PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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February 29, 2012

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

Re: Advice Filing 12-002
Docket UE 245 - PacifiCorp's 2013 Transition Adjustment Mechanism
Schedule 201, Net Power Costs, Cost-Based Supply Service

PacifiCorp d/b/a Pacific Power submits for filing an original and five copies of the tariff pages identified below to implement PacifiCorp's 2013 Transition Adjustment Mechanism ("TAM"). The Company is requesting an effective date of January 1, 2013, for these tariff sheets.

A. Description of Filing

The purpose of the TAM filing is to update net power costs for 2013 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. The TAM Guidelines adopted by Commission Order No. 09-274 specify that if the TAM is filed in a year in which Pacific Power files a general rate case, then the TAM will be filed no later than March 1 to allow for a January 1 rate effective date. Accordingly, the Company is filing the TAM before March 1.

This tariff filing is supported by testimony and exhibits from the following Company witnesses addressing net power costs and pricing:

- Gregory N. Duvall, Director, Net Power Costs
- Judith M. Ridenour, Regulatory Consultant, Cost of Service and Pricing

B. Tariff Sheets

Second Revision of Sheet No. 201-1	Schedule 201	Net Power Costs
Second Revision of Sheet No. 201-2	Schedule 201	Net Power Costs
Second Revision of Sheet No. 201-3	Schedule 201	Net Power Costs

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 Bryce Dalley, Director, Regulatory Affairs and Revenue Requirement, at (503) 813-6389.

A copy of this filing has been served on all parties to PacifiCorp's last TAM proceeding, Docket UE 227, as indicated on the attached certificate of service. Confidential material in support of the filing has been provided to parties under the protective order adopted in Order No. 10-069.

Sincerely,

William R Griffith M/B

William R. Griffith
Vice President, Regulation

Enclosures

cc: UE 227 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 29th of February, 2012, I caused to be served, via email and/or overnight delivery, 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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Gregory N. Duvall
Exhibit PAC/100

REDACTED
Docket No. UE-245
Exhibit PAC/100
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Redacted Direct Testimony of Gregory N. Duvall

February 2012

DIRECT TESTIMONY OF GREGORY N. DUVALL

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ATTACHED EXHIBITS

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

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Director, 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 PacifiCorp 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 and was responsible for directing the analytical effort for the Multi-State Process ("MSP"). I currently direct the work of the load forecasting group, the net power cost group, and the renewable compliance area.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony in this case?

A. I present the Company's proposed 2013 Transition Adjustment Mechanism ("TAM") net power costs ("NPC"). Specifically, my testimony:

- Summarizes the content of the filing.
- Describes the primary drivers behind the increase in NPC for 2013, as well as

factors that mitigate the increase.

- Describes changes the Company has made to the NPC study since the Company's 2012 TAM.
- Updates wind integration and hedging costs included in the Company's NPC.
- Describes how the filing is consistent with the TAM Guidelines.
- Introduces the other witness, Ms. Judith M. Ridenour, who provides testimony in support of the proposed tariffs and estimated rates.

Summary of PacifiCorp's 2013 TAM Filing

Q. Please provide background on the Company's 2013 TAM filing.

A. The TAM is the Company's annual filing to update its NPC in rates. The updated NPC are used to set the transition adjustments for direct access customers and, in this case, become effective in rates on January 1, 2013. The Company is filing the 2013 TAM concurrently with a request for a general rate increase, Docket UE 246 ("2012 General Rate Case").

Q. What are the forecast normalized system-wide NPC for calendar year 2013?

A. The Company's total forecast normalized system-wide NPC for calendar year 2013 are $1.504 billion. This is approximately $9 million higher than the baseline NPC in the 2012 TAM, Docket UE 227. The 2012 NPC baseline was reduced by a $32 million settlement adjustment, producing in-rates system NPC of $1.463 billion. NPC in this case are approximately $41 million higher than the adjusted NPC from UE 227.

Q. What is the estimated increase in Oregon-allocated NPC for calendar year 2013?

A. As shown on Exhibit PAC/101, on an Oregon-allocated basis, the forecasted normalized NPC for calendar year 2013 are $370.2 million. This is approximately $3.5 million higher than the NPC authorized in the 2012 TAM. As pointed out above, the 2012 NPC currently in rates reflect the settlement adjustment from Docket UE 227.

Q. Does the proposed rate increase in the filing reflect the changes in load since UE 227?

A. Yes. The 2013 load forecast in the filing reflects a decrease in Oregon loads when compared to the 2012 forecast loads from UE 227. The rates approved in UE 227 will under-collect $6.4 million in the 2013 test period. Thus, the proposed rate increase in this filing is increased from $3.5 million to $9.9 million. This present revenue change due to load variance is shown in Exhibit PAC/101. As explained in Ms. Ridenour's testimony, the 2013 TAM proposes an overall average increase of approximately 0.8 percent.

Q. Have Oregon's allocation factors changed since the 2012 TAM?

A. Yes. Oregon's allocation factors have decreased due to changes in the forecasted Oregon load relative to changes in the forecasted load for the Company's other jurisdictions. If the allocation factors in the 2013 TAM had not changed, NPC allocated to Oregon customers would have been $7.75 million higher.

Q. Please generally describe the drivers of the Company's NPC in this filing.

A. Table 1 illustrates the change in system-wide NPC by category from the NPC baseline in the 2012 TAM:

TABLE 1
Net Power Cost Reconciliation ($millions)

UE-227 OR TAM In-Rates Net Power Cost	**1,463**
Settlement Adjustment	**32**
Subtotal	**1,495**
Wholesale Sales	98
Purchase Power	(16)
Coal Generation	16
Gas Generation	(90)
Wheeling Hydro and Other	1
Total Increase/(Decrease)	**9**
Oregon TAM 2013	**1,504**

As shown in Table 1, the $9 million change in NPC after accounting for the settlement adjustment is driven largely by a $98 million decrease in wholesale sales revenue and a $16 million increase in coal expenses. These increases in NPC are largely offset by a $90 million decrease in natural gas expense and a $16 million decrease in purchased power expense.

Q. How has the operation of the Company's system changed since the 2012 TAM?

A. On an energy basis, the Company's retail load forecast is lower by 371 gigawatt-hours ("GWh"), wholesale sales volumes decreased by 2,562 GWh and purchased power volumes decreased by 2,836 GWh. The Company's gas generation increased by 414 GWh and coal generation decreased by 367 GWh for a net change in thermal generation of 47 GWh. The changes in the dispatch of the

Company's thermal generation fleet can be best explained by changes in wholesale power prices and coal prices compared to the 2012 TAM. I will discuss the relationship of electricity prices, natural gas prices, and the operating costs of the thermal generation fleet in more detail later in my testimony.

Discussion of Major Cost Drivers in NPC

Q. Please discuss the reduction in wholesale sales revenue in the 2013 NPC forecast.

A. As shown in Table 1, on a system-wide basis, wholesale sales revenues have declined by $98 million (or 17 percent) since the 2012 TAM, driven by a reduction in the volume of sales of approximately 18 percent or 2,562 GWh.

Q. Please explain why the volume of wholesale sales has declined.

A. Wholesale sales are split into three categories: long-term firm, short-term firm, and system balancing. For long-term firm sales, sales contracts with NVEnergy, Pacific Gas and Electric Company, and Southern California Edison expire before 2013 and account for a reduction in sales of 2,081 GWh. In the short-term firm wholesale sales category, transactions with delivery of power in 2012 that expire before 2013 account for 2,562 GWh of the reduction in volume. This reduction in short-term firm sales is partially offset by an increase in system balancing sales of 2,105 GWh, as computed by the Generation and Regulation Initiative Decision ("GRID") model.

Q. Why has purchased power expense decreased by $16 million?

A. The primary driver of the decrease in purchased power expense is a reduced volume of purchased power.

Q. Why are the volumes of market purchases lower in the 2013 TAM?

A. As discussed previously, the Company's obligation to provide power associated with its long-term firm wholesale sales has decreased by 2,081 GWh, and retail load has decreased by 371 GWh. In addition, because the 2012 TAM reflected lower market prices than the current filing, the model used purchased power to meet these previous obligations of sales and retail load. With the increase in market prices compared to the prior TAM and the lower volume of retail and wholesale sales, the Company does not need to purchase as much power in 2013 as it did in 2012.

Q. Are there any factors that offset the reduction in purchased power expense?

A. Yes. The Company has entered into three new 20-year Qualifying Facility ("QF") contracts that increase purchased power expense in 2013 by $36.3 million. In addition, two QF contracts that were included for part of the year in the 2012 TAM are included for the entire year in the 2013 TAM, increasing purchased power expense by $19.0 million. The total increase to purchased power expense from these five QF contracts is $55.4 million. Also reflected in purchased power expense is an increase of $27.4 million associated with an increase in generation from the Hermiston gas plant. The Hermiston expense in purchased power reflects the half of the Hermiston gas plant that is acquired under a long-term purchased power agreement by the Company. These increases in purchased power expense due to QF contracts and the Hermiston plant are offset by reduced volumes of purchases from the market in both short-term firm and system balancing purchases.

Q. Please identify the five QF contracts discussed above.

A. The five contracts discussed above are the Biomass One project located in Oregon, the Five Pine and North Point projects located in Idaho, and the Pioneer I and II wind projects located in Wyoming.

Q. Please discuss the reduction in retail loads referenced above.

A. The Company calculated 2013 TAM NPC using the 2013 sales and loads forecast I sponsor in the Company's 2012 General Rate Case. As I explain in my testimony in that filing, the 371 GWh reduction in the retail load forecast is driven by the following factors: (a) lower forecasted residential sales due to slower than expected economic recovery; (b) lower forecasted commercial sales due to lower residential growth and slippage in the timing of expected load increases at data centers; and (c) higher industrial sales due to forecasted new loads in the oil and gas extraction sector, offset in part by a loss in sales from some industrial customers opting to use their on-site generation to serve their own load.

Q. Please explain why natural gas expense decreased by $90 million since the 2012 TAM.

A. The Company's natural gas expense decreased in this filing despite the increase in total natural gas requirements associated with increased natural gas-fired generation. The primary reason is the lower swap expense associated with lower hedge prices relative to forecast market prices and reduced hedge volumes, plus continued low natural gas market prices in the 2013 TAM. I will provide more detail on the Company's hedging changes later in my testimony.

Q. Please discuss the changes in wholesale electricity prices and the changes in natural gas prices since the 2012 TAM.

A. Wholesale electricity prices increased by approximately 13 percent while natural gas prices are roughly the same as the natural gas prices in the 2012 TAM. To understand the impact these changes have on NPC, it is important to look at them on a monthly basis, as well as by high load hour ("HLH") and low load hour ("LLH"). Table 2 shows the change in wholesale electricity prices (average market price at the Mid-Columbia ("Mid-C") and Palo Verde ("PV") trading hubs) by month and by HLH and LLH. Table 3 shows the change in natural gas prices at the Opal trading hub by month, which is a source of gas for the gas plants located in Utah.

Table 2

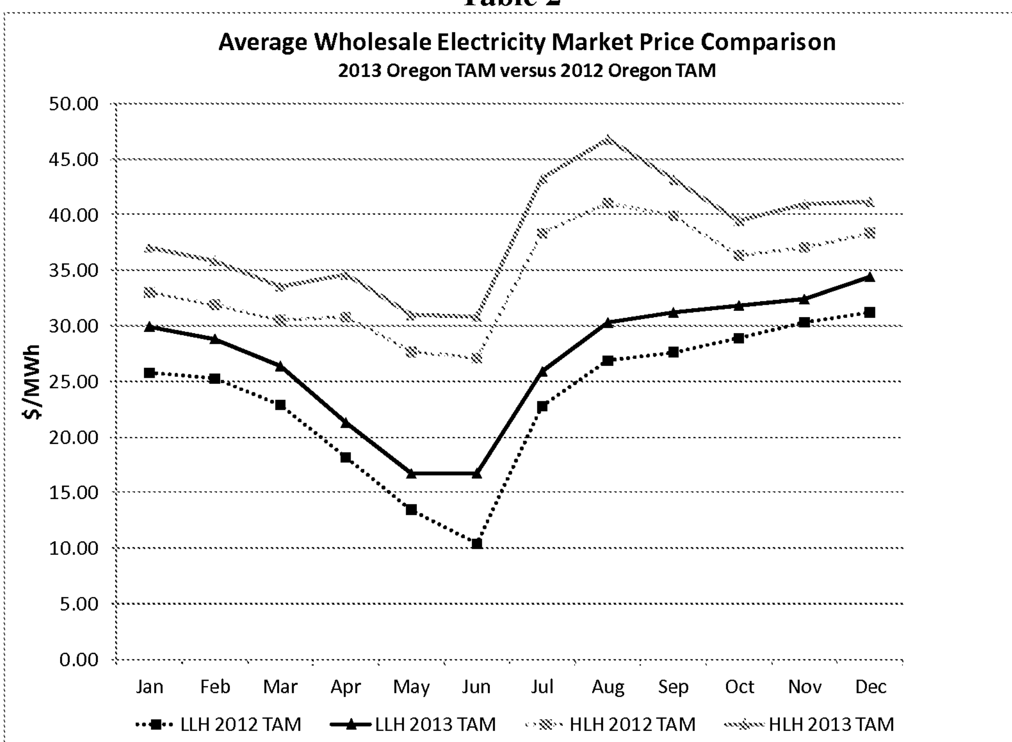
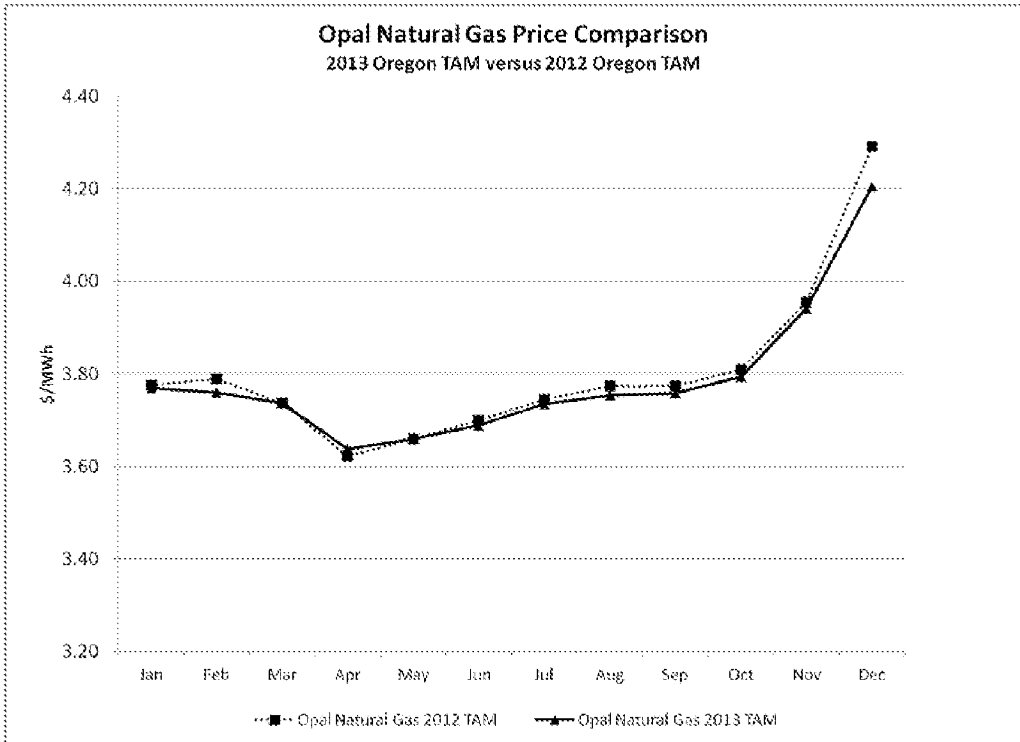


Table 3



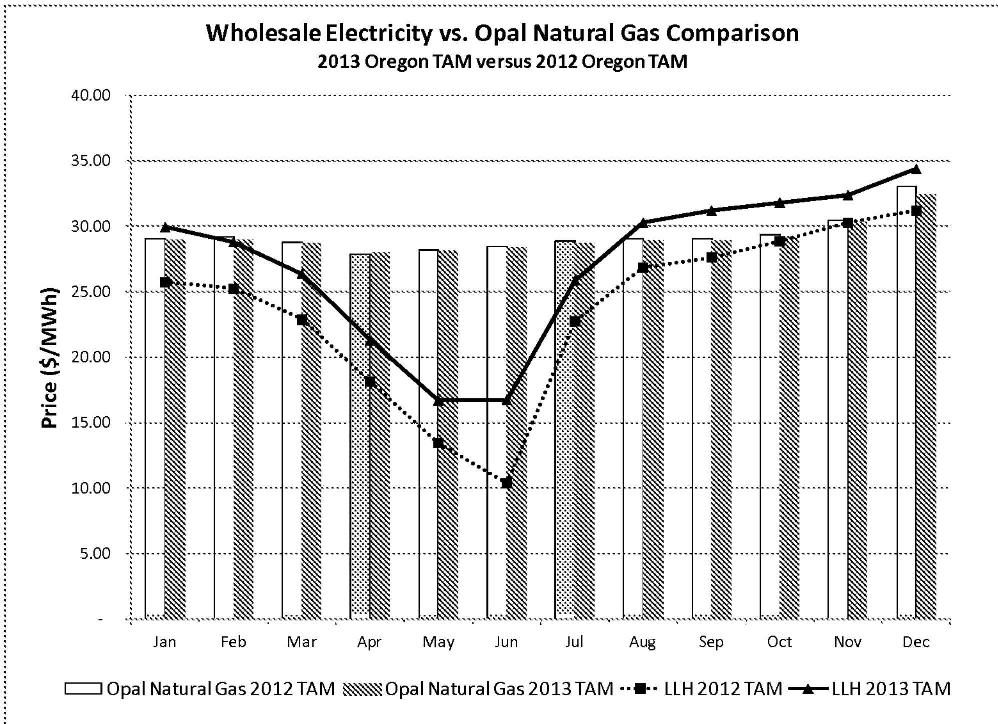
Q. What do Tables 2 and 3 show?

A. Table 2 shows that wholesale power prices are higher for both HLH and LLH in every month of 2013. Table 3 shows that natural gas prices are nearly the same in this filing as compared to the natural gas prices in the final update of the 2012 TAM. This change in the relationship of wholesale electricity market prices and natural gas prices caused natural gas-fired generation to become more economic and increased the Company's natural gas plant generation in the current filing. Table 4 below illustrates the economics of the Company's natural gas-fired plants compared to the prices reflected in the 2012 TAM.

Q. Please describe Table 4.

A. Table 4 compares the same wholesale electric prices as in Table 2 above with the equivalent dollar-per-megawatt-hour price of a combined cycle combustion turbine using the Opal natural gas prices shown in Table 3.

Table 4



Q. What does Table 4 show?

A. Table 4 shows that, in 2013, natural gas plants are economic in the months of September through December in light load hours when they were not economic in 2012. This helps to explain the increase in natural gas generation between this case and the 2012 TAM.

Q. Please explain the increase in coal expenses in this case.

A. Approximately $15.7 million of the total Company NPC increase in this case is attributable to coal expenses. Of this amount, $20.3 million is attributable to an increase in price, and ($4.6) million is attributable to a reduction in volume due to reduced coal generation. Price increases are reflected in the costs of third-party coal supply and transportation agreements as well as the Company's Deer Creek mine. Higher Deer Creek mine operating costs, approximately $12 million, account for about 60 percent of the overall price increase.

Q. Please explain the reduction in coal generation in this case.

A. Coal generation has decreased because coal prices are higher in 2013 compared to the 2012 TAM, resulting in less economic dispatch of the coal units. Coal generation has fallen by approximately 367 GWh—from 44,199 GWh in the 2012 TAM to 43,833 GWh in 2013. Unlike natural gas generation that increased as a result of changing market prices, coal generation declined. The majority of the decline occurred at the Dave Johnston, Hunter, and Huntington plants, where coal prices increased the most.

Determination of NPC and Model Inputs and Outputs

Q. Please explain NPC.

A. NPC 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 NPC.

A. NPC are calculated for a future test period based on projected data using GRID. GRID is a production cost model that simulates the operation of the Company's power system on an hourly basis.

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

A. Yes. The Company has used the GRID model to determine NPC in its Oregon filings for several years.

Q. Is the Company using the same version of the GRID model as used in its 2012 TAM?

A. Yes.

Q. What inputs were updated for this filing?

A. All inputs have been updated since the 2012 TAM, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the Company's generation facilities.

Q. Has the Company changed its GRID model topology?

A. Yes. There are two main changes to the GRID model topology. The first change better reflects the wheeling contracts with Idaho Power Company and the impact of the Populus to Terminal transmission line. The second change better reflects the operational constraints of the Company's wheeling contracts with BPA after the expiration of the BPA peaking contract.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is attached to my testimony as Exhibit PAC/102. Additional data with more detailed analyses are also available in hourly, daily, monthly, and annual formats by HLH and LLH.

Changes to the NPC Study since the 2012 TAM

Q. What changes has the Company made to the NPC study since the 2012 TAM?

A. The Company refined the following inputs to GRID:

- Hydro Generation—The Company now inputs normalized generation into the GRID model on a weekly basis, as opposed to hourly, to better reflect the Company's operation of its hydro facilities for generating and providing reserves.
- Bear River—The normalized capacity and generation now includes the impact of flood control years and reflects the Company's more recent operation of the Cutler and Oneida plants, including providing an increased level of reserves through motoring of the units.
- California Independent System Operator ("Cal ISO")—Transactions with the Cal ISO are now modeled in GRID on a normalized basis using historical purchases and sales. This change, discussed in more detail later in my testimony, is in response to the Industrial Customers of Northwest Utilities ("ICNU") Cal ISO adjustment in the 2012 TAM. This modeling change also responds to the Commission's direction in the 2012 TAM order, Order No. 11-435 ("2012 TAM Order") "evidence in future TAM proceedings that more precisely quantifies the level of benefits from the Cal ISO transactions, as well as evidence demonstrating that the Cal ISO is a counterparty at these market hubs."[1]
- DC Intertie—The Company's right to use the DC Intertie has now been added to the GRID topology. This allows GRID to purchase power at the Nevada Oregon Border ("NOB") market hub to serve load. This change is in response to ICNU's DC Intertie adjustment in the 2012 TAM.

[1] Order No. 11-435 at 25.

- Gadsby Must-Run—As discussed later in my testimony, the Gadsby peaking units 4, 5 and 6 are no longer modeled as must-run units overnight. This change is in response to ICNU's Gadsby must-run adjustment in the 2012 TAM. This modeling change also responds to the Commission's direction in the 2012 TAM order to "see clear and direct evidence that the modeling of the units in GRID is reflective of actual operations."[2]
- Hydro Planned and Forced Outages—The Company modeled planned and forced outages at its hydro facilities. In the partial stipulation in Docket UM 1355, the Company agreed to remove hydro forced outages from Docket UE 207 but reserved the right to include hydro forced outages in a future TAM proceeding.[3]
- Oregon Solar Project—The Company included the NPC benefit of the energy value for the Oregon solar project, which is discussed in more detail in Company witness Mr. Bruce W. Griswold's testimony (Exhibit PAC/800) in the 2012 General Rate Case. In determining the NPC dispatch benefit included in the GRID model, the Company used the estimated hourly output of the facility by HLH and LLH and multiplied the monthly energy by the Mid-C HLH and LLH wholesale market prices, respectively.
- Super Peak Price adjustment—The Company removed the super peak price adjustment ("Q-factor") from hourly price scalars applied to super peak hours during select summer months (June through September). Previously, the Company included a Q-factor adjustment to more closely align prices for

[2] *Id* at 27.
[3] Order No. 10-414 at 29.

summer super peak forward products with price premiums in super peak forward offers. The Q-factor adjustment, tempered with restrictions to ensure that standard on-peak prices align with forward market quotes, no longer achieves its originally intended objective, and was consequently removed from the Company's hourly price scalar calculation.

Wind Integration Costs

Q. What are the Company's wind integration costs included in NPC?

A. The costs of integrating wind generation in the Company's balancing authority areas included in NPC are approximately $3.87/MWh.

Q. Does the Company continue to base its wind integration costs on the results of the 2010 Wind Integration Study ("Wind Study") from the 2011 Integrated Resource Plan (Docket LC 52)?

A. Yes. The Company continues to believe that the level of reserves required to integrate wind generation net of system load, as identified in the Wind Study, is appropriate.

Q. Has the Company made any changes to the reserve requirements since the 2012 TAM?

A. Yes. The reserve requirement from the Wind Study has been increased to integrate the additional wind capacity in 2013. The Wind Study calculated that an average of 533 MW of reserves were necessary to integrate 2,046 MW of wind capacity. This level of reserves was included in the 2012 TAM. In this case, the 2013 test year includes an average of 2,400 MW of wind capacity, 354 MW more than in the amount of wind included in the Wind Study. To integrate this additional capacity, the Company increased the reserve requirement by 37 MW to 570 MW, based on the relationship between the reserves required at the two highest penetration levels in the Wind Study.

Hedging Update

Q. Please discuss the change in hedged gas prices and volume in the 2013 TAM compared to the 2012 TAM.

A. The 2013 TAM reflects a lower percentage volume of natural gas hedges, approximately [redacted] percent of the Company's net open position, compared to a hedged percentage volume of [redacted] percent in the 2012 TAM Rebuttal Update. In addition to the smaller percentage volume of hedges, which allows a larger percentage volume of natural gas to be priced at current market prices, the hedged volume of [redacted] percent reflected in the 2013 TAM also reflects lower hedge costs. Hedge costs represent the difference between the average hedge contract strike price and the forecast market price. For example, the average cost per MMBTU of the 2012 natural gas swaps was [redacted]/MMBTU; this filing reflects an average swap cost of [redacted]/MMBTU.

Q. Was the execution of the hedge transactions reflected in the 2013 TAM consistent with the Company's Risk Management Policy and Front Office Procedures and Practices?

A. Yes.

Q. Has the Company made any modifications to its Risk Management Policy or Front Office Procedures and Practices since the 2012 TAM?

A. No, although the Front Office Procedures and Practices are currently in the process of being updated.

Q. Has the Commission scheduled a workshop to discuss the Company's present and future hedging strategies, consistent with the 2012 TAM Order encouraging the Company to review its hedging policies and practices with Staff and stakeholders?

A. Yes. The Commission scheduled a workshop with the Company, Portland General Electric, and interested parties for March 19, 2012.

Other Issues Referenced the 2012 TAM Order

Q. In compliance with the 2012 TAM Order, is the Company providing further information and analysis on specific NPC issues?

A. Yes. In the 2012 TAM Order, the Commission directed the Company to address certain NPC issues or provide further explanation on the following topics in the 2013 TAM:

- GRID Market Capacity Limits
- Cal-ISO Charges
- Gadsby Unit 4-6 modeling

GRID Market Capacity Limits

Q. In its 2012 TAM Order, how did the Commission resolve the issue of modeling market caps in GRID?

A. The Commission accepted the Company's modeling of market caps on a non-precedential basis and directed Staff to conduct workshops with parties to address and attempt to resolve the Company's approach to modeling market caps. In the absence of an agreement prior to the 2013 TAM filing, the Commission directed both the Company and Staff to provide additional analysis and evidence on the issue.

Q. Did the Company attend a Staff workshop on market cap modeling with interested parties?

A. Yes. On January 11, 2012 the Company attended a workshop with Staff and interested stakeholders; however, parties were unable to reach an agreement on the appropriate methodology to use in this filing.

Q. Please explain why the Company believes it is important to model market capacity limits in GRID.

A. The GRID model assumes unlimited market depth for system balancing sales and purchases; it does not consider load requirements, transmission constraints, market illiquidity, or static assumptions about market prices that would not allow the Company to make sales at the forecast price. The Company's transmission access to a market point limits its ability to sell its generation in that market; similarly, counterparties' demand for purchases is limited by their transmission access and their own load and resource balance. Without market caps, the GRID model has no constraints to reflect counterparties' inability to make economic transactions.

Q. Please explain the static assumptions of market prices in GRID.

A. The Company's official forward price curve produces an hourly price that remains static in GRID in each hour, regardless of the changes in load and resource balance. The driving force behind market prices in real-time is based on the dispatch cost of additional generation, therefore an increase in load or reduction in resources will require that higher cost resources be dispatched, or vice versa. Thus, prices are impacted by changes in the loads and resources of all market participants, including the Company. Without market caps, the GRID model will overestimate sales revenues as it continues to make sales at the hourly market price, even though additional sales would push market prices down.

Q. How did the Company model market caps in previous TAM proceedings?

A. In Docket UE 216 and in previous TAM filings, the Company capped GRID in the four major wholesale sales markets, Mid C, California Oregon Border ("COB"), Four Corners, and PV during the graveyard hours (1 am – 6 am), and market caps at the Mona market in all hours. Within these four major market hubs the Company modeled market caps based on an average of four years of historical graveyard spot market sales at each hub.

Q. How did the Company change its modeling of market caps in the 2012 TAM and in this filing?

A. Consistent with the previous market cap methodology, the Company continues to model market caps at the four major market hubs—Mid-C, COB, Four Corners, and PV—and added consistent market caps at the Mead and Mona market hubs to ensure sales in all markets are treated consistently. The difference in the methodology is that the Company now specifies market depth in all hours, segregated by HLH and LLH periods, and bases the cap on a four-year historical average of both spot and short-term firm wholesales sales levels.

Q. Why did the Company change its modeling of market caps in the 2012 TAM and in this filing?

A. The previous market cap methodology was restricted to the graveyard hours and the Company limited its market depth calculation based on an average of spot market sales only. The Company's refined approach models market depth in all hours and sets the cap using a broader range of historic market transactions. This approach produces a more accurate and comprehensive model of the power markets in which the Company transacts. In the 2012 TAM, the Company also demonstrated that the refined approach reduced the impact of market caps on the Company's final NPC.

Q. How does the GRID modeling of wholesale sales compare with actual sales levels?

A. Table 5 below shows a comparison of the volumes of actual short-term firm wholesale sales modeled in GRID versus actual short-term firm wholesale sales over the last four years.

Table 5

GRID vs Actual (MWh)

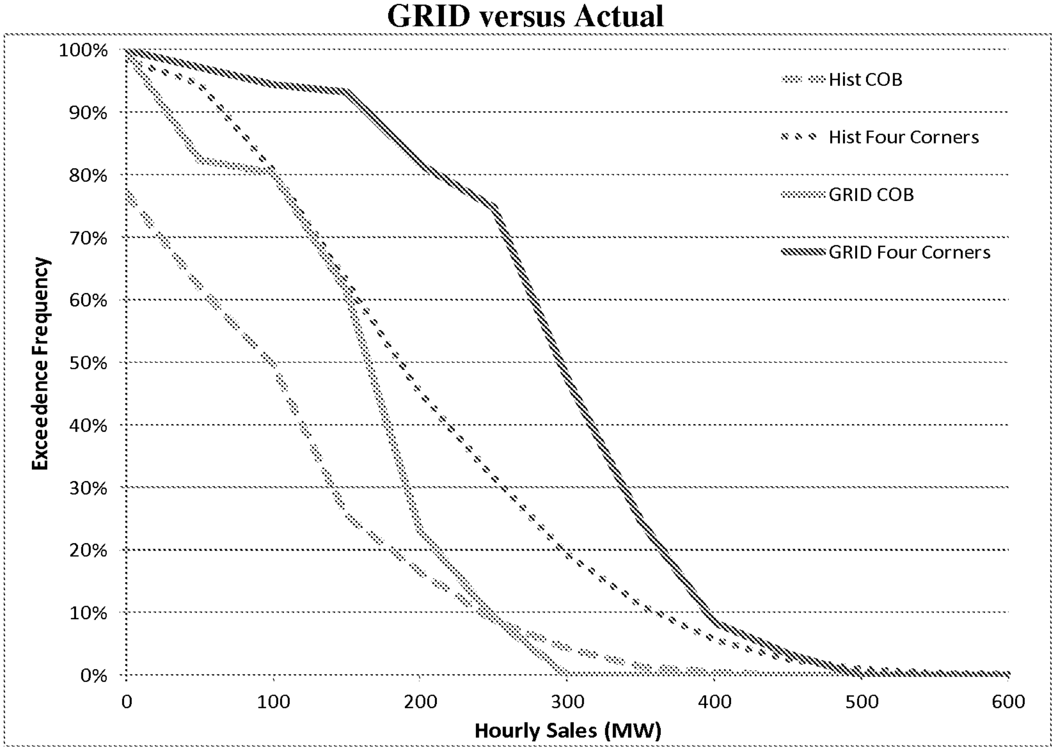
	2007	**2008**	**2009**	**2010**	**2011**
GRID Sales Volume	18,344,663	31,618,999	13,229,220	10,490,633	9,212,496
Actual Sales Volume	8,934,640	7,892,769	8,089,341	4,754,401	6,802,152
Difference	(9,410,023)	(23,726,230)	(5,139,879)	(5,736,232)	(2,410,344)

As shown in Table 5, GRID over forecasts wholesale power sales in every year. Removing market caps would cause GRID to further over forecast wholesale power sales.

Q. Table 5 shows that GRID over-forecasts wholesale sales compared to actual. Does that also mean that GRID over-forecasts sales in every hour compared to actual?

A. No. As stated previously, GRID is a perfect foresight model with static prices; it cannot take into consideration the peak volumes of actual wholesale sales, which may have been due to unexpected wind generation, changes in prices, or off-system contingency events. While there may be specific hours in which actual operations has higher wholesale sales volumes due to real-time market conditions, on average GRID will over-forecast the volume of wholesale sales the Company is able to make without market caps in place. Table 6 below illustrates the wholesale sales modeled in GRID with market caps in place in this filing and actual sales for the 12 months ending June 2011.

Table 6
GRID versus Actual



As shown in Table 6, even with market caps in place, GRID continues to overestimate actual wholesale sales in total, and only underestimates a small frequency of sales at very high purchase levels.

Q. Why does the Company continue to use a four-year historical average when there is a declining trend in wholesale sales volumes?

A. The Company continues to use a four-year historical average because it is a conservative estimate of what the Company expects to occur in the test period. However, the Company will continue to analyze the use of a four-year historical average and its ability to accurately represent the depth of the relevant wholesale markets going forward.

Q. Due to the fact that the GRID model overestimates wholesale sales as compared to actual wholesale sales levels, and has consistently done so for the past five years, is it reasonable to continue to reflect the Commission's trading and arbitrage adjustment from Docket UE 191, Order No. 07-446?

A. No. In Order No. 07-446, the Commission decided that the GRID model results should be adjusted as necessary to incorporate revenues associated with arbitrage and wholesale trading activities. The facts in that case showed that GRID underestimated wholesale sales volumes when compared to 2006 actual wholesale sales volumes. However, as Table 5 above shows, the GRID model now consistently overestimates the volume of wholesale sales; therefore, there is no longer any justification to adjust the GRID model results by imputing trading and arbitrage margins.

Cal ISO Modeled Transactions

Q. Please explain why the Company is explicitly modeling Cal ISO transactions in the GRID model in the 2013 TAM.

A. The Company is explicitly modeling the Cal ISO transactions in response to the 2012 TAM Order in which the Commission stated that it expects "to see evidence in future TAM proceedings that more precisely quantifies the level of benefits from Cal ISO transactions, as well as evidence demonstrating that the Cal ISO is a counterparty at these market hubs."[4] By explicitly modeling these transactions in the GRID model, based on historical transaction levels, the Company has demonstrated that the Cal ISO is a counterparty and quantified the associated benefits.

Q. How many transactions did the Company enter into with the Cal ISO during the 12-month period ending June 2011?

A. The Company entered into 5,726 transactions with the Cal ISO during the 12 month period ending June 2011. About half of these transactions were at COB, about a third at Four-Corners, and the majority of the remaining transactions were at Mona.

Q. Please explain how the Company modeled Cal ISO transactions in this filing.

A. Based on the 12 months ending June 2011, the Company calculated the average amount of energy sold to and purchased from the Cal ISO on a monthly basis and by HLH and LLH. The Company modeled expected transactions with Cal ISO at three major points of delivery based on historical information: Four Corners,

[4] Order No. 11-435 at 25.

COB, and Mona. The Company also included the expected Cal ISO wheeling fees and service fees.

Gadsby Must-Run Operations

Q. Has the Company changed how it models its Gadsby units 4, 5 and 6 in the 2013 TAM versus the 2012 TAM?

A. Yes. In the 2012 TAM filing, the Company modeled Gadsby units 4, 5 and 6 as must run units during all hours, but in the 2013 TAM the Company models the Gadsby units as must run only during the HLH.

Q. Did the Commission direct the Company to provide additional evidence showing that the Company's modeling of the Gadsby units was reasonable?

A. Yes. The Commission directed the Company to provide additional information that showed that the modeled generation of Gadsby units 4, 5 and 6 was reasonable when compared to historical information. In response to the Commission's request, please refer to Table 7, which shows the historical generation levels of the Gadsby units, including the previous and current TAM filing.

Table 7

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Modeled 2012	Modeled 2013
MWh	250,518	349,713	255,281	125,920	335,671	222,439
Capacity Factor	24%	33%	24%	12%	32%	21%

Table 7 shows that the Company's modeled generation of Gadsby units 4, 5 and 6 in this case is reasonable when compared to the actual historical operation of the units.

Other Input Changes to Comply with Previous TAM Dockets

Q. Has the Company continued to include changes to NPC inputs in accordance with the stipulation in Docket UE 216?

A. Yes. The Company has continued to include changes for the items identified in the UE 216 stipulation. Specifically, in the UE 216 stipulation the Company agreed to reflect the following methodological changes in the 2012 TAM:

- Screens – The Company uses a daily screening methodology that is more effective than that used in UE 216 and is based on logic which commits all gas plants up and backs down those that are not economic.
- Black Hills CTs – The Company uses a four-year average for the costs of the Black Hills combustion turbines.
- Heat Rates – The Company has not implemented adjustments for scrubbers or other capital projects as they relate to heat rates, but instead relies on the traditional analysis of four years of actual data to derive the heat rate inputs.
- APS Supplemental Coal and Other – The Company models the option contracts to be exercised only when economic.
- The Company does not include inter-hour wind integration charges for non-owned wind facilities.
- The Company includes modeling of non-firm transmission links and expenses using a four-year average.

Compliance with TAM Guidelines

Q. Did the Company prepare this filing in accordance with the TAM Guidelines adopted by Order No. 09-274 as clarified and amended in Order No. 09-432?

A. Yes. The Company has complied with the TAM Guidelines applicable to the initial TAM filing when filing a TAM concurrently with a general rate case.

Q. Did the Company provide notice to parties on changes to the GRID model before filing this case?

A. Yes. On January 30, 2012, the Company sent a notice to Commission Staff, the Citizens' Utility Board of Oregon, ICNU, and Noble Americas Energy Solutions, LLC, to inform parties that the Company had not made changes to its GRID model used to calculate NPC in this case.

Q. Does this filing include updates to all NPC components identified in Attachment A to the TAM Guidelines?

A. Yes.

Q. Has the Company provided information regarding its anticipated subsequent TAM updates?

A. Yes. Exhibit PAC/103 contains a list of known contracts and other revenues that could be included in the Company's TAM updates in this case based on the best information available at the time the Company prepared the NPC study. The Company will update this list as new information becomes available.

Q. Has the Company agreed 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 this initial filing. The historical base period used for outage rates in this filing is the 48-month period ending June 2011.

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

A. In compliance with Attachment B to the TAM Guidelines, the Company provided access to the GRID model and workpapers concurrently with this initial filing. Specifically, the Company is providing the NPC report workbook and the GRID project report.

Introduction of Witness

Q. Please identify the other Company witness supporting the 2013 TAM and provide a brief explanation of the witness' testimony.

A. Ms. Judith M. Ridenour, Regulatory Consultant, Pricing & Cost of Service, 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.

Gregory N. Duvall
Exhibit PAC/101

Docket No. UE-245
Exhibit PAC/101
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

CY 2013 Transition Adjustment Mechanism

February 2012

PacifiCorp
CY 2013 TAM

	ACCT.	Total Company: UE-227 Final TAM CY 2012	Total Company: TAM CY 2013	Factor	Factors CY 2012	Factors CY 2013	Oregon Allocated: UE-227 Final TAM CY 2012	Oregon Allocated: TAM CY 2013
Sales for Resale								
Existing Firm PPL	447	25,687,328	25,837,906	SG	26.314%	25.777%	6,759,357	6,660,277
Existing Firm UPL	447	25,490,583	30,104,809	SG	26.314%	25.777%	6,707,586	7,760,163
Post-Merger Firm	447	463,122,887	405,383,133	SG	26.314%	25.777%	121,866,048	104,496,238
Non-Firm	447	-		SE	24.796%	24.314%	-	-
Total Sales for Resale		514,300,798	461,325,848				135,332,992	118,916,679
Purchased Power								
Existing Firm Demand PPL	555	3,986,517	5,432,688	SG	26.314%	25.777%	1,049,011	1,400,392
Existing Firm Demand UPL	555	46,848,001	51,932,017	SG	26.314%	25.777%	12,327,572	13,386,597
Existing Firm Energy	555	26,937,826	37,962,219	SE	24.796%	24.314%	6,679,426	9,229,951
Post-merger Firm	555	570,696,383	582,081,940	SG	26.314%	25.777%	150,172,913	150,044,164
Secondary Purchases	555	-		SE	24.796%	24.314%	-	-
Other Generation Expense	555	3,633,079	5,498,155	SG	26.314%	25.777%	956,008	1,417,268
Total Purchased Power		652,101,807	682,907,019				171,184,929	175,478,372
Wheeling Expense								
Existing Firm PPL	565	27,123,063	24,712,270	SG	26.314%	25.777%	7,137,156	6,370,120
Existing Firm UPL	565	-	-	SG	26.314%	25.777%	-	-
Post-merger Firm	565	102,633,849	103,920,275	SG	26.314%	25.777%	27,007,047	26,787,690
Non-Firm	565	2,855,823	2,899,400	SE	24.796%	24.314%	708,122	704,946
Total Wheeling Expense		132,612,736	131,531,945				34,852,325	33,862,757
Fuel Expense								
Fuel Consumed - Coal	501	700,992,991	717,884,157	SE	24.796%	24.314%	173,816,205	174,542,900
Fuel Consumed - Coal (Cholla)	501	57,666,585	56,457,816	SSECH/SE	25.371%	24.314%	14,630,638	13,726,882
Fuel Consumed - Gas	501	6,860,109	6,359,116	SE	24.796%	24.314%	1,701,013	1,546,125
Natural Gas Consumed	547	420,276,987	349,046,222	SE	24.796%	24.314%	104,210,672	84,865,419
Simple Cycle Comb. Turbines	547	35,476,150	17,197,901	SSECT/SE	24.788%	24.314%	8,793,761	4,181,415
Steam from Other Sources	503	3,760,489	4,183,520	SE	24.796%	24.314%	932,440	1,017,161
Total Fuel Expense		1,225,033,311	1,151,128,733				304,084,729	279,879,902
Net Power Cost (Per GRID)		1,495,447,056	1,504,241,849				374,788,992	370,304,351
Liquidated Damages Adjustment		(405,489)		SG	26.314%	25.777%	(106,700)	
UE-227 Settlement Adjustment		(31,921,264)					(8,000,000)	
Oregon Situs Solar Project Benefit			(145,921)	OR	100.000%	100.000%		(145,921)
Total Net of Adjustments		1,463,120,302	1,504,095,928				366,682,292	370,158,430
Increase Absent Load Change								3,476,138
Oregon-allocated NPC Baseline in Rates from UE-227							366,682,292	
$ Change due to load variance from UE-227 forecast							(6,426,615)	
2013 Recovery of NPC in Rates							360,255,677	
Increase Including Load Change								**9,902,753**

Docket No. UE-245
Exhibit PAC/102
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

February 2012

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2013	01/13-12/13	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills s27013/s28160	12,873,106	1,082,096	1,041,092	1,082,795	1,071,922	1,050,317	1,055,195	1,086,602	1,091,085	1,065,088	1,085,502	1,072,224	1,089,186
BPA Wind s42818	2,658,533	333,182	279,306	270,443	210,046	198,293	160,832	120,620	114,334	150,360	219,760	276,798	324,558
LADWP (IPP Layoff)	30,104,809	2,762,963	2,413,655	2,301,815	1,748,673	2,645,460	2,594,592	2,776,554	2,757,022	1,979,348	3,229,887	2,315,320	2,579,523
SMUD s24296	12,964,800	1,465,200	754,800	92,500	259,000	-	-	1,143,300	1,772,300	1,731,600	1,801,900	1,883,300	2,060,900
UMPA II s45631	9,417,737	593,283	561,909	593,283	527,339	522,691	877,206	1,779,848	1,400,151	792,640	593,283	582,825	593,283
Total Long Term Firm Sales	68,018,985	6,236,724	5,050,762	4,340,835	3,816,980	4,416,760	4,687,826	6,906,924	7,134,891	5,719,036	6,930,332	6,130,466	6,647,449
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	9,597,128	1,608,840	1,412,640	1,608,840	-	-	-	1,677,104	1,741,608	1,548,096	-	-	-
Electric Swaps Sales	9,096,903	1,870,949	1,879,062	2,793,735	-	-	-	61,500	51,480	70,560	876,720	853,058	639,840
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	18,694,031	3,479,789	3,291,702	4,402,575	-	-	-	1,738,604	1,793,088	1,618,656	876,720	853,058	639,840
System Balancing Sales													
COB	49,505,944	5,047,620	3,566,096	3,744,646	3,799,717	936,313	643,408	3,320,128	3,976,311	5,711,557	5,554,381	6,313,952	6,891,818
Four Corners	92,515,923	7,328,015	6,525,489	5,652,695	4,503,222	4,334,375	3,961,630	11,330,075	13,299,805	10,698,044	8,003,781	8,898,470	7,980,322
Mead	32,927,351	2,848,203	2,510,385	2,594,825	2,584,261	2,508,542	1,923,661	3,330,983	3,249,577	2,985,400	2,846,779	2,891,579	2,653,158
Mid Columbia	43,757,583	6,440,891	3,867,513	2,015,547	2,269,761	-	-	1,131,756	2,171,885	4,583,673	4,543,198	8,680,793	8,052,567
Mona	25,267,395	1,846,001	1,549,118	1,789,376	1,382,100	967,409	1,251,832	3,376,228	4,595,360	2,835,037	2,720,093	1,585,360	1,369,479
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	130,638,637	11,605,709	11,246,264	11,234,856	10,409,547	11,306,700	12,318,463	9,179,650	7,907,587	7,977,782	13,136,103	12,082,943	12,233,033
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	374,612,832	35,116,439	29,264,865	27,031,945	24,948,608	20,053,339	20,098,994	31,668,819	35,200,524	34,791,493	36,804,334	40,453,097	39,180,377
Total Special Sales For Resale	461,325,848	44,832,951	37,607,329	35,775,354	28,765,588	24,470,099	24,786,819	40,314,347	44,128,503	42,129,185	44,611,386	47,436,620	46,467,666

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2013	01/13-12/13	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental p27875	2,645,331	354,444	397,769	391,219	160,229	-	-	201,072	287,176	205,200	-	210,985	437,239
BPA Reserve Purchase	296,483	15,607	18,468	31,432	23,975	29,137	32,174	32,903	28,225	22,814	24,819	20,214	16,716
Combine Hills Wind p160595	4,297,314	411,414	268,177	475,537	334,716	310,895	374,277	359,070	356,223	339,473	364,457	406,451	296,623
Deseret Purchase p194277	34,105,073	2,991,374	2,858,948	2,991,374	2,634,560	2,329,255	2,439,607	2,991,374	2,991,374	2,947,232	2,991,374	2,947,232	2,991,374
Douglas PUD Settlement p38185	1,403,650	59,528	64,310	94,675	151,708	251,823	290,097	194,448	104,007	53,363	50,217	51,265	38,209
Gemstate p99489	2,867,100	233,400	230,400	238,600	230,400	230,400	230,400	230,400	240,700	230,400	252,700	285,900	233,400
Georgia-Pacific Camas	8,442,461	717,031	647,641	717,031	693,901	717,031	693,901	717,031	717,031	693,901	717,031	693,901	717,031
Hermiston Purchase p99563	104,983,159	9,393,422	8,819,563	9,288,981	7,815,461	6,162,301	5,723,856	9,284,755	10,132,764	9,530,964	9,673,913	9,409,368	9,747,813
IPP Purchase	30,104,809	2,762,963	2,413,655	2,301,815	1,748,673	2,645,460	2,594,592	2,776,554	2,757,022	1,979,348	3,229,887	2,315,320	2,579,523
Kennecott Generation Incentive	1,823,579	-	-	-	-	-	-	975,047	848,532	-	-	-	-
MagCorp p229846	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves p510378	4,787,940	392,980	372,930	380,950	396,990	409,020	405,010	405,010	405,010	405,010	405,010	405,010	405,010
Nucor p346856	5,457,000	454,750	454,750	454,750	454,750	454,750	454,750	454,750	454,750	454,750	454,750	454,750	454,750
P4 Production p137215/p145258	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
PGE Cove p83984	345,000	28,750	28,750	28,750	28,750	28,750	28,750	28,750	28,750	28,750	28,750	28,750	28,750
Rock River Wind p100371	4,940,852	602,517	475,742	480,872	376,609	360,308	271,920	193,856	234,277	304,304	436,139	593,369	610,939
Small Purchases east	102,703	11,572	11,919	11,716	8,542	7,066	5,582	5,668	4,842	10,316	6,109	9,234	10,137
Small Purchases west	15,932	246	810	108	1,816	6,090	689	1,018	1,516	1,209	1,313	621	496
Three Buttes Wind p460457	20,598,497	2,306,650	1,597,913	2,349,691	1,692,947	1,714,438	1,182,987	1,054,440	1,080,204	1,422,073	1,786,072	2,006,039	2,405,043
Top of the World Wind p522807	40,244,928	5,294,292	3,993,679	3,807,445	3,097,121	2,664,390	2,419,138	1,930,629	2,085,897	2,260,701	2,894,540	4,235,120	5,561,979
Tri-State Purchase p27057	9,969,503	822,787	771,247	735,214	846,365	785,610	805,057	896,728	900,446	864,540	867,813	854,626	819,070
West Valley Toll	16,811,701	1,676,760	756,648	614,000	771,885	798,099	942,051	1,895,882	2,363,476	2,052,601	1,982,081	1,465,782	1,492,436
Wolverine Creek Wind p244520	10,044,128	744,683	587,233	1,170,468	1,126,297	1,097,599	855,368	835,249	783,781	729,150	631,089	825,533	657,678
Long Term Firm Purchases Total	324,287,142	30,941,835	26,437,217	28,231,292	24,262,361	22,669,087	21,416,872	27,131,299	28,472,668	26,202,764	28,464,730	28,886,135	31,170,882
Seasonal Purchased Power													
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2013	**01/13-12/13**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
Qualifying Facilities													
QF California	4,367,288	417,099	498,531	560,519	755,318	764,067	560,048	185,079	100,906	87,791	84,098	115,352	238,480
QF Idaho	5,682,433	391,783	356,961	433,144	476,733	599,075	668,556	572,354	460,299	422,624	448,229	435,547	417,130
QF Oregon	22,216,590	1,901,022	1,752,380	2,060,135	2,287,629	2,390,856	2,092,015	1,730,261	1,614,349	1,667,444	1,555,549	1,407,745	1,757,204
QF Utah	1,350,031	97,381	101,654	115,216	126,446	133,793	125,888	115,055	115,468	99,035	115,210	113,155	91,730
QF Washington	15	1	0	1	2	1	2	2	2	2	1	0	0
QF Wyoming	776,687	30,681	29,444	29,059	47,449	102,137	102,954	110,349	110,287	99,745	54,867	30,064	29,652
Biomass p234159 QF	15,240,734	1,351,900	1,226,296	1,351,900	1,315,340	883,262	1,306,144	1,351,900	1,362,965	1,087,154	1,362,966	1,304,157	1,336,752
Butter Creek Wind QF	8,501	-	-	-	-	-	-	-	-	-	-	-	8,501
Chevron Wind p499335 QF	3,027,024	344,288	323,250	329,848	137,384	159,140	160,948	149,159	241,754	199,260	309,806	325,146	347,042
DCFP p316701 QF	33,802	1,530	1,001	3,063	2,670	2,821	1,458	1,189	1,887	3,141	6,556	5,839	2,647
Evergreen BioPower p351030 QF	2,799,481	219,448	187,958	200,842	203,880	240,768	202,494	231,024	314,283	295,849	327,072	223,773	152,089
Five Pine Wind QF	6,617,575	595,978	508,454	602,989	471,714	475,898	381,887	484,000	573,878	484,746	588,065	645,652	804,314
Mountain Wind 1 p367721 QF	8,434,188	1,204,043	766,008	784,904	592,253	500,215	361,148	404,015	544,170	623,963	716,405	830,352	1,106,712
Mountain Wind 2 p398449 QF	12,218,709	1,757,305	1,072,022	1,117,670	806,170	872,009	688,680	796,416	848,297	788,553	851,849	1,114,887	1,504,852
North Point Wind QF	14,472,619	1,290,851	1,103,985	1,304,050	1,035,257	1,032,286	845,086	1,078,677	1,274,176	1,076,993	1,294,266	1,396,013	1,740,981
Oregon Wind Farm QF	10,953,979	635,255	698,771	890,599	1,093,657	1,110,894	1,277,959	1,307,008	1,006,804	807,256	830,445	961,949	333,383
Pioneer Wind Park I QF	10,739,493	1,262,584	1,237,746	1,114,650	779,532	640,872	570,757	411,433	466,881	691,520	932,542	1,284,901	1,346,075
Pioneer Wind Park II QF	11,133,129	1,300,105	1,276,791	1,151,266	818,451	671,798	595,897	432,098	483,614	709,219	971,456	1,335,623	1,386,811
Power County North Wind QF p5756	3,658,947	376,217	340,290	346,372	281,492	223,253	213,727	210,072	219,876	255,680	322,301	369,968	499,699
Power County South Wind QF p5756	3,481,046	363,485	325,372	332,739	267,253	211,841	201,499	195,611	204,496	241,288	304,498	355,508	477,456
Roseburg Dillard QF	1,303,922	177,955	169,924	47,416	15,360	-	-	165,256	203,156	198,440	37,182	79,010	210,223
SF Phosphates	4,946,232	353,583	328,110	408,849	432,587	364,106	424,448	477,977	468,460	463,346	486,226	373,112	365,428
Spanish Fork Wind 2 p311681 QF	2,780,964	179,943	195,205	172,236	162,891	168,417	240,680	288,442	345,757	277,529	226,662	250,330	272,874
Sunnyside p83997/p59965 QF	26,824,733	2,359,193	2,262,077	2,332,058	1,563,478	2,056,956	2,352,703	2,395,842	2,434,976	2,315,850	2,008,381	2,341,961	2,401,257
Tesoro QF	1,543,137	135,473	114,862	119,731	107,134	99,976	90,146	156,062	167,289	162,576	132,273	128,417	129,199
US Magnesium QF	3,235,642	381,122	336,376	304,460	-	-	-	368,996	398,007	393,040	388,851	315,749	349,041
Qualifying Facilities Total	177,846,901	17,128,226	15,213,468	16,113,714	13,780,078	13,704,441	13,465,122	13,618,275	13,962,037	13,452,044	14,355,755	15,744,211	17,309,530
Mid-Columbia Contracts													
Douglas - Wells p60828	3,633,747	301,003	301,003	301,003	301,003	301,003	301,003	301,003	301,003	306,430	306,430	306,430	306,430
Grant Reasonable	(5,988,942)	(499,079)	(499,079)	(499,079)	(499,079)	(499,079)	(499,079)	(499,079)	(499,079)	(499,079)	(499,079)	(499,079)	(499,079)
Grant Surplus p258951	1,964,863	163,739	163,739	163,739	163,739	163,739	163,739	163,739	163,739	163,739	163,739	163,739	163,739
Mid-Columbia Contracts Total	(390,332)	(34,336)	(34,336)	(34,336)	(34,336)	(34,336)	(34,336)	(34,336)	(34,336)	(28,910)	(28,910)	(28,910)	(28,910)
Total Long Term Firm Purchases	501,743,711	48,035,725	41,616,349	44,310,670	38,008,103	36,339,191	34,847,658	40,715,238	42,400,368	39,625,897	42,791,576	44,601,436	48,451,502

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Net Power Cost Analysis

12 months ended December 2013	01/13-12/13	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Storage & Exchange													
APS Exchange p58118/s58119	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange p64706/p64888	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind p63507	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind p79207	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho p64885/p83975/p647	(1,184)	-	-	-	-	-	(30)	(81)	(1,074)	-	-	-	-
Cargill p483225/s6 p485390/s89	1,416,800	-	-	-	-	-	-	478,400	496,800	441,600	-	-	-
Cowlitz Swift p65787	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I p63508/p63510	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange p340325	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
PSCO FC III p63362/s63361	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange p66276	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line p105228	-	-	-	-	-	-	-	-	-	-	-	-	-
Shell p489963/s489962	369,600	-	-	-	-	-	-	124,800	129,600	115,200	-	-	-
Total Storage & Exchange	7,185,216	450,000	450,000	450,000	450,000	450,000	449,970	1,053,119	1,075,326	1,006,800	450,000	450,000	450,000
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	14,360,900	1,145,950	1,006,200	1,145,950	1,168,960	1,234,480	1,199,600	2,518,880	2,615,760	2,325,120	-	-	-
Mona	7,191,800	-	-	-	-	-	-	2,428,400	2,521,800	2,241,600	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	3,282,862	(95,056)	(54,624)	(1,768)	-	-	-	1,392,300	1,018,170	1,023,840	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	24,835,562	1,050,894	951,576	1,144,182	1,168,960	1,234,480	1,199,600	6,339,580	6,155,730	5,590,560	-	-	-
System Balancing Purchases													
COB	18,715,624	427,168	857,662	367,461	762,261	3,949,194	4,011,811	2,288,181	2,051,776	416,239	1,371,700	1,599,897	612,275
Four Corners	10,984,131	656,262	819,981	1,422,380	1,571,044	639,038	819,553	1,838,065	1,013,275	429,947	97,775	739,000	937,811
Mead	1,687,501	6,046	1,838	74,689	-	4,656	20,548	240,019	404,044	139,166	427,599	17,654	351,242
Mid Columbia	80,988,638	1,005,007	3,231,135	7,044,402	3,632,578	12,181,691	10,178,813	15,762,299	16,644,576	6,063,799	5,224,347	9,393	10,600
Mona	28,115,217	1,789,966	2,124,172	981,713	2,345,664	2,974,841	2,234,970	1,476,127	975,068	2,079,145	2,414,686	4,563,858	4,155,007
NOB	581,918	14,734	18,322	-	-	247,511	72,153	65,744	18,457	781	-	13,162	131,053
Palo Verde	2,494,480	4,091	1,405	4,450	-	-	-	717,058	893,783	873,693	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	76,868	-	-	-	-	76,868	-	-	-	-	-	-	-
Total System Balancing Purchases	143,644,376	3,903,275	7,054,514	9,895,096	8,311,547	20,073,799	17,337,847	22,387,493	22,000,979	10,002,770	9,536,106	6,942,963	6,197,989
Total Purchased Power & Net Inte	677,408,864	53,439,894	50,072,439	55,799,948	47,938,609	58,097,470	53,835,075	70,495,430	71,632,402	56,226,027	52,777,681	51,994,398	55,099,490

Exhibit PAC/102
Duvall/4

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2013	01/13-12/13	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Wheeling & U. of F. Expense													
Firm Wheeling	131,356,391	11,107,555	11,100,421	10,931,826	11,129,172	10,596,898	10,879,080	11,344,666	10,078,055	10,741,449	10,951,134	11,401,674	11,094,463
ST Firm & Non-Firm	175,554	21,696	12,159	9,174	362	3,332	13,072	9,596	14,846	11,631	26,022	27,450	26,214
Total Wheeling & U. of F. Expense	131,531,945	11,129,251	11,112,580	10,941,000	11,129,534	10,600,230	10,892,152	11,354,262	10,092,900	10,753,080	10,977,156	11,429,123	11,120,677
Coal Fuel Burn Expense													
Carbon	22,236,651	2,011,396	1,768,655	2,110,043	1,010,149	1,663,065	1,648,058	2,022,738	2,162,519	1,920,779	2,044,158	1,886,182	1,988,910
Cholla	56,649,979	5,160,514	4,538,191	4,683,978	2,512,413	4,569,148	4,297,173	5,186,895	5,346,624	5,084,342	5,223,180	4,957,223	5,090,298
Colstrip	15,652,078	1,395,179	1,259,396	1,393,202	1,039,546	1,170,834	1,117,322	1,395,179	1,394,191	1,348,930	1,395,179	1,348,930	1,394,191
Craig	22,921,763	2,002,903	1,808,782	2,002,149	1,942,360	1,209,029	1,942,335	2,024,419	2,024,042	1,958,641	2,024,419	1,958,641	2,024,042
Dave Johnston	61,981,611	4,468,994	4,723,036	4,950,941	3,876,751	5,537,727	5,588,443	6,005,086	6,012,831	5,695,228	5,633,039	5,006,905	4,482,632
Hayden	13,883,261	1,293,037	1,201,045	1,083,928	604,600	1,188,776	1,002,732	1,148,116	1,331,610	1,265,337	1,263,070	1,192,658	1,308,350
Hunter	158,009,498	14,144,813	12,818,326	11,074,210	12,680,818	12,062,611	11,086,493	13,870,627	14,655,672	13,580,842	14,207,472	13,636,397	14,191,218
Huntington	102,526,966	9,183,249	8,304,879	9,340,511	8,597,200	8,057,466	7,540,218	9,127,392	9,455,810	8,342,556	6,613,555	8,808,274	9,155,854
Jim Bridger	192,614,516	16,304,724	14,950,618	16,547,406	13,718,390	12,231,642	13,735,539	17,913,626	17,942,688	17,337,006	17,940,558	16,948,926	17,043,391
Naughton	108,284,936	9,483,311	8,271,004	6,817,228	9,115,829	9,379,321	8,993,188	9,511,778	9,521,525	9,149,182	9,400,904	9,169,308	9,472,358
Ramp Loss	(983,605)	(57,930)	(89,620)	(81,833)	(67,969)	(103,177)	(67,038)	(94,320)	(86,882)	(68,772)	(92,283)	(91,775)	(82,005)
Wyodak	20,564,320	1,829,886	1,652,422	1,828,028	1,770,091	1,041,133	1,733,632	1,792,532	1,792,056	1,733,600	1,791,298	1,770,244	1,829,398
Total Coal Fuel Burn Expense	774,341,974	67,220,077	61,206,734	61,749,790	56,800,180	58,007,574	58,618,095	69,904,067	71,552,684	67,347,671	67,444,550	66,591,913	67,898,639
Gas Fuel Burn Expense													
Chehalis	59,923,166	6,354,072	68,752	-	4,601,893	-	-	6,675,073	9,008,309	8,416,258	9,509,670	8,032,945	7,256,194
Currant Creek	77,931,137	6,926,568	6,200,869	6,680,236	6,116,792	6,245,770	6,095,266	6,510,764	6,589,073	5,693,335	6,492,181	6,814,778	7,565,504
Gadsby	5,301,396	-	-	-	-	-	-	1,791,519	2,303,937	1,146,937	59,003	-	-
Gadsby CT	13,482,760	1,144,956	994,573	1,135,626	1,068,407	1,110,045	1,082,615	1,131,955	1,137,419	1,101,840	1,148,963	1,155,825	1,270,536
Hermiston	49,008,817	4,499,592	4,107,800	4,403,852	3,737,777	2,090,262	1,698,600	4,149,361	4,986,244	4,485,486	5,159,975	4,636,364	5,053,504
Lake Side	74,967,311	6,982,201	6,075,849	6,843,979	5,702,877	4,411,443	2,649,145	7,810,227	8,179,641	7,633,967	4,204,878	6,967,066	7,506,037
Total Gas Fuel Burn	280,614,587	25,907,389	17,447,843	19,063,692	21,227,747	13,857,520	11,525,626	28,068,899	32,204,623	28,477,823	26,574,671	27,606,978	28,651,776
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	65,656,502	7,834,723	6,165,586	6,859,455	3,822,735	3,929,700	3,762,735	6,371,275	6,321,055	6,086,325	4,667,174	5,142,983	4,692,757
Clay Basin Gas Storage	33,446	(97,694)	(95,599)	(90,818)	51,523	51,523	51,523	51,523	51,523	51,523	51,523	6,425	(49,530)
Pipeline Reservation Fees	26,298,704	2,214,787	2,100,006	2,214,787	2,173,797	2,214,787	2,173,797	2,214,787	2,214,787	2,173,797	2,214,787	2,173,797	2,214,787
Total Gas Fuel Burn Expense	372,603,239	35,859,206	25,617,836	28,047,116	27,275,802	20,053,530	17,513,681	36,706,484	40,791,988	36,789,468	33,508,155	34,930,183	35,509,791
Other Generation													
Blundell	4,183,520	371,988	336,039	372,117	314,462	350,106	328,358	339,166	339,225	338,889	361,047	360,070	372,053
Wind Integration Charge	5,498,155	588,064	464,548	555,589	448,672	439,159	401,727	349,184	351,703	367,010	442,316	527,354	562,829
Total Other Generation	9,681,675	960,052	800,587	927,706	763,134	789,265	730,085	688,350	690,928	705,899	803,363	887,424	934,881
Net Power Cost	**1,504,241,849**	123,775,529	111,202,848	121,690,205	115,141,671	123,077,970	116,802,268	148,834,246	150,632,400	129,692,960	120,899,519	118,396,420	124,095,812
Net Power Cost/Net System Load	**25.03**	**23.71**	**23.98**	**24.64**	**24.58**	**25.10**	**24.11**	**26.84**	**27.40**	**26.85**	**24.87**	**24.14**	**23.75**

Exhibit PAC/102
Duvall/5

Gregory N. Duvall
Exhibit PAC/103

Docket No. UE-245
Exhibit PAC/103
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 Known Contracts Expected to be Updated during the 2013 TAM

February 2012

List of Known Contracts Expected to be Updated during the 2013 TAM

Sales and Purchases of Electricity and Natural Gas

1. New electricity sales and purchase contracts, physical and financial, including contracts with qualifying facilities.
2. Changes in contract terms of existing electricity sales and purchase and exchange contracts.
3. New natural gas sales and purchase contracts, physical and financial.
4. Changes in contract terms of existing natural gas sales and purchase contracts.
5. Contracts whose prices are linked to market indexes and inflation rates.
6. Sales contract with Black Hills Company for energy price and fixed payments.
7. Purchase contracts for generation and fixed costs from the Mid Columbia projects.
8. Purchase contract with Tri-State Generation and Transmission Association Inc for energy price.
9. New purchase contract with Kennecott for generation incentives, or remove the expenses and impact on load of the assumed contract if new contract is not executed.
10. New qualifying facility purchase contracts with Tesoro and US Magnesium, or remove the assumed contracts if not executed.
11. Purchase expenses of PGE Cove based on PGE projection.
12. Election decision for Grant Meaningful Priority.

Transportation and Storage of Natural Gas

13. New pipeline and storage contracts for transporting natural gas from market to Company's generating facilities.
14. Changes in contract terms of existing pipeline and storage contracts.
15. Contracts whose prices are linked to market indexes and inflation rates.

Wheeling Expenses and Transmission

16. New transmission contracts to wheeling power to serve the Company's load obligations.
17. Changes in contract terms of existing transmission contracts.
18. Wheeling expenses that are impacted by changes in third parties' transmission tariff rates.
19. Power, Transmission and Wind Integration rates that are impact by BPA rate cases.
20. Contracts whose prices are linked to market indexes and inflation rates.

<u>Coal Expense –</u>

The table below lists the coal and transportation contracts that maybe affected by changed in volumes as well as changes to market indexes and inflation rates.

		Captive		Coal Contracts		Transportation Contacts	
Plant	Supplier/Mine	Volume	Price	Volume	Price	Volume	Price
Bridger	Bridger Coal Company	√					
	Ambre Energy/Black Butte			√	√		
	Union Pacific Railway					√	√
Carbon	Deer Creek	√					
	America West/Horizon			√			
	Arch - Sufco/Dugout/Skyline			√	√		
	Rhino Energy/Castle Valley			√			
	Utah American Energy/West Ridge			√			
	Utah Trucking					√	√
Cholla	Peabody Coalsales/Lee Ranch			√	√		
	BNSF Railway					√	√
Colstrip	Westmoreland/Rosebud			√	√		
Craig	Trapper	√					
	Western Fuels/Colowyo				√		
	Union Pacific Railway						√
Hayden	Peabody/Twentymile			√	√		
	Pirate Trucking					√	√
Hunter	Deer Creek	√					
	America West/Horizon			√			
	Arch - Sufco/Dugout/Skyline			√	√		
	Rhino Energy/Castle Valley			√			
	Utah American Energy/West Ridge			√			
	Utah Trucking					√	√
Huntington	Deer Creek	√					
	America West/Horizon			√			
	Arch - Sufco/Dugout/Skyline			√	√		
	Rhino Energy/Castle Valley			√			
	Utah American Energy/West Ridge			√			
	Utah Trucking					√	√
Johnston	Open Position			√	√		
	Arch/Coal Creek			√			
	Peabody/Rawhide			√			
	Western Fuels/Dry Fork			√	√		
	BNSF Railway					√	√
Naughton	Westmoreland Kemmerer/Kemmerer			√	√		
Wyodak	Black Hills/Wyodak			√	√		

Judith M. Ridenour
Exhibit PAC/200

Docket No. UE-245
Exhibit PAC/200
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

February 2012

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

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

Qualifications

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. In my current position, 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 ("GRC"), Docket UE 217 ("UE 217") and Transition Adjustment Mechanism ("TAM"), Docket UE 227 ("UE 227").

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I will explain the changes in the Company's TAM tariff and rate design, present the Company's proposed TAM rates and proposed tariff, and provide a summary of the impact of the proposed rate change on customers' bills.

TAM Design and Proposed Tariff

Q. Please describe the Company's tariff rate schedule that collects net power costs ("NPC").

A. The Company collects NPC through Schedule 201, Net Power Costs, Cost-Based Supply Service. Collecting NPC through a separate rate schedule allows NPC to be more easily and accurately updated through TAM filings.

Q. What is the rate design test period for this TAM?

A. In accordance with the TAM Guidelines adopted by Order No. 09-274, the rate design test year for this TAM, which is filed concurrently with a GRC, is the rate design test year for the GRC, which is the forecast 12 months ending December 31, 2013.

Q. How have the proposed NPC been allocated to the rate schedule classes?

A. Consistent with the TAM Guidelines, the proposed NPC have been allocated to the customer classes proportionately based on the generation allocation factors from the Company's most recent cost of service study, which was included in the Company's GRC filed concurrently with this TAM filing. This methodology accurately allocates NPC to each customer class and ensures synchronization between the TAM and GRC. The spread of the proposed NPC to the customer classes is shown in page one of Exhibit PAC/201.

Q. Have you prepared an exhibit showing the present and proposed Schedule 201 rates and revenues?

A. Yes. Pages two and three of Exhibit PAC/201 show the present and proposed Schedule 201 rates and revenues.

Q. Have the proposed Schedule 201 rates been designed consistent with the TAM Guidelines?

A. Yes. The proposed Schedule 201 rates are designed to collect revenues from rate schedules based on the rate spread set forth in the TAM Guidelines and described above. Additionally, the rates in the Company's proposed Schedule 201 utilize the same rate blocks and relationships between rate blocks as the existing Schedule 200 and 201 rates and the proposed Schedule 200 rates in the GRC filed concurrently with this TAM.

Q. Please describe Exhibit PAC/202.

A. Exhibit PAC/202 contains the revised tariff Schedule 201, Net Power Costs, Cost-Based Supply Service.

Q. Is the Company proposing changes to its one-year or three-year option Transition Adjustment tariffs (Schedules 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 Schedules 294 and 295, Transition Adjustment, once the final TAM 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 0.8 percent on a net basis. Page one of Exhibit PAC/203 shows the estimated effect of the Company's proposed prices by Delivery Service schedule both exclusive (base) and inclusive (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 Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. Have you prepared an exhibit which shows the impact on customer bills as a result of the proposed changes to Schedule 201?

A. Yes. Exhibit PAC/203 contains monthly billing comparisons for customers at different usage levels served on each of the major 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 Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

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

A. The estimated monthly impact to the average residential customer using 950 kilowatt-hours per month is $0.69.

Q. Does this conclude your direct testimony?

A. Yes.

Judith M. Ridenour
Exhibit PAC/201

Docket No. UE-245
Exhibit PAC/201
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Rate Spread and Rates

February 2012

PACIFIC POWER
STATE OF OREGON
Functionalized Net Power Cost Revenue Requirement
Forecast 12 Months Ended December 31, 2013
Dollars in Thousands

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential	**General Service**		**General Service**		**General Service**		**Large Power Service**			**Irrigation**	**Street Lgt.**
		Total		Sch 23		Sch 28		Sch 30		Sch 48T			Sch 41	Sch 51, 53, 54
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	Functionalized Generation Revenue Requirement from GRC	$732,202	$309,208	$61,944	$71	$112,629	$1,036	$68,328	$4,933	$34,812	$86,043	$40,735	$11,457	$1,006
2														
3	Net Power Cost Revenue Requirement	$370,158												
4	Net Power Cost Collection for Schedules not included in COS Study*	$1,915												
5	Net Power Cost for Schedules Included in COS Study	$368,243												
6														
7														
8	Generation Allocation Factors from GRC	100.00%	42.23%	8.46%	0.01%	15.38%	0.14%	9.33%	0.67%	4.75%	11.75%	5.56%	1.56%	0.14%
9														
10														
11	**Functionalized Net Power Cost Revenue Requirement- (Target)**	**$368,243**	**$155,509**	**$31,153**	**$36**	**$56,644**	**$521**	**$34,364**	**$2,481**	**$17,508**	**$43,273**	**$20,487**	**$5,762**	**$506**
12	Other Generation Revenue Requirement - (Target)	$363,958	$153,699	$30,791	$35	$55,985	$515	$33,964	$2,452	$17,304	$42,769	$20,248	$5,695	$500
13	Sum	$732,202	$309,208	$61,944	$71	$112,629	$1,036	$68,328	$4,933	$34,812	$86,043	$40,735	$11,457	$1,006

*Revenues by rate schedule as follow:

Schedule 47 Primary	$737
Schedule 47 Transmission	$553
Schedule 15	$261
Schedule 50	$196
Schedule 51 (partial)	$279
Schedule 52	$16
Employee Discount	($126)
Total not in study	$1,915

Exhibit PAC/201
Ridenour/1

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues

Forecast 12 Months Ended December 31, 2013

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Rates	Revenues
Schedule 4, Residential					
First Block kWh (0-1,000)	3,948,030,052	2.550 ¢	$100,674,766	2.621 ¢	$103,477,868
Second Block kWh (> 1,000)	1,452,836,421	3.483 ¢	$50,602,293	3.580 ¢	$52,011,544
	5,400,866,473		$151,277,059		$155,489,412
				Change	$4,212,353
Employee Discount					
First Block kWh (0-1,000)	11,484,472	2.550 ¢	$292,854	2.621 ¢	$301,008
Second Block kWh (> 1,000)	5,710,623	3.483 ¢	$198,901	3.580 ¢	$204,440
	17,195,095		$491,755		$505,448
		Discount	-$122,939	Discount	-$126,362
				Change	-$3,423
Schedule 23, Small General Service					
Secondary Voltage					
1st 3,000 kWh, per kWh	856,570,502	2.971 ¢	$25,448,710	3.020 ¢	$25,868,429
All additional kWh, per kWh	236,024,449	2.204 ¢	$5,201,979	2.240 ¢	$5,286,948
	1,092,594,951		$30,650,689		$31,155,377
				Change	$504,688
Primary Voltage					
1st 3,000 kWh, per kWh	836,443	2.878 ¢	$24,073	2.925 ¢	$24,466
All additional kWh, per kWh	494,537	2.136 ¢	$10,563	2.171 ¢	$10,736
	1,330,980		$34,636		$35,202
				Change	$566
Schedule 28, General Service 31-200kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	1,409,538,253	2.816 ¢	$39,692,597	2.901 ¢	$40,890,705
All additional kWh, per kWh	558,266,695	2.739 ¢	$15,290,925	2.822 ¢	$15,754,286
	1,967,804,948		$54,983,522		$56,644,991
				Change	$1,661,469
Primary Voltage					
1st 20,000 kWh, per kWh	9,685,033	2.609 ¢	$252,683	2.808 ¢	$271,956
All additional kWh, per kWh	9,110,106	2.539 ¢	$231,306	2.733 ¢	$248,979
	18,795,139		$483,989		$520,935
				Change	$36,946
Schedule 30, General Service 201-999kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	187,732,515	3.096 ¢	$5,812,199	3.188 ¢	$5,984,913
All additional kWh, per kWh	1,026,570,446	2.685 ¢	$27,563,416	2.765 ¢	$28,384,673
	1,214,302,961		$33,375,615		$34,369,586
				Change	$993,971
Primary Voltage					
1st 20,000 kWh, per kWh	12,534,699	3.061 ¢	$383,687	3.141 ¢	$393,715
All additional kWh, per kWh	76,851,297	2.647 ¢	$2,034,254	2.716 ¢	$2,087,281
	89,385,996		$2,417,941		$2,480,996
				Change	$63,055
Schedule 41, Agricultural Pumping Service					
Secondary Voltage					
Winter, 1st 100 kWh/kW, per kWh	1,842,166	3.897 ¢	$71,789	4.005 ¢	$73,779
Winter, All additional kWh, per kWh	1,796,594	2.655 ¢	$47,700	2.728 ¢	$49,011
Summer, All kWh, per kWh	206,075,649	2.655 ¢	$5,471,308	2.728 ¢	$5,621,744
	209,714,409		$5,590,797		$5,744,534
				Change	$153,737
Primary Voltage					
Winter, 1st 100 kWh/kW, per kWh	8,263	3.774 ¢	$312	3.878 ¢	$320
Winter, All additional kWh, per kWh	44,696	2.571 ¢	$1,149	2.642 ¢	$1,181
Summer, All kWh, per kWh	574,929	2.571 ¢	$14,781	2.642 ¢	$15,190
	627,888		$16,242		$16,691
				Change	$449
Schedule 47, Large General Service, Partial Requirements 1,000kW and over					
Primary Voltage					
On-Peak, per on-peak kWh	18,845,893	2.663 ¢	$501,866	2.741 ¢	$516,566
Off-Peak, per off-peak kWh	8,192,094	2.613 ¢	$214,059	2.691 ¢	$220,449
	27,037,987		$715,925		$737,015
				Change	$21,090
Transmission Voltage					
On-Peak, per on-peak kWh	13,246,613	2.539 ¢	$336,332	2.597 ¢	$344,015
Off-Peak, per off-peak kWh	8,216,785	2.489 ¢	$204,516	2.547 ¢	$209,282
	21,463,398		$540,848		$553,297
				Change	$12,449

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues

Forecast 12 Months Ended December 31, 2013

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Rates	Revenues
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
On-Peak, per on-peak kWh	399,171,764	2.766 ¢	$11,041,091	2.850 ¢	$11,376,395
Off-Peak, per off-peak kWh	218,871,139	2.716 ¢	$5,944,540	2.800 ¢	$6,128,392
	618,042,903		$16,985,631		$17,504,787
				Change	$519,156
Primary Voltage					
On-Peak, per on-peak kWh	982,307,452	2.663 ¢	$26,158,847	2.741 ¢	$26,925,047
Off-Peak, per off-peak kWh	607,639,708	2.613 ¢	$15,877,626	2.691 ¢	$16,351,585
	1,589,947,160		$42,036,473		$43,276,632
				Change	$1,240,159
Transmission Voltage					
On-Peak, per on-peak kWh	448,520,508	2.539 ¢	$11,387,936	2.597 ¢	$11,648,078
Off-Peak, per off-peak kWh	346,999,262	2.489 ¢	$8,636,812	2.547 ¢	$8,838,071
	795,519,770		$20,024,748		$20,486,149
				Change	$461,401
Schedule 15, Outdoor Area Lighting Service					
Secondary Voltage					
All kWh, per kWh	9,709,823	2.664 ¢	$258,367	2.690 ¢	$260,899
	9,709,823		$258,367		$260,899
				Change	$2,532
Schedule 50, Mercury Vapor Street Lighting Service					
Secondary Voltage					
All kWh, per kWh	8,845,474	2.190 ¢	$193,380	2.212 ¢	$195,510
	8,845,474		$193,380		$195,510
				Change	$2,130
Schedule 51, 55, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	18,679,735	3.456 ¢	$645,497	3.490 ¢	$652,751
	18,679,735		$645,497		$652,751
				Change	$7,255
Schedule 52, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	599,203	2.647 ¢	$15,861	2.673 ¢	$16,017
	599,203		$15,861		$16,017
				Change	$156
Schedule 53, Street Lighting Service, Consumer-Owned System					
Secondary Voltage					
All kWh, per kWh	9,578,780	1.130 ¢	$108,240	1.141 ¢	$109,294
	9,578,780		$108,240		$109,294
				Change	$1,054
Schedule 54, Recreational Field Lighting					
Secondary Voltage					
All kWh, per kWh	1,189,338	1.947 ¢	$23,156	1.966 ¢	$23,382
	1,189,338		$23,156		$23,382
				Change	$226
TOTAL Before Employee Discount			**$360,378,616**		**$370,273,457**
Employee Discount			-$122,939		-$126,362
TOTAL SCHEDULE 201	**13,096,037,316**		**$360,255,677**		**$370,147,095**
				Change	**$9,891,418**
Schedule 47 Unscheduled kWh	1,702,669				
Total Forecast kWH	13,097,739,985				

Judith M. Ridenour
Exhibit PAC/202

Docket No. UE-245
Exhibit PAC/202
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 201

February 2012

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 201

NET POWER COSTS
COST-BASED SUPPLY SERVICE

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 Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. 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 Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Monthly Billing

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage** Secondary	Primary	Transmission	
4	Per kWh	0-1000 kWh	2.621¢			(I)
		> 1000 kWh	3.580¢			(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).

		Secondary	Primary	Transmission	
23	First 3,000 kWh, per kWh	3.020 ¢	2.925¢		(I)
	All additional kWh, per kWh	2.240¢	2.171¢		(I)
28	First 20,000 kWh, per kWh	2.901¢	2.808¢		(I)
	All additional kWh, per kWh	2.822¢	2.733¢		(I)
30	First 20,000 kWh, per kWh	3.188¢	3.141¢		(I)
	All additional kWh, per kWh	2.765¢	2.716¢		(I)
41	Winter, first 100 kWh/kW, per kWh	4.005¢	3.878¢		(I)
	Winter, all additional kWh, per kWh	2.728¢	2.642¢		(I)
	Summer, all kWh, per kWh	2.728¢	2.642¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		**Secondary**	**Delivery Voltage** **Primary**	**Transmission**	
47/48	Per kWh On-Peak	2.850¢	2.741¢	2.597¢	(I)
	Per kWh, Off-Peak	2.800¢	2.691¢	2.547¢	(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	2.673¢	(I)
	For dusk to midnight operation, per kWh	2.673¢	(I)
54	Per kWh	1.966¢	(I)

15	**Type of Luminaire**	**Nominal Rating**	**Monthly kWh**	**RatePer Luminaire**	
	Mercury Vapor	7,000	76	$ 2.04	(I)
	Mercury Vapor	21,000	172	$ 4.63	(I)
	Mercury Vapor	55,000	412	$11.08	(I)
	High Pressure Sodium	5,800	31	$ 0.83	
	High Pressure Sodium	22,000	85	$ 2.29	(I)
	High Pressure Sodium	50,000	176	$ 4.73	(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	$1.68	$3.80	$9.11	(I)
Vertical, per lamp	$1.68	$3.80		(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	$1.68			(I)
On 26-foot poles, vertical, per lamp	$1.68			(I)
On 30-foot poles, horizontal, per lamp		$3.80		(I)
On 30-foot poles, vertical, per lamp		$3.80		(I)
On 33-foot poles, horizontal, per lamp			$9.11	(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.68			(I)
On 26-foot poles, vertical, per lamp	$1.68			(I)
On 30-foot poles, horizontal, per lamp		$3.80		(I)
On 30-foot poles, vertical, per lamp		$3.80		(I)
On 33-foot poles, horizontal, per lamp			$9.11	(I)

51

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$1.08	(I)
High Pressure Sodium	9,500	100	44	$1.54	
High Pressure Sodium	16,000	150	64	$2.23	
High Pressure Sodium	22,000	200	85	$2.97	
High Pressure Sodium	27,500	250	115	$4.01	
High Pressure Sodium	50,000	400	176	$6.14	
Metal Halide	9,000	100	39	$1.36	
Metal Halide	12,000	175	68	$2.37	
Metal Halide	19,500	250	94	$3.28	
Metal Halide	32,000	400	149	$5.20	(I)

53

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.35	
High Pressure Sodium	9,500	100	44	$0.50	
High Pressure Sodium	16,000	150	64	$0.73	(I)
High Pressure Sodium	22,000	200	85	$0.97	(I)
High Pressure Sodium	27,500	250	115	$1.31	(I)
High Pressure Sodium	50,000	400	176	$2.01	(I)
Metal Halide	9,000	100	39	$0.44	
Metal Halide	12,000	175	68	$0.78	(I)
Metal Halide	19,500	250	94	$1.07	(I)
Metal Halide	32,000	400	149	$1.70	(I)
Metal Halide	107,800	1,000	354	$4.04	(I)

Non-Listed Luminaire, per kWh 1.141¢ (I)

55

Types of Luminaire	Compares to HPSV Lamp Size of (Watts)	Monthly kWh	Rate Per Luminaire	
Light Emitting Diode	100	29	$1.01	(I)
Light Emitting Diode	150	41	$1.43	(I)

(continued)

Judith M. Ridenour
Exhibit PAC/203

Docket No. UE-245
Exhibit PAC/203
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

February 2012

TAM Price Change

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2013

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	479,457	5,400,866	$564,491	$12,962	$577,453	$568,703	$12,962	$581,665	$4,212	0.8%	$4,212	0.7%	1
2	**Total Residential**		479,457	5,400,866	$564,491	$12,962	$577,453	$568,703	$12,962	$581,665	$4,212	0.8%	$4,212	0.7%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	75,333	1,093,926	$120,069	($1,442)	$118,627	$120,574	($1,442)	$119,132	$505	0.4%	$505	0.4%	3
4	Gen. Svc. 31 - 200 kW	28	9,818	1,986,600	$161,266	$7,928	$169,194	$162,964	$7,928	$170,892	$1,698	1.1%	$1,698	1.0%	4
5	Gen. Svc. 201 - 999 kW	30	815	1,303,689	$98,119	$2,348	$100,467	$99,176	$2,348	$101,524	$1,057	1.1%	$1,057	1.1%	5
6	Large General Service >= 1,000 kW	48	208	3,003,510	$201,084	($9,613)	$191,471	$203,305	($9,613)	$193,692	$2,221	1.1%	$2,221	1.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	5	50,204	$3,585	($177)	$3,408	$3,619	($177)	$3,442	$34	1.1%	$34	1.2%	7
8	Agricultural Pumping Service	41	8,090	210,342	$24,940	($3,282)	$21,658	$25,094	($3,282)	$21,812	$154	0.6%	$154	0.7%	8
9	**Total Commercial & Industrial**		94,269	7,648,271	$609,063	($4,238)	$604,825	$614,732	($4,238)	$610,494	$5,669	0.9%	$5,669	0.9%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,850	9,710	$1,298	$257	$1,555	$1,301	$257	$1,558	$3	0.2%	$3	0.2%	10
11	Street Lighting Service	50	250	8,845	$1,022	$221	$1,243	$1,024	$221	$1,245	$2	0.2%	$2	0.2%	11
12	Street Lighting Service HPS	51	733	18,680	$3,433	$732	$4,165	$3,440	$732	$4,172	$7	0.2%	$7	0.2%	12
13	Street Lighting Service	52	50	599	$73	$16	$89	$73	$16	$89	$0	0.2%	$0	0.2%	13
14	Street Lighting Service	53	260	9,579	$621	$147	$768	$622	$147	$769	$1	0.2%	$1	0.1%	14
15	Recreational Field Lighting	54	103	1,189	$104	$22	$126	$104	$22	$126	$0	0.2%	$0	0.2%	15
16	**Total Public Street Lighting**		8,246	48,602	$6,551	$1,395	$7,946	$6,564	$1,395	$7,959	$13	0.2%	$13	0.2%	16
17	**Total Sales to Ultimate Consumers**		581,972	13,097,739	$1,180,105	$10,119	$1,190,224	$1,190,000	$10,119	$1,200,119	$9,895	0.8%	$9,895	0.8%	17
18	**Employee Discount**			17,195	($445)	($10)	($455)	($448)	($10)	($458)	($3)		($3)		18
19	**Total Sales with Employee Discount**		581,972	13,097,739	$1,179,660	$10,109	$1,189,769	$1,189,551	$10,109	$1,199,660	$9,891	0.8%	$9,891	0.8%	19
20	AGA Revenue				$2,716		$2,716	$2,716		$2,716	$0		$0		20
21	**Total Sales with Employee Discount and AGA**		581,972	13,097,739	$1,182,376	$10,109	$1,192,485	$1,192,267	$10,109	$1,202,376	$9,891	0.8%	$9,891	0.8%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$19.47	$19.54	$0.07	0.36%
200	$28.82	$28.97	$0.15	0.52%
300	$38.17	$38.40	$0.23	0.60%
400	$47.52	$47.82	$0.30	0.63%
500	$56.87	$57.24	$0.37	0.65%
600	$66.22	$66.65	$0.43	0.65%
700	$75.57	$76.08	$0.51	0.67%
800	$84.92	$85.51	$0.59	0.69%
900	$94.28	$94.94	$0.66	0.70%
950	**$98.94**	**$99.63**	**$0.69**	**0.70%**
1,000	$103.62	$104.35	$0.73	0.70%
1,100	$115.51	$116.33	$0.82	0.71%
1,200	$127.39	$128.33	$0.94	0.74%
1,300	$139.28	$140.31	$1.03	0.74%
1,400	$151.17	$152.30	$1.13	0.75%
1,500	$163.06	$164.28	$1.22	0.75%
1,600	$174.93	$176.26	$1.33	0.76%
2,000	$222.48	$224.21	$1.73	0.78%
3,000	$341.34	$344.07	$2.73	0.80%
4,000	$460.19	$463.92	$3.73	0.81%
5,000	$579.05	$583.78	$4.73	0.82%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$69	$78	$69	$79	0.36%	0.33%
	750	$94	$103	$94	$103	0.40%	0.37%
	1,000	$118	$128	$119	$128	0.43%	0.39%
	1,500	$168	$177	$169	$178	0.45%	0.42%
10	1,000	$118	$128	$119	$128	0.43%	0.39%
	2,000	$217	$227	$218	$228	0.46%	0.45%
	3,000	$316	$326	$318	$327	0.48%	0.47%
	4,000	$399	$408	$401	$410	0.47%	0.46%
20	4,000	$428	$437	$430	$439	0.44%	0.43%
	6,000	$593	$603	$596	$605	0.44%	0.43%
	8,000	$758	$768	$761	$771	0.44%	0.44%
	10,000	$923	$933	$927	$937	0.45%	0.44%
30	9,000	$899	$908	$902	$912	0.42%	0.41%
	12,000	$1,146	$1,156	$1,151	$1,161	0.42%	0.42%
	15,000	$1,394	$1,403	$1,400	$1,409	0.43%	0.42%
	18,000	$1,642	$1,651	$1,649	$1,658	0.43%	0.43%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$67	$77	$68	$77	0.37%	0.31%
	750	$91	$101	$92	$101	0.39%	0.36%
	1,000	$115	$125	$116	$125	0.42%	0.39%
	1,500	$163	$173	$164	$174	0.44%	0.42%
10	1,000	$115	$125	$116	$125	0.42%	0.39%
	2,000	$211	$221	$212	$222	0.46%	0.44%
	3,000	$307	$317	$309	$318	0.47%	0.46%
	4,000	$387	$397	$389	$399	0.47%	0.46%
20	4,000	$416	$425	$418	$427	0.44%	0.43%
	6,000	$576	$585	$578	$588	0.44%	0.43%
	8,000	$736	$745	$739	$749	0.44%	0.44%
	10,000	$896	$906	$900	$910	0.44%	0.44%
30	9,000	$873	$882	$877	$886	0.41%	0.41%
	12,000	$1,113	$1,123	$1,118	$1,127	0.42%	0.42%
	15,000	$1,353	$1,363	$1,359	$1,368	0.43%	0.42%
	18,000	$1,593	$1,603	$1,600	$1,610	0.43%	0.43%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$314	$316	0.84%
	4,500	$422	$426	0.93%
	7,500	$637	$644	1.03%
31	6,200	$632	$637	0.86%
	9,300	$855	$863	0.95%
	15,500	$1,301	$1,314	1.04%
40	8,000	$811	$818	0.86%
	12,000	$1,098	$1,109	0.96%
	20,000	$1,674	$1,691	1.05%
60	12,000	$1,209	$1,220	0.87%
	18,000	$1,641	$1,657	0.96%
	30,000	$2,487	$2,514	1.05%
80	16,000	$1,603	$1,617	0.87%
	24,000	$2,172	$2,193	0.96%
	40,000	$3,296	$3,331	1.05%
100	20,000	$1,997	$2,014	0.88%
	30,000	$2,699	$2,725	0.97%
	50,000	$4,105	$4,148	1.05%
200	40,000	$3,910	$3,944	0.89%
	60,000	$5,315	$5,367	0.97%
	100,000	$8,126	$8,212	1.06%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$386	$396	2.39%
	6,000	$483	$495	2.55%
	7,500	$580	$595	2.65%
31	9,300	$780	$799	2.45%
	12,400	$980	$1,005	2.59%
	15,500	$1,179	$1,211	2.69%
40	12,000	$1,001	$1,026	2.46%
	16,000	$1,259	$1,292	2.60%
	20,000	$1,517	$1,558	2.70%
60	18,000	$1,496	$1,533	2.47%
	24,000	$1,877	$1,926	2.61%
	30,000	$2,254	$2,315	2.70%
80	24,000	$1,979	$2,028	2.48%
	32,000	$2,482	$2,547	2.62%
	40,000	$2,986	$3,067	2.71%
100	30,000	$2,459	$2,520	2.48%
	40,000	$3,088	$3,169	2.62%
	50,000	$3,717	$3,818	2.72%
200	60,000	$4,826	$4,947	2.51%
	80,000	$6,085	$6,246	2.64%
	100,000	$7,343	$7,544	2.74%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,364	$2,383	0.80%
	30,000	$2,962	$2,989	0.92%
	50,000	$4,157	$4,200	1.05%
200	40,000	$4,166	$4,201	0.85%
	60,000	$5,361	$5,413	0.97%
	100,000	$7,751	$7,835	1.10%
300	60,000	$6,107	$6,158	0.85%
	90,000	$7,899	$7,976	0.97%
	150,000	$11,484	$11,610	1.10%
400	80,000	$7,950	$8,019	0.86%
	120,000	$10,340	$10,441	0.98%
	200,000	$15,120	$15,287	1.11%
500	100,000	$9,819	$9,904	0.86%
	150,000	$12,806	$12,932	0.98%
	250,000	$18,781	$18,989	1.11%
600	120,000	$11,687	$11,789	0.87%
	180,000	$15,272	$15,423	0.99%
	300,000	$22,441	$22,691	1.11%
800	160,000	$15,424	$15,559	0.87%
	240,000	$20,204	$20,404	0.99%
	400,000	$29,763	$30,095	1.12%
1000	200,000	$19,161	$19,329	0.87%
	300,000	$25,136	$25,386	0.99%
	500,000	$37,085	$37,499	1.12%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$2,908	$2,931	0.81%
	40,000	$3,495	$3,526	0.88%
	50,000	$4,083	$4,120	0.93%
200	60,000	$5,271	$5,315	0.85%
	80,000	$6,446	$6,505	0.92%
	100,000	$7,620	$7,694	0.96%
300	90,000	$7,762	$7,828	0.85%
	120,000	$9,525	$9,612	0.92%
	150,000	$11,287	$11,396	0.96%
400	120,000	$10,198	$10,286	0.86%
	160,000	$12,548	$12,664	0.92%
	200,000	$14,898	$15,042	0.97%
500	150,000	$12,628	$12,737	0.86%
	200,000	$15,565	$15,710	0.93%
	250,000	$18,503	$18,682	0.97%
600	180,000	$15,058	$15,188	0.86%
	240,000	$18,583	$18,755	0.93%
	300,000	$22,107	$22,323	0.97%
800	240,000	$19,917	$20,090	0.87%
	320,000	$24,617	$24,847	0.93%
	400,000	$29,317	$29,603	0.98%
1000	300,000	$24,777	$24,993	0.87%
	400,000	$30,652	$30,938	0.93%
	500,000	$36,526	$36,884	0.98%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$175	$202	$175	$176	$204	$175	0.86%	0.92%	0.00%
	3,000	$262	$289	$175	$265	$292	$175	0.86%	0.91%	0.00%
	5,000	$437	$464	$175	$441	$468	$175	0.86%	0.89%	0.00%
Three Phase										
20	4,000	$350	$403	$350	$353	$407	$350	0.86%	0.92%	0.00%
	6,000	$525	$578	$350	$529	$583	$350	0.86%	0.90%	0.00%
	10,000	$875	$928	$350	$882	$936	$350	0.86%	0.89%	0.00%
100	20,000	$1,749	$2,016	$1,504	$1,764	$2,035	$1,504	0.86%	0.92%	0.00%
	30,000	$2,624	$2,891	$1,504	$2,646	$2,917	$1,504	0.86%	0.90%	0.00%
	50,000	$4,373	$4,640	$1,504	$4,411	$4,682	$1,504	0.86%	0.89%	0.00%
300	60,000	$5,248	$6,049	$3,770	$5,293	$6,105	$3,770	0.86%	0.92%	0.00%
	90,000	$7,872	$8,673	$3,770	$7,939	$8,752	$3,770	0.86%	0.90%	0.00%
	150,000	$13,120	$13,921	$3,770	$13,232	$14,045	$3,770	0.86%	0.89%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$253	$279	$175	$255	$281	$175	0.87%	0.91%	0.00%
	4,000	$337	$363	$175	$340	$366	$175	0.87%	0.90%	0.00%
	5,000	$421	$447	$175	$425	$451	$175	0.87%	0.89%	0.00%
Three Phase										
20	6,000	$505	$557	$350	$510	$562	$350	0.87%	0.91%	0.00%
	8,000	$674	$726	$350	$680	$732	$350	0.87%	0.90%	0.00%
	10,000	$842	$894	$350	$850	$902	$350	0.87%	0.89%	0.00%
100	30,000	$2,527	$2,785	$1,494	$2,549	$2,811	$1,494	0.87%	0.91%	0.00%
	40,000	$3,369	$3,628	$1,494	$3,398	$3,660	$1,494	0.87%	0.90%	0.00%
	50,000	$4,212	$4,470	$1,494	$4,248	$4,510	$1,494	0.87%	0.89%	0.00%
300	90,000	$7,581	$8,356	$3,760	$7,647	$8,432	$3,760	0.87%	0.91%	0.00%
	120,000	$10,108	$10,883	$3,760	$10,195	$10,981	$3,760	0.87%	0.90%	0.00%
	150,000	$12,635	$13,410	$3,760	$12,744	$13,530	$3,760	0.87%	0.89%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$23,825	$24,084	1.09%
	500,000	$35,142	$35,574	1.23%
	700,000	$46,458	$47,064	1.30%
2,000	600,000	$47,299	$47,818	1.10%
	1,000,000	$68,403	$69,268	1.26%
	1,400,000	$90,225	$91,436	1.34%
6,000	1,800,000	$137,724	$139,282	1.13%
	3,000,000	$203,189	$205,785	1.28%
	4,200,000	$268,655	$272,288	1.35%
12,000	3,600,000	$274,300	$277,414	1.14%
	6,000,000	$405,230	$410,421	1.28%
	8,400,000	$536,160	$543,428	1.36%

Notes:

On-Peak kWh	64.59%
Off-Peak kWh	35.41%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$22,823	$23,064	1.06%
	500,000	$33,623	$34,025	1.19%
	700,000	$44,424	$44,986	1.27%
2,000	600,000	$45,276	$45,758	1.06%
	1,000,000	$65,346	$66,149	1.23%
	1,400,000	$86,134	$87,259	1.31%
6,000	1,800,000	$131,911	$133,357	1.10%
	3,000,000	$194,276	$196,686	1.24%
	4,200,000	$256,641	$260,015	1.31%
12,000	3,600,000	$262,662	$265,554	1.10%
	6,000,000	$387,392	$392,213	1.24%
	8,400,000	$512,122	$518,871	1.32%

Notes:

On-Peak kWh	61.78%
Off-Peak kWh	38.22%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	500,000	$32,705	$33,003	0.91%
	700,000	$42,960	$43,378	0.97%
2,000	1,000,000	$63,282	$63,879	0.94%
	1,400,000	$82,981	$83,817	1.01%
6,000	3,000,000	$188,155	$189,948	0.95%
	4,200,000	$247,253	$249,762	1.01%
12,000	6,000,000	$374,709	$378,293	0.96%
	8,400,000	$492,903	$497,921	1.02%

Notes:

On-Peak kWh	56.38%
Off-Peak kWh	43.62%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.