6.602	6.581	6.688	6.805	6.891	6.923	7.008	8.238	8.551
Currant Creek	5.047	6.429	6.399	5.625	4.485	4.411	4.485	4.489	4.436	4.306	4.202	4.905	6.395
Gadsby	5.207	6.622	6.591	5.799	4.632	4.556	4.632	4.636	4.582	4.449	4.342	5.061	6.587
Gadsby CT	5.207	6.622	6.591	5.799	4.632	4.556	4.632	4.636	4.582	4.449	4.342	5.061	6.587
Hermiston	3.992	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	4.173	4.173
Lake Side	5.081	6.472	6.442	5.662	4.514	4.440	4.515	4.519	4.466	4.335	4.230	4.937	6.437
Little Mountain	5.207	6.622	6.591	5.799	4.632	4.556	4.632	4.636	4.582	4.449	4.342	5.061	6.587

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Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Peak Capacity (Nameplate)													
Blundell	23	23	23	23	23	23	23	23	23	23	23	23	23
Blundell Bottoming Cycle	11	11	11	11	11	11	11	11	11	11	11	11	11
Carbon	172	172	172	172	172	172	172	172	172	172	172	172	172
Cholla	387	387	387	387	387	387	387	387	387	387	387	387	387
Colstrip	148	148	148	148	148	148	148	148	148	148	148	148	148
Craig	166	166	166	166	166	166	166	166	166	166	166	166	166
Dave Johnston	762	762	762	762	762	757	757	757	757	757	757	762	762
Hayden	78	78	78	78	78	78	78	78	78	78	78	78	78
Hunter	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,118	1,118	1,123	1,123	1,123	1,123
Huntington	895	895	895	895	895	895	895	895	895	895	895	895	895
Jim Bridger	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413
Naughton	700	700	700	700	700	695	695	695	695	695	695	700	700
Wyodak	280	279	280	280	279	277	274	267	268	274	278	280	280
Chehalis	529	529	528	524	522	514	509	500	500	507	520	527	529
Currant Creek	549	549	549	548	547	543	539	533	534	540	545	548	549
Gadsby	231	231	231	231	231	231	231	231	231	231	231	231	231
Gadsby CT	123	123	123	123	121	121	121	117	117	121	121	123	123
Hermiston	248	248	246	246	241	237	235	232	232	237	241	246	248
Lake Side	584	584	577	569	561	576	572	568	569	574	557	570	580
Little Mountain	14	14	14	14	14	13	13	12	12	13	14	14	14
Capacity Factor													
Blundell	90.2%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	48.6%	94.1%	94.1%
Carbon	76.1%	84.2%	85.2%	76.1%	83.5%	73.1%	77.6%	79.3%	80.4%	75.8%	72.0%	43.7%	82.7%
Cholla	85.1%	87.5%	88.2%	45.6%	90.2%	88.5%	88.0%	88.8%	89.6%	89.6%	89.1%	88.7%	88.1%
Colstrip	89.3%	92.4%	92.4%	92.4%	92.4%	92.4%	92.4%	92.4%	92.4%	72.4%	74.5%	92.4%	92.4%
Craig	92.8%	94.4%	94.3%	86.5%	88.1%	93.7%	93.9%	93.3%	94.4%	93.9%	94.1%	93.2%	94.4%
Dave Johnston	88.6%	90.8%	90.8%	90.7%	90.8%	90.7%	90.7%	90.7%	90.7%	85.1%	71.4%	90.6%	90.8%
Hayden	92.8%	95.4%	95.4%	63.8%	95.4%	95.4%	95.4%	95.4%	95.4%	95.4%	95.4%	95.4%	95.4%
Hunter	80.6%	86.7%	86.1%	62.1%	77.7%	80.3%	80.6%	81.7%	82.7%	80.7%	81.8%	80.6%	86.6%
Huntington	84.5%	88.3%	88.3%	88.2%	52.6%	84.5%	86.7%	86.9%	88.6%	87.7%	87.0%	86.6%	88.6%
Jim Bridger	83.0%	86.9%	86.6%	83.2%	63.2%	66.8%	86.9%	86.9%	87.3%	87.3%	87.2%	87.0%	87.1%
Naughton	88.3%	90.2%	90.4%	90.1%	67.4%	85.4%	91.0%	91.0%	91.0%	91.0%	90.9%	91.0%	90.5%
Wyodak	91.0%	94.0%	94.0%	93.7%	94.2%	94.2%	94.2%	94.2%	94.2%	94.2%	79.0%	72.2%	94.0%
Chehalis	31.8%	54.6%	-	-	-	-	-	58.0%	61.2%	59.8%	60.7%	38.4%	47.4%
Currant Creek	48.9%	37.5%	39.8%	50.4%	71.0%	45.4%	48.7%	56.6%	56.6%	54.0%	40.7%	47.9%	39.3%
Gadsby	12.5%	-	-	-	-	-	13.8%	33.5%	34.8%	29.8%	26.5%	10.9%	-
Gadsby CT	18.9%	15.4%	9.0%	-	23.0%	2.7%	20.1%	31.4%	31.7%	28.8%	34.7%	19.5%	11.5%
Hermiston	82.1%	92.2%	91.2%	87.4%	46.9%	58.0%	52.8%	91.8%	92.8%	92.4%	92.2%	92.8%	93.4%
Lake Side	65.4%	53.3%	49.8%	56.3%	83.4%	57.1%	60.6%	79.5%	80.5%	78.7%	56.6%	75.5%	53.5%
Little Mountain	74.1%	99.6%	99.6%	99.6%	99.6%	99.6%	-	13.7%	37.9%	20.5%	99.6%	99.6%	99.6%
Foote Creek I	35.9%	53.1%	47.9%	41.6%	32.4%	31.3%	25.0%	17.5%	18.4%	26.7%	37.4%	48.0%	52.7%
Glenrock Wind	38.3%	50.0%	43.0%	41.2%	38.2%	30.8%	31.6%	26.1%	28.1%	34.4%	39.7%	45.5%	51.8%
Glenrock III Wind	36.4%	47.7%	41.0%	39.2%	36.3%	29.1%	29.9%	24.4%	26.5%	32.7%	37.8%	43.4%	49.5%
Goodnoe Wind	32.4%	20.0%	28.8%	44.4%	33.4%	34.9%	41.7%	39.4%	34.3%	27.0%	33.7%	30.8%	20.3%
High Plains Wind	35.7%	48.2%	40.6%	39.6%	36.0%	36.3%	28.8%	23.0%	23.9%	28.8%	30.9%	43.5%	48.7%
Leaning Juniper 1	34.7%	21.6%	25.8%	39.6%	32.7%	42.6%	46.8%	48.1%	40.8%	35.6%	32.6%	25.1%	24.2%
Marengo I	32.0%	31.4%	35.7%	33.8%	35.6%	31.9%	32.2%	30.0%	29.1%	29.4%	31.0%	31.3%	32.7%
Marengo II	30.4%	49.6%	39.5%	38.1%	27.6%	23.7%	30.1%	24.8%	25.1%	24.4%	23.4%	33.0%	26.8%
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	40.3%	59.6%	46.0%	50.1%	37.1%	34.6%	30.8%	23.1%	27.1%	30.3%	40.2%	50.2%	54.7%
Seven Mile II Wind	40.3%	59.6%	46.0%	50.1%	37.1%	34.6%	30.8%	23.1%	27.1%	30.3%	40.2%	50.2%	54.7%

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Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Wind Integration Charge													
Foote Creek I	102,699	12,892	10,506	10,105	7,611	7,605	5,865	4,253	4,466	6,260	9,075	11,269	12,794
Glenrock Wind	332,471	36,809	28,625	30,312	27,213	22,675	22,529	19,189	20,690	24,548	29,268	32,442	38,172
Glenrock III Wind	124,409	13,846	10,745	11,363	10,181	8,432	8,385	7,094	7,676	9,169	10,960	12,182	14,375
High Plains Wind	309,370	35,480	27,001	29,176	25,636	26,751	20,556	16,976	17,585	20,555	22,727	31,025	35,902
Marengo I	393,136	32,850	33,648	35,285	35,941	33,338	32,512	31,293	30,373	29,681	32,407	31,668	34,139
Marengo II	187,226	25,913	18,628	19,890	13,929	12,361	15,227	12,975	13,096	12,325	12,202	16,669	14,013
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	349,596	43,929	30,606	36,878	26,476	25,496	21,961	17,024	19,928	21,606	29,584	35,802	40,304
Seven Mile II Wind	68,862	8,653	6,029	7,264	5,215	5,022	4,326	3,353	3,925	4,256	5,827	7,052	7,939
Combine Hills	111,503	10,670	6,964	12,330	8,689	8,068	9,707	9,317	9,245	8,810	9,457	10,546	7,702
Rock River	142,099	17,329	13,686	13,830	10,837	10,363	7,823	5,577	6,736	8,750	12,538	17,058	17,571
Three Buttes Wind	171,403	-	-	-	-	-	18,553	16,529	16,932	22,282	27,986	31,436	37,685
Wolverine Creek	176,896	13,112	10,346	20,599	19,833	19,334	15,070	14,711	13,807	12,842	11,119	14,535	11,587
BPA FC II Generation	5,650	709	578	556	419	418	323	234	246	344	499	620	704
BPA FC IV Generation	52,734	6,619	5,394	5,189	3,908	3,905	3,012	2,184	2,293	3,214	4,660	5,786	6,569
EWEB FC I Generation	27,563	3,460	2,820	2,712	2,043	2,041	1,574	1,141	1,198	1,680	2,436	3,024	3,434
PSCo FC III Generation	79,101	9,929	8,092	7,783	5,862	5,857	4,517	3,276	3,439	4,822	6,990	8,680	9,854
Long Hollow	333,438	38,586	34,980	29,681	28,391	22,034	22,320	13,777	17,983	21,051	27,716	34,649	42,273
SCL State Line generation	491,423	45,306	35,245	47,394	42,627	40,883	49,269	39,940	41,770	35,906	39,256	38,482	35,346
--	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	188,345	24,118	14,287	22,311	12,854	13,268	11,583	10,839	15,113	13,571	13,736	18,868	17,798
Mountain Wind 2 QF	249,558	31,957	18,931	29,562	17,031	17,581	15,347	14,362	20,024	17,982	18,200	25,000	23,582
Oregon Wind Farm QF	111,235	6,333	6,992	8,958	11,025	11,340	13,066	13,435	10,351	8,330	8,407	9,667	3,332
Spanish Fork Wind 2 QF	55,562	4,484	3,689	3,500	3,695	3,438	4,611	6,114	6,123	5,203	4,608	4,616	5,480
Subtotal Wind Generation	4,064,277	422,983	327,791	384,676	319,416	300,209	308,137	263,591	283,000	293,188	339,656	401,076	420,555
Generation subject to BPA Wind Integration Charges													
Goodnoe Wind	266,887	13,956	18,183	31,076	22,609	24,419	28,225	27,556	23,970	18,281	23,542	20,857	14,214
Leaning Juniper 1	305,473	16,176	17,454	29,577	23,680	31,823	33,873	35,958	30,532	25,784	24,369	18,181	18,066
Total Generation (MWh)	4,636,637	453,115	363,428	445,329	365,705	356,451	370,234	327,105	337,502	337,253	387,568	440,114	452,835
Wind Integration Charge $/MWh		1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
BPA Wind Integration Charge per kW-month		2.72	2.72	2.72	2.72	2.72	2.72	2.72	2.72	2.72	2.72	2.72	2.72
Company Wind Integration Charge	4,673,919	486,431	376,960	442,377	367,328	345,240	354,357	303,130	325,449	337,166	390,605	461,237	483,638
Goodnoe Wind	3,068,160	255,680	255,680	255,680	255,680	255,680	255,680	255,680	255,680	255,680	255,680	255,680	255,680
Leaning Juniper 1	3,280,320	273,360	273,360	273,360	273,360	273,360	273,360	273,360	273,360	273,360	273,360	273,360	273,360
Total Wind Integration Charge ($)	11,022,399	1,015,471	906,000	971,417	896,368	874,280	883,397	832,170	854,489	866,206	919,645	990,277	1,012,678
Additional Fixed Costs													
Gadsby	892,193	-	-	-	-	-	166,614	172,320	170,305	160,020	149,909	73,024	-
Gadsby CT	249,191	45,083	30,972	-	16,794	15,678	15,425	15,953	15,766	14,814	15,906	19,663	43,136
Chehalis	3,055,596	478,207	-	-	-	-	-	416,229	421,454	457,729	502,010	341,315	438,652
Additional O&M	166,498	45,152	-	-	-	-	-	-	-	47,974	73,372	-	-
Startup Fuel	2,889,098	433,055	-	-	-	-	-	416,229	421,454	409,755	428,638	341,315	438,652
Currant Creek	5,176,905	454,716	350,382	397,842	-	311,987	306,996	627,515	623,772	594,747	420,939	635,730	452,280
Additional O&M	1,430,000	-	-	-	-	-	-	310,000	310,000	300,000	210,000	300,000	-
Startup Fuel	3,746,905	454,716	350,382	397,842	-	311,987	306,996	317,515	313,772	294,747	210,939	335,730	452,280
Lake Side	3,641,154	638,497	512,494	468,521	-	678,057	695,050	-	-	-	13,462	-	635,072
Additional O&M	504,000	-	-	-	-	240,000	264,000	-	-	-	-	-	-
Startup Fuel	3,137,154	638,497	512,494	468,521	-	438,057	431,050	-	-	-	13,462	-	635,072
Total Fixed Costs	13,015,039	1,616,504	893,848	866,364	16,794	1,005,721	1,184,085	1,232,018	1,231,297	1,227,311	1,102,226	1,069,732	1,569,141

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12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
						Mills / kWh							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	32.25	32.07	33.66	31.70	32.47	32.21	32.84	31.51	31.91	32.57	32.05	32.44	31.80
BPA Wind	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30
Hurricane Sale	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
LADWP (IPP Layoff)	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57
PSCO	69.91	68.90	70.84	70.11	70.96	70.33	70.91	68.90	68.90	69.55	70.21	70.71	68.99
SMUD	37.00	37.00	37.00	37.00	37.00	-	-	37.00	37.00	37.00	37.00	37.00	37.00
UMPA II	43.64	43.33	45.40	43.33	43.97	43.33	43.97	43.33	43.33	43.97	43.33	43.97	43.33
Total Long Term Firm Sales	46.54	45.58	47.19	48.22	48.57	48.48	48.53	45.39	45.24	45.84	45.78	46.18	45.79
Short Term Firm Sales													
COB	79.36	74.81	75.24	75.36	82.80	82.80	82.80	81.96	81.96	81.96	82.80	82.80	82.80
Four Corners	56.74	57.31	57.31	57.31	56.37	56.37	56.37	56.37	56.37	56.37	56.37	56.37	56.37
Mid Columbia	69.11	67.72	67.89	67.94	70.00	70.00	70.00	74.50	74.50	74.50	-	-	-
Palo Verde	60.30	61.10	61.75	61.93	58.72	57.96	58.72	62.64	62.64	62.52	59.09	59.01	59.09
Total Short Term Firm Sales	69.72	67.82	68.43	68.44	68.20	67.28	68.20	73.83	73.83	73.82	72.15	72.15	72.15
System Balancing Sales													
COB	57.74	66.31	59.46	55.86	55.44	45.43	42.69	59.15	63.91	62.05	60.29	60.12	64.09
Four Corners	56.56	56.35	54.78	52.27	48.83	44.51	51.19	73.79	73.43	63.71	54.29	51.68	56.45
Mid Columbia	59.56	63.56	57.56	51.38	40.49	35.74	36.30	56.98	63.77	67.54	59.38	60.85	63.29
Mona	58.63	56.36	52.73	51.44	49.35	45.27	60.19	83.28	84.75	64.37	52.50	48.36	54.33
Palo Verde	54.89	53.96	53.70	50.28	50.17	50.07	58.98	65.25	67.13	60.21	52.16	50.96	54.02
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	57.30	59.84	56.08	52.65	50.23	45.13	49.31	66.66	69.75	64.68	56.28	55.10	59.57
Total Special Sales For Resale	57.84	59.81	58.47	57.09	53.77	50.18	53.23	63.23	64.55	62.74	56.27	55.42	58.64

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12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	49.09	39.97	40.00	29.69	46.13	46.02	62.13	82.55	97.77	98.23	42.94	32.45	37.46
Blanding Purchase	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Combine Hills	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08
Deseret Purchase	41.04	40.61	43.02	40.61	41.36	40.61	41.36	40.61	40.61	41.36	40.61	41.36	40.61
Douglas PUD Settlement	27.57	27.52	27.42	27.42	27.61	27.58	27.43	27.45	27.69	27.82	27.59	27.82	27.79
Gemstate	72.54	-	-	-	-	146.63	21.20	16.08	17.78	-	-	-	-
Georgia-Pacific Camas	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49
Grant County 10 aMW purchase	79.55	89.29	92.91	88.29	72.18	62.60	59.36	73.02	81.85	87.57	82.72	96.70	99.76
Hurricane Purchase	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Idaho Power RTSA Purchase	58.57	63.64	58.52	53.50	45.74	34.10	49.25	68.24	68.88	56.66	58.49	59.66	62.65
IPP Purchase	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57
MagCorp Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p189046	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50
Morgan Stanley p272154-7	200.57	-	-	-	-	-	-	138.19	-	-	-	-	-
PGE Cove	21.00	20.71	22.29	20.71	21.21	20.71	21.21	20.71	20.71	21.21	20.71	21.21	20.71
Rock River	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
Roseburg Forest Products	57.01	56.72	57.14	57.25	57.22	56.72	57.22	56.99	56.99	56.94	56.99	56.94	56.99
Small Purchases east	66.07	80.37	80.93	81.09	80.49	80.49	80.66	80.31	80.53	79.76	33.59	80.58	80.00
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	63.80	-	-	-	-	-	63.80	63.80	63.80	63.80	63.80	63.80	63.80
Tri-State Purchase	64.23	61.79	65.45	62.32	80.81	72.69	65.59	56.34	54.94	59.49	70.81	68.55	64.37
Wolverine Creek	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11
Long Term Firm Purchases Total	58.29	54.01	56.53	53.94	61.84	58.78	62.46	62.93	61.72	60.85	56.16	55.64	55.55
Seasonal Purchased Power													
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

PacifiCorp

_OR GRC CY2010 - NPC Study GOLD _2009 03 17

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Qualifying Facilities													
QF California	118.20	117.51	116.29	134.28	112.70	112.36	114.90	118.20	127.28	130.63	133.13	123.73	118.22
QF Idaho	54.30	53.83	53.76	53.97	54.03	54.20	54.24	54.74	54.59	54.53	54.57	54.57	54.50
QF Oregon	86.06	86.19	86.90	87.92	87.47	86.19	85.47	84.42	83.39	85.13	85.93	85.55	86.13
QF Utah	52.36	52.49	54.69	55.98	53.27	49.73	50.38	50.53	49.55	51.29	52.76	55.93	53.62
QF Washington	147.06	147.18	148.12	147.48	146.86	145.35	146.17	146.29	147.14	147.42	147.75	147.49	148.21
QF Wyoming	63.67	96.63	98.86	97.36	68.21	60.08	60.76	60.36	60.48	61.30	64.56	98.05	97.70
Biomass	157.11	156.76	158.70	156.76	157.36	156.76	157.36	156.76	156.76	157.36	156.76	157.36	156.76
Douglas County Forest Products QF	48.73	60.64	55.47	50.86	46.10	35.63	34.43	57.62	-	-	-	-	-
Evergreen BioPower QF	53.25	52.82	53.45	53.65	53.59	52.65	53.59	53.31	53.16	53.20	53.19	53.20	53.03
ExxonMobil QF	48.65	62.25	59.38	49.53	34.49	28.53	30.56	52.70	55.00	44.64	44.64	49.21	58.02
Mountain Wind 1 QF	56.04	60.63	58.31	53.32	48.15	49.34	51.00	63.53	65.59	58.09	52.47	52.58	57.55
Mountain Wind 2 QF	65.30	68.64	65.16	61.18	54.09	55.00	64.52	85.75	82.12	68.28	57.35	60.03	65.08
Oregon Wind Farm QF	64.14	64.80	64.81	64.86	64.61	63.50	64.08	63.46	63.28	63.63	64.06	64.75	65.46
Simplot Phosphates	50.99	50.84	51.68	50.84	51.10	50.84	51.10	50.84	50.84	51.10	50.84	51.10	50.84
Spanish Fork Wind 2 QF	53.06	54.88	52.33	50.02	46.09	45.01	50.80	59.62	61.13	54.12	49.34	50.53	53.59
Sunnyside	67.03	66.16	68.37	85.67	64.64	61.55	63.10	66.89	67.18	68.04	71.57	65.19	65.35
Qualifying Facilities Total	68.57	72.01	71.96	69.01	65.32	62.90	64.00	75.30	72.56	68.16	67.03	65.18	69.99
Mid-Columbia Contracts													
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Chelan - Rocky Reach	13.07	10.53	14.57	14.80	11.89	10.59	10.19	10.69	14.10	20.40	17.39	15.40	13.46
Douglas - Wells	19.06	15.36	21.54	22.18	17.20	14.30	14.68	15.14	20.46	31.03	26.38	23.29	20.26
Grant Displacement	27.59	29.66	30.50	28.49	26.79	22.32	19.39	25.17	29.03	30.82	31.34	33.47	34.85
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	20.53	15.19	20.87	21.46	19.85	19.87	18.21	18.12	22.97	29.68	25.31	22.22	19.38
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	3.62	1.93	1.74	2.13	4.51	4.23	2.62	4.31	3.37	4.23	4.33	4.80	5.30
Total Long Term Firm Purchases													
COB	69.25	69.25	69.25	69.25	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	75.46	-	-	-	-	-	-	75.90	75.90	74.28	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	(64.80)	(628.71)	(916.32)	(1,155.78)	-	-	-	59.39	66.99	49.75	-	-	-
System Balancing Purchases													
COB	54.18	55.89	55.58	48.24	51.49	31.75	35.75	64.00	85.01	58.12	54.97	50.78	52.72
Four Corners	46.55	44.24	43.20	39.03	43.62	44.61	71.15	89.94	71.91	57.47	45.40	45.50	43.32
Mid Columbia	43.10	58.56	53.54	51.74	44.61	29.04	30.26	48.23	57.05	52.18	54.27	52.20	55.36
Mona	51.71	44.08	48.42	41.97	41.31	30.07	37.27	76.22	-	55.90	50.53	53.79	53.51
Palo Verde	43.33	43.53	44.26	45.01	42.30	36.20	43.73	41.42	43.52	59.59	40.33	40.38	38.54
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	50.42	-	-	55.29	55.30	27.53	-	-	-	-	-	-	-
Total System Balancing Purchases	46.93	47.40	48.09	44.59	44.20	29.37	31.10	63.52	62.55	54.09	51.55	52.57	52.01

Exhibit PPL(TAM)/103
Duvall/17

PacifiCorp

_OR GRC CY2010 - NPC Study GOLD _2009 03 17

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Thermal Resources													
Blundell	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
Carbon	16.95	16.86	16.84	17.01	16.89	17.09	16.99	16.97	16.95	17.04	16.84	17.23	16.88
Cholla	19.05	19.06	19.05	19.05	19.05	19.06	19.06	19.05	19.05	19.05	19.05	19.05	19.06
Colstrip	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.70	10.72	10.71	10.71
Craig	15.37	15.37	15.37	15.38	15.36	15.37	15.37	15.38	15.37	15.37	15.37	15.38	15.37
Dave Johnston	8.92	8.92	8.92	8.92	8.92	8.92	8.92	8.92	8.92	8.92	8.92	8.92	8.92
Hayden	17.94	17.94	17.94	17.96	17.94	17.94	17.94	17.94	17.94	17.94	17.94	17.94	17.94
Hunter	14.05	13.99	14.00	14.02	14.07	14.08	14.08	14.07	14.06	14.08	14.07	14.08	14.00
Huntington	14.54	14.53	14.53	14.53	14.53	14.54	14.54	14.55	14.53	14.54	14.54	14.55	14.53
Jim Bridger	17.54	17.54	17.54	17.54	17.55	17.54	17.54	17.54	17.53	17.53	17.53	17.54	17.53
Naughton	14.88	14.88	14.88	14.88	14.87	14.86	14.88	14.88	14.88	14.88	14.88	14.88	14.88
Wyodak	8.83	8.82	8.82	8.82	8.82	8.83	8.83	8.85	8.85	8.83	8.82	8.82	8.82
Total Coal Expenses	14.49	14.48	14.48	14.31	14.27	14.34	14.52	14.53	14.52	14.59	14.73	14.55	14.49
Chehalis	53.19	58.51	-	-	-	-	-	48.61	49.21	49.45	49.93	59.07	61.11
Currant Creek	36.60	47.90	47.65	41.97	32.89	32.95	33.02	32.97	32.57	31.45	30.72	36.21	47.62
Gadsby	56.43	-	-	-	-	-	62.08	57.01	56.00	55.23	53.81	58.72	-
Gadsby CT	63.37	95.87	95.42	-	62.03	65.96	56.93	56.64	55.82	54.23	50.58	70.29	95.36
Hermiston	35.79	34.35	35.15	34.91	40.86	38.33	39.67	35.01	34.88	34.94	34.63	36.14	35.81
Lake Side	34.88	45.55	45.18	40.49	31.02	31.16	31.39	31.76	31.32	30.28	29.41	34.55	45.42
Little Mountain	89.14	108.01	107.51	94.58	75.54	74.81	-	79.89	75.85	74.82	70.83	82.55	107.44
Total Thermal Resources	53.36	58.34	56.82	54.29	48.31	56.03	55.19	52.37	52.22	51.71	50.18	52.52	56.29

Docket No. UE-
Exhibit PPL(TAM)/200
Witness: A. Robert Lasich

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of A. Robert Lasich

March 2009

Q. Please state your name, business address and present position with PacifiCorp, dba Pacific Power ("Company").

A. My name is A. Robert Lasich. My business address is 1407 West North Temple, Suite 320, Salt Lake City, Utah 84116. My position is President, PacifiCorp Energy.

Qualifications

Q. Briefly describe your education and business experience.

A. I have a Bachelor of Arts degree from Indiana University, a Master's degree in Business Administration from the University of Cincinnati and a Law degree from Indiana University. I joined MidAmerican Energy Company in October 1997 and have held positions of increasing responsibility, including Senior Attorney, Vice President, gas supply and trading and Vice President, MidAmerican Energy Holdings Company, responsible for integration and transition matters related to the acquisition of PacifiCorp. Prior to that, I was with the law firm of Dale & Eke P.C, where I focused on real estate and corporate law. Prior to admission to the practice of law, I held several accounting and financial positions with Cabot Corporation and its successor organizations. I was appointed President of PacifiCorp Energy in August 2007 after 1 ½ years as Vice President and General Counsel, and was elected to the PacifiCorp Board of Directors in March 2006. As President, I have responsibility for the electric generation, commercial and energy trading, and coal-mining operations for the Company.

Q. What is the purpose of your testimony?

A. I explain the Company's overall approach to providing the coal supply for the Company's coal plants. In addition, my testimony:

- Explains the coal cost increases reflected in the filing and describes the primary reasons for the increases;
- Reviews the Company's affiliate mine coal costs relative to market opportunities; and
- Demonstrates that Oregon customers benefit from the Company's diversified coal supply strategy.

Overview of the Coal Supplies for the Company's Coal Plants

Q. How does the Company plan to meet fuel supplies for its coal plants in 2010?

A. The Company employs a diversified coal supply strategy. For 2010, the Company will meet approximately 68 percent of its fuel requirements from third-party, multi-year contracts, 30 percent will be supplied with coal from the Company's affiliate mines and the remaining 2 percent will come from the spot coal market.

Q. What percentage of the Company's purchase coal contracts are fixed and what percentage are indexed?

A. The percentage split is roughly 50/50. Thus, for 2010, approximately 33 percent of the Company's total coal supply will be priced under fixed-price contracts and 35 percent will be priced under contracts that escalate/de-escalate based on changes to producer and consumer price indices.

Q. Please identify the affiliate mines which supply the Company's coal plants.

A. Coal production from the Company's Bridger Coal Mine is dedicated to the Jim Bridger Plant. The Deer Creek Mine supplies a portion of both Hunter and Huntington coal requirements and the Trapper Mine is dedicated to the Craig Plant.

Coal Cost Increases in 2010 TAM

Q. Do coal costs in the 2010 TAM reflect an increase from current levels?

A. Yes. The Company's coal costs have increased from an average cost of \$23.75/ton in 2008 to an average cost of \$26.69/ton in 2010, an increase of \$2.94/ton over the two-year period. This reflects increases in purchased coal under both fixed and escalating contracts and increases in costs at the affiliate mines.

Q. What are the primary factors causing this increase in coal costs?

A. Overall, there are three primary factors contributing to the cost increase:

- Execution of a new coal supply agreement with the Black Butte Mine for the Bridger Plant, as well as higher operating costs at the Bridger Mine,
- Fixed contract price escalation under the Arch agreement, and
- Higher operating costs at the Deer Creek mine.

Coal Costs Related to the Bridger Plant

Q Please describe the new coal supply agreement with the Black Butte Mine for the Bridger Plant.

A. The Company obtains approximately a third of the coal necessary to fuel the Bridger Plant from the Black Butte Mine. This coal comes from a mine similar to the Bridger surface mine in design and geology. The new agreement replaces an existing agreement that expires in December 2009. The 2010 price under the new contract is approximately 34 percent higher than the 2008 coal price. This 2010 pricing takes into account lower priced carryover tonnage from the prior contract. Excluding the carryover tonnage, the new contract price increase is over 50 percent.

Q. Please provide an overview of cost increases at the Bridger Mine reflected in this filing.

A. Bridger Mine costs in the 2010 TAM are projected to increase from $29.37/ton in 2008 to $33.54/ton in 2010. The Bridger Mine is located in Southwest Wyoming and operated by the Bridger Coal Company ("BCC"). It consists of two different mining operations: an underground mine and a surface mine. The Bridger Mine is subject to substantially increased taxes and royalty payments in the test period due to higher valuations driven by higher market prices. Higher production taxes and royalties, alone account for approximately $1.70/ton cost increase in 2010, more than 40 percent of the total increase.

Q. How has the Bridger surface mine changed in recent years?

A. For many years, BCC was able to extract coal at the Bridger surface mine using low-cost highwall mining. The mine has now reached the stage, however, where BCC has replaced this production method with higher-cost dragline mining to properly steward the resources of the mine. Additionally, current accounting pronouncement EITF04-6 requires that production costs be assigned only to extracted coal, not coal that is uncovered but remains in the pit. This contributes to higher costs in 2010 because more coal is scheduled to be uncovered than will actually be extracted; the opposite will be true in a year when previously uncovered coal is ultimately extracted.

Q. Do Bridger surface mine costs in this case also reflect an increase associated with final reclamation charges?

A. Yes. The current filing includes a new contribution charge of $0.84/ton for final reclamation. This reclamation charge reflects the most recent final reclamation study prepared by BCC as well as BCC's trust fund balance as of December 2008. The trust fund is utilized to perform final reclamation and monitoring activities required under the Surface Mine Control and Reclamation Act of 1977. Trust fund earnings in 2007 and 2008 were negatively impacted by the downturn in the economy.

Q. What other specific drivers are causing Bridger Mine costs to increase?

A. Other major contributing factors include:

- Increases in labor costs due to an increase in workforce size and wage and benefit increases,
- Commodity cost escalation,
- Maintenance cost increases as mining equipment is scheduled for rebuilds, component exchanges, etc., and
- Increases in depreciation, depletion and amortization expense of approximately $0.30/ton associated with additional mine infrastructure placed in service in 2010.

Q. Please compare Bridger Mine costs relative to other supply options.

A. The Company's fueling strategy was developed to insure low cost, optimum quality, and a secure long-term coal supply for the Company's plants. The Bridger Mine continues to be the optimum long-term coal supply for the Bridger Plant, in combination with the Black Butte Mine agreement. The Southwest Wyoming coal market represents a niche market, with total annual production estimated at only 15 million tons. The Bridger and Naughton Plants consume approximately 11.5 million, or 75 percent of the native production. Most of the remaining local production is consumed by nearby industrial customers. The Company has contracted for all available supplies from the Black Butte Mine. There is no additional capacity in the area to supply the Bridger Plant.

Q. Outside of the Southwest Wyoming area, what options are available to supply the Bridger Plant?

A. Powder River Basin ("PRB") coals are the most feasible market alternative for supplying the Bridger Plant. These supplies are located approximately 560 miles from the plant, so transportation costs are a major cost driver. The Company has periodically evaluated PRB coals relative to the Bridger Mine. Without considering the capital modifications to the unloading facility nor the retrofitting of the generating units to burn PRB coals, PRB coal is still more expensive. Based on the latest Union Pacific rail transportation proposal, the delivered cost of PRB coal is over $5/ton higher than coal from the Bridger Mine in the test period. Thus, coal from the Bridger Mine remains below the costs of any market alternative available to the Company.

Arch Contract for Coal Supply to Carbon and Hunter Coal Plants

Q. Please describe the increase under the long-term agreement with Arch.

A. The Company has a long-term coal supply agreement with Arch CoalSales for up to 4.5 million tons or approximately 57 percent of the total Utah coal supplies in 2010. This contract supplies the Carbon and Hunter coal plants. The contract included a price reopener in 2007. This price reopener also established the annual price increases for 2008, 2009 and 2010. The coal price is projected to increase by $3.91/ton in 2010 or $18 million. The full impact of the price reopener as well as annual fixed contract increases was minimized by a price collar the Company had negotiated in advance of the reopener.

Coal Costs Related to the Hunter and Huntington Plants

Q. Please explain the increases in Deer Creek Mine costs between 2008 and 2010.

A. The Deer Creek Mine is located in Utah. Deer Creek Mine costs are projected to increase to $32.44/ton, up from the 2008 price of $25.08/ton. The major cost drivers include labor cost increases, an increase in longwall setup costs and major overhaul expense due to an additional longwall move and shorter longwall panels, an increase in materials and supplies costs due to higher continuous miner production rates, an increase in royalty costs and depreciation expense and a decrease in production due to required longwall maintenance.

Q. How do Deer Creek Mine costs compare to Utah market alternatives?

A. The Federal Energy Regulatory Commission's ("FERC") Energy Market Snapshot of Regional Coal Prices of March 9, 2009, provides indicative spot coal prices for Utah. Utah spot coal prices have continued to increase – from approximately $33/ton in the beginning of 2008 to over $70/ton in 2009. Based on discussions with other coal producers in Utah, the Company expects coal prices to hover near $70/ton through 2011. Deer Creek Mine costs are approximately one-half of these market prices.

Q. Does a comparison between the Company's Trapper Mine, located in Colorado, and market alternatives produce a similar result?

A. Yes. The Colorado coal market has experienced the same cost increases as Utah. The Trapper Mine's 2010 price of $28.51/ton is very attractive as compared to prevailing market prices.

Q. **Please summarize the benefits of the Company's coal supply strategy to Oregon customers.**

A. The Company has pursued a diversified coal supply strategy, relying on fixed contracts, indexed contracts and affiliate-owned coal mines to meet the fuel needs of its coal plants. This strategy has resulted in a long-term, stable and low-cost supply of coal. In particular, the operating cost for each of the three affiliate mines remains considerably less than market. The Company is committed to regular review of its fueling strategies in its efforts to reduce fuel costs and optimize customer benefits.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL(TAM)/300
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

March 2009

Q. Please state your name, business address and present position with PacifiCorp, dba Pacific Power ("Company").

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah St., Suite 2000, Portland, Oregon 97232. My present position is Consultant, Pricing & Cost of Service, in the Regulation Department.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree in Mathematics from Reed College. I joined the Company in the Regulation Department in October 2000. I assumed my present responsibilities in May 2001.

Q. Please describe your current duties.

A. I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the Company's six state service territory, including those contained in the Company's last Oregon General Rate Case, Docket UE 179.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified for the Company in regulatory proceedings in Oregon and California.

Purpose of Testimony

Q. What are your responsibilities in this proceeding?

A. I will present the Company's proposed Transition Adjustment Mechanism ("TAM") prices and proposed tariffs. I will also provide a comparison of present and proposed customer rates.

Price Change and Tariffs

Q. How does the Company propose to collect the price change from customers?

A. Consistent with past TAM filings and with OAR 860-038-0200 (requiring unbundling), the Company proposes to spread the revenue change to customer classes by a uniform percentage change to the present generation-related revenues being collected through Schedule 200, Cost-Based Supply Service. The revenue change will be applied on a cents per kilowatt-hour basis through revised Schedule 200 rates.

Q. What rate design test year has been used to calculate the Schedule 200 present revenues and to determine the TAM adjustment rates?

A. A 2010 forecast rate design test year was used to calculate Schedule 200 present revenues and to determine the TAM adjustment rates. Use of a rate design test year equal to the year in which the TAM rates will be effective is consistent with the amended stipulation approved in Order No. 08-543 in the Company's 2009 TAM, Docket UE 199 ("UE 199"). A 2010 forecast by schedule was prepared and used in this TAM filing.

Q. Have you also incorporated a Load Growth/Loss Adjustment consistent with Order No. 08-543 in UE 199?

A. Yes. In Order No. 08-543, the Commission approved the Stipulation in UE 199, which provides that the Company should design future TAM filings "to recover the Company's Oregon-allocated NPC, including consideration of the increased/decreased revenues due to load growth/load loss." As discussed by Company witness Greg Duvall, the Oregon load forecast for the 2010 test period is lower than the forecast for the 2009 test period used in UE 199. Exhibit PPL(TAM)/301 shows the calculation of the Load Growth/Loss Adjustment for 2010 consistent with the adjustment calculation from Exhibit C of the UE 199 Amended Stipulation, as approved in Order No. 08-543.

Q. Have you prepared an exhibit showing the calculation of the proposed TAM adjustment rates?

A. Yes. Exhibit PPL(TAM)/302 shows the calculation of the proposed TAM adjustment rates which will be added to present Schedule 200 rates. Columns 1 and 2 list the Delivery Service schedules receiving Cost-Based Supply Service on Schedule 200. Column 3 shows the 2010 forecast kilowatt-hours by rate schedule. Column 4 shows the present Schedule 200 Cost-Based Supply Service revenues as calculated from present rates on the 2010 rate design test year. Column 5 shows the net power cost increase by Delivery Service schedule. Column 6 shows the Load Growth/Loss Adjustment by Delivery Service schedule. Column 7 totals the revenue by Delivery Service schedule and Column 8 translates the revenue change into a cents per kilowatt-hour TAM adjustment rate which will be added to present Schedule 200 rates.

Q. Please describe Exhibit PPL(TAM)/303.

A. Exhibit PPL(TAM)/303 contains the revised Schedule 200, Cost-Based Supply Service. The cents per kilowatt-hour rates shown in Exhibit PPL(TAM)/302 have been added to the present rates for each Delivery Service schedule listed in Schedule 200. For Delivery Service schedules with multiple rate blocks on Schedule 200, the rate increase applies equally to each block.

Q. Is the Company proposing changes to its one-year or three-year option Transition Adjustment tariffs (Schedule 294 and 295) at this time?

A. No. The Transition Adjustment will be established in November, just prior to the open enrollment window. The Company will file changes to Schedule 294 and 295, Transition Adjustment, once the 2010 rates have been posted and are known.

Comparison of Present and Proposed Customer Rates

Q. What are the overall effects of the changes proposed in this filing?

A. The overall proposed increase to rates is 2.1 percent on a net basis. Exhibit PPL(TAM)/304 shows the estimated effect of the Company's proposed prices by Delivery Service schedule both base and net of applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. Have you prepared an exhibit which shows a comparison of present and proposed customer rates?

A. Yes. Exhibit PPL(TAM)/305 contains monthly billing comparisons for various size customers on each of the main residential, commercial and industrial Delivery Service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules including the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power

Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. What is the estimated monthly impact to an average size residential customer?

A. The estimated monthly impact to a residential customer using 950 kilowatt-hours is $1.57.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL(TAM)/301
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Load Growth/Loss Adjustment

March 2009

PACIFIC POWER & LIGHT COMPANY
ADJUSTMENT FOR REVENUES RESULTING FROM LOAD GROWTH/LOSS
FOR TAM EFFECTIVE JANUARY 1, 2010

				Formula
(1)	Oregon-allocated NPC Baseline in Rates from UE 199	$	266,835,529	
(2)	2009 MWH*		14,026,969	
(3)	$/MWH in Rates		19.02	(1) / (2)
(4)	2010 MWH*		13,267,901	
(5)	2010 Recovery of NPC in Rates	$	252,395,751	(3) * (4)
(6)	Adjustment for Revenues Resulting from Load Growth/Loss	$	14,439,778	(1) - (5)

*Excluding MWh which do not pay the TAM adjustment.

Docket No. UE-
Exhibit PPL(TAM)/302
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Development of TAM Adjustment for January 1, 2010

March 2009

PACIFIC POWER & LIGHT COMPANY
DEVELOPMENT OF TAM ADJUSTMENT FOR JANUARY 1, 2010
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Sch No.	kWh[1]	January 1, 2010 Sch 200 Present Revenue	Proposed TAM Adjustment: Net Power Cost Increase Revenue	Proposed TAM Adjustment: Growth/ Loss Adjustment Revenue	Proposed TAM Adjustment: Total Adjustment Revenue	Proposed TAM Adjustment: Total Adjustment Cents\kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(6)
							(5)+(6)	(7)/(3)
	Residential							
1	Residential	4	5,435,845,633	$226,599,972	$2,586,450	$6,090,764	$8,677,214	0.160
2	**Total Residential**		5,435,845,633	$226,599,972	$2,586,450	$6,090,764	$8,677,214	
	Commercial & Industrial							
3	Gen. Svc. < 31 kW	23	1,013,940,497	$42,927,417	$489,981	$1,153,843	$1,643,824	0.162
4	Gen. Svc. 31 - 200 kW	28	2,045,065,385	$84,830,155	$968,265	$2,280,144	$3,248,409	0.159
5	Gen. Svc. 201 - 999 kW	30	1,378,646,160	$55,560,675	$634,179	$1,493,411	$2,127,590	0.154
6	Large General Service >= 1,000 kW	48	2,643,901,271	$99,835,377	$1,139,538	$2,683,468	$3,823,005	0.144
7	Partial Req. Svc. >= 1,000 kW	47	565,102,620	$20,957,166	$239,209	$563,306	$802,515	0.144
8	Agricultural Pumping Service	41	136,791,880	$5,648,605	$64,474	$151,828	$216,303	0.158
9	**Total Commercial & Industrial**		7,783,447,813	$309,759,395	$3,535,645	$8,326,000	$11,861,645	
	Lighting							
10	Outdoor Area Lighting Service	15	10,467,219	$238,234	$2,719	$6,403	$9,123	0.087
11	Street Lighting Service	50	10,738,031	$203,271	$2,320	$5,464	$7,784	0.072
12	Street Lighting Service HPS	51	16,084,697	$480,611	$5,486	$12,918	$18,404	0.114
13	Street Lighting Service	52	1,185,726	$27,141	$310	$730	$1,039	0.088
14	Street Lighting Service	53	9,316,113	$91,112	$1,040	$2,449	$3,489	0.037
15	Recreational Field Lighting	54	815,719	$13,729	$157	$369	$526	0.064
16	**Total Public Street Lighting**		48,607,505	$1,054,098	$12,032	$28,333	$40,365	
17	**Total Sales to Ultimate Consumers**		13,267,900,951	$537,413,465	$6,134,126	$14,445,097	$20,579,223	
18	**Employee Discount**			($197,897)	($2,259)	($5,319)	($7,578)	
19	**Total Sales with Employee Discount**		13,267,900,951	$537,215,568	$6,131,867	$14,439,778	$20,571,645	

[1] Excludes unscheduled energy

Docket No. UE-
Exhibit PPL(TAM)/303
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule 200

March 2009

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take this service or who have elected to take service under Schedules 212 or 213. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-270, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Energy Charge

The Monthly Billing shall be the Energy Charge.

Delivery Service Schedule No.			Delivery Voltage: Secondary	Primary	Transmission	
4	Per kWh	0 - 500 kWh	3.681¢			(I)
		501-1000 kWh	4.333¢			|
		> 1000 kWh	5.309¢			(I)

For Schedule 4, 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).

Delivery Service Schedule No.		Secondary	Primary	Transmission	
23	First 3,000 kWh, per kWh	4.664¢	4.548¢		(I)
	All additional kWh, per kWh	3.505¢	3.421¢		|
28	First 20,000 kWh, per kWh	4.341¢	4.263¢		|
	All additional kWh, per kWh	4.228¢	4.153¢		|
30	First 20,000 kWh, per kWh	4.706¢	4.615¢		|
	All additional kWh, per kWh	4.101¢	4.011¢		|
41	Winter, first 100 kWh/kW, per kWh	6.193¢	6.035¢		|
	Winter, all additional kWh, per kWh	4.270¢	4.165¢		(I)

(continued)

Energy Charge *(continued)*

Delivery Service Schedule No.		Secondary	Primary	Transmission	
		Delivery Voltage			
41	Summer, all kWh, per kWh	4.270 ¢	4.165¢		(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.

47/48	Per kWh On-Peak	4.120¢	3.941¢	3.774¢	(I)
	Per kWh, Off-Peak	4.020¢	3.841¢	3.674¢	(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.

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	For dusk to dawn operation, per kWh	2.377¢	(I)
	For dusk to midnight operation, per kWh	2.377¢	(I)
54	Per kWh	1.747¢	(I)

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
Mercury Vapor	7,000	76	$1.80	(I)
Mercury Vapor	21,000	172	$4.06	
Mercury Vapor	55,000	412	$9.74	
High Pressure Sodium	5,800	31	$0.73	
High Pressure Sodium	22,000	85	$2.01	
High Pressure Sodium	50,000	176	$4.16	(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	$1.49	$3.38	$8.10	(I)
Vertical, per lamp	$1.49	$3.38		(I)

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	$1.49			(I)
On 26-foot poles, vertical, per lamp	$1.49			
On 30-foot poles, horizontal , per lamp		$3.38		
On 30-foot poles, vertical, per lamp		$3.38		
On 33-foot poles, horizontal , per lamp			$8.10	(I)

(continued)

Energy Charge *(continued)*

Delivery Service Schedule No.

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	$1.49			(I)
On 26-foot poles, vertical, per lamp	$1.49			
On 30-foot poles, horizontal ,per lamp		$3.38		
On 30-foot poles, vertical, per lamp		$3.38		
On 33-foot poles, horizontal , per lamp			$8.10	(I)

51

Types of Luminaire	Nominal rating	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,000	31	$0.96	(I)
High Pressure Sodium	9,500	44	$1.36	
High Pressure Sodium	16,000	64	$1.99	
High Pressure Sodium	22,000	85	$2.64	
High Pressure Sodium	27,500	115	$3.57	
High Pressure Sodium	50,000	176	$5.46	
Metal Halide	9,000	39	$1.21	
Metal Halide	12,000	68	$2.11	
Metal Halide	19,500	94	$2.92	
Metal Halide	32,000	149	$4.62	(I)

53

Types of Luminaire	Nominal rating	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	31	$0.31	(I)
High Pressure Sodium	9,500	44	$0.45	
High Pressure Sodium	16,000	64	$0.65	
High Pressure Sodium	22,000	85	$0.86	
High Pressure Sodium	27,500	115	$1.17	
High Pressure Sodium	50,000	176	$1.79	
Metal Halide	9,000	39	$0.40	
Metal Halide	12,000	68	$0.69	
Metal Halide	19,500	94	$0.95	
Metal Halide	32,000	149	$1.51	
Metal Halide	107,800	354	$3.59	(I)

Non-Listed Luminaire, per kWh 1.015¢ (I)

(continued)

Judith M. Ridenour
Exhibit PPL(TAM)/304

Docket No. UE-
Exhibit PPL(TAM)/304
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed TAM Price Change

March 2009

TAM Price Change - Effective January 1, 2010

PACIFIC POWER & LIGHT COMPANY
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, 2010

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
												Base Rates		Net Rates		
Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Base Rates[1]	Adders[2]	Net Rates	Base Rates	Adders[2]	Net Rates	($000)	%[3]	($000)	%[3]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	478,485	5,435,846	$471,595	$18,970	$490,565	$480,272	$18,970	$499,242	$8,677	1.8%	$8,677	1.8%	1
2	**Total Residential**			478,485	5,435,846	$471,595	$18,970	$490,565	$480,272	$18,970	$499,242	$8,677	1.8%	$8,677	1.8%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,055	1,013,941	$90,889	($2,688)	$88,201	$92,533	($2,688)	$89,845	$1,644	1.8%	$1,644	1.9%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,101	2,045,065	$125,492	$14,255	$139,747	$128,740	$14,255	$142,995	$3,248	2.6%	$3,248	2.3%	4
5	Gen. Svc. 201 - 999 kW	30	30	853	1,378,646	$78,688	$6,369	$85,057	$80,816	$6,369	$87,185	$2,128	2.7%	$2,128	2.5%	5
6	Large General Service >= 1,000 kW	48	48	215	2,643,901	$130,705	$3,542	$134,247	$134,528	$3,542	$138,070	$3,823	3.0%	$3,823	2.9%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	571,965	$25,720	$767	$26,487	$26,523	$767	$27,290	$803	3.0%	$803	2.9%	7
8	Agricultural Pumping Service	41	41	6,108	136,792	$14,323	($3,071)	$11,252	$14,539	($3,071)	$11,468	$216	1.5%	$216	1.9%	8
9	Agricultural Pumping - Other	33	33	2,062	118,046	$3,839	$344	$4,183	$3,839	$344	$4,183	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			93,401	7,908,356	$469,656	$19,518	$489,174	$481,518	$19,518	$501,036	$11,862	2.5%	$11,862	2.4%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,404	10,466	$1,312	$132	$1,444	$1,321	$132	$1,453	$9	0.7%	$9	0.6%	11
12	Street Lighting Service	50	50	287	10,738	$1,171	$124	$1,295	$1,179	$124	$1,303	$8	0.7%	$8	0.6%	12
13	Street Lighting Service HPS	51	51	686	16,085	$2,829	$270	$3,099	$2,847	$270	$3,117	$18	0.6%	$18	0.6%	13
14	Street Lighting Service	52	52	79	1,186	$134	$14	$148	$135	$14	$149	$1	0.8%	$1	0.7%	14
15	Street Lighting Service	53	53	250	9,316	$590	$75	$665	$593	$75	$668	$3	0.5%	$3	0.5%	15
16	Recreational Field Lighting	54	54	105	816	$70	$6	$76	$71	$6	$77	$1	1.4%	$1	1.3%	16
17	**Total Public Street Lighting**			8,811	48,607	$6,106	$621	$6,727	$6,146	$621	$6,767	$40	0.7%	$40	0.6%	17
18	**Total Sales to Ultimate Consumers**			580,697	13,392,809	$947,357	$39,109	$986,466	$967,936	$39,109	$1,007,045	$20,579	2.2%	$20,579	2.1%	18
19	**Employee Discount**				18,481	($396)	($16)	($412)	($404)	($16)	($420)	($8)		($8)		19
20	**Total Sales with Employee Discount**			580,697	13,392,809	$946,961	$39,093	$986,054	$967,532	$39,093	$1,006,625	$20,571	2.2%	$20,571	2.1%	20
21	AGA Revenue					$2,380		$2,380	$2,380		$2,380	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			580,697	13,392,809	$949,341	$39,093	$988,434	$969,912	$39,093	$1,009,005	$20,571	2.2%	$20,571	2.1%	22

[1] Includes the Klamath Rate Reconciliation Adjustment (Schedule 92).
[2] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[3] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Docket No. UE-
Exhibit PPL(TAM)/305
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Monthly Billing Comparisons

March 2009

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 4 + Supply Service Schedule 200
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$15.76	$15.93	$0.17	1.08%
200	$23.30	$23.63	$0.33	1.42%
300	$30.84	$31.33	$0.49	1.59%
400	$38.39	$39.04	$0.65	1.69%
500	$45.91	$46.74	$0.83	1.81%
600	$54.12	$55.11	$0.99	1.83%
700	$62.33	$63.48	$1.15	1.85%
800	$70.54	$71.86	$1.32	1.87%
900	$78.74	$80.22	$1.48	1.88%
950	$82.85	$84.42	$1.57	1.89%
1,000	$86.96	$88.61	$1.65	1.90%
1,100	$96.17	$97.99	$1.82	1.89%
1,200	$105.38	$107.36	$1.98	1.88%
1,300	$114.61	$116.75	$2.14	1.87%
1,400	$123.82	$126.13	$2.31	1.87%
1,500	$133.03	$135.50	$2.47	1.86%
1,600	$142.24	$144.87	$2.63	1.85%
2,000	$179.10	$182.40	$3.30	1.84%
3,000	$271.25	$276.19	$4.94	1.82%
4,000	$363.39	$369.98	$6.59	1.81%
5,000	$455.53	$463.77	$8.24	1.81%

* Net rate including Schedules 91, 98, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 23 + Supply Service Schedule 200
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	$54	$62	$55	$63	1.53%	1.33%
	750	$73	$81	$74	$82	1.71%	1.54%
	1,000	$92	$100	$93	$102	1.82%	1.67%
	1,500	$129	$137	$132	$140	1.94%	1.83%
10	1,000	$92	$100	$93	$102	1.82%	1.67%
	2,000	$167	$175	$170	$178	2.00%	1.90%
	3,000	$242	$250	$247	$255	2.07%	2.00%
	4,000	$305	$313	$312	$320	2.19%	2.13%
20	4,000	$330	$338	$337	$345	2.02%	1.98%
	6,000	$456	$464	$466	$474	2.19%	2.16%
	8,000	$582	$591	$596	$604	2.29%	2.26%
	10,000	$709	$717	$725	$733	2.36%	2.33%
30	9,000	$696	$704	$711	$719	2.16%	2.13%
	12,000	$885	$893	$905	$913	2.26%	2.24%
	15,000	$1,074	$1,083	$1,099	$1,108	2.33%	2.31%
	18,000	$1,264	$1,272	$1,294	$1,302	2.38%	2.36%
31	9,300	$720	$728	$735	$743	2.16%	2.13%
	12,400	$915	$923	$936	$944	2.26%	2.24%
	15,500	$1,111	$1,119	$1,137	$1,145	2.33%	2.31%
	18,600	$1,307	$1,315	$1,338	$1,346	2.38%	2.36%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 23 + Supply Service Schedule 200
General Service - Primary 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	$53	$61	$54	$62	1.58%	1.37%
	750	$71	$80	$73	$81	1.76%	1.57%
	1,000	$90	$98	$91	$100	1.86%	1.71%
	1,500	$126	$134	$129	$137	1.99%	1.87%
10	1,000	$90	$98	$91	$100	1.86%	1.71%
	2,000	$163	$171	$166	$174	2.05%	1.95%
	3,000	$236	$244	$241	$249	2.12%	2.05%
	4,000	$297	$306	$304	$312	2.25%	2.19%
20	4,000	$322	$330	$329	$337	2.07%	2.02%
	6,000	$445	$453	$455	$463	2.25%	2.21%
	8,000	$568	$576	$581	$589	2.35%	2.32%
	10,000	$691	$699	$707	$716	2.41%	2.39%
30	9,000	$678	$687	$693	$702	2.21%	2.19%
	12,000	$863	$871	$883	$891	2.32%	2.30%
	15,000	$1,047	$1,055	$1,072	$1,080	2.39%	2.37%
	18,000	$1,232	$1,240	$1,262	$1,270	2.44%	2.42%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 28 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$331	$338	2.23%
	7,500	$499	$512	2.46%
	10,500	$668	$685	2.57%
31	9,300	$670	$685	2.27%
	15,500	$1,019	$1,044	2.49%
	21,700	$1,366	$1,401	2.60%
40	12,000	$861	$881	2.28%
	20,000	$1,311	$1,344	2.50%
	28,000	$1,752	$1,797	2.62%
60	18,000	$1,286	$1,316	2.29%
	30,000	$1,950	$1,999	2.52%
	42,000	$2,611	$2,679	2.63%
80	24,000	$1,703	$1,742	2.31%
	40,000	$2,584	$2,650	2.54%
	56,000	$3,466	$3,557	2.65%
100	30,000	$2,117	$2,166	2.32%
	50,000	$3,219	$3,301	2.54%
	70,000	$4,320	$4,435	2.65%
200	60,000	$4,167	$4,265	2.36%
	100,000	$6,371	$6,535	2.57%
	140,000	$8,574	$8,804	2.67%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 28 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$333	$341	2.21%
	7,500	$493	$505	2.49%
	10,500	$653	$670	2.64%
31	9,300	$671	$686	2.27%
	15,500	$1,001	$1,027	2.53%
	21,700	$1,329	$1,365	2.67%
40	12,000	$861	$881	2.28%
	20,000	$1,287	$1,320	2.54%
	28,000	$1,704	$1,750	2.69%
60	18,000	$1,287	$1,316	2.29%
	30,000	$1,914	$1,963	2.57%
	42,000	$2,540	$2,608	2.71%
80	24,000	$1,702	$1,741	2.31%
	40,000	$2,535	$2,601	2.58%
	56,000	$3,369	$3,461	2.72%
100	30,000	$2,114	$2,163	2.32%
	50,000	$3,156	$3,238	2.59%
	70,000	$4,198	$4,313	2.73%
200	60,000	$4,144	$4,242	2.37%
	100,000	$6,228	$6,392	2.63%
	140,000	$8,312	$8,541	2.76%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 30 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
100	30,000	$2,311	$2,359	2.06%
	50,000	$3,284	$3,363	2.42%
	70,000	$4,257	$4,368	2.61%
200	60,000	$4,169	$4,264	2.28%
	100,000	$6,115	$6,273	2.59%
	140,000	$8,061	$8,283	2.75%
300	90,000	$6,140	$6,283	2.32%
	150,000	$9,059	$9,297	2.63%
	210,000	$11,978	$12,311	2.78%
400	120,000	$8,049	$8,239	2.36%
	200,000	$11,940	$12,258	2.66%
	280,000	$15,832	$16,276	2.81%
500	150,000	$9,963	$10,201	2.39%
	250,000	$14,828	$15,224	2.67%
	350,000	$19,692	$20,247	2.82%
600	180,000	$11,878	$12,163	2.40%
	300,000	$17,715	$18,191	2.69%
	420,000	$23,553	$24,219	2.83%
800	240,000	$15,707	$16,088	2.42%
	400,000	$23,490	$24,125	2.70%
	560,000	$31,273	$32,162	2.84%
1000	300,000	$19,536	$20,012	2.44%
	500,000	$29,265	$30,058	2.71%
	700,000	$38,994	$40,104	2.85%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 30 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$2,265	$2,312	2.10%
	50,000	$3,219	$3,298	2.46%
	70,000	$4,173	$4,284	2.66%
200	60,000	$4,085	$4,181	2.33%
	100,000	$5,994	$6,153	2.65%
	140,000	$7,903	$8,125	2.81%
300	90,000	$6,014	$6,157	2.37%
	150,000	$8,878	$9,115	2.68%
	210,000	$11,741	$12,074	2.84%
400	120,000	$7,902	$8,093	2.41%
	200,000	$11,720	$12,037	2.71%
	280,000	$15,537	$15,981	2.86%
500	150,000	$9,780	$10,018	2.43%
	250,000	$14,552	$14,948	2.73%
	350,000	$19,323	$19,878	2.87%
600	180,000	$11,657	$11,943	2.45%
	300,000	$17,383	$17,859	2.74%
	420,000	$23,110	$23,776	2.88%
800	240,000	$15,412	$15,793	2.47%
	400,000	$23,047	$23,682	2.75%
	560,000	$30,682	$31,570	2.90%
1000	300,000	$19,167	$19,643	2.48%
	500,000	$28,711	$29,504	2.76%
	700,000	$38,254	$39,365	2.90%

* Net rate including Schedules 91, 290 and 297.

Pacific Power & Light Company
Billing Comparison
Delivery Service Schedule 41 + Supply Service Schedule 200
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	3,000	$197	$216	$185	$202	$221	$185	2.48%	2.26%	0.00%
	5,000	$328	$348	$185	$336	$356	$185	2.48%	2.34%	0.00%
	7,000	$459	$479	$185	$470	$490	$185	2.48%	2.38%	0.00%
Three Phase										
20	6,000	$393	$433	$371	$403	$443	$371	2.48%	2.25%	0.00%
	10,000	$656	$695	$371	$672	$711	$371	2.48%	2.34%	0.00%
	14,000	$918	$957	$371	$941	$980	$371	2.48%	2.38%	0.00%
100	30,000	$1,967	$2,166	$1,504	$2,016	$2,215	$1,504	2.48%	2.25%	0.00%
	50,000	$3,278	$3,478	$1,504	$3,359	$3,559	$1,504	2.48%	2.34%	0.00%
	70,000	$4,589	$4,790	$1,504	$4,703	$4,904	$1,504	2.48%	2.38%	0.00%
300	90,000	$5,900	$6,498	$3,770	$6,046	$6,644	$3,770	2.48%	2.25%	0.00%
	150,000	$9,833	$10,434	$3,770	$10,077	$10,678	$3,770	2.48%	2.34%	0.00%
	210,000	$13,767	$14,370	$3,770	$14,108	$14,711	$3,770	2.48%	2.38%	0.00%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power & Light Company
Billing Comparison
Delivery Service Schedule 41 + Supply Service Schedule 200
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	$190	$209	$185	$194	$214	$185	2.57%	2.34%	0.00%
	5,000	$316	$335	$185	$324	$343	$185	2.58%	2.43%	0.00%
	7,000	$442	$462	$185	$454	$473	$185	2.58%	2.47%	0.00%
Three Phase										
20	6,000	$379	$418	$371	$389	$427	$371	2.58%	2.34%	0.00%
	10,000	$632	$670	$371	$648	$687	$371	2.57%	2.43%	0.00%
	14,000	$885	$923	$371	$907	$946	$371	2.58%	2.47%	0.00%
100	30,000	$1,896	$2,089	$1,494	$1,944	$2,138	$1,494	2.58%	2.34%	0.00%
	50,000	$3,159	$3,354	$1,494	$3,241	$3,435	$1,494	2.58%	2.43%	0.00%
	70,000	$4,423	$4,619	$1,494	$4,537	$4,732	$1,494	2.58%	2.47%	0.00%
300	90,000	$5,687	$6,268	$3,760	$5,833	$6,415	$3,760	2.58%	2.34%	0.00%
	150,000	$9,478	$10,062	$3,760	$9,722	$10,306	$3,760	2.58%	2.43%	0.00%
	210,000	$13,269	$13,856	$3,760	$13,611	$14,197	$3,760	2.58%	2.47%	0.00%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
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	$18,526	$18,971	2.40%
	500,000	$27,526	$28,268	2.69%
	700,000	$36,526	$37,565	2.84%
2,000	600,000	$36,733	$37,623	2.42%
	1,000,000	$54,173	$55,657	2.74%
	1,400,000	$71,749	$73,826	2.89%
4,000	1,200,000	$72,376	$74,155	2.46%
	2,000,000	$107,527	$110,494	2.76%
	2,800,000	$142,679	$146,832	2.91%
6,000	1,800,000	$107,505	$110,175	2.48%
	3,000,000	$160,233	$164,682	2.78%
	4,200,000	$212,961	$219,190	2.93%

Notes:

On-Peak kWh	64.01%
Off-Peak kWh	35.99%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
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	$17,200	$17,645	2.59%
	500,000	$25,824	$26,566	2.87%
	700,000	$34,448	$35,487	3.01%
2,000	600,000	$34,122	$35,012	2.61%
	1,000,000	$50,811	$52,294	2.92%
	1,400,000	$67,635	$69,711	3.07%
4,000	1,200,000	$67,195	$68,975	2.65%
	2,000,000	$100,843	$103,810	2.94%
	2,800,000	$134,491	$138,644	3.09%
6,000	1,800,000	$100,311	$102,980	2.66%
	3,000,000	$150,783	$155,233	2.95%
	4,200,000	$201,255	$207,485	3.10%

Notes:

On-Peak kWh	60.53%
Off-Peak kWh	39.47%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
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	300,000	$15,939	$16,384	2.79%
	500,000	$24,210	$24,952	3.06%
	700,000	$32,481	$33,519	3.20%
2,000	600,000	$31,610	$32,500	2.82%
	1,000,000	$47,592	$49,075	3.12%
	1,400,000	$63,710	$65,786	3.26%
4,000	1,200,000	$62,181	$63,961	2.86%
	2,000,000	$94,416	$97,383	3.14%
	2,800,000	$126,651	$130,804	3.28%
6,000	1,800,000	$93,114	$95,784	2.87%
	3,000,000	$141,467	$145,917	3.15%
	4,200,000	$189,820	$196,049	3.28%

Notes:

On-Peak kWh	56.04%
Off-Peak kWh	43.96%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.