PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2013

***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 No. 13-005**
**Docket UE 264 - PacifiCorp's 2014 Transition Adjustment Mechanism**

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing an original and five copies of the tariff pages identified below to implement PacifiCorp's 2014 Transition Adjustment Mechanism (TAM). The Company is requesting an effective date of January 1, 2014, for these tariff sheets.

## A. Description of Filing

The purpose of the TAM filing is to update net power costs for 2014 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 PacifiCorp files a general rate case, then the TAM must be filed no later than March 1 to allow for a January 1 rate effective date. Accordingly, the Company is filing the 2014 TAM on March 1, 2013.

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
- Cindy A. Crane, Vice President, Interwest Mining Company and Fuel Resources
- Judith M. Ridenour, Regulatory Specialist, Cost of Service and Pricing

## B. Tariff Sheets

| | | |
|---|---|---|
| Fourth Revision of Sheet No. 201-1 | Schedule 201 | Net Power Costs |
| Third Revision of Sheet No. 201-2 | Schedule 201 | Net Power Costs |
| Third Revision of Sheet No. 201-3 | Schedule 201 | Net Power Costs |
| First Revision of Sheet No. 294-1 | Schedule 294 | Transition Adjustment |
| Third Revision of Sheet No. 295-1 | Schedule 295 | Transition Adjustment – Three-Year Cost of Service Opt-Out |

## 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, at (503) 813-6389.

A copy of this filing has been served on all parties to PacifiCorp's 2013 TAM proceeding, docket UE 245, as indicated on the attached certificate of service. Confidential material in support of the filing has been provided to parties under Order No. 10-069, the standing protective order adopted for all TAM proceedings.

Sincerely,

William R. Griffith /RBD

William R. Griffith
Vice President, Regulation

Enclosures

cc: UE 245 Service List

**CERTIFICATE OF SERVICE**

I hereby certify that on this 1st of March, 2013, I caused to be served, via E-mail, 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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Supervisor, Regulatory Operations

Docket No. UE 264
Exhibit PAC/100
Witness: Gregory N. Duvall

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Direct Testimony of Gregory N. Duvall**

**March 2013**

## DIRECT TESTIMONY OF GREGORY N. DUVALL

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## ATTACHED EXHIBITS

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

A. My name is 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 professional 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 2014 Transition Adjustment Mechanism (TAM) net power costs (NPC). Specifically, my testimony:

- Summarizes the content of the filing.

- Describes the primary drivers behind the reduction in total Company NPC for 2014.
- Describes the Company's implementation of the Commission order in docket UE 245 (2013 TAM).
- Describes refinements to modeling inputs the Company has made since the Company's 2013 TAM.
- Presents the Company's 2012 Wind Integration Study (2012 Wind Study), and the modeling of wind integration in this proceeding.
- Describes how the filing is consistent with the TAM Guidelines.

**Q. Please identify the other Company witnesses supporting the 2014 TAM.**

A. Two additional Company witnesses provide testimony supporting the Company's filing. Ms. Cindy A. Crane, Vice President, Interwest Mining & Fuels, provides testimony supporting the coal costs included in the 2014 test period. Ms. Judith M. Ridenour, Regulatory Specialist, Pricing & Cost of Service, presents the Company's proposed tariffs and rate design and provides a comparison of existing and estimated customer rates.

## SUMMARY OF PACIFICORP'S 2014 TAM FILING

**Q. Please provide background on the Company's 2014 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, 2014. The Company is filing the 2014 TAM concurrently with a request for a general rate increase in docket UE 263 (2013 Rate Case). As explained in Ms. Ridenour's testimony, the

2014 TAM results in an overall average rate reduction of approximately $1.0 million, or 0.1 percent.

**Q. What are the forecasted normalized system-wide NPC for calendar year 2014?**

A. The Company's total forecasted normalized system-wide NPC for calendar year 2014 are $1.457 billion. This is approximately $15.5 million lower than the $1.473 billion currently included in rates.

**Q. What are the estimated Oregon-allocated NPC for calendar year 2014?**

A. As shown on Exhibit PAC/101, on an Oregon-allocated basis, the forecasted normalized NPC for calendar year 2014 are $363.1 million. This is approximately $0.4 million higher than the Oregon-allocated NPC of $362.7 million from the 2013 TAM.

**Q. Does the proposed rate reduction reflect changes in Oregon load since the 2013 TAM?**

A. Yes. The 2014 load forecast in the filing reflects an increase in Oregon load compared to the 2013 forecast loads from the 2013 TAM. As a result of the increased Oregon load, the rates approved in the 2013 TAM will collect an additional $1.4 million during 2014. This additional revenue offsets the slight increase in Oregon-allocated NPC, resulting in an overall rate reduction for the 2014 TAM.

**Q. Have Oregon's allocation factors changed since the 2013 TAM?**

A. Yes. Oregon's allocation factors have increased due to changes in the forecasted

Oregon load relative to changes in the forecasted load in the Company's other jurisdictions.

**Q. Please explain the changes in the Company's total system loads between this filing and the 2013 TAM.**

A. Despite an increase in Oregon load from 2013 to 2014, the forecast total system load for the 2014 TAM is 513,619 MWh, or 0.85 percent, lower than the forecasted system load included in the 2013 TAM. This reduction in system load impacts most categories of NPC, including purchased power, wholesale sales, and thermal generation. The load forecast used for the 2014 TAM is the same forecast used in the 2013 Rate Case, and Ms. Kelcey A. Brown provides supporting testimony describing the load forecast in that docket.

**Q. Please generally describe the changes in NPC compared to the 2013 TAM.**

A. Table 1 illustrates the change in system-wide NPC by category from the NPC baseline in the 2013 TAM:

**Table 1**
**Net Power Cost Reconciliation**

| | ($ millions) | $/MWh |
|---|---|---|
| **OR TAM CY 2013** | **$1,473** | **$24.51** |
| Increase/(Decrease) to NPC: | | |
| Wholesale Sales Revenue | ($4) | |
| Purchased Power Expense | ($69) | |
| Coal Fuel Expense | $41 | |
| Natural Gas Fuel Expense | $6 | |
| Wheeling, Hydro and Other Expense | $10 | |
| **Total Increase/(Decrease) to NPC** | **($16)** | |
| **OR TAM CY 2014** | **$1,457** | **$24.46** |

As shown in Table 1, the reduction in NPC is largely driven by the savings in purchased power expense. This change is partially offset by an increase in coal expenses, along with smaller increases in natural gas, wheeling, and other expenses. On a total company basis, the proposed NPC represents a reduction of 1.1 percent from the amounts currently included in rates.

**Q. Does this filing reflect changes in the Company's system operations since the 2013 TAM?**

A. Yes. First, the 2014 TAM includes the Company's new 637 MW natural gas-fired generating plant (Lake Side 2), which is scheduled to come online during the test period. The Company has filed a separate tariff rider in the 2013 Rate Case to add Lake Side 2 to rates when it goes into service in the second quarter of 2014. In a parallel manner, the TAM includes the variable cost benefits of Lake Side 2 in NPC from June 2014 forward.

Second, before 2014 the Company will transfer three generating facilities—Chehalis, Leaning Juniper, and Goodnoe Hills—from the Bonneville Power Administration (BPA) balancing authority area to PacifiCorp's west balancing authority area (PACW). Each of these plants has been electronically connected to BPA's balancing authority area since the date of acquisition. Starting in 2013, the Company will have the necessary capital upgrades and contractual arrangements with BPA to enable the Company to operate each plant within PACW. For the wind plants, this change avoids expenses previously paid to BPA for wind integration and avoids potential curtailment by BPA under Dispatch Standing Order 216 and Oversupply Management Protocol. For

Chehalis, this change allows PacifiCorp to use the plant to provide reserve capacity and avoid certain transmission-related expenses, which has the effect of reducing NPC.

## DISCUSSION OF MAJOR COST DRIVERS IN NPC

**Q. Why has purchased power expense decreased in the 2014 TAM?**

A. Purchased power is split into three main categories in the Company's NPC report: long-term firm, short-term firm, and system balancing purchases. The majority of the reduction in purchased power expense is due to lower volumes of short-term firm and system balancing purchases. Short-term firm purchases are transactions spanning up to one year that the Company has already entered for the test period. System balancing purchases are transactions generated by the Generation and Regulation Initiative Decision (GRID) model as it balances the system on an hourly basis, and are a proxy for future short-term firm transactions.

At the time of filing the 2014 TAM, 47,600 MWh of short-term firm purchase transactions have been executed for 2014, compared to 514,400 MWh for 2013 as reflected in the final TAM update for the 2013 TAM. The volume of short-term firm purchases will increase in the July and November TAM updates when the Company reduces its open position as the test period gets closer.

System balancing purchases for 2014 are 1,026,473 MWh (17 percent) lower than in the 2013 TAM. Lower volumes of these market purchases are attributable to lower system load, higher wholesale market prices for electricity, and higher generation from natural gas-fired resources. Together, the reduction in short-term firm and system balancing purchases account for $52.5 million of the reduction in purchased power expense. Most of the remaining reduction in purchased power expense is due to the expiration of the West Valley Tolling agreement, which reduces purchased power expense by $13.8 million.

**Q. Did wholesale sales revenue in the 2014 TAM increase as compared to the 2013 TAM?**

A. Yes. As shown in Table 1, on a system-wide basis wholesale sales revenue increased by $4 million (one percent) since the 2013 TAM. This change is driven by higher market prices, but the increase in revenue is offset by a 472,281 MWh (four percent) reduction in sales volume.

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

A. Similar to purchased power, wholesale sales are split into three categories: long-term firm, short-term firm, and system balancing. In this case, long-term firm sales are relatively flat. There are currently no short-term firm sales transactions executed for 2014, compared to 278,400 MWh of short-term firm sales included in the final 2013 TAM update. As with short-term firm purchases, these volumes will increase in the July and November TAM updates when the Company reduces its open position as the test period gets closer. System balancing sales are also lower by 176,570 MWh (two percent), in part because the Company is not designating certain natural gas-fired plants as "must run" for wind integration purposes in the 2014 TAM, a change I discuss later in my testimony. System balancing sales will increase as GRID rebalances the system around the additional short-term firm purchases and sales added in future updates.

**Q. Please further describe the changes in wholesale electricity and natural gas prices since the 2013 TAM.**

A. Market prices for electricity and natural gas changed as a result of both the shift in test period from 2013 to 2014 and the update from the Company's November 8, 2012 Official Forward Price Curve (OFPC) (used in the 2013 TAM Final Update) to the December 31, 2012 OFPC (used in the 2014 TAM Initial Filing). Figure 1 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 high load hours (HLH) and light load hours (LLH). Figure 2 shows the change in natural gas prices at the Opal trading hub by month, which is a source of gas for the Company's gas plants located in Utah.

**Figure 1**

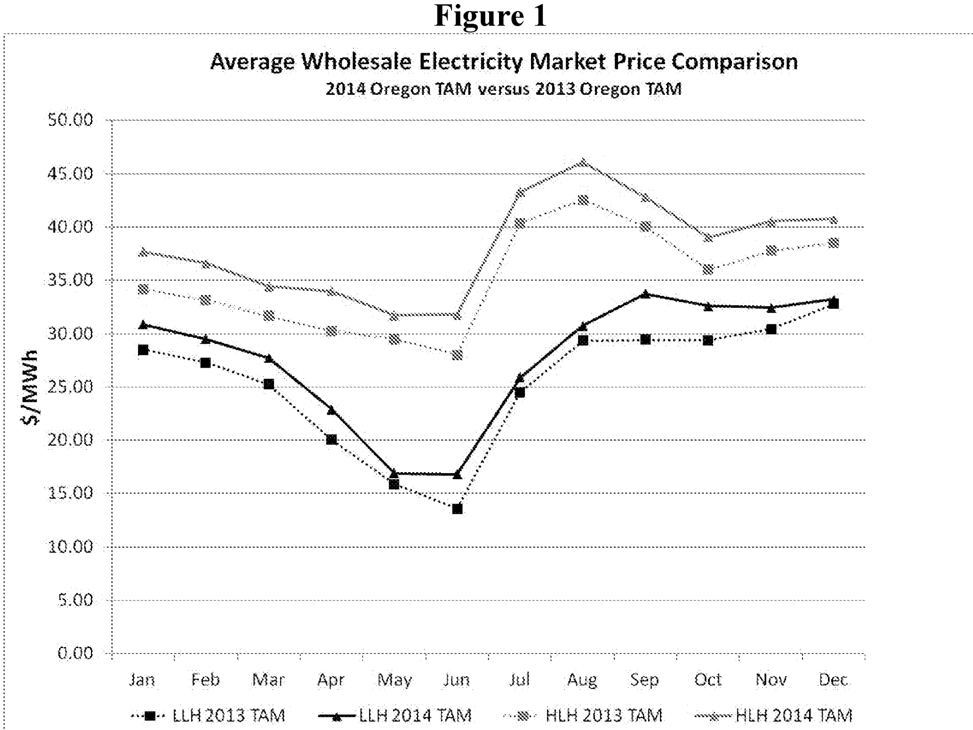
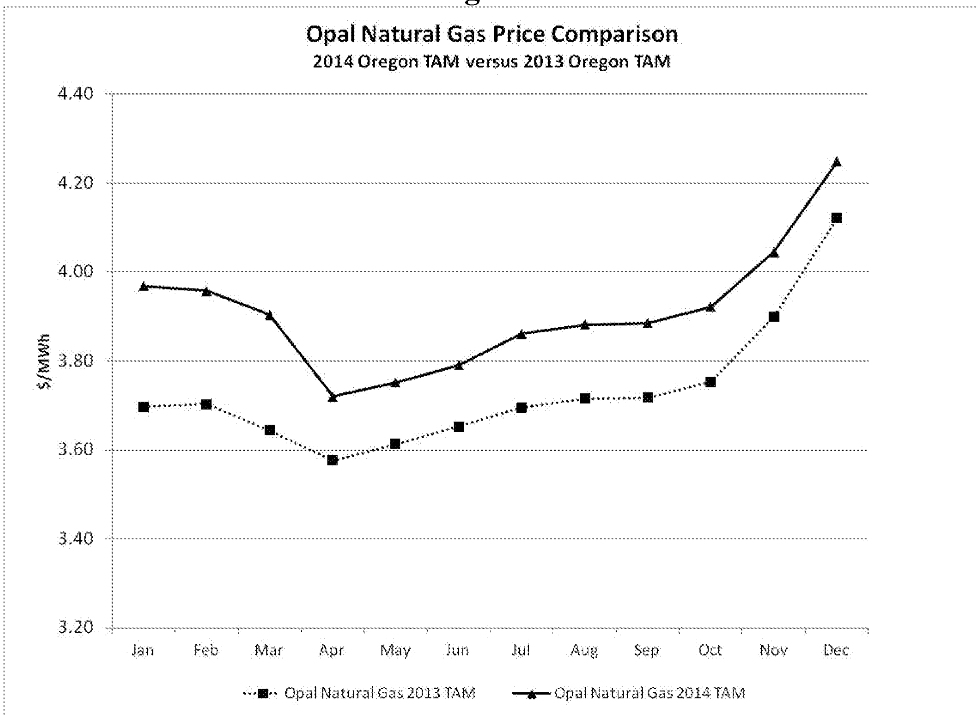


**Figure 2**




**Q. What do Figures 1 and 2 demonstrate?**

A. Figure 1 shows that, compared with the OFPC used in the final TAM study in the 2013 TAM, wholesale power prices in the current filing are higher for both HLH and LLH in every month, a nine percent increase overall. Figure 2 shows that natural gas prices are approximately five percent higher in this filing as compared to the natural gas prices in the final update of the 2013 TAM. The relatively larger increase in wholesale electricity market prices compared with natural gas prices causes natural gas-fired generation to become more economic, increasing the value of the Company's natural gas generation in the current filing.

**Q. Did generation from natural gas-fired resources increase compared to the 2013 TAM?**

A. Yes. Compared to the 2013 TAM, generation increased at the Company's Chehalis, Hermiston, and Lake Side natural gas facilities. In addition, the 2014

TAM includes the new Lake Side 2 plant which adds natural gas-fired generation capacity. During the seven months that Lake Side 2 is forecast to operate during 2014, it will provide 1,815,894 MWh of generation. As shown in Table 1, total natural gas expense is approximately $6 million higher than in the 2013 TAM.

The additional gas-fired generation is partially offset by the removal of the "must run" requirements in GRID for Currant Creek and the Gadsby combustion turbines, which allows these units to cycle on and off based on economics rather than requiring that these specific resources be available to provide regulating service for the Company's load and wind generation. This change in the modeled operation of these plants is the result of updating the reserve requirements to the Company's 2012 Wind Integration Study, which I will discuss later in my testimony.

**Q. Please explain the $41 million increase in coal fuel expense.**

A. The increase in coal fuel expense is driven by increases in the unit cost of coal at various coal-fired generation facilities owned by the Company. Increased prices cause total fuel expense to be approximately $53 million higher than the 2013 TAM, but the increase is partially offset by a 668,743 MWh (two percent) reduction in the volume of coal generation for 2014, for a net increase of $41 million. The reduction in coal generation is primarily attributed to the Jim Bridger plant, and is due to increases in fuel expense and a reduction in minimum operating levels. During periods where market prices are low relative to fuel costs, the GRID model is able to reduce output from the Jim Bridger plant to lower levels compared to the 2013 TAM. Additional information supporting the increase in coal costs is provided in the testimony of Ms. Crane.

**Q. What caused the $10 million increase in wheeling, hydro, and other expense shown in Table 1?**

A. The increase is mainly attributed to the BPA wheeling rate increase. On November 15, 2012, BPA filed its 2014 Joint Power and Transmission Rate Proceeding and proposed rate changes that will increase the Company's BPA transmission expenses by roughly 15 percent. New rates are scheduled to take effect beginning October 2013. The Company has roughly 5,000 MW of BPA transmission capacity. Point-to-Point (PTP) and Formula Power Transmission (FPT) service accounts for 83 percent of this service, and these rates are increasing by roughly 20 percent. This increase is partially offset by reductions in the rates for Network Transmission and Southern Intertie service.

**Q. What assumptions did the Company make in the 2014 TAM regarding the transmission rates proposed in the current BPA rate case?**

A. The Company applied the proposed rates set forth in BPA's initial proposal.

**Q. Does the Company propose to update the expenses related to all contracts with BPA?**

A. Yes. The Company plans to reflect the preliminary Record of Decision (ROD) in the BPA rate case, currently expected in June 2013, in its TAM Rebuttal Update. The Company proposes to reflect BPA's Final ROD, currently expected in late July 2013, in the TAM Final Update. While the TAM Guidelines do not specifically address how the Company may update NPC to reflect BPA rate changes, the Company applied a similar approach in docket UE 227, the 2012 TAM. In that case, Staff agreed that the Company could reflect BPA rate changes in NPC as long as they were approved, and therefore became known and measurable, during the course of the TAM. The Final Update in the 2012 TAM included an update for BPA's final ROD.

**Q. Please provide background on the Company's interruptible contracts with Monsanto, Nucor, and US Magnesium.**

A. The Company currently has contracts with three large industrial customers, one in Idaho (Monsanto) and two in Utah (Nucor and US Magnesium), that give the Company the ability to curtail the customer's load for economic purposes or as non-spin reserve capacity. The Monsanto and Nucor contracts expire at the end of 2013, and the Company is actively working with the customers to negotiate contracts for 2014 and beyond. US Magnesium's contract expires at the end of 2014.

In addition, the Company is currently working toward issuing a request for proposals for operating reserves (Operating Reserve RFP) in its east balancing authority area. In conjunction with contract negotiations, the three interruptible industrial customers will be invited to participate in the Operating Reserve RFP.

**Q. How has the Company modeled these contracts in the 2014 TAM?**

A. For purposes of the 2014 TAM, the Company has assumed that these three interruptible contracts remain in place at current prices and curtailment levels. Depending on the outcome of the contract negotiations and the Operating Reserve RFP, however, the price and structure of these contracts may change.

**Q. What issues are raised by potential updates to these interruptible contracts?**

A. It is possible that the updated contracts would call for different amounts of load to be curtailed, impacting the net system load used to calculate NPC for 2014. It is also possible that the contracts could be structured such that curtailed load would be reflected as reductions to the jurisdictional load used to compute allocation factors under the 2010 Protocol allocation method. Inter-jurisdictional allocation factors are discussed in the testimony of Mr. Gary W. Tawwater in the 2013 Rate Case. Either of these scenarios could require updates to the TAM—for the load forecast or inter-jurisdictional allocation factors—that have normally been viewed as beyond the scope of the TAM Guidelines.

**Q. How does the Company propose to address this issue in the 2014 TAM?**

A. The Company proposes to update all aspects of the TAM impacted by changes to these large interruptible contracts, including loads and allocation factors. This would require an exception to the TAM Guidelines. Because the 2014 TAM is filed concurrently with the 2013 Rate Case, the Commission has greater flexibility to allow a TAM Guideline modification in this case. The alternative would be to preclude any update to the Company's large interruptible contracts, an approach that would produce a less accurate NPC forecast in the 2014 TAM.

**Q. Has the Commission previously allowed a similar, case-specific exception to the TAM Guidelines to permit the Company to update loads in the TAM?**

A. Yes. The 2012 TAM was the Company's last stand-alone TAM. In that case, the Company accepted Staff's proposal to update the Company's load forecast for the Rebuttal Update, reducing Oregon NPC by approximately $7.9 million. The

Commission approved a contested Stipulation which expressly set forth the reduction to NPC associated with the update to the load forecast.[1]

## DETERMINATION OF NPC

**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 since 2002. As I discuss below, the Company has updated various inputs to the GRID model to comply with the Commission order in the 2013 TAM and refined others in an effort to improve the NPC calculation for the 2014 test period.

**Q. Is the Company using the same version of the GRID model as used in its 2013 TAM?**

A. Yes.

**Q. What general inputs were updated for this filing?**

A. The Company updated inputs to the GRID model to reflect the information available at the time the Company prepared the NPC study for the current filing.

[1] *In re PacifiCorp, dba Pacific Power, 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435, Appendix A at pg. 2 (November 4, 2011).

In addition to system load, the Company updated wholesale sales and purchase contracts for electricity, natural gas and wheeling; wholesale market prices for electricity and natural gas; fuel expenses; transmission capability; characteristics of the Company's generation facilities; and planned outages and forced outages of the Company's generation resources. The historical base period used for outage rates and other inputs relying on four-year historical averages in this filing is the 48-month period ending June 2012.

**Q. What reports does the GRID model produce?**

A. The major output from the GRID model is the NPC report. This is the same information contained in Exhibit PAC/102, and an electronic version is included in the workpapers accompanying the Company's filing. 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 2013 TAM

**Q. Has the Company modeled NPC in accordance with the Commission's final order in the 2013 TAM?**

A. Yes. The 2014 TAM Initial Filing is fully consistent with Order No. 12-409 in the 2013 TAM, as follows:

- Market Caps—Wholesale market sales caps are calculated based on the highest of the four most recently available relevant averages for each trading hub, by month and by HLH and LLH periods.
- Arbitrage and Trading Revenue Credit—No adjustment is made to impute additional revenue for arbitrage and trading transactions.

- Third-Party Wind Integration—The cost of integrating third-party wind is included in the test period NPC. Related revenue will be passed back to customers consistent with the partial stipulation adopted in Order No. 12-493 in the 2012 Rate Case.
- Hydro Forced Outages—The Commission did not adopt any changes to the forced outage modeling in the 2013 TAM, but urged the Company and parties to review the modeling of hydro forced outages and make changes is necessary. The Company has refined its calculation of forced outages for hydro units with storage capability, which I will describe later in my testimony.

In addition to the items resolved in Order No. 12-409, in the 2013 TAM the Company agreed to revise its NPC modeling to exclude the cost of integrating the Rolling Hills wind project and correct a small amount of unintentional uneconomic dispatch of the Chehalis natural gas plant. Both of these changes are also included in the 2014 TAM.

**Q. Has the Company refined any inputs to the GRID model to improve the accuracy of its forecast?**

A. Yes. In Order No. 12-409, the Commission stated, "as the company and others continue to raise questions about the accuracy and reasonableness of GRID forecasts, we will expect Pacific Power to refine its modeling to produce the best possible estimates of all components of net power costs."[2] Consistent with that

[2] *In re PacifiCorp, dba Pacific Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7 (October 29, 2012).

directive, the forecast NPC for the 2014 TAM includes improved modeling of hydro forced outages and wind generation profiles.

**Q. Please explain how the Company modeled hydro forced outages in this case.**

A. Similar to the method used for thermal plants, the Company has reflected a normalized level of forced outages on hydro units with storage capability[3] as a flat percentage reduction to the available capacity across all hours of the pro forma period. The reduction to plant capacity is based on a 48-month history of forced outages by plant. In addition, an adjustment to reflect energy lost due to forced outages is made to hydro generation based on historical measurements which began in January 2011.

**Q. How were hydro forced outages modeled in the 2013 TAM?**

A. In the 2013 TAM, the Company calculated the average outage days per month based on a 48-month history. The scheduled hydro generation determined by the Vista model was then adjusted by randomly placing outages during weeks of the respective months.

**Q. How does the Company's proposed method in this case improve the approach used in the 2013 TAM?**

A. The Company's proposed method is consistent with how forced outages are modeled in determining the capacity of thermal generating units. In addition, adjusting for lost energy based on historical measurements captures the flexibility of hydro projects with storage capability to shift generation around outages.

[3] Output from run of river hydro facilities is included based on historical generation, including the impact of outages.

**Q. Please explain how the Company used historical wind output to calculate the wind generation profile in this case.**

A. Wind generation is included in GRID based on a "P50" forecast. A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than forecast. Typically such a forecast is developed for an individual project by combining wind speed measurements taken before project construction with a detailed model of turbine locations and performance characteristics. The projected output in a given hour is then averaged across each month to develop a 12 x 24 matrix of average hourly output. The Company has historically input wind generation into GRID using the P50 forecast divided into six four-hour blocks per day. Generation was flat over the four-hour block, and each period was the same for every day during a month. Consequently, the wind generation in GRID exhibited very little variation.

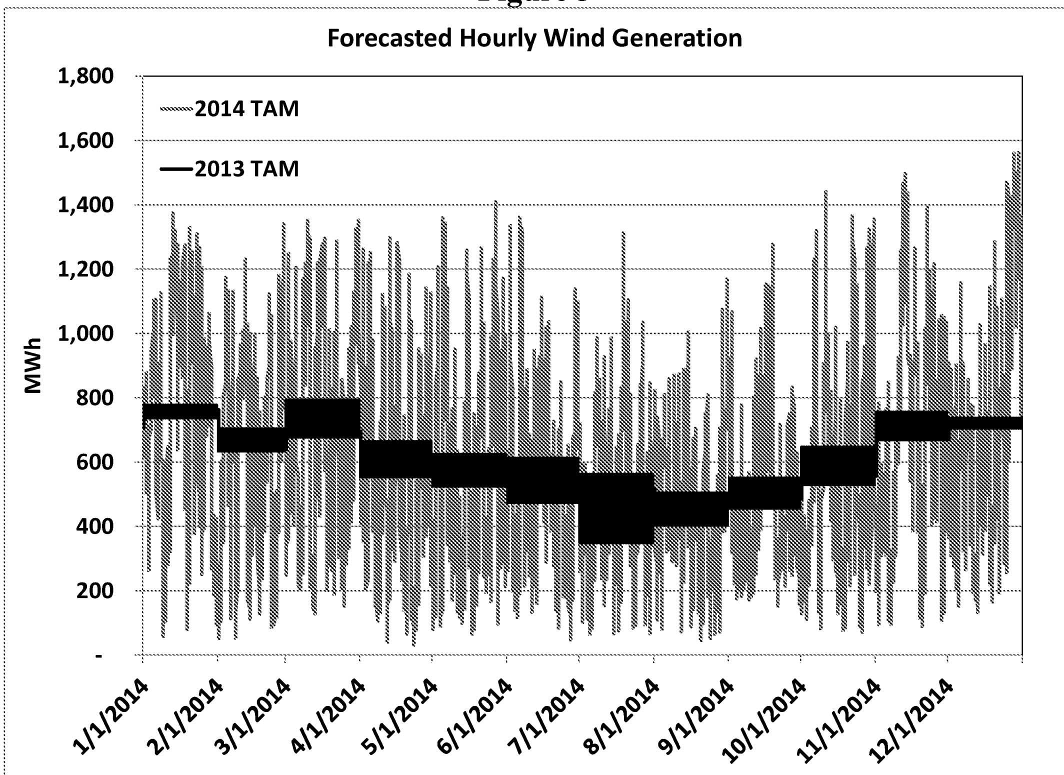
In this case, the Company has continued to use the P50 forecast approach for determining total wind generation, but used the Company's actual 2011 energy output data from its owned and purchased wind facilities to shape hourly wind generation profiles. The Company scaled actual generation levels up or down so that, when the output within the traditional four-hour blocks is averaged over the course of a month, it is the same as in the P50 forecast. In other words, the total energy output of the wind facilities is the same as the P50 forecast used in previous cases, but the shape of the generation varies on an hourly basis consistent with actual output during 2011.

**Q. Why did the Company refine the modeling of its hourly wind profiles to reflect historical performance?**

A. As noted above, the Commission's final order in the 2013 TAM encouraged the Company to refine its modeling where possible to improve the accuracy of its NPC forecast. With respect to forecasting wind resource availability, the Commission previously found that "the most recent reliable data should be used to set rates for the test period."[4] These directives encouraged PacifiCorp to develop wind profiles that capture the volatility of wind generation in forecast NPC. Figure 3 illustrates the difference in wind generation profiles. The darker line with smooth step changes represents the previous wind inputs using four-hour blocks. The highly variable line represents the wind inputs that vary hourly based on historical volatility, with the same total wind generation volume as the P50 forecast.

[4] *In re PacifiCorp, dba Pacific Power, Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 (November 14, 2008).

**Figure 3**




Clearly, an average wind generation forecast shaped over flat four-hour blocks does not capture the actual variability associated with wind generation on PacifiCorp's system. Applying the 2011 actual wind generation pattern to the total average wind generation P50 volumes improves the accuracy of forecasted NPC by capturing more of the cost impacts associated with intermittent wind generation on an hourly basis using the most recent reliable data available.

## WIND INTEGRATION

**Q. Has the Company updated its modeling of wind integration costs?**

A. Yes. The Company's wind integration costs are now based on the latest version of the draft 2012 Wind Study underway as part of the development of the

Company's 2013 Integrated Resource Plan.[5] The 2012 Wind Study is the result of an extensive public process that received guidance from a Technical Review Committee that included numerous subject-matter experts. The 2012 Wind Study indicates that the estimated cost of wind integration has declined, primarily because of lower forecast natural gas and power market prices.

**Q. How has the modeling of wind integration changed as a result of the 2012 Wind Study?**

A. There are three modeling changes compared with the prior TAM:

- The reserve requirements included in the GRID model reflect the results of the 2012 Wind Study, with adjustments to integrate all additional wind capacity that will be online during the test period, including the Leaning Juniper and Goodnoe Hills plants that will be transferred to PACW.
- The "must run" settings for Currant Creek and the Gadsby combustion turbines have been removed and these plants are dispatched based on economics.
- The inter-hour integration costs for load and wind have been updated.

**Q. What level of reserves is included in the 2014 TAM as a result of the 2012 Wind Study?**

A. The 2012 Wind Study concludes that an average of 579 MW of reserves were necessary on PacifiCorp's system in calendar year 2011 to integrate 2,126 MW of

[5] *See* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/2012WIS/2013IRP_2012WindIntegration-DRAFTReport-11-15-12.pdf.

wind capacity. The 2014 TAM includes an average of 606 MW of regulating reserves to integrate 2,454 MW of wind capacity.

## 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. As previously discussed, the Company has proposed an exception to the TAM Guidelines in this case to allow an update for changes in load and allocation factors if the Company's interruptible contracts are renewed with a structure that is different than the modeling included in the 2014 TAM Initial Filing.

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

A. Yes. On January 30, 2013, the Company sent a notice to Staff, Citizens' Utility Board of Oregon, Industrial Customers of Northwest Utilities, 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. 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.

**Q. Does this conclude your direct testimony?**

A. Yes.

Docket No. UE 264
Exhibit PAC/101
Witness: Gregory N. Duvall

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Gregory N. Duvall**

**CY 2013 Transition Adjustment Mechanism**

**March 2013**

**PacifiCorp**
**CY 2014 TAM**

| | | Total Company | | | | | Oregon Allocated | |
|---|---|---|---|---|---|---|---|---|
| | ACCT. | UE-245 Final TAM CY 2013 | TAM CY 2014 | Factor | Factors CY 2013 | Factors CY 2014 | UE-245 Final TAM CY 2013 | TAM CY 2014 |
| **Sales for Resale** | | | | | | | | |
| Existing Firm PPL | 447 | 26,954,864 | 27,098,027 | SG | 25.777% | 26.053% | 6,948,197 | 7,059,849 |
| Existing Firm UPL | 447 | 30,104,809 | 30,332,094 | SG | 25.777% | 26.053% | 7,760,163 | 7,902,421 |
| Post-Merger Firm | 447 | 411,312,892 | 414,706,102 | SG | 25.777% | 26.053% | 106,024,762 | 108,043,387 |
| Non-Firm | 447 | - | - | SE | 24.314% | 24.687% | - | - |
| **Total Sales for Resale** | | 468,372,565 | 472,136,224 | | | | 120,733,122 | 123,005,658 |
| **Purchased Power** | | | | | | | | |
| Existing Firm Demand PPL | 555 | 2,770,392 | 2,845,214 | SG | 25.777% | 26.053% | 714,128 | 741,264 |
| Existing Firm Demand UPL | 555 | 51,880,572 | 52,544,159 | SG | 25.777% | 26.053% | 13,373,335 | 13,689,330 |
| Existing Firm Energy | 555 | 25,377,752 | 25,882,481 | SE | 24.314% | 24.687% | 6,170,224 | 6,389,539 |
| Post-merger Firm | 555 | 602,895,671 | 532,436,997 | SG | 25.777% | 26.053% | 155,409,352 | 138,715,820 |
| Secondary Purchases | 555 | - | - | SE | 24.314% | 24.687% | - | - |
| Other Generation Expense | 555 | 4,324,005 | 3,354,157 | SG | 25.777% | 26.053% | 1,114,605 | 873,859 |
| **Total Purchased Power** | | 687,248,392 | 617,063,008 | | | | 176,781,645 | 160,409,811 |
| **Wheeling Expense** | | | | | | | | |
| Existing Firm PPL | 565 | 24,712,270 | 27,925,313 | SG | 25.777% | 26.053% | 6,370,120 | 7,275,382 |
| Existing Firm UPL | 565 | - | - | SG | 25.777% | 26.053% | - | - |
| Post-merger Firm | 565 | 104,782,875 | 110,506,851 | SG | 25.777% | 26.053% | 27,010,044 | 28,790,352 |
| Non-Firm | 565 | 2,848,300 | 5,105,200 | SE | 24.314% | 24.687% | 692,522 | 1,260,307 |
| **Total Wheeling Expense** | | 132,343,444 | 143,537,364 | | | | 34,072,686 | 37,326,041 |
| **Fuel Expense** | | | | | | | | |
| Fuel Consumed - Coal | 501 | 723,280,800 | 760,735,004 | SE | 24.314% | 24.687% | 175,855,014 | 187,800,618 |
| Fuel Consumed - Coal (Cholla) | 501 | 55,986,523 | 59,706,693 | SSECH/SE | 24.314% | 24.687% | 13,612,294 | 14,739,632 |
| Fuel Consumed - Gas | 501 | 5,235,787 | 3,416,494 | SE | 24.314% | 24.687% | 1,273,004 | 843,421 |
| Natural Gas Consumed | 547 | 316,175,110 | 334,359,033 | SE | 24.314% | 24.687% | 76,873,295 | 82,542,321 |
| Simple Cycle Comb. Turbines | 547 | 17,063,157 | 7,134,120 | SSECT/SE | 24.314% | 24.687% | 4,148,654 | 1,761,181 |
| Steam from Other Sources | 503 | 3,762,209 | 3,374,877 | SE | 24.314% | 24.687% | 914,725 | 833,147 |
| **Total Fuel Expense** | | 1,121,503,586 | 1,168,726,221 | | | | 272,676,986 | 288,520,320 |
| **Net Power Cost (Per GRID)** | | 1,472,722,858 | 1,457,190,370 | | | | 362,798,195 | 363,250,514 |
| Oregon Situs Solar Project Benefit | | (130,638) | (138,381) | OR | 100.000% | 100.000% | (130,638) | (138,381) |
| **Total Net of Adjustments** | | 1,472,592,220 | 1,457,051,989 | | | | 362,667,557 | 363,112,133 |
| | | | | | | | Increase Absent Load Change | 444,576 |
| | | | | | Oregon-allocated NPC Baseline in Rates from UE-245 | | $362,667,557 | |
| | | | | | $ Change due to load variance from UE-245 forecast | | 1,439,708 | |
| | | | | | 2014 Recovery of NPC in Rates | | $364,107,266 | |
| | | | | | | | **Increase Including Load Change** | **(995,132)** |
| | | | | | | | | Variance From Original Filing |

Docket No. UE 264
Exhibit PAC/102
Witness: Gregory N. Duvall

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Gregory N. Duvall**

**Net Power Cost Report**

**March 2013**

PacifiCorp

## _OR TAM CY2014 NPC Study_2013 02 12 (Conf)

**Net Power Cost Analysis**

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| 12 months ended December 2014 | 01/14-12/14 | Jan-14 | Feb-14 | Mar-14 | Apr-14 |
|---|---|---|---|---|---|
| **Special Sales For Resale** | | | | | |
| Long Term Firm Sales | | | | | |
| Black Hills s27013/s28160 | 14,133,227 | 1,198,917 | 1,145,680 | 1,204,545 | 1,179,826 |
| BPA Wind s42818 | 2,756,339 | 345,439 | 289,581 | 280,393 | 217,774 |
| Hurricane Sale s393046 | 12,839 | 1,070 | 1,070 | 1,070 | 1,070 |
| LADWP (IPP Layoff) | 30,332,094 | 2,485,817 | 2,199,792 | 2,121,987 | 1,807,896 |
| NVE s811499 | - | - | - | - | - |
| Pacific Gas & Electric s524491 | - | - | - | - | - |
| SCE s513948 | - | - | - | - | - |
| SMUD s24296 | 12,964,800 | 1,639,100 | 799,200 | 18,500 | 340,400 |
| UMPA II s45631 | 9,544,220 | 593,283 | 561,909 | 593,283 | 582,825 |
| Total Long Term Firm Sales | 69,743,519 | 6,263,626 | 4,997,232 | 4,219,777 | 4,129,790 |
| Short Term Firm Sales | | | | | |
| COB | - | - | - | - | - |
| Colorado | - | - | - | - | - |
| Four Corners | - | - | - | - | - |
| Idaho | - | - | - | - | - |
| Mead | - | - | - | - | - |
| Mid Columbia | - | - | - | - | - |
| Mona | - | - | - | - | - |
| NOB | - | - | - | - | - |
| Palo Verde | - | - | - | - | - |
| SP15 | - | - | - | - | - |
| Utah | - | - | - | - | - |
| West Main | - | - | - | - | - |
| Wyoming | - | - | - | - | - |
| Electric Swaps Sales | 2,505,418 | 741,464 | 754,704 | 1,090,524 | 471,640 |
| STF Index Trades | - | - | - | - | - |
| Total Short Term Firm Sales | 2,505,418 | 741,464 | 754,704 | 1,090,524 | 471,640 |
| System Balancing Sales | | | | | |
| COB | 65,872,541 | 7,591,703 | 5,353,656 | 5,347,488 | 3,369,071 |
| Four Corners | 104,264,776 | 7,506,269 | 6,903,826 | 5,998,160 | 7,959,770 |
| Mead | 37,231,892 | 3,102,155 | 2,764,202 | 2,791,081 | 2,802,170 |
| Mid Columbia | 37,809,632 | 5,547,218 | 4,858,356 | 3,461,481 | 70,836 |
| Mona | 28,143,942 | 1,862,403 | 1,687,627 | 1,408,365 | 1,994,821 |
| NOB | - | - | - | - | - |
| Palo Verde | 126,564,462 | 10,152,879 | 10,047,283 | 10,355,325 | 10,815,241 |
| SP15 | - | - | - | - | - |
| Trapped Energy | 41 | - | - | - | - |
| Total System Balancing Sales | 399,887,287 | 35,762,627 | 31,614,950 | 29,361,899 | 27,011,909 |
| **Total Special Sales For Resale** | 472,136,224 | 42,767,717 | 37,366,886 | 34,672,201 | 31,613,339 |

| 12 months ended December 2014 | May-14 | Jun-14 | Jul-14 | Aug-14 |
|---|---|---|---|---|
| **Special Sales For Resale** | | | | |
| Long Term Firm Sales | | | | |
| Black Hills s27013/s28160 | 1,146,527 | 1,071,292 | 1,204,060 | 1,204,105 |
| BPA Wind s42818 | 205,587 | 166,749 | 125,058 | 118,541 |
| Hurricane Sale s393046 | 1,070 | 1,070 | 1,070 | 1,070 |
| LADWP (IPP Layoff) | 2,494,627 | 2,710,454 | 2,915,750 | 2,892,791 |
| NVE s811499 | - | - | - | - |
| Pacific Gas & Electric s524491 | - | - | - | - |
| SCE s513948 | - | - | - | - |
| SMUD s24296 | - | 388,500 | 1,254,300 | 1,646,500 |
| UMPA II s45631 | 563,942 | 906,953 | 1,779,848 | 1,400,150 |
| Total Long Term Firm Sales | 4,411,752 | 5,245,019 | 7,280,085 | 7,263,157 |
| Short Term Firm Sales | | | | |
| COB | - | - | - | - |
| Colorado | - | - | - | - |
| Four Corners | - | - | - | - |
| Idaho | - | - | - | - |
| Mead | - | - | - | - |
| Mid Columbia | - | - | - | - |
| Mona | - | - | - | - |
| NOB | - | - | - | - |
| Palo Verde | - | - | - | - |
| SP15 | - | - | - | - |
| Utah | - | - | - | - |
| West Main | - | - | - | - |
| Wyoming | - | - | - | - |
| Electric Swaps Sales | 329,368 | (93,700) | (840,788) | (753,272) |
| STF Index Trades | - | - | - | - |
| Total Short Term Firm Sales | 329,368 | (93,700) | (840,788) | (753,272) |
| System Balancing Sales | | | | |
| COB | 508,496 | 633,930 | 5,105,351 | 7,485,827 |
| Four Corners | 5,536,802 | 5,363,229 | 14,031,487 | 14,966,813 |
| Mead | 2,934,928 | 2,659,200 | 3,615,942 | 3,771,957 |
| Mid Columbia | - | - | 946,635 | 1,944,340 |
| Mona | 1,394,789 | 1,978,594 | 3,138,665 | 3,509,302 |
| NOB | - | - | - | - |
| Palo Verde | 9,791,828 | 10,932,425 | 8,988,135 | 8,820,022 |
| SP15 | - | - | - | - |
| Trapped Energy | - | - | - | - |
| Total System Balancing Sales | 20,166,843 | 21,567,378 | 35,826,215 | 40,498,261 |
| **Total Special Sales For Resale** | 24,907,963 | 26,718,697 | 42,265,513 | 47,008,146 |

| 12 months ended December 2014 | Sep-14 | Oct-14 | Nov-14 | Dec-14 |
|---|---|---|---|---|
| **Special Sales For Resale** | | | | |
| Long Term Firm Sales | | | | |
| Black Hills s27013/s28160 | 1,186,022 | 1,203,785 | 1,176,638 | 1,211,829 |
| BPA Wind s42818 | 155,892 | 227,846 | 286,981 | 336,498 |
| Hurricane Sale s393046 | 1,070 | 1,070 | 1,070 | 1,070 |
| LADWP (IPP Layoff) | 2,042,916 | 3,473,690 | 2,505,671 | 2,680,705 |
| NVE s811499 | - | - | - | - |
| Pacific Gas & Electric s524491 | - | - | - | - |
| SCE s513948 | - | - | - | - |
| SMUD s24296 | 1,676,100 | 1,583,600 | 1,676,100 | 1,942,500 |
| UMPA II s45631 | 792,640 | 593,283 | 582,825 | 593,283 |
| Total Long Term Firm Sales | 5,854,640 | 7,083,273 | 6,229,285 | 6,765,884 |
| Short Term Firm Sales | | | | |
| COB | - | - | - | - |
| Colorado | - | - | - | - |
| Four Corners | - | - | - | - |
| Idaho | - | - | - | - |
| Mead | - | - | - | - |
| Mid Columbia | - | - | - | - |
| Mona | - | - | - | - |
| NOB | - | - | - | - |
| Palo Verde | - | - | - | - |
| SP15 | - | - | - | - |
| Utah | - | - | - | - |
| West Main | - | - | - | - |
| Wyoming | - | - | - | - |
| Electric Swaps Sales | (135,250) | 197,757 | 294,155 | 448,816 |
| STF Index Trades | - | - | - | - |
| Total Short Term Firm Sales | (135,250) | 197,757 | 294,155 | 448,816 |
| System Balancing Sales | | | | |
| COB | 8,055,688 | 6,646,206 | 7,484,692 | 8,290,435 |
| Four Corners | 9,196,249 | 8,725,716 | 9,982,384 | 8,094,070 |
| Mead | 3,310,792 | 3,360,287 | 3,145,555 | 2,973,625 |
| Mid Columbia | 3,441,708 | 4,620,054 | 6,658,186 | 6,260,819 |
| Mona | 3,011,414 | 3,039,931 | 2,414,814 | 2,703,216 |
| NOB | - | - | - | - |
| Palo Verde | 11,857,158 | 12,221,510 | 11,426,006 | 11,156,650 |
| SP15 | - | - | - | - |
| Trapped Energy | - | - | - | 41 |
| Total System Balancing Sales | 38,873,010 | 38,613,704 | 41,111,636 | 39,478,854 |
| **Total Special Sales For Resale** | 44,592,399 | 45,894,735 | 47,635,076 | 46,693,554 |

| 12 months ended December 2014 | 01/14-12/14 | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Purchased Power & Net Interchange** | | | | | | | | | | | | | |
| Long Term Firm Purchases | | | | | | | | | | | | | |
| APS Supplemental p27875 | 888,931 | 82,327 | 88,660 | - | 94,041 | 125,064 | - | 163,575 | - | - | - | 168,765 | 166,500 |
| Blanding Purchase p379174 | 30,485 | 2,589 | 2,339 | 2,589 | 2,506 | 2,589 | 2,506 | 2,589 | 2,589 | 2,506 | 2,589 | 2,506 | 2,589 |
| BPA Reserve Purchase | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Combine Hills Wind p160595 | 4,721,025 | 452,445 | 294,182 | 523,139 | 367,365 | 341,486 | 411,545 | 394,481 | 391,208 | 372,846 | 400,343 | 446,574 | 325,411 |
| Deseret Purchase p194277 | 35,090,562 | 3,057,429 | 2,922,969 | 3,057,429 | 3,012,609 | 2,284,284 | 2,500,914 | 3,057,429 | 3,057,429 | 3,012,609 | 3,057,429 | 3,012,609 | 3,057,429 |
| Douglas PUD Settlement p38185 | 1,586,965 | 56,219 | 63,012 | 122,891 | 209,601 | 262,373 | 302,079 | 208,553 | 108,265 | 63,393 | 71,891 | 63,688 | 54,998 |
| Gemstate p99489 | 3,173,700 | 259,700 | 256,600 | 261,600 | 256,600 | 256,600 | 256,600 | 256,600 | 275,500 | 256,600 | 279,000 | 298,600 | 259,700 |
| Georgia-Pacific Camas | 8,005,931 | 679,956 | 614,153 | 679,956 | 658,022 | 679,956 | 658,022 | 679,956 | 679,956 | 658,022 | 679,956 | 658,022 | 679,956 |
| Grant County 10 aMW p66274 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Hermiston Purchase p99563 | 88,429,951 | 8,412,540 | 7,652,463 | 7,741,297 | 5,515,954 | 4,518,633 | 4,880,828 | 7,549,362 | 8,329,303 | 7,995,238 | 8,691,946 | 8,414,519 | 8,727,867 |
| Hurricane Purchase p393045 | 124,675 | 10,390 | 10,390 | 10,390 | 10,390 | 10,390 | 10,390 | 10,390 | 10,390 | 10,390 | 10,390 | 10,390 | 10,390 |
| IPP Purchase | 30,332,094 | 2,485,817 | 2,199,792 | 2,121,987 | 1,807,896 | 2,494,627 | 2,710,454 | 2,915,750 | 2,892,791 | 2,042,916 | 3,473,690 | 2,505,671 | 2,680,705 |
| Kennecott Generation Incentive | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LADWP p491303-4 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MagCorp p229846 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MagCorp Reserves p510378 | 5,922,770 | 453,130 | 545,360 | 477,190 | 509,270 | 477,190 | 509,270 | 489,220 | 477,190 | 509,270 | 477,190 | 509,270 | 489,220 |
| Nucor p346856 | 5,763,000 | 480,250 | 480,250 | 480,250 | 480,250 | 480,250 | 480,250 | 480,250 | 480,250 | 480,250 | 480,250 | 480,250 | 480,250 |
| 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 | 270,000 | 22,500 | 22,500 | 22,500 | 22,500 | 22,500 | 22,500 | 22,500 | 22,500 | 22,500 | 22,500 | 22,500 | 22,500 |
| Rock River Wind p100371 | 4,940,853 | 602,477 | 475,465 | 480,833 | 376,185 | 360,263 | 271,745 | 193,727 | 234,387 | 304,450 | 436,506 | 593,879 | 610,937 |
| Small Purchases east | 63,612 | 6,169 | 5,843 | 6,927 | 5,272 | 4,441 | 4,456 | 4,014 | 4,540 | 6,041 | 5,035 | 5,050 | 5,824 |
| Small Purchases west | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Three Buttes Wind p460457 | 20,598,497 | 2,305,957 | 1,595,827 | 2,351,686 | 1,690,904 | 1,714,594 | 1,181,550 | 1,054,247 | 1,080,038 | 1,423,022 | 1,787,220 | 2,006,944 | 2,406,509 |
| Top of the World Wind p522807 | 40,244,943 | 5,293,929 | 3,991,014 | 3,804,691 | 3,095,183 | 2,664,504 | 2,418,361 | 1,930,206 | 2,086,326 | 2,260,849 | 2,895,806 | 4,238,570 | 5,565,507 |
| Tri-State Purchase p27057 | 10,491,879 | 861,466 | 806,628 | 770,828 | 826,750 | 851,604 | 871,364 | 944,589 | 957,739 | 921,614 | 928,153 | 897,193 | 853,952 |
| West Valley Toll | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Wolverine Creek Wind p244520 | 10,148,500 | 752,809 | 592,882 | 1,184,315 | 1,138,353 | 1,108,620 | 863,581 | 843,890 | 791,566 | 736,652 | 637,177 | 834,559 | 664,094 |
| Long Term Firm Purchases Total | 290,828,373 | 27,944,764 | 24,286,994 | 25,767,162 | 21,746,315 | 20,326,634 | 20,023,080 | 22,867,994 | 23,548,632 | 22,745,832 | 26,003,737 | 26,836,225 | 28,731,004 |
| | | | | | | | | | | | | | |
| Seasonal Purchased Power | | | | | | | | | | | | | |
| Constellation 2013-2016 | 6,315,320 | - | - | - | - | - | - | 2,246,608 | 2,207,712 | 1,861,000 | - | - | - |
| | | | | | | | | | | | | | |
| Seasonal Purchased Power Total | 6,315,320 | - | - | - | - | - | - | 2,246,608 | 2,207,712 | 1,861,000 | - | - | - |

PacifiCorp

# _OR TAM CY2014 NPC Study_2013 02 12 (Conf)

**Net Power Cost Analysis**

| 12 months ended December 2014 | 01/14-12/14 | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Qualifying Facilities | | | | | | | | | | | | | |
| QF California | 6,484,251 | 598,463 | 666,890 | 746,700 | 943,655 | 957,277 | 740,437 | 358,398 | 271,530 | 252,291 | 254,890 | 280,015 | 413,703 |
| QF Idaho | 5,761,423 | 400,337 | 364,706 | 442,098 | 485,931 | 608,076 | 681,903 | 586,368 | 470,809 | 421,132 | 447,139 | 437,495 | 415,428 |
| QF Oregon | 28,573,701 | 2,376,158 | 2,199,106 | 2,565,806 | 2,890,102 | 3,078,287 | 2,691,743 | 2,321,342 | 2,192,886 | 2,242,030 | 2,052,721 | 1,805,121 | 2,158,396 |
| QF Utah | 1,479,880 | 102,812 | 108,080 | 124,327 | 136,385 | 146,757 | 151,054 | 129,083 | 125,176 | 109,054 | 123,353 | 124,136 | 99,664 |
| QF Washington | 540,168 | 23,402 | 23,399 | 23,367 | 27,872 | 44,135 | 66,052 | 82,868 | 87,527 | 74,407 | 40,281 | 23,456 | 23,402 |
| QF Wyoming | 820,551 | 33,655 | 32,391 | 31,721 | 50,804 | 106,694 | 107,417 | 115,151 | 115,036 | 104,170 | 58,055 | 32,687 | 32,769 |
| Biomass One QF | 13,959,322 | 1,377,264 | 1,248,655 | 1,377,264 | 669,775 | 681,086 | 662,105 | 1,377,265 | 1,377,264 | 1,109,553 | 1,387,312 | 1,318,590 | 1,373,190 |
| Butter Creek Wind QF | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Chevron Wind p499335 QF | 2,768,349 | 349,376 | 336,640 | 332,339 | 141,314 | 163,665 | 163,950 | 147,450 | 245,924 | 200,165 | 306,517 | 318,301 | 62,708 |
| DCFP p316701 QF | 47,542 | 1,595 | 1,043 | 3,315 | 2,768 | 10,154 | 9,305 | 1,693 | 1,668 | 2,830 | 6,207 | 4,634 | 2,328 |
| Evergreen BioPower p351030 QF | 2,682,014 | 236,910 | 195,953 | 191,475 | 200,081 | 223,997 | 174,525 | 213,861 | 267,963 | 267,963 | 307,378 | 226,040 | 175,869 |
| Five Pine Wind QF | 7,012,206 | 631,658 | 538,807 | 639,592 | 500,428 | 505,233 | 405,386 | 512,743 | 606,087 | 514,693 | 622,867 | 681,952 | 852,759 |
| Mountain Wind 1 p367721 QF | 8,431,982 | 1,201,785 | 767,173 | 777,967 | 597,004 | 500,884 | 359,154 | 403,328 | 530,957 | 623,818 | 723,907 | 845,050 | 1,100,955 |
| Mountain Wind 2 p398449 QF | 12,197,204 | 1,754,283 | 1,073,247 | 1,113,679 | 811,417 | 873,809 | 682,723 | 793,988 | 820,036 | 786,510 | 858,947 | 1,134,646 | 1,493,919 |
| North Point Wind QF | 15,335,660 | 1,368,135 | 1,169,896 | 1,383,212 | 1,098,266 | 1,095,920 | 897,085 | 1,142,745 | 1,345,684 | 1,143,526 | 1,370,851 | 1,474,511 | 1,845,831 |
| OM Power I Geothermal QF | 4,010,196 | 387,630 | 347,151 | 383,340 | 341,740 | 331,705 | 283,772 | 255,303 | 264,429 | 301,315 | 357,096 | 370,301 | 386,415 |
| Oregon Wind Farm QF | 11,336,823 | 673,662 | 730,610 | 910,785 | 1,137,887 | 1,158,337 | 1,316,766 | 1,358,301 | 1,025,768 | 840,222 | 855,736 | 992,837 | 335,915 |
| Pioneer Wind Park II QF | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Power County North Wind QF p5756 | 3,868,758 | 356,889 | 359,953 | 327,469 | 314,542 | 254,641 | 216,337 | 277,290 | 254,274 | 287,790 | 377,388 | 362,609 | 479,577 |
| Power County South Wind QF p5756 | 3,697,973 | 386,215 | 345,660 | 353,814 | 284,212 | 225,443 | 214,395 | 207,730 | 216,431 | 256,866 | 323,318 | 376,389 | 507,501 |
| Roseburg Dillard QF | 1,119,448 | 143,925 | 138,052 | 37,063 | 13,215 | - | - | 147,005 | 177,665 | 179,444 | 32,186 | 68,102 | 182,791 |
| SF Phosphates | 2,414,255 | 167,774 | 159,028 | 207,027 | 214,346 | 172,257 | 209,907 | 248,913 | 224,620 | 233,716 | 220,842 | 178,276 | 177,550 |
| Spanish Fork Wind 2 p311681 QF | 2,802,188 | 179,935 | 197,659 | 172,847 | 164,545 | 170,907 | 239,285 | 292,241 | 346,929 | 281,921 | 229,612 | 250,184 | 276,122 |
| Sunnyside p83997/p59965 QF | 27,321,569 | 2,403,339 | 2,296,550 | 2,370,796 | 1,587,109 | 2,172,215 | 2,397,716 | 2,461,823 | 2,437,939 | 2,348,338 | 2,030,299 | 2,373,713 | 2,441,732 |
| Tesoro QF | 1,442,853 | 123,896 | 111,773 | 123,896 | 120,129 | 120,700 | 116,782 | 120,549 | 120,700 | 116,782 | 124,170 | 119,581 | 123,896 |
| Threemile Canyon Wind QF p50013 | 2,006,794 | 148,827 | 157,145 | 170,988 | 161,551 | 207,934 | 187,916 | 169,522 | 167,323 | 158,196 | 184,118 | 143,383 | 149,892 |
| US Magnesium QF | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Qualifying Facilities Total | 166,115,111 | 15,427,927 | 13,569,566 | 14,810,886 | 12,895,079 | 13,810,115 | 12,975,715 | 13,724,960 | 13,694,625 | 12,856,732 | 13,295,189 | 13,942,007 | 15,112,311 |
| Mid-Columbia Contracts | | | | | | | | | | | | | |
| Douglas - Wells p60828 | 3,662,351 | 303,599 | 303,599 | 303,599 | 303,599 | 303,599 | 303,599 | 303,599 | 303,599 | 308,390 | 308,390 | 308,390 | 308,390 |
| Grant Reasonable | (6,200,845) | (516,737) | (516,737) | (516,737) | (516,737) | (516,737) | (516,737) | (516,737) | (516,737) | (516,737) | (516,737) | (516,737) | (516,737) |
| Grant Surplus p258951 | 1,841,467 | 153,456 | 153,456 | 153,456 | 153,456 | 153,456 | 153,456 | 153,456 | 153,456 | 153,456 | 153,456 | 153,456 | 153,456 |
| Mid-Columbia Contracts Total | (697,026) | (59,682) | (59,682) | (59,682) | (59,682) | (59,682) | (59,682) | (59,682) | (59,682) | (54,892) | (54,892) | (54,892) | (54,892) |
| Total Long Term Firm Purchases | 462,561,778 | 43,313,008 | 37,796,878 | 40,518,366 | 34,581,712 | 34,077,066 | 32,939,113 | 38,779,879 | 39,391,286 | 37,408,672 | 39,244,034 | 40,723,340 | 43,788,424 |

Exhibit PAC/102
Duvall/3

**PacifiCorp**

# _OR TAM CY2014 NPC Study_2013 02 12 (Conf)

**Net Power Cost Analysis**

| 12 months ended December 2014 | 01/14-12/14 | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Storage & Exchange | | | | | | | | | | | | | |
| APS Exchange p58118/s58119 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Black Hills CTs p64676 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| BPA Exchange p64706/p64888 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| BPA FC II Wind p63507 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| BPA FC IV Wind p79207 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| BPA So. Idaho p64885/p83975/p647( | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Cargill p483225/s6 p485390/s89 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 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 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total Storage & Exchange | 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 |
| Short Term Firm Purchases | | | | | | | | | | | | | |
| COB | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Colorado | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Four Corners | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Idaho | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mead | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mid Columbia | 899,640 | - | - | - | 287,280 | 309,960 | 302,400 | - | - | - | - | - | - |
| Mona | - | - | - | - | - | - | - | - | - | - | - | - | - |
| NOB | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Palo Verde | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SP15 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Utah | - | - | - | - | - | - | - | - | - | - | - | - | - |
| West Main | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Wyoming | - | - | - | - | - | - | - | - | - | - | - | - | - |
| STF Electric Swaps | 1,495,629 | (69,420) | 92,520 | 371,670 | 475,176 | 1,123,824 | 1,437,000 | 56,238 | (554,034) | (532,725) | (3,564) | (321,984) | (579,072) |
| STF Index Trades | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total Short Term Firm Purchases | 2,395,269 | (69,420) | 92,520 | 371,670 | 762,456 | 1,433,784 | 1,739,400 | 56,238 | (554,034) | (532,725) | (3,564) | (321,984) | (579,072) |
| System Balancing Purchases | | | | | | | | | | | | | |
| COB | 14,361,248 | 183,727 | 66,755 | 309,157 | 933,448 | 4,709,592 | 3,756,315 | 2,052,108 | 960,365 | 572,922 | 104,304 | 259,146 | 453,411 |
| Four Corners | 9,196,272 | 437,925 | 266,146 | 1,072,799 | 595,176 | 568,097 | 2,584,569 | 1,343,921 | 300,723 | 349,384 | 343,273 | 781,919 | 552,341 |
| Mead | 42,263 | 1,153 | 563 | 3,580 | 308 | 537 | 4,826 | 6,959 | 4,528 | 5,311 | 3,402 | 871 | 10,225 |
| Mid Columbia | 89,554,151 | 458,725 | 1,924,311 | 6,824,872 | 12,858,272 | 13,723,605 | 12,079,985 | 16,944,630 | 16,017,003 | 3,249,806 | 4,597,150 | 380,825 | 494,967 |
| Mona | 29,646,716 | 5,794,169 | 3,476,171 | 5,433,446 | 2,262,641 | 2,177,406 | 1,881,334 | 382,081 | 77,552 | 415,713 | 1,062,482 | 4,024,295 | 2,659,427 |
| NOB | 531,083 | - | - | - | 419 | 100,864 | 205,272 | 42,764 | - | - | 101,174 | 80,590 | - |
| Palo Verde | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SP15 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Emergency Purchases | 20,071 | - | - | - | - | 20,071 | - | - | - | - | - | - | - |
| Total System Balancing Purchases | 143,351,804 | 6,875,699 | 5,733,947 | 13,643,853 | 16,650,264 | 21,300,172 | 20,512,300 | 20,772,462 | 17,360,170 | 4,593,135 | 6,211,785 | 5,527,646 | 4,170,371 |
| **Total Purchased Power & Net Inte** | 613,708,851 | 50,569,287 | 44,073,345 | 54,983,888 | 52,444,431 | 57,261,023 | 55,640,813 | 60,058,579 | 56,647,423 | 41,919,082 | 45,902,255 | 46,379,002 | 47,829,723 |

# _OR TAM CY2014 NPC Study_2013 02 12 (Conf)

**Net Power Cost Analysis**

| 12 months ended December 2014 | 01/14-12/14 | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Wheeling & U. of F. Expense** | | | | | | | | | | | | | |
| Firm Wheeling | 143,491,371 | 12,247,968 | 11,644,201 | 11,844,199 | 12,084,576 | 11,762,006 | 12,796,602 | 12,262,529 | 11,392,038 | 11,657,090 | 11,515,553 | 12,107,058 | 12,177,552 |
| ST Firm & Non-Firm | 45,993 | 8,726 | 5,625 | 3,555 | 1,947 | 2,474 | 3,124 | 1,784 | 1,574 | 826 | 1,011 | 1,055 | 14,292 |
| **Total Wheeling & U. of F. Expense** | 143,537,364 | 12,256,694 | 11,649,825 | 11,847,754 | 12,086,523 | 11,764,480 | 12,799,726 | 12,264,313 | 11,393,613 | 11,657,916 | 11,516,564 | 12,108,113 | 12,191,844 |
| **Coal Fuel Burn Expense** | | | | | | | | | | | | | |
| Carbon | 24,730,775 | 2,191,536 | 2,023,480 | 2,296,847 | 1,989,546 | 1,948,610 | 1,901,204 | 2,162,509 | 2,174,320 | 1,990,287 | 2,095,961 | 1,738,943 | 2,217,532 |
| Cholla | 59,850,901 | 5,285,468 | 4,792,106 | 4,998,916 | 4,727,358 | 4,281,626 | 4,062,394 | 4,881,393 | 5,578,984 | 5,371,289 | 5,325,773 | 5,118,981 | 5,426,613 |
| Colstrip | 16,146,604 | 1,448,635 | 1,307,989 | 1,447,457 | 1,240,449 | 726,325 | 1,380,058 | 1,448,635 | 1,447,457 | 1,401,753 | 1,448,635 | 1,400,575 | 1,448,635 |
| Craig | 23,822,392 | 2,084,474 | 1,882,383 | 2,083,524 | 2,017,111 | 1,379,429 | 2,005,253 | 2,084,474 | 2,083,524 | 2,017,111 | 2,084,474 | 2,016,160 | 2,084,474 |
| Dave Johnston | 61,996,743 | 5,198,558 | 4,976,095 | 4,302,994 | 4,016,571 | 5,106,075 | 5,114,962 | 5,784,537 | 5,844,739 | 5,545,582 | 5,595,964 | 5,238,136 | 5,272,529 |
| Hayden | 14,497,082 | 1,432,366 | 1,295,406 | 1,354,995 | 1,343,455 | 1,365,481 | 1,156,645 | 1,228,048 | 1,414,539 | 914,816 | 670,882 | 927,751 | 1,392,698 |
| Hunter | 168,354,079 | 14,779,699 | 13,500,738 | 11,389,867 | 11,908,687 | 14,024,340 | 13,181,919 | 15,087,697 | 15,302,967 | 14,825,390 | 14,975,019 | 14,352,685 | 15,025,072 |
| Huntington | 120,317,835 | 10,730,658 | 9,761,914 | 10,726,753 | 10,135,592 | 9,846,323 | 9,011,608 | 10,974,148 | 11,389,433 | 9,721,109 | 8,374,830 | 8,725,245 | 10,920,222 |
| Jim Bridger | 198,897,218 | 17,958,327 | 16,636,207 | 17,545,988 | 14,385,910 | 12,085,977 | 13,184,857 | 18,152,080 | 18,182,947 | 16,577,162 | 18,041,269 | 17,758,447 | 18,388,046 |
| Naughton | 108,009,803 | 9,633,416 | 8,777,677 | 6,493,515 | 7,013,162 | 9,291,304 | 9,169,514 | 9,679,190 | 9,713,263 | 9,412,420 | 9,715,925 | 9,387,972 | 9,722,444 |
| Ramp Loss | (1,017,838) | (68,398) | (86,195) | (79,605) | (91,904) | (98,973) | (93,048) | (94,519) | (82,735) | (65,214) | (79,403) | (84,258) | (93,586) |
| Wyodak | 24,836,103 | 2,208,216 | 2,002,517 | 2,210,522 | 2,126,383 | 1,301,258 | 2,015,158 | 2,172,678 | 2,173,980 | 2,103,976 | 2,173,324 | 2,144,920 | 2,203,170 |
| **Total Coal Fuel Burn Expense** | 820,441,697 | 72,882,955 | 66,870,317 | 64,771,776 | 60,812,322 | 61,257,773 | 62,090,523 | 73,560,870 | 75,223,419 | 69,815,680 | 70,422,654 | 68,725,560 | 74,007,849 |
| **Gas Fuel Burn Expense** | | | | | | | | | | | | | |
| Chehalis | 50,020,688 | 4,159,242 | 2,834,725 | 384,749 | 437,704 | - | - | 6,359,268 | 7,643,597 | 7,848,786 | 8,845,402 | 5,508,058 | 5,999,158 |
| Currant Creek | 58,872,142 | 6,304,149 | 6,269,879 | 6,445,538 | 5,388,532 | 4,012,747 | 1,267,829 | 5,580,018 | 6,769,936 | 5,103,997 | 3,612,849 | 3,864,741 | 4,251,928 |
| Gadsby | 3,129,562 | - | - | - | - | - | - | 1,406,537 | 1,723,025 | - | - | - | - |
| Gadsby CT | 5,988,994 | 846,405 | 668,200 | 693,934 | 442,696 | 181,461 | 85,843 | 607,043 | 855,221 | 546,527 | 459,142 | 426,209 | 176,312 |
| Hermiston | 38,651,977 | 4,051,931 | 3,404,246 | 3,387,797 | 1,917,659 | 937,032 | 1,299,938 | 3,325,759 | 4,097,457 | 3,814,674 | 4,144,994 | 3,944,722 | 4,325,769 |
| Lake Side | 80,632,252 | 7,506,791 | 7,060,596 | 7,352,775 | 6,006,751 | 4,885,282 | 4,297,744 | 7,778,927 | 8,782,001 | 8,226,793 | 4,524,957 | 7,403,495 | 6,806,139 |
| Lake Side 2 | 53,593,264 | - | - | - | - | - | 6,180,489 | 7,494,956 | 8,199,681 | 7,752,763 | 7,977,481 | 7,821,284 | 8,166,611 |
| Little Mountain | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Naughton - Gas | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Not Used | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total Gas Fuel Burn | 290,888,880 | 22,868,517 | 20,237,647 | 18,264,793 | 14,193,341 | 10,016,521 | 13,131,842 | 32,552,507 | 38,070,918 | 33,293,541 | 29,564,826 | 28,968,510 | 29,725,917 |
| Gas Physical | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas Swaps | 18,976,176 | 2,516,518 | 2,303,140 | 2,635,434 | (70,950) | (102,610) | (161,100) | 2,380,552 | 2,297,612 | 2,251,830 | 1,703,636 | 1,746,390 | 1,475,724 |
| Clay Basin Gas Storage | 111,251 | (77,613) | (75,239) | (63,942) | 50,863 | 50,863 | 50,863 | 50,863 | 50,863 | 50,863 | 50,863 | 7,558 | (35,554) |
| Pipeline Reservation Fees | 34,933,341 | 2,605,367 | 2,468,415 | 2,605,367 | 3,001,365 | 3,049,746 | 3,001,365 | 3,049,746 | 3,049,746 | 3,001,365 | 3,049,746 | 3,001,365 | 3,049,746 |
| **Total Gas Fuel Burn Expense** | 344,909,647 | 27,912,789 | 24,933,962 | 23,441,653 | 17,174,619 | 13,014,520 | 16,022,971 | 38,033,668 | 43,469,139 | 38,597,599 | 34,369,071 | 33,723,823 | 34,215,832 |
| **Other Generation** | | | | | | | | | | | | | |
| Blundell | 3,374,877 | 302,515 | 273,251 | 302,547 | 274,682 | 238,802 | 266,943 | 275,822 | 275,851 | 275,539 | 293,617 | 292,792 | 302,515 |
| Integration Charge | 3,354,157 | 335,586 | 273,736 | 317,825 | 270,345 | 272,339 | 259,184 | 248,220 | 247,213 | 239,687 | 269,155 | 299,750 | 321,117 |
| **Total Other Generation** | 6,729,034 | 638,101 | 546,988 | 620,371 | 545,027 | 511,140 | 526,127 | 524,043 | 523,064 | 515,226 | 562,773 | 592,542 | 623,632 |
| **Net Power Cost** | **1,457,190,370** | 121,492,109 | 110,707,552 | 120,993,241 | 111,449,584 | 118,900,973 | 120,361,463 | 142,175,961 | 140,248,511 | 117,913,104 | 116,878,582 | 113,893,964 | 122,175,326 |
| **Net Power Cost/Net System Load** | **24.46** | **23.08** | **23.96** | **24.81** | **24.14** | **24.73** | **24.49** | **26.20** | **26.18** | **24.85** | **24.20** | **23.48** | **23.17** |

Exhibit PAC/102
Duvall/5

Docket No. UE 264
Exhibit PAC/103
Witness: Gregory N. Duvall

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Gregory N. Duvall**

**List of Known Contracts Expected to be Updated during the 2014 TAM**

**March 2013**

**List of Known Contracts Expected to be Updated during the 2014 Oregon 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 contracts with interruptible industrial customers Monsanto and Nucor and corresponding impacts on load and allocation factors.
10. New qualifying facility purchase contracts with Chevron Wind, George DeRuyter and Sons Dairy, Duane Wiggins, Lower Valley Energy, Loyd Fery, Paul Lucky, Roseburg Dillard, Roush Hydro, Simplot, Stahlbush.
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. Transmission rates that are impacted by the BPA rate case, based on preliminary Record of Decision in June 2013 and Final Record of Decision in July 2013.
20. Contracts whose prices are linked to market indexes and inflation rates.

<u>Wind Integration</u>

21. Regulating reserve requirement and inter-hour integration cost in 2012 Wind Integration Study updates.

## Coal Expense Update Items

| | | 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 Mine | | | √ | √ | | |
| | BNSF Railway | | | | | √ | √ |
| Colstrip | Westmoreland - Rosebud Mine | | | √ | √ | √ | √ |
| Craig | Trapper Mine | √ | | | | | |
| | Rio Tinto - Colowyo Mine | | | | √ | | |
| | Union Pacific Railway | | | | | | √ |
| Hayden | Peabody - Twentymile Mine | | | √ | √ | | |
| | Union Pacific Railway | | | | | √ | √ |
| 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 | | | | | √ | √ |
| D Johnston | Open Position | | | √ | √ | | |
| | Arch - Coal Creek | | | √ | | | |
| | Cloud Peak - Cordero | | | √ | | | |
| | BNSF Railway | | | | | √ | √ |
| Naughton | Westmoreland - Kemmerer Mine | | | √ | √ | | |
| Wyodak | Black Hills - Wyodak Mine | | | √ | √ | | |

REDACTED
Docket No. UE 264
Exhibit PAC/200
Witness: Cindy A. Crane

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**
**Direct Testimony of Cindy A. Crane**

**March 2013**

**DIRECT TESTIMONY OF CINDY A. CRANE**

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

A. My name is Cindy A. Crane. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. My position is Vice President, Interwest Mining Company and Fuel Resources for PacifiCorp Energy.

## QUALIFICATIONS

**Q. Briefly describe your professional experience.**

A. I joined PacifiCorp in 1990 and have held positions of increasing responsibility, including Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis, and Vice President of Strategy and Division Services. My responsibilities have included the management and development of PacifiCorp's ten-year business plan, assessing individual business strategies for PacifiCorp Energy, managing the construction of the Company's Wyoming wind plants, and assessing the feasibility of a nuclear power plant. In March 2009, I was appointed to my present position as Vice President of Interwest Mining Company and Fuel Resources. In my position I am responsible for the operations of Energy West Mining Company and Bridger Coal Company, as well as overall coal supply acquisition and fuel management for PacifiCorp's coal-fired generating plants.

## PURPOSE AND SUMMARY

**Q. What is the purpose of your testimony?**

A. I explain the Company's overall approach to providing the coal supply for the

Company's coal-fired generating plants and support for the level of coal costs included in fuel expense in this case.

**Q. Please summarize your testimony.**

A. My testimony:

- Explains the primary causes of the $41.2 million total-company coal cost increase reflected in the 2014 Transition Adjustment Mechanism (TAM);
- Provides background on the third-party coal contracts and current contract price reopeners;
- Reviews the Company's affiliate mine coal costs and compares them to other supply alternatives; and
- Demonstrates that Oregon customers benefit from the Company's diversified coal supply strategy.

## OVERVIEW OF THE COMPANY'S COAL SUPPLIES

**Q. How does the Company plan to meet fuel supplies for its coal plants in 2014?**

A. As reflected below in Table 1: *Coal Sourcing*, the Company employs a diversified coal supply strategy. The Company will supply approximately 66.1 percent of its coal requirements from third-party, multi-year contracts and 33.9 percent with coal from the Company's affiliate mines. Approximately 27 percent of the Company's total coal requirements are supplied under fixed-price contracts, 35.2 percent under contracts that escalate or de-escalate based on changes to producer and consumer price indices, and 3.9 percent will be supplied to the Dave Johnston plant from currently unidentified Powder River Basin mines.

**Table 1: Coal Sourcing**

| | Plant | Price Reopener | MMBtu's (000's) | MMBtu's (000's) | |
|---|---|---|---|---|---|
| Captive Mines | | | | | |
| Bridger Coal Company/Bridger | Bridger | | 67,699 | | |
| Energy West/Deer Creek | Utah | | 78,950 | | |
| Trapper Mining Inc/Trapper | Craig | | 8,459 | | |
| Subtotal Captive Mines | | | | 155,108 | 33.9% |
| Fixed Price Contracts | | | | | |
| Rhino Energy/Castle Valley | Utah | | 7,080 | | |
| America West Resources/Horizon | Utah | | - | | |
| Arch/Sufco | Utah | | 53,406 | | |
| Utah American Energy/West Ridge | Utah | | 21,038 | | |
| Arch/Coal Creek | Dave Johnston | | 8,350 | | |
| Cloud Peak - Cordero | Dave Johnston | | 34,000 | | |
| Subtotal Fixed Price Contracts | | | | 123,875 | 27.0% |
| Escalating Contracts | | | | | |
| Ambre Energy/Black Butte | Bridger | | 30,992 | | |
| Peabody/Lee Ranch | Cholla | √ | 27,203 | | |
| Westmoreland/Rosebud | Colstrip | | 12,473 | | |
| Western Fuels/Colowyo | Craig | | 5,199 | | |
| Peabody/Twentymile | Hayden | | 6,254 | | |
| Westmoreland/Kemmerer | Naughton | | 54,095 | | |
| Black Hills/Wyodak | Wyodak | √ | 25,169 | | |
| Subtotal Escalating Contracts | | | | 161,386 | 35.2% |
| Spot/Unidentified Supplies | Dave Johnston | | 17,779 | 17,779 | 3.9% |
| Total Coal Supplies | | | | 458,147 | 100% |

**Q. Please explain how the Company's Utah plants are supplied with coal.**

A. The Utah plants are sourced collectively through a diversified portfolio of coal supplies. While the Deer Creek mine supplies primarily the Huntington plant and a portion of the Hunter plant, the contract coal supplies are typically interchangeable between the plants.

**Q. Why is it important that they be interchangeable?**

A. Interchangeable coal supplies allow the Company to minimize transportation costs between the coal mines and generating plants while ensuring the coal quality blend meets plant quality specifications.

**Q. Table 1 includes spot/unidentified coal for the Dave Johnston plant. Please explain this reference in the context of the current fuel strategy for the Dave Johnston plant.**

A. The Dave Johnston plant is projected to consume approximately 3.5 million tons in 2014; the Company currently has 2.5 million tons of coal for the plant under contract. The Company intends to solicit multi-year coal supplies from Powder River Basin mines during the second quarter of 2013 upon finalization of the transportation contract with the Burlington Northern Santa Fe Railway Company (BNSF), discussed below.

## COAL COST INCREASES IN THE 2014 TAM

**Q. Do coal costs in the 2014 TAM reflect an increase from cost levels reflected in the Company's previous TAM, docket UE 245 (2013 TAM)?**

A. Yes. As mentioned in the testimony of Mr. Gregory N. Duvall, test period coal costs have increased on a total-company basis from $779.3 million in the final update in the 2013 TAM update to $820.4 million in the 2014 TAM, an increase of $41.2 million. The increase related to higher coal prices is approximately $53.5 million; the decrease relating to reduced coal-fired generation is approximately $12.3 million.

**Q. What are the primary drivers of the $53.5 million increase in coal prices?**

A. Approximately $16.5 million of the increase is associated with third-party coal purchases and transportation costs, $36.7 million is associated with the Company's affiliated mines and $0.3 million is associated with increased operating costs at the Hunter prep plant.

## THIRD-PARTY COAL COSTS

**Q. Please identify the major aspects of the $16.5 million increase in third-party coal supplies.**

A. The Company expects third-party coal supply cost increases at all of the plants, as set forth below:

**Table 3: Contract Prices**

| Plant | Contract | Millions ($) |
|---|---|---|
| Cholla | Lee Ranch Rail and Coal Cost Increase | [redacted] |
| Wyodak | Wyodak Contract Price Increase | |
| Dave Johnston | Lower Powder River Basin Prices | |
| Dave Johnston | BNSF Rail Rate Increase | |
| Naughton | Kemmerer Mine Price Increase | |
| Utah | West Ridge, Sufco, Castle Valley Coal Cost Increases | |
| Bridger | Black Butte Rail and Coal Cost Increase | |
| Hayden | Peabody Contract Replacement | |
| Colstrip | Rosebud Mine Cost Increase | |
| Other | | |
| Total Contract Cost Increases | | |

### Coal Supply Agreements for the Wyoming Plants

#### *Wyodak*

**Q. Please describe the increase relating to the Wyodak contract.**

A. Black Hills Corporation subsidiary, Wyodak Resources Development Company, has been the exclusive coal supplier to the Wyodak plant since it was placed in service in 1978. A contract dispute between Wyodak Resources and the Company over the billing of severance and ad valorem taxes and federal royalties resulted in the New Restated and Amended Coal Supply Agreement dated January 2001.

The previous coal supply agreement, Further Restated and Amended Coal Supply Agreement dated May 5, 1987, contemplated a June 8, 2013 termination with an option for the Company to extend the coal supply agreement for an additional 10 years, to June 8, 2023, at a coal price based upon "fair market value."

The Company was able to secure an approximate [redacted] per ton reduction in the Wyodak coal price starting in 2001 under the New Restated and Amended Coal Supply Agreement. As part of the settlement, the Company exercised its extension option provided under the 1987 agreement. The contract was extended through 2022, which reflected the depreciable life of the Wyodak plant at that time. The settlement also incorporated the fair market valuation contemplated in the 1987 agreement with two price reopeners: July 1, 2014, and July 1, 2019.

**Q. Please explain how the Wyodak coal price is reset under the July 1, 2014 price reopener.**

A. The agreement provides for the purchase coal price to be set equal to the sum of the spot price of Powder River Basin 8400 Btu coal, average rail transportation costs from the two closest Powder River Basin mines to the Wyodak plant in railroad supplied railcars, and a levelized fixed charge associated with construction of a hypothetical rail unloading facility amortized on a straight-line basis over 20 years.

**Q. Did the Company retain an engineering firm to analyze the costs required to construct a rail unloading facility?**

A. Yes. The Company retained Burns & McDonnell Engineering Company to perform a feasibility study of a new railcar unloading facility, stockout, and transferring facilities at the Wyodak plant. Burns & McDonnell developed two cost estimates in 2012 dollars: [redacted] including a [redacted] located at the Wyodak plant and [redacted] absent the [redacted]. The lower figure was used to develop test period costs.

**Q. Have you identified the overall increase in Wyodak plant costs as a result of the price reopener?**

A. Yes. Based on the current forward price for Powder River Basin 8400 Btu coal and a projection of rail rates, as well as the [redacted] rail unloading facility, the Company projects the contract price to increase by approximately [redacted] per ton on July 1, 2014, to [redacted] per ton. This July 1, 2014 price reset accounts for approximately [redacted] of the overall [redacted] Wyodak coal price increase. The remainder of the increase is associated with escalation reflecting monthly changes in contract-specific producer and consumer price increases, and production taxes and royalties.

**Q. Do you anticipate updating the Wyodak coal prices in rebuttal testimony?**

A. Yes. The Company expects to engage Wyodak Resources Development Company in contract negotiations during the second quarter for the rail unloading facility. Additionally, the contract defines the Powder River Basin 8400 Btu coal price as the spot price for Powder River Basin coal as published by Coal Daily during the period of April 2013 to March 2014. The spot coal prices will be refreshed before the rebuttal update.

***Naughton***

**Q. Please explain the [redacted] million increase in Kemmerer mine costs compared to the 2013 TAM.**

A. Coal costs at the Naughton generating plant will increase from [redacted] per ton to [redacted] per ton in the 2014 TAM, an increase of a [redacted] per ton, or [redacted]. The contract price under the Company's contract with the Kemmerer mine adjusts with changes in contract-specific producer and consumer price indices, as well as production taxes and royalties. Higher diesel fuel expense and mining machinery and equipment costs were the primary drivers of the cost increase.

***Bridger***

**Q. Please explain the [redacted] million increase in Black Butte costs.**

A. The delivered cost of Black Butte coal to the Jim Bridger generating plant has increased to [redacted] per ton in the 2013 TAM to [redacted] per ton, an increase of [redacted] per ton. Approximately [redacted] per ton is associated with higher Free-On-Board (F.O.B.) mine costs, and [redacted] per ton is associated with application of an anti-freezing agent during the winter months.

***Dave Johnston***

**Q. Does the 2014 TAM reflect an increase in Dave Johnston generating plant coal supply costs?**

A. The Initial Filing in this case does not reflect an increase in coal supply costs for the Dave Johnston plant.

**Q. What is the status of the rail transportation agreement with the BNSF for service to the Dave Johnston plant?**

A. The current rail service for the Dave Johnston plant, executed in January 1998, expires December 31, 2013. The Company has been in negotiations with the BNSF regarding a new multi-year transportation agreement for the Dave Johnston plant.

**Q. What costs have been incorporated in the Company's filing for Dave Johnston rail rates and spot market supply?**

A. The 2014 TAM incorporates the BNSF counter-proposal from January 29, 2013. The coal price for Dave Johnston's spot coal in the 2014 TAM reflects the forward price for Powder River Basin 8400 Btu coal as of January 25, 2013. Based on the BNSF's proposal, rail rates will increase [redacted] per ton, from [redacted] per ton in the 2013 TAM to [redacted] per ton in the 2014 TAM. This increase, however, is offset by the lower commodity price for Powder River Basin 8400 Btu coal. The Company plans to update both rail rates and spot market supply costs in the Company's Rebuttal update.

**Coal Supply Agreements for the Utah Plants**

**Q. Which non-affiliated mines will supply coal to the Company's Utah plants in 2014?**

A. The Company has a diversified portfolio of multi-year coal supply agreements with Arch's Sufco mine, Utah American Energy's West Ridge mine, Rhino Energy's Castle Valley Mine, and America West Resources' Horizon Mine.

America West, however, has not supplied coal since June 2012 and has filed for bankruptcy.

**Q. Have prices for coal supply to the Utah plants increased above levels reflected in the 2013 TAM?**

A. Yes. Collectively, coal supply costs have increased by approximately $2.7 million over the 2013 TAM. Both the West Ridge and Castle Valley supply agreements provide for annual fixed price increases, F.O.B.: Castle Valley from [redacted] per ton to [redacted] per ton, and West Ridge from [redacted] per ton to [redacted] per ton. The Company's coal supply agreement with Sufco is escalated based on the annual change in the GDP-IPD and increased slightly by [redacted] per ton above the prior TAM.

**Coal Supply Agreements for the Joint-Owned Plants**

**Q. Please describe the coal supply arrangements for the Cholla plant.**

A. The Cholla plant is supplied under a long-term coal supply agreement with Peabody's Lee Ranch/El Segundo mine complex through 2024. The long-term contract was the result of a request for proposals issued in May 2005. Historically, the plant had been supplied almost entirely from Pittsburg & Midway's McKinley mine; however, McKinley's impending reserve depletion required the Cholla plant owners to elect a new fueling source. Peabody's proposal for the Cholla plant included two price reopeners: January 1, 2013, and January 1, 2018.

**Q. How are prices adjusted under the Peabody contract price reopener?**

A. The contract allows for either party to request renegotiation of the contract price by providing written notice to the other Party no later than 90 days and no earlier than six months before the price reopener effective date. Peabody provided this notice in July 2012. The renegotiated price must adjust for changes in alignment between contract escalators and El Segundo mining costs, subject to independent verification, and may not adjust for production-related cost changes that were known at the time of signing the original contract.

**Q. What is the status of current negotiations with Peabody?**

A. The Cholla plant owners have maintained discussions with Peabody. Based on the operating cost information provided, Peabody has yet to demonstrate that the contract indices are not in alignment with El Segundo mining costs, although Peabody continues to assert otherwise. Given this disagreement, the dispute has been forwarded to senior management in accordance with the contract terms. If senior management is unable to achieve a resolution, then either Peabody or the Cholla plant owners may pursue legal remedies under the contract.

**Q. What price has the Company assumed for Cholla in the test period?**

A. Based upon the Company's assessment of the most likely outcome in current negotiations with Peabody, the Company forecasts that delivered coal costs will increase from [redacted] per ton in the 2013 TAM to [redacted] per ton in the current TAM, an increase of [redacted] per ton, with the contract reopener accounting for [redacted] of this amount or [redacted] percent of the F.O.B. coal price. The remainder is primarily attributable to increased royalties resulting from more coal production from federal coal leases.

Despite the current disagreement between the parties, the Company anticipates that the Cholla plant owners and Peabody will likely reach settlement before the 2014 TAM Rebuttal update. The Company will update its Cholla coal supply costs at that time.

**Q. Do most of the Company's long-term contracts include some price reopener or price reset?**

A. Yes. Most of the Company's long-term coal supply agreements have a price reopener or price reset, which protects both parties. Considering the 19-year contract term of the Cholla coal supply agreement, multiple reopeners would be standard.

**Q. Did the Company include any increase for the Cholla contract reopener in the 2013 TAM?**

A. No, the Company had not received any supporting documentation from Peabody at the time the Rebuttal update was prepared.

**Q. Has the Hayden plant's coal cost changed from the 2013 TAM update?**

A. Yes, delivered coal prices have increased from [redacted] per ton to [redacted] per ton, an increase of [redacted] per ton or [redacted] million. In addition to the quarterly contract escalation, the coal contract provides for a fixed [redacted] per ton increase effective January 1, 2014.

**Q. Please explain the [redacted] million increase in Colstrip test period costs.**

A. Colstrip costs have increased from [redacted] per ton to [redacted] per ton, or [redacted] per ton. Colstrip costs are developed based on Western Energy's Annual Operating Plan (AOP) for the Rosebud mine. The AOP is reviewed and approved annually by the Colstrip Unit 3 & 4 owners. The increase in 2014 is primarily attributable to an increase in Rosebud's depreciation expense.

**Captive Mine Costs**

**Q. Please explain the increase associated with the captive mines.**

A. Deer Creek mine production costs have increased from [redacted] per ton to [redacted] per ton, an increase of [redacted] per ton. Bridger mine costs have increased from [redacted] per ton to [redacted] per ton, an increase of [redacted] per ton, and Trapper mine costs have decreased from [redacted] to [redacted] per ton, or [redacted] per ton. These changes result in the following increases:

**Table 2: Captive Mine Cost Increase**

| | Millions ($) |
|---|---|
| Captive Mines | [redacted] |
| Bridger Coal Company | |
| Deer Creek | |
| Prep Plant | |
| Trapper | |
| Total Captive Cost Increase | |

***Bridger Coal Company***

**Q. Please describe the change in Bridger Coal Company coal costs.**

A. Bridger Coal Company costs have increased by approximately [redacted] million over the 2013 TAM. Bridger Coal Company test period costs have increased from [redacted] per ton to [redacted] per ton, an increase of [redacted] per ton or [redacted] million. An increase in Bridger coal's heat content accounts for a [redacted] million decrease.

**Q. Have Bridger Coal Company's production levels changed?**

A. Yes. Bridger Coal Company's production has decreased from 6.0 million tons in the 2013 TAM to 5.6 million tons in the current test period: surface coal production decreased by approximately 275,426 tons, and underground coal production decreased 124,577 less tons.

**Q. Please explain the [redacted] per ton increase in Bridger coal costs.**

A. In addition to the impact of reduced production, there are three other primary drivers of the cost increase: increased contribution levels to the final reclamation trust; a reduction in final reclamation work in 2014 compared to 2013; and a change in mine inventory levels.

**Q. How much of the overall increase is associated with increased final reclamation trust contributions?**

A. Approximately [redacted] per ton. The Bridger Coal Company owners established a final reclamation trust in 1989 to fund actual final reclamation work. As part of its current long-range mine planning efforts, Bridger Coal Company has updated its final reclamation plan. The increase in trust contributions is necessary to ensure sufficient funds exist in the trust to support final reclamation activities during and after the mine ceases production.

**Q. Will Bridger Coal Company perform the same level of final reclamation in 2014 as in the 2013 TAM?**

A. No. Actual final reclamation, measured in cubic yards, will decrease from 21.4 million in the 2013 TAM to 6.6 million in the current TAM. Since the cash operating costs associated with final reclamation are debited against the final reclamation liability, the decrease in final reclamation volume results in a reduction in operating costs charged to the final reclamation and a corresponding increase in Bridger Coal Company's mine operating costs. Test period costs have increased by approximately [redacted] per ton because only [redacted] million is being debited to final reclamation in 2014 TAM compared to the [redacted] million debited in the 2013 TAM.

**Q. Have Bridger Coal Company inventory levels for the underground mine changed from the 2013 TAM?**

A. Yes. The 2013 TAM reflected underground mine inventory to significantly increase (384,991 tons) during the year. Comparatively, underground inventory levels are projected to increase by 98,033 tons in the 2014 TAM. With the 2013 TAM, the increase in underground inventory levels resulted in approximately $6 million being charged to coal inventory rather than 2013 operating costs; only $0.3 million is being charged in the 2014 TAM. The difference in amounts allocated to coal inventory in the respective TAMs results in an approximately [redacted] per ton increase in mine operating costs.

**Q. How do Bridger Coal Company costs compare to the Company's other supply options?**

A. Test period delivered costs of coal supply from Bridger Coal Company are comparable to prices under the current Black Butte contract ([redacted] per ton and [redacted], respectively).

***Deer Creek Mine***

**Q. Please describe the [redacted] million increase related to Deer Creek mine production costs.**

A. Deer Creek mine production costs are projected to increase from [redacted] per ton in the prior TAM to [redacted] per ton in the current filing, an increase of [redacted] per ton.

There are four primary drivers for the Deer Creek cost increase: (1) reduced coal production; (2) increased depreciation expense; (3) increased post-retirement expense; and (3) increased royalty expense. Deer Creek's coal production is projected to be approximately 288,000 tons lower in the current test period; the lower production accounts for approximately [redacted] per ton of the [redacted] per ton increase.

**Q. How much is depreciation, depletion, and amortization expense increasing?**

A. Depreciation is increasing by [redacted] per ton. The increase in depreciation expense is the result of the new depreciation rates that reflect a reduced economic life of the Deer Creek mine. The new life of mine plan for Deer Creek reflects depletion of economically recoverable reserves in December 2019.

**Q. How is the Deer Creek mine life in the 2014 TAM different than what was reflected the 2013 TAM?**

A. The 2013 TAM reflected a September 2021 end to the mine's economic life. As a result of an ongoing drilling program, Energy West personnel have identified reserve areas in the mine that are not economically recoverable due to extremely high ash content or contain minimal inner burden between the Hiawatha and Blind Canyon seams. The drilling program identified ash content levels as high as 20 percent; Deer Creek's ash content typically ranges between 12 percent to 14 percent. The areas of minimal inner burden present roof control concerns. Having already mined the upper Blind Canyon seam, the thin level of inner burden, could result in collapse of the roof during mining of the Hiawatha seam.

Obtaining approval of roof control and ventilation plans from the Mining Safety Health and Administration in thinning inner burden mining areas is unlikely.

**Q. Is the December 2019 depreciable life for the Deer Creek mine consistent with the Company's recently filed application to approve its new Depreciation Study in docket UM 1647?**

A, Yes. The Company filed its new depreciation study in Oregon on January 31, 2013 in docket UM 1647. The depreciable life and depreciation rates for the Deer Creek mine in the 2014 TAM filing are consistent with the rates the Company proposed in docket UM 1647.

**Q. Why are Deer Creek's post-retirement benefits changing?**

A. Deer Creek mine production costs include projected post retirement benefits expense based on actuarial evaluations. The 2014 post-retirement expenses were prepared by Aon Hewitt in 2012. Test period costs have increased from [redacted] million in the 2013 TAM to [redacted] million in the 2014 TAM, or a [redacted] per ton increase.

**Q. Do the above cost increases impact Deer Creek's royalty expenses?**

A. Yes. The Company's royalty obligations are determined by adding a return on net mine investment to actual mine operating costs. The above increases result in additional royalty expense, approximately [redacted] per ton.

**Q. How do Deer Creek mine costs compare to the Company's other Utah supplies?**

A. The weighted average delivered cost of Deer Creek coal in the current test period to the Hunter and Huntington plants is approximately [redacted] per ton, which is almost [redacted] per ton less than the delivered cost of West Ridge coal to Hunter and Huntington and approximates the 2014 cost of Sufco coal to the Huntington plant.

**Q. Have Trapper mine costs changed from the 2013 TAM?**

A. Trapper mine costs have decreased from [redacted] per ton in the 2013 TAM to [redacted] per ton in the 2014 TAM, a decrease of [redacted] per ton primarily due to lower stripping costs.

**Q. How does the Company's Trapper mine compare to other alternatives?**

A. Favorably. Trapper's test period costs are considerably less than any of the Company's other Colorado coal supplies. The price is roughly [redacted] per ton less than the [redacted] per ton delivered price of Colowyo coal to the Craig plant and approximately [redacted] per ton less than the delivered coal price of Twentymile coal to the Hayden plant.

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

A. Customers have significantly benefited from the Company's diversified fueling strategy. The Company has pursued a diversified coal supply strategy, relying on fixed contracts, indexed contracts and affiliate-owned coal mines to meet the fuel needs of its coal-fired generating plants. While coal costs have increased in this case as a result of various factors, the Company's strategy has resulted in a long-term, stable and low-cost supply of coal for its customers.

**Q. Does this conclude your direct testimony?**

A. Yes.

Docket No. UE 264
Exhibit PAC/300
Witness: Judith M. Ridenour

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Direct Testimony of Judith M. Ridenour**

**March 2013**

**DIRECT TESTIMONY OF JUDITH M. RIDENOUR**

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**ATTACHED EXHIBITS**

Exhibit PAC/301 – Proposed TAM Rate Spread and Rates

Exhibit PAC/302 – Proposed Tariffs

Exhibit PAC/303 - Estimated Effect of Proposed TAM Price Change

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or 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 Specialist, Pricing & Cost of Service, in the Regulation Department.

**QUALIFICATIONS**

**Q. Briefly describe your education and professional experience.**

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, docket UE 246 (2012 Rate Case) and Transition Adjustment Mechanism (TAM), docket UE 245 (2013 TAM).

**PURPOSE OF TESTIMONY**

**Q. What is the purpose of your testimony?**

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

## TAM DESIGN AND PROPOSED TARIFFS

**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, because this TAM is filed concurrently with the Company's 2013 general rate case (2013 Rate Case), the rate design test year for the TAM is the rate design test year for the 2013 Rate Case, which is the forecast 12 months ending December 31, 2014.

**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 2013 Rate Case. This methodology accurately allocates NPC to each customer class and ensures synchronization between the TAM and rate case. The spread of the proposed NPC to the customer classes is shown in page one of Exhibit PAC/301.

**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/301 show the present and proposed Schedule 201 rates and revenues.

**Q. Is the proposed Schedule 201 rate design 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 use 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 2013 Rate Case.

**Q. Please describe Exhibit PAC/302.**

A. Exhibit PAC/302 contains the revised tariff Schedule 201, Net Power Costs, Cost-Based Supply Service along with proposed housekeeping revisions to the Transition Adjustment tariffs, Schedules 294 and 295.

**Q. What changes has the Company proposed for the Transition Adjustment tariffs?**

A. The Company is proposing changes to the language in Transition Adjustment tariffs 294 and 295 to better align the two tariffs and to clarify the applicability of the tariff rates. As in past years, the Company will file changes to the rate sections of the Transition Adjustment tariffs once the final TAM rates have been posted and are known. The Transition Adjustment rates will be established in November, just before the open enrollment window.

## COMPARISON OF PRESENT AND PROPOSED CUSTOMER RATES

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

A. The overall proposed effect is a decrease to rates of -0.1 percent on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/303 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 that shows the impact on customer bills as a result of the proposed changes to Schedule 201?**

A. Yes. Exhibit PAC/303 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 900 kilowatt-hours per month is a bill decrease of -$0.31.

**Q. Does this conclude your direct testimony?**

A. Yes.

Docket No. UE 264
Exhibit PAC/301
Witness: Judith M. Ridenour

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Judith M. Ridenour**

**Proposed TAM Rate Spread and Rates**

**March 2013**

**PACIFIC POWER**
**STATE OF OREGON**
**Functionalized Net Power Cost Revenue Requirement**
**Forecast 12 Months Ended December 31, 2014**
**Dollars in Thousands**

| | | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | **Residential** | **General Service** | | **General Service** | | **General Service** | | **Large Power Service** | | | **Irrigation** | **Street Lgt.** |
| | | Total | | Sch 23 | | Sch 28 | | Sch 30 | | Sch 48T | | | Sch 41 | Sch 51, 53, 54 |
| Line | Description | | (sec) | (sec) | (pri) | (sec) | (pri) | (sec) | (pri) | (sec) | (pri) | (trn) | | |
| 1 | Functionalized Generation Revenue Requirement from GRC | $747,123 | $315,584 | $64,163 | $63 | $115,362 | $1,030 | $71,457 | $5,170 | $33,171 | $84,778 | $42,586 | $12,830 | $928 |
| 2 | | | | | | | | | | | | | | |
| 3 | Net Power Cost Revenue Requirement | $363,112 | | | | | | | | | | | | |
| 4 | Net Power Cost Collection for Schedules not included in COS Study* | $4,370 | | | | | | | | | | | | |
| 5 | Net Power Cost for Schedules Included in COS Study | $358,742 | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | |
| 8 | Generation Allocation Factors from GRC | 100.00% | 42.24% | 8.59% | 0.01% | 15.44% | 0.14% | 9.56% | 0.69% | 4.44% | 11.35% | 5.70% | 1.72% | 0.12% |
| 9 | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | |
| 11 | **Functionalized Net Power Cost Revenue Requirement- (Target)** | **$358,742** | **$151,532** | **$30,809** | **$30** | **$55,393** | **$494** | **$34,311** | **$2,483** | **$15,928** | **$40,708** | **$20,448** | **$6,161** | **$446** |
| 12 | Other Generation Revenue Requirement - (Target) | $388,381 | $164,052 | $33,354 | $33 | $59,969 | $535 | $37,146 | $2,688 | $17,244 | $44,071 | $22,138 | $6,670 | $483 |
| 13 | Sum | $747,123 | $315,584 | $64,163 | $63 | $115,362 | $1,030 | $71,457 | $5,170 | $33,171 | $84,778 | $42,586 | $12,830 | $928 |

*Revenues by rate schedule as follow:

| | |
|---|---|
| Schedule 47 Primary | $3,303 |
| Schedule 47 Transmission | $457 |
| Schedule 15 | $211 |
| Schedule 50 | $146 |
| Schedule 51 (partial) | $241 |
| Schedule 52 | $12 |
| Total not in study | $4,370 |

Exhibit PAC/301
Ridenour/1

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

**Forecast 12 Months Ended December 31, 2014**

| | | Present Schedule 201 | | Proposed Schedule 201 | |
|---|---|---|---|---|---|
| Rate Schedule | Forecast Energy | Rates | Revenues | Rates | Revenues |
| **Schedule 4, Residential** | | | | | |
| First Block kWh (0-1,000) | 3,976,721,700 | 2.606 ¢ | $103,633,368 | 2.572 ¢ | $102,281,282 |
| Second Block kWh (> 1,000) | 1,402,846,969 | 3.559 ¢ | $49,927,324 | 3.512 ¢ | $49,267,986 |
| | 5,379,568,669 | | $153,560,692 | | $151,549,268 |
| | | | | Change | -$2,011,424 |
| **Schedule 23, Small General Service** | | | | | |
| Secondary Voltage | | | | | |
| 1st 3,000 kWh, per kWh | 854,629,409 | 2.930 ¢ | $25,040,642 | 2.972 ¢ | $25,399,586 |
| All additional kWh, per kWh | 245,180,628 | 2.173 ¢ | $5,327,775 | 2.204 ¢ | $5,403,781 |
| | 1,099,810,037 | | $30,368,417 | | $30,803,367 |
| | | | | Change | $434,950 |
| Primary Voltage | | | | | |
| 1st 3,000 kWh, per kWh | 792,413 | 2.838 ¢ | $22,489 | 2.879 ¢ | $22,814 |
| All additional kWh, per kWh | 354,704 | 2.106 ¢ | $7,470 | 2.137 ¢ | $7,580 |
| | 1,147,117 | | $29,959 | | $30,394 |
| | | | | Change | $435 |
| **Schedule 28, General Service 31-200kW** | | | | | |
| Secondary Voltage | | | | | |
| 1st 20,000 kWh, per kWh | 1,402,035,556 | 2.891 ¢ | $40,532,848 | 2.828 ¢ | $39,649,566 |
| All additional kWh, per kWh | 572,241,543 | 2.812 ¢ | $16,091,432 | 2.751 ¢ | $15,742,365 |
| | 1,974,277,099 | | $56,624,280 | | $55,391,931 |
| | | | | Change | -$1,232,349 |
| Primary Voltage | | | | | |
| 1st 20,000 kWh, per kWh | 9,746,389 | 2.787 ¢ | $271,632 | 2.697 ¢ | $262,860 |
| All additional kWh, per kWh | 8,827,384 | 2.712 ¢ | $239,399 | 2.624 ¢ | $231,631 |
| | 18,573,773 | | $511,031 | | $494,491 |
| | | | | Change | -$16,540 |
| **Schedule 30, General Service 201-999kW** | | | | | |
| Secondary Voltage | | | | | |
| 1st 20,000 kWh, per kWh | 180,025,326 | 3.095 ¢ | $5,571,784 | 3.106 ¢ | $5,591,587 |
| All additional kWh, per kWh | 1,066,138,835 | 2.684 ¢ | $28,615,166 | 2.694 ¢ | $28,721,780 |
| | 1,246,164,161 | | $34,186,950 | | $34,313,367 |
| | | | | Change | $126,417 |
| Primary Voltage | | | | | |
| 1st 20,000 kWh, per kWh | 12,257,555 | 3.064 ¢ | $375,571 | 3.071 ¢ | $376,430 |
| All additional kWh, per kWh | 79,340,490 | 2.649 ¢ | $2,101,730 | 2.655 ¢ | $2,106,490 |
| | 91,598,045 | | $2,477,301 | | $2,482,920 |
| | | | | Change | $5,619 |
| **Schedule 41, Agricultural Pumping Service** | | | | | |
| Secondary Voltage | | | | | |
| Winter, 1st 100 kWh/kW, per kWh | 2,861,725 | 4.050 ¢ | $115,900 | 3.886 ¢ | $111,207 |
| Winter, All additional kWh, per kWh | 2,445,439 | 2.759 ¢ | $67,470 | 2.647 ¢ | $64,731 |
| Summer, All kWh, per kWh | 225,681,647 | 2.759 ¢ | $6,226,557 | 2.647 ¢ | $5,973,793 |
| | 230,988,811 | | $6,409,927 | | $6,149,731 |
| | | | | Change | -$260,196 |
| Primary Voltage | | | | | |
| Winter, 1st 100 kWh/kW, per kWh | 9,811 | 3.922 ¢ | $385 | 3.763 ¢ | $369 |
| Winter, All additional kWh, per kWh | 56,114 | 2.672 ¢ | $1,499 | 2.564 ¢ | $1,439 |
| Summer, All kWh, per kWh | 348,776 | 2.672 ¢ | $9,319 | 2.564 ¢ | $8,943 |
| | 414,701 | | $11,203 | | $10,751 |
| | | | | Change | -$452 |
| **Schedule 47, Large General Service, Partial Requirements 1,000kW and over** | | | | | |
| Primary Voltage | | | | | |
| On-Peak, per on-peak kWh | 84,413,283 | 2.609 ¢ | $2,202,343 | 2.681 ¢ | $2,263,120 |
| Off-Peak, per off-peak kWh | 39,529,056 | 2.559 ¢ | $1,011,549 | 2.631 ¢ | $1,040,009 |
| | 123,942,339 | | $3,213,892 | | $3,303,129 |
| | | | | Change | $89,237 |
| Transmission Voltage | | | | | |
| On-Peak, per on-peak kWh | 10,531,685 | 2.429 ¢ | $255,815 | 2.485 ¢ | $261,712 |
| Off-Peak, per off-peak kWh | 8,003,363 | 2.379 ¢ | $190,400 | 2.435 ¢ | $194,882 |
| | 18,535,048 | | $446,215 | | $456,594 |
| | | | | Change | $10,379 |

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

**Forecast 12 Months Ended December 31, 2014**

| Rate Schedule | Forecast Energy | Present Schedule 201 Rates | Present Schedule 201 Revenues | Proposed Schedule 201 Rates | Proposed Schedule 201 Revenues |
|---|---|---|---|---|---|
| **Schedule 48, Large General Service, 1,000kW and over** | | | | | |
| Secondary Voltage | | | | | |
| On-Peak, per on-peak kWh | 370,279,657 | 2.730 ¢ | $10,108,635 | 2.784 ¢ | $10,308,586 |
| Off-Peak, per off-peak kWh | 205,466,197 | 2.680 ¢ | $5,506,494 | 2.734 ¢ | $5,617,446 |
| | 575,745,854 | | $15,615,129 | | $15,926,032 |
| | | | | Change | $310,903 |
| Primary Voltage | | | | | |
| On-Peak, per on-peak kWh | 943,087,671 | 2.609 ¢ | $24,605,157 | 2.681 ¢ | $25,284,180 |
| Off-Peak, per off-peak kWh | 586,385,011 | 2.559 ¢ | $15,005,592 | 2.631 ¢ | $15,427,790 |
| | 1,529,472,682 | | $39,610,749 | | $40,711,970 |
| | | | | Change | $1,101,221 |
| Transmission Voltage | | | | | |
| On-Peak, per on-peak kWh | 472,809,887 | 2.429 ¢ | $11,484,552 | 2.485 ¢ | $11,749,326 |
| Off-Peak, per off-peak kWh | 357,086,194 | 2.379 ¢ | $8,495,081 | 2.435 ¢ | $8,695,049 |
| | 829,896,081 | | $19,979,633 | | $20,444,375 |
| | | | | Change | $464,742 |
| **Schedule 15, Outdoor Area Lighting Service** | | | | | |
| Secondary Voltage | | | | | |
| All kWh, per kWh | 9,286,499 | 2.287 ¢ | $212,447 | 2.275 ¢ | $211,314 |
| | 9,286,499 | | $212,447 | | $211,314 |
| | | | | Change | -$1,133 |
| **Schedule 50, Mercury Vapor Street Lighting Service** | | | | | |
| Secondary Voltage | | | | | |
| All kWh, per kWh | 7,823,337 | 1.880 ¢ | $147,131 | 1.870 ¢ | $146,235 |
| | 7,823,337 | | $147,131 | | $146,235 |
| | | | | Change | -$896 |
| **Schedule 51, 55, Street Lighting Service, Company-Owned System** | | | | | |
| Secondary Voltage | | | | | |
| All kWh, per kWh | 19,612,310 | 2.967 ¢ | $582,552 | 2.951 ¢ | $578,817 |
| | 19,612,310 | | $582,552 | | $578,817 |
| | | | | Change | -$3,735 |
| **Schedule 52, Street Lighting Service, Company-Owned System** | | | | | |
| Secondary Voltage | | | | | |
| All kWh, per kWh | 523,143 | 2.273 ¢ | $11,891 | 2.261 ¢ | $11,828 |
| | 523,143 | | $11,891 | | $11,828 |
| | | | | Change | -$63 |
| **Schedule 53, Street Lighting Service, Consumer-Owned System** | | | | | |
| Secondary Voltage | | | | | |
| All kWh, per kWh | 8,966,764 | 0.970 ¢ | $86,978 | 0.965 ¢ | $86,529 |
| | 8,966,764 | | $86,978 | | $86,529 |
| | | | | Change | -$448 |
| **Schedule 54, Recreational Field Lighting** | | | | | |
| Secondary Voltage | | | | | |
| All kWh, per kWh | 1,249,347 | 1.672 ¢ | $20,889 | 1.663 ¢ | $20,777 |
| | 1,249,347 | | $20,889 | | $20,777 |
| | | | | Change | -$112 |
| **TOTAL** | **13,167,595,817** | | **$364,107,266** | | **$363,123,820** |
| | | | | **Change** | **-$983,445** |
| Schedule 47 Unscheduled kWh | 1,374,749 | | | | |
| Total Forecast kWH | 13,168,970,566 | | | | |

Docket No. UE 264
Exhibit PAC/302
Witness: Judith M. Ridenour

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Judith M. Ridenour**

**Proposed Tariffs**

**March 2013**

**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 | 2.572¢ | | | (R) |
| | | > 1000 kWh | 3.512¢ | | | (R) |
| 5 | Per kWh | 0-1000 kWh | 2.572¢ | | | (R) |
| | | > 1000 kWh | 3.512¢ | | | (R) |

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

| | | Secondary | Primary | Transmission | |
|---|---|---|---|---|---|
| 23 | First 3,000 kWh, per kWh | 2.972¢ | 2.879¢ | | (I) |
| | All additional kWh, per kWh | 2.204¢ | 2.137¢ | | (I) |
| 28 | First 20,000 kWh, per kWh | 2.828¢ | 2.697¢ | | (R) |
| | All additional kWh, per kWh | 2.751¢ | 2.624¢ | | (R) |
| 30 | First 20,000 kWh, per kWh | 3.106¢ | 3.071¢ | | (I) |
| | All additional kWh, per kWh | 2.694¢ | 2.655¢ | | (I) |
| 41 | Winter, first 100 kWh/kW, per kWh | 3.886¢ | 3.763¢ | | (R) |
| | Winter, all additional kWh, per kWh | 2.647¢ | 2.564¢ | | (R) |
| | Summer, all kWh, per kWh | 2.647¢ | 2.564¢ | | (R) |

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

(continued)

**Monthly Billing (continued)**

| **Delivery Service Schedule No.** | | **Delivery Voltage** Secondary | Primary | Transmission | |
|---|---|---|---|---|---|
| 47/48 | Per kWh On-Peak | 2.784¢ | 2.681¢ | 2.485¢ | (I) |
| | Per kWh, Off-Peak | 2.734¢ | 2.631¢ | 2.435¢ | (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 | 2.261¢ | (R) |
| | For dusk to midnight operation, per kWh | 2.261¢ | (R) |
| 54 | Per kWh | 1.663¢ | (R) |

| 15 | **Type of Luminaire** | **Nominal Rating** | **Monthly kWh** | **RatePer Luminaire** | |
|---|---|---|---|---|---|
| | Mercury Vapor | 7,000 | 76 | $ 1.73 | (R) |
| | Mercury Vapor | 21,000 | 172 | $ 3.91 | (R) |
| | Mercury Vapor | 55,000 | 412 | $ 9.37 | (R) |
| | High Pressure Sodium | 5,800 | 31 | $ 0.71 | |
| | High Pressure Sodium | 22,000 | 85 | $ 1.93 | (R) |
| | High Pressure Sodium | 50,000 | 176 | $ 4.00 | (R) |

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 | $1.42 | $3.22 | $7.70 | (R) |
| Vertical, per lamp | $1.42 | $3.22 | | (R) |

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 | $1.42 | | | (R) |
| On 26-foot poles, vertical, per lamp | $1.42 | | | (R) |
| On 30-foot poles, horizontal, per lamp | | $3.22 | | (R) |
| On 30-foot poles, vertical, per lamp | | $3.22 | | (R) |
| On 33-foot poles, horizontal, per lamp | | | $7.70 | (R) |

(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 | $1.42 | | | (R) |
| On 26-foot poles, vertical, per lamp | $1.42 | | | (R) |
| On 30-foot poles, horizontal, per lamp | | $3.22 | | (R) |
| On 30-foot poles, vertical, per lamp | | $3.22 | | (R) |
| On 33-foot poles, horizontal, per lamp | | | $7.70 | (R) |

51

| **Types of Luminaire** | **Nominal rating** | **Watts** | **Monthly kWh** | **Rate Per Luminaire** | |
|---|---|---|---|---|---|
| High Pressure Sodium | 5,800 | 70 | 31 | $0.91 | (R) |
| High Pressure Sodium | 9,500 | 100 | 44 | $1.30 | |
| High Pressure Sodium | 16,000 | 150 | 64 | $1.89 | |
| High Pressure Sodium | 22,000 | 200 | 85 | $2.51 | |
| High Pressure Sodium | 27,500 | 250 | 115 | $3.39 | |
| High Pressure Sodium | 50,000 | 400 | 176 | $5.19 | |
| Metal Halide | 9,000 | 100 | 39 | $1.15 | |
| Metal Halide | 12,000 | 175 | 68 | $2.01 | |
| Metal Halide | 19,500 | 250 | 94 | $2.77 | |
| Metal Halide | 32,000 | 400 | 149 | $4.40 | (R) |

53

| **Types of Luminaire** | **Nominal rating** | **Watts** | **Monthly kWh** | **Rate Per Luminaire** | |
|---|---|---|---|---|---|
| High Pressure Sodium | 5,800 | 70 | 31 | $0.30 | |
| High Pressure Sodium | 9,500 | 100 | 44 | $0.42 | (R) |
| High Pressure Sodium | 16,000 | 150 | 64 | $0.62 | |
| High Pressure Sodium | 22,000 | 200 | 85 | $0.82 | |
| High Pressure Sodium | 27,500 | 250 | 115 | $1.11 | (R) |
| High Pressure Sodium | 50,000 | 400 | 176 | $1.70 | (R) |
| Metal Halide | 9,000 | 100 | 39 | $0.38 | |
| Metal Halide | 12,000 | 175 | 68 | $0.66 | |
| Metal Halide | 19,500 | 250 | 94 | $0.91 | |
| Metal Halide | 32,000 | 400 | 149 | $1.44 | (R) |
| Metal Halide | 107,800 | 1,000 | 354 | $3.42 | (R) |

Non-Listed Luminaire, per kWh 0.965¢ (R)

55

| **Types of Luminaire** | **Compares to HPSV Lamp Size of (Watts)** | **Monthly kWh** | **Rate Per Luminaire** | |
|---|---|---|---|---|
| Light Emitting Diode | 100 | 29 | $0.86 | |
| Light Emitting Diode | 150 | 41 | $1.21 | (R) |

(continued)

**Purpose**

The purpose of this Schedule is to adjust prices to reflect the results of the ongoing valuation method under OAR 860-038-0140.

**Applicable**

This Schedule is applicable to all Nonresidential Consumers receiving service under Schedule 220, Standard Offer Service, Schedule 230, Emergency Supply Service or the applicable Direct Access Service Schedule except consumers electing a multi-year opt-out. (N)

**Transition Adjustment**

The transition adjustment is the difference between the estimated market value of the electricity that is freed up when a customer chooses to leave Cost-Based Supply Service for Direct Access versus the Company's regulated price. The estimated market value of the freed up electricity is determined by running two system simulations – one simulation with the Company serving the Direct Access Consumer and one simulation with the Company not serving the Direct Access Consumer. The difference between the two scenarios is analyzed to calculate the impact on the Company's total system. The impacts are then used to determine the Weighted Market Value of the energy, which is then compared to the Customer's energy-only tariff schedule rate.

The Transition Adjustment amounts are shown below for each rate schedule, by Heavy Load Hours (HLH), Light Load Hours (LLH) and voltage level, where applicable. Adjustments are expressed on a cents per kilowatt-hour basis. (M),(C) from bottom of page

**Notification of Transition Adjustment**

Based on the announcement date defined in OAR 860-038-275, the Company will post on its website (www.pacificpower.net) the monthly on- and off-peak transition adjustment for each delivery service schedule shown on Schedule 201 for each applicable delivery voltage level for Nonresidential Consumers for the 12-month period from January 1 through December 31 of the calendar year subsequent to the announcement date. (C)

**Balancing Account**

Beginning January 2006, the Company will accrue in this account, the costs, resulting from changes in the forward price curve that occurred during the open enrollment window, the load actually participating in Direct Access as compared to the assumed level of participation in the simulations, and any executed energy transactions resulting from significant load departure, if such costs exceed $250,000. The Company shall accrue interest on transition adjustment balances, whether positive or negative, at the Company's authorized rate of return. Amounts in this account will be recovered through an adjustment schedule from all consumers eligible for direct access. (C)

(continued)

**Available**

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

**Applicable**

To Large Nonresidential Consumers who have chosen to opt-out of the Company's Cost-Based Supply Service Schedule 201 for a minimum three-year period and who currently receive Delivery Service under Schedules 47, 48, 747, or 748 or Consumers who receive service under Delivery Service Schedules 30, 47 and/or 48 or 730, 747 and/or 748 under a single corporate name with meters of more than 200 kW of billing demand at least once in the previous thirteen months that total to at least 2 MW. (C)

(D)

**Total Eligible Load**

A total load of 200 MW will be accepted under this schedule.

**Transition Adjustment**

The Transition Adjustments for each three-year period are listed below by applicable enrollment period. (C)

The annual Transition Adjustment amounts are shown below for each Delivery Service rate schedule, by voltage level, for Heavy Load Hours (HLH) and Light Load Hours (LLH). Adjustments are expressed on a cents per kilowatt-hour basis. (C) (C) (C)

**Energy Supply**

The Consumer must elect to purchase energy from an ESS (Direct Access Service) for all of the Consumer's Points of Delivery under this schedule.

**Notification of Transition Adjustment**

Based on the announcement date defined in OAR 860-038-275, the Company will post on its website (www.pacificpower.net) the transition adjustment for each eligible delivery service schedule shown on Schedule 201 for each applicable delivery voltage level for Nonresidential Consumers for the 3-year period from January 1 of the calendar year subsequent to the announcement date.

**Balancing Account**

Beginning January 2007, the Company will accrue in this account, the costs, resulting from changes in the forward price curve that occurred during the open enrollment window, the load actually participating in Direct Access as compared to the assumed level of participation in the simulations, and any executed energy transactions resulting from significant load departure, if such costs exceed $250,000. The Company shall accrue interest on the transition adjustment balances, whether positive or negative, at the Company's authorized rate of return. Amounts in this account will be recovered through an adjustment schedule from all consumers eligible for direct access. (C)

(continued)

Docket No. UE 264
Exhibit PAC/303
Witness: Judith M. Ridenour

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Judith M. Ridenour**

**Estimated Effect of Proposed TAM Price Change**

**March 2013**

**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, 2014**

| | | | | | Present Revenues ($000) | | | Proposed Revenues ($000) | | | Change | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | Base Rates | | Net Rates | | |
| Line No. | Description | Sch No. | No. of Cust | MWh | Base Rates | Adders[1] | Net Rates | Base Rates | Adders[1] | Net Rates | ($000) | %[2] | ($000) | %[2] | Line No. |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | |
| | | | | | | | (5) + (6) | | | (8) + (9) | (8) - (5) | (11)/(5) | (10) - (7) | (13)/(7) | |
| | **Residential** | | | | | | | | | | | | | | |
| 1 | Residential | 4 | 485,586 | 5,379,569 | $582,985 | $2,529 | $585,514 | $580,974 | $2,529 | $583,503 | ($2,011) | -0.4% | ($2,011) | -0.3% | 1 |
| 2 | **Total Residential** | | 485,586 | 5,379,569 | $582,985 | $2,529 | $585,514 | $580,974 | $2,529 | $583,503 | ($2,011) | -0.4% | ($2,011) | -0.3% | 2 |
| | **Commercial & Industrial** | | | | | | | | | | | | | | |
| 3 | Gen. Svc. < 31 kW | 23 | 73,886 | 1,100,957 | $113,973 | $4,460 | $118,433 | $114,408 | $4,460 | $118,868 | $435 | 0.4% | $435 | 0.4% | 3 |
| 4 | Gen. Svc. 31 - 200 kW | 28 | 9,924 | 1,992,850 | $170,542 | $2,033 | $172,575 | $169,293 | $2,033 | $171,326 | ($1,249) | -0.7% | ($1,249) | -0.7% | 4 |
| 5 | Gen. Svc. 201 - 999 kW | 30 | 762 | 1,337,763 | $101,252 | $360 | $101,612 | $101,384 | $360 | $101,744 | $132 | 0.1% | $132 | 0.1% | 5 |
| 6 | Large General Service >= 1,000 kW | 48 | 205 | 2,935,115 | $195,337 | ($10,456) | $184,881 | $197,214 | ($10,456) | $186,758 | $1,877 | 1.0% | $1,877 | 1.0% | 6 |
| 7 | Partial Req. Svc. >= 1,000 kW | 47 | 6 | 143,852 | $11,333 | ($514) | $10,819 | $11,433 | ($514) | $10,919 | $100 | 1.0% | $100 | 1.0% | 7 |
| 8 | Agricultural Pumping Service | 41 | 8,046 | 231,404 | $25,361 | ($1,402) | $23,959 | $25,100 | ($1,402) | $23,698 | ($261) | -1.0% | ($261) | -1.1% | 8 |
| 9 | **Total Commercial & Industrial** | | 92,829 | 7,741,941 | $617,798 | ($5,519) | $612,279 | $618,832 | ($5,519) | $613,313 | $1,034 | 0.2% | $1,034 | 0.2% | 9 |
| | **Lighting** | | | | | | | | | | | | | | |
| 10 | Outdoor Area Lighting Service | 15 | 6,768 | 9,286 | $1,140 | $218 | $1,358 | $1,139 | $218 | $1,357 | ($1) | -0.1% | ($1) | -0.1% | 10 |
| 11 | Street Lighting Service | 50 | 251 | 7,823 | $828 | $170 | $998 | $827 | $170 | $997 | ($1) | -0.1% | ($1) | -0.1% | 11 |
| 12 | Street Lighting Service HPS | 51 | 747 | 19,612 | $3,291 | $706 | $3,997 | $3,287 | $706 | $3,993 | ($4) | -0.1% | ($4) | -0.1% | 12 |
| 13 | Street Lighting Service | 52 | 44 | 523 | $65 | $12 | $77 | $65 | $12 | $77 | ($0) | -0.1% | ($0) | -0.1% | 13 |
| 14 | Street Lighting Service | 53 | 266 | 8,967 | $533 | $108 | $641 | $533 | $108 | $641 | ($0) | -0.1% | ($0) | -0.1% | 14 |
| 15 | Recreational Field Lighting | 54 | 104 | 1,249 | $99 | $20 | $119 | $99 | $20 | $119 | ($0) | -0.1% | ($0) | -0.1% | 15 |
| 16 | **Total Public Street Lighting** | | 8,180 | 47,460 | $5,956 | $1,234 | $7,190 | $5,950 | $1,234 | $7,184 | ($6) | -0.1% | ($6) | -0.1% | 16 |
| 17 | **Total Sales to Ultimate Consumers** | | 586,595 | 13,168,970 | $1,206,739 | ($1,756) | $1,204,983 | $1,205,756 | ($1,756) | $1,204,000 | ($983) | -0.1% | ($983) | -0.1% | 17 |
| 18 | AGA Revenue | | | | $2,439 | | $2,439 | $2,439 | | $2,439 | $0 | | $0 | | 18 |
| 19 | **Total Sales with AGA** | | 586,595 | 13,168,970 | $1,209,178 | ($1,756) | $1,207,422 | $1,208,195 | ($1,756) | $1,206,439 | ($983) | -0.1% | ($983) | -0.1% | 19 |

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

# 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 | $19.70 | $19.66 | ($0.04) | -0.20% |
| 200 | $29.28 | $29.21 | ($0.07) | -0.24% |
| 300 | $38.88 | $38.77 | ($0.11) | -0.28% |
| 400 | $48.46 | $48.33 | ($0.13) | -0.27% |
| 500 | $58.04 | $57.87 | ($0.17) | -0.29% |
| 600 | $67.62 | $67.40 | ($0.22) | -0.33% |
| 700 | $77.20 | $76.95 | ($0.25) | -0.32% |
| 800 | $86.79 | $86.51 | ($0.28) | -0.32% |
| **900** | **$96.37** | **$96.06** | **($0.31)** | **-0.32%** |
| 950 | $101.15 | $100.82 | ($0.33) | -0.33% |
| 1,000 | $105.95 | $105.60 | ($0.35) | -0.33% |
| 1,100 | $118.00 | $117.61 | ($0.39) | -0.33% |
| 1,200 | $130.07 | $129.62 | ($0.45) | -0.35% |
| 1,300 | $142.12 | $141.63 | ($0.49) | -0.34% |
| 1,400 | $154.19 | $153.65 | ($0.54) | -0.35% |
| 1,500 | $166.24 | $165.65 | ($0.59) | -0.35% |
| 1,600 | $178.28 | $177.64 | ($0.64) | -0.36% |
| 2,000 | $226.52 | $225.68 | ($0.84) | -0.37% |
| 3,000 | $347.08 | $345.76 | ($1.32) | -0.38% |
| 4,000 | $467.64 | $465.84 | ($1.80) | -0.38% |
| 5,000 | $588.20 | $585.91 | ($2.29) | -0.39% |

* 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**

| kW | | Monthly Billing* | | | | Percent Difference | |
|---|---|---|---|---|---|---|---|
| | | Present Price | | Proposed Price | | | |
| Load Size | kWh | Single Phase | Three Phase | Single Phase | Three Phase | Single Phase | Three Phase |
| 5 | 500 | $68 | $77 | $68 | $78 | 0.32% | 0.27% |
| | 750 | $93 | $102 | $93 | $103 | 0.34% | 0.31% |
| | 1,000 | $118 | $127 | $118 | $128 | 0.36% | 0.35% |
| | 1,500 | $168 | $177 | $168 | $178 | 0.39% | 0.37% |
| 10 | 1,000 | $118 | $127 | $118 | $128 | 0.36% | 0.35% |
| | 2,000 | $218 | $227 | $218 | $227 | 0.40% | 0.38% |
| | 3,000 | $317 | $326 | $318 | $327 | 0.41% | 0.40% |
| | 4,000 | $401 | $410 | $403 | $412 | 0.40% | 0.39% |
| 20 | 4,000 | $429 | $438 | $431 | $440 | 0.38% | 0.37% |
| | 6,000 | $597 | $606 | $599 | $609 | 0.38% | 0.37% |
| | 8,000 | $765 | $774 | $768 | $777 | 0.38% | 0.37% |
| | 10,000 | $933 | $943 | $937 | $946 | 0.38% | 0.38% |
| 30 | 9,000 | $905 | $914 | $908 | $917 | 0.35% | 0.35% |
| | 12,000 | $1,157 | $1,166 | $1,162 | $1,171 | 0.36% | 0.36% |
| | 15,000 | $1,410 | $1,419 | $1,415 | $1,424 | 0.36% | 0.36% |
| | 18,000 | $1,662 | $1,671 | $1,668 | $1,677 | 0.37% | 0.36% |

* 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 | $76 | $67 | $76 | 0.31% | 0.29% |
| | 750 | $91 | $100 | $91 | $101 | 0.35% | 0.32% |
| | 1,000 | $115 | $124 | $116 | $125 | 0.36% | 0.34% |
| | 1,500 | $164 | $173 | $164 | $174 | 0.38% | 0.36% |
| 10 | 1,000 | $115 | $124 | $116 | $125 | 0.36% | 0.34% |
| | 2,000 | $212 | $221 | $213 | $222 | 0.40% | 0.38% |
| | 3,000 | $309 | $318 | $310 | $319 | 0.41% | 0.40% |
| | 4,000 | $391 | $400 | $393 | $402 | 0.40% | 0.40% |
| 20 | 4,000 | $418 | $427 | $420 | $429 | 0.38% | 0.37% |
| | 6,000 | $582 | $591 | $584 | $593 | 0.38% | 0.38% |
| | 8,000 | $746 | $755 | $749 | $758 | 0.38% | 0.38% |
| | 10,000 | $910 | $919 | $913 | $922 | 0.38% | 0.38% |
| 30 | 9,000 | $882 | $891 | $886 | $895 | 0.36% | 0.36% |
| | 12,000 | $1,128 | $1,137 | $1,132 | $1,141 | 0.37% | 0.36% |
| | 15,000 | $1,374 | $1,383 | $1,379 | $1,388 | 0.37% | 0.37% |
| | 18,000 | $1,619 | $1,629 | $1,625 | $1,635 | 0.37% | 0.37% |

* 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 | | Monthly Billing* | | Percent |
|---|---|---|---|---|
| Load Size | kWh | Present Price | Proposed Price | Difference |
| 15 | 3,000 | $329 | $327 | -0.59% |
| | 4,500 | $432 | $429 | -0.68% |
| | 7,500 | $637 | $632 | -0.76% |
| 31 | 6,200 | $658 | $654 | -0.61% |
| | 9,300 | $870 | $864 | -0.69% |
| | 15,500 | $1,294 | $1,284 | -0.78% |
| 40 | 8,000 | $843 | $838 | -0.62% |
| | 12,000 | $1,117 | $1,109 | -0.70% |
| | 20,000 | $1,664 | $1,651 | -0.78% |
| 60 | 12,000 | $1,257 | $1,249 | -0.62% |
| | 18,000 | $1,667 | $1,656 | -0.70% |
| | 30,000 | $2,472 | $2,453 | -0.78% |
| 80 | 16,000 | $1,663 | $1,653 | -0.62% |
| | 24,000 | $2,204 | $2,188 | -0.70% |
| | 40,000 | $3,273 | $3,247 | -0.78% |
| 100 | 20,000 | $2,069 | $2,056 | -0.63% |
| | 30,000 | $2,737 | $2,718 | -0.70% |
| | 50,000 | $4,074 | $4,042 | -0.78% |
| 200 | 40,000 | $4,039 | $4,013 | -0.63% |
| | 60,000 | $5,375 | $5,337 | -0.71% |
| | 100,000 | $8,048 | $7,984 | -0.79% |

* 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 | $416 | $412 | -1.00% |
| | 6,000 | $510 | $504 | -1.09% |
| | 7,500 | $604 | $597 | -1.15% |
| 31 | 9,300 | $833 | $825 | -1.03% |
| | 12,400 | $1,028 | $1,016 | -1.12% |
| | 15,500 | $1,222 | $1,208 | -1.18% |
| 40 | 12,000 | $1,068 | $1,057 | -1.04% |
| | 16,000 | $1,319 | $1,304 | -1.12% |
| | 20,000 | $1,570 | $1,551 | -1.18% |
| 60 | 18,000 | $1,592 | $1,575 | -1.05% |
| | 24,000 | $1,962 | $1,940 | -1.13% |
| | 30,000 | $2,329 | $2,301 | -1.19% |
| 80 | 24,000 | $2,102 | $2,080 | -1.05% |
| | 32,000 | $2,592 | $2,562 | -1.14% |
| | 40,000 | $3,081 | $3,044 | -1.19% |
| 100 | 30,000 | $2,610 | $2,582 | -1.06% |
| | 40,000 | $3,221 | $3,185 | -1.14% |
| | 50,000 | $3,833 | $3,787 | -1.19% |
| 200 | 60,000 | $5,112 | $5,057 | -1.07% |
| | 80,000 | $6,334 | $6,262 | -1.15% |
| | 100,000 | $7,557 | $7,466 | -1.20% |

* 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 Load Size | kWh | Monthly Billing* Present Price | Monthly Billing* Proposed Price | Percent Difference |
|---|---|---|---|---|
| 100 | 20,000 | $2,497 | $2,499 | 0.09% |
| | 30,000 | $3,050 | $3,053 | 0.11% |
| | 50,000 | $4,156 | $4,162 | 0.13% |
| 200 | 40,000 | $4,322 | $4,326 | 0.10% |
| | 60,000 | $5,429 | $5,435 | 0.12% |
| | 100,000 | $7,642 | $7,652 | 0.14% |
| 300 | 60,000 | $6,328 | $6,334 | 0.10% |
| | 90,000 | $7,988 | $7,997 | 0.12% |
| | 150,000 | $11,308 | $11,323 | 0.14% |
| 400 | 80,000 | $8,212 | $8,221 | 0.10% |
| | 120,000 | $10,425 | $10,438 | 0.12% |
| | 200,000 | $14,852 | $14,873 | 0.14% |
| 500 | 100,000 | $10,125 | $10,136 | 0.10% |
| | 150,000 | $12,892 | $12,908 | 0.12% |
| | 250,000 | $18,425 | $18,451 | 0.14% |
| 600 | 120,000 | $12,038 | $12,051 | 0.10% |
| | 180,000 | $15,358 | $15,377 | 0.12% |
| | 300,000 | $21,998 | $22,029 | 0.14% |
| 800 | 160,000 | $15,865 | $15,881 | 0.11% |
| | 240,000 | $20,291 | $20,316 | 0.12% |
| | 400,000 | $29,144 | $29,186 | 0.14% |
| 1000 | 200,000 | $19,691 | $19,712 | 0.11% |
| | 300,000 | $25,224 | $25,255 | 0.12% |
| | 500,000 | $36,290 | $36,342 | 0.14% |

* 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 | $2,961 | $2,963 | 0.07% |
| | 40,000 | $3,504 | $3,507 | 0.08% |
| | 50,000 | $4,047 | $4,051 | 0.08% |
| 200 | 60,000 | $5,283 | $5,287 | 0.07% |
| | 80,000 | $6,369 | $6,374 | 0.08% |
| | 100,000 | $7,455 | $7,462 | 0.09% |
| 300 | 90,000 | $7,769 | $7,775 | 0.07% |
| | 120,000 | $9,398 | $9,406 | 0.08% |
| | 150,000 | $11,028 | $11,037 | 0.09% |
| 400 | 120,000 | $10,168 | $10,175 | 0.07% |
| | 160,000 | $12,340 | $12,350 | 0.08% |
| | 200,000 | $14,513 | $14,525 | 0.09% |
| 500 | 150,000 | $12,572 | $12,581 | 0.08% |
| | 200,000 | $15,287 | $15,300 | 0.08% |
| | 250,000 | $18,003 | $18,018 | 0.09% |
| 600 | 180,000 | $14,976 | $14,987 | 0.08% |
| | 240,000 | $18,234 | $18,249 | 0.08% |
| | 300,000 | $21,493 | $21,512 | 0.09% |
| 800 | 240,000 | $19,783 | $19,798 | 0.08% |
| | 320,000 | $24,128 | $24,148 | 0.08% |
| | 400,000 | $28,473 | $28,498 | 0.09% |
| 1000 | 300,000 | $24,591 | $24,610 | 0.08% |
| | 400,000 | $30,022 | $30,047 | 0.08% |
| | 500,000 | $35,454 | $35,485 | 0.09% |

* 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 | $185 | $211 | $155 | $183 | $208 | $155 | -1.25% | -1.35% | 0.00% |
| | 3,000 | $277 | $304 | $155 | $274 | $300 | $155 | -1.25% | -1.31% | 0.00% |
| | 5,000 | $462 | $488 | $155 | $456 | $482 | $155 | -1.25% | -1.29% | 0.00% |
| Three Phase | | | | | | | | | | |
| 20 | 4,000 | $370 | $422 | $309 | $365 | $417 | $309 | -1.25% | -1.35% | 0.00% |
| | 6,000 | $554 | $607 | $309 | $548 | $599 | $309 | -1.25% | -1.32% | 0.00% |
| | 10,000 | $924 | $977 | $309 | $913 | $964 | $309 | -1.25% | -1.29% | 0.00% |
| 100 | 20,000 | $1,848 | $2,112 | $1,360 | $1,825 | $2,083 | $1,360 | -1.25% | -1.35% | 0.00% |
| | 30,000 | $2,772 | $3,036 | $1,360 | $2,738 | $2,996 | $1,360 | -1.25% | -1.32% | 0.00% |
| | 50,000 | $4,620 | $4,884 | $1,360 | $4,563 | $4,821 | $1,360 | -1.25% | -1.29% | 0.00% |
| 300 | 60,000 | $5,545 | $6,335 | $3,420 | $5,475 | $6,249 | $3,420 | -1.25% | -1.35% | 0.00% |
| | 90,000 | $8,317 | $9,107 | $3,420 | $8,213 | $8,987 | $3,420 | -1.25% | -1.32% | 0.00% |
| | 150,000 | $13,861 | $14,651 | $3,420 | $13,688 | $14,462 | $3,420 | -1.25% | -1.29% | 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 | $269 | $294 | $155 | $265 | $290 | $155 | -1.24% | -1.31% | 0.00% |
| | 4,000 | $358 | $384 | $155 | $354 | $379 | $155 | -1.24% | -1.30% | 0.00% |
| | 5,000 | $448 | $473 | $155 | $442 | $467 | $155 | -1.24% | -1.28% | 0.00% |
| Three Phase | | | | | | | | | | |
| 20 | 6,000 | $537 | $588 | $309 | $531 | $581 | $309 | -1.24% | -1.31% | 0.00% |
| | 8,000 | $717 | $768 | $309 | $708 | $758 | $309 | -1.24% | -1.30% | 0.00% |
| | 10,000 | $896 | $947 | $309 | $885 | $935 | $309 | -1.24% | -1.29% | 0.00% |
| 100 | 30,000 | $2,687 | $2,942 | $1,349 | $2,654 | $2,904 | $1,349 | -1.24% | -1.31% | 0.00% |
| | 40,000 | $3,583 | $3,838 | $1,349 | $3,538 | $3,788 | $1,349 | -1.24% | -1.30% | 0.00% |
| | 50,000 | $4,478 | $4,734 | $1,349 | $4,423 | $4,673 | $1,349 | -1.24% | -1.29% | 0.00% |
| 300 | 90,000 | $8,061 | $8,827 | $3,409 | $7,961 | $8,711 | $3,409 | -1.24% | -1.31% | 0.00% |
| | 120,000 | $10,748 | $11,514 | $3,409 | $10,614 | $11,365 | $3,409 | -1.24% | -1.30% | 0.00% |
| | 150,000 | $13,435 | $14,201 | $3,409 | $13,268 | $14,019 | $3,409 | -1.24% | -1.29% | 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 | $24,604 | $24,771 | 0.68% |
| | 500,000 | $35,136 | $35,414 | 0.79% |
| | 700,000 | $45,668 | $46,058 | 0.85% |
| 2,000 | 600,000 | $48,725 | $49,058 | 0.68% |
| | 1,000,000 | $67,999 | $68,555 | 0.82% |
| | 1,400,000 | $88,146 | $88,925 | 0.88% |
| 6,000 | 1,800,000 | $141,388 | $142,389 | 0.71% |
| | 3,000,000 | $201,832 | $203,500 | 0.83% |
| | 4,200,000 | $262,275 | $264,611 | 0.89% |
| 12,000 | 3,600,000 | $281,370 | $283,372 | 0.71% |
| | 6,000,000 | $402,257 | $405,594 | 0.83% |
| | 8,400,000 | $523,144 | $527,816 | 0.89% |

Notes:

| | |
| --- | --- |
| On-Peak kWh | 64.31% |
| Off-Peak kWh | 35.69% |

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

**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 | $23,423 | $23,646 | 0.95% |
| | 500,000 | $33,387 | $33,758 | 1.11% |
| | 700,000 | $43,351 | $43,870 | 1.20% |
| 2,000 | 600,000 | $46,321 | $46,766 | 0.96% |
| | 1,000,000 | $64,459 | $65,201 | 1.15% |
| | 1,400,000 | $83,471 | $84,509 | 1.24% |
| 6,000 | 1,800,000 | $134,393 | $135,728 | 0.99% |
| | 3,000,000 | $191,429 | $193,654 | 1.16% |
| | 4,200,000 | $248,466 | $251,580 | 1.25% |
| 12,000 | 3,600,000 | $267,348 | $270,018 | 1.00% |
| | 6,000,000 | $381,421 | $385,871 | 1.17% |
| | 8,400,000 | $495,494 | $501,723 | 1.26% |

Notes:

| | |
|---|---|
| On-Peak kWh | 61.66% |
| Off-Peak kWh | 38.34% |

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

# 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 | $32,956 | $33,245 | 0.88% |
| | 700,000 | $42,208 | $42,612 | 0.96% |
| 2,000 | 1,000,000 | $63,133 | $63,710 | 0.91% |
| | 1,400,000 | $80,721 | $81,529 | 1.00% |
| 6,000 | 3,000,000 | $187,267 | $188,998 | 0.92% |
| | 4,200,000 | $240,031 | $242,454 | 1.01% |
| 12,000 | 6,000,000 | $372,201 | $375,662 | 0.93% |
| | 8,400,000 | $477,729 | $482,574 | 1.01% |

Notes:

| | |
|---|---|
| On-Peak kWh | 56.97% |
| Off-Peak kWh | 43.03% |

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