PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 1, 2015

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
3930 Fairview Industrial Dr. S.E.
Salem, OR 97302-1166

Attn: Filing Center

Re: Advice No. 15-005
Docket UE 296—PacifiCorp's 2016 Transition Adjustment Mechanism

In compliance with ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing the following proposed tariff pages associated with Tariff P.U.C. OR No. 36, which sets forth all rates, tolls, charges, rules, and regulations applicable to electric service in Oregon. The Company requests an effective date of January 1, 2016.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2016 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. This tariff filing is supported by testimony and exhibits from the following witnesses:

- Brian S. Dickman, Director, Net Power Costs
- Frank C. Graves, Principal at The Brattle Group
- Stephen A. Larsen, Vice President, Interwest Mining Company and Fuel Resources
- Judith M. Ridenour, Specialist, Cost of Service and Pricing

B. Tariff Sheets

Sixth Revision of Sheet No. 201-1	Schedule 201	Net Power Costs – Cost-Based Supply Service
Fifth Revision of Sheet No. 201-2	Schedule 201	Net Power Costs – Cost-Based Supply Service
Sixth Revision of Sheet No. 201-3	Schedule 201	Net Power Costs – Cost-Based Supply Service
Fourth Revision of Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Revenues
Third Revision of Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Revenues
Fourth Revision of Sheet No. 205-3	Schedule 205	TAM Adjustment for Other Revenues

C. Correspondence

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

Oregon Dockets
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Sarah K. Wallace
Assistant General Counsel
825 NE Multnomah Street, Suite 1800
Portland, OR 97232
sarah.wallace@pacificorp.com

Katherine A. McDowell
McDowell, Rackner & Gibson PC
419 SW 11th Ave, Suite 400
Portland, OR 97204
Katherine@mcd-law.com

Additionally, PacifiCorp 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 Street, Suite 2000
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to Natasha Siores, Director, Regulatory Affairs & Revenue Requirement, at (503) 813-6583.

A copy of this filing has been served on all parties to PacifiCorp's 2015 TAM proceeding, docket UE 287, 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,

R. Bryce Dalley /AS

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: UE 287 Service List

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's 2016 Transition Adjustment Mechanism on the parties listed below via electronic mail and/or overnight delivery in compliance with OAR 860-001-0180.

SERVICE LIST
UE 287

OPUC Dockets (W)
Citizens' Utility Board of Oregon
610 Broadway, Suite 400
Portland, OR 97205
dockets@oregoncub.org

Robert Jenks (C)
Citizens' Utility Board of Oregon
610 Broadway, Suite 400
Portland, OR 97205
bob@oregoncub.org

Sommer Templet
Citizens' Utility Board of Oregon
610 Broadway, Suite 400
Portland, OR 97205
sommer@oregoncub.org

S. Bradley Van Cleve (C)
Davison Van Cleve PC
333 SW Taylor – Ste 400
Portland, OR 97204
bvc@dvclaw.com

Bradley Mullins (C)
Mountain West Analytics
333 SW Taylor – Ste 400
Portland, OR 97204
brmullins@mwanalytics.com

Kevin Higgins (C)
Energy Strategies LLC
215 State St Ste 200
Salt Lake City, UT 84111-2322
Khiggins@energystrat.com

Tyler C. Pepple (C)
Davison Van Cleve PC
333 SW Taylor – Ste 400
Portland, OR 97204
tcp@dvclaw.com

Michael T. Weirich (C)
PUC Staff – Department of Justice
Business Activities Section
1162 Court Street NE
Salem, OR 97301-4096
Michael.weirich@state.or.us

Katherine A McDowell
McDowell Rackner & Gibson PC
419 SW 11th Ave, Suite 400
Portland, OR 97205
Katherine@mcd-law.com

Greg Bass
Noble Americas Energy Solutions LLC
401 West A St., Ste. 500
San Diego, CA 92101
gbass@noblesolutions.com

Sarah Wallace (C)
Pacific Power
825 NE Multnomah St Ste 1800
Portland, OR 97232
Sarah.wallace@pacificorp.com

Oregon Dockets (W)
Pacific Power
825 NE Multnomah St, Ste 2000
Portland, OR 97232
oregondockets@pacificorp.com

Gregory M. Adams (C)
Richardson & O'Leary
PO Box 7218
Boise, ID 83702
greg@richardsonandoleary.com

Douglas C. Tingey
Portland General Electric
121 SW Salmon St. 1WTC 13
Portland, OR 97204
Doug.tingey@pgn.com

Jay Tinker
Portland General Electric
121 SW Salmon St. 1WTC-0702
Portland, OR 97204
pge.opuc.filings@pgn.com

Jorge Ordonez (C)
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308
jorge.ordonez@state.or.us

Dated this 1st of April 2015.

Carrie Meyer

Carrie Meyer
Supervisor, Regulatory Operations

Docket No. UE 296
Exhibit PAC/100
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Brian S. Dickman

April 2015

DIRECT TESTIMONY OF BRIAN S. DICKMAN

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ATTACHED EXHIBITS

Exhibit PAC/101—Oregon-Allocated Net Power Costs

Exhibit PAC/102—Net Power Costs Report

Exhibit PAC/103—Update to Other Revenues

Exhibit PAC/104—Energy Imbalance Market Costs

Confidential Exhibit PAC/105—Energy Imbalance Market Import and Export Summary

Exhibit PAC/106—List of Expected or Known Contract Updates

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

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Before joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing. I have been employed by the Company since 2003, including positions in revenue requirement and regulatory affairs. I assumed my current role managing the Company's net power cost group in March 2012.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the public utility commissions in Oregon, California, Idaho, Utah, and Wyoming.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. I present the Company's proposed 2016 Transition Adjustment Mechanism (TAM) net power costs (NPC). Specifically, my testimony:

- Summarizes the content of the filing;

- Defines NPC and describes the NPC increase in the 2016 TAM compared to the final NPC in the Company's previous TAM, docket UE 287 (2015 TAM);[1]

- Discusses the Company's treatment of its participation in an energy imbalance market (EIM) with the California Independent System Operator Corporation (CAISO) and the expected incremental benefits relative to the optimized NPC forecast produced by the Generation and Regulation Initiative Decision Tools model (GRID);

- Describes several modeling changes to improve NPC forecast accuracy;

- Describes changes to the Company's resource portfolio since the 2015 TAM; and

- Describes how the filing is consistent with the TAM Guidelines.

Q. Please identify the other Company witnesses supporting the 2016 TAM.

A. Three additional Company witnesses provide testimony supporting the Company's filing. Mr. Frank C. Graves, principal at The Brattle Group, provides testimony supporting the Company's NPC modeling change to more accurately account for the price impact of system balancing transactions. Mr. Stephen A. Larsen, Vice President, Interwest Mining & Fuels, provides testimony supporting the coal costs included in the 2016 TAM. Ms. Judith M. Ridenour, Regulatory Specialist, Pricing & Cost of Service, presents the Company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

SUMMARY OF PACIFICORP'S 2016 TAM FILING

Q. Please provide background on the Company's 2016 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

[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 (Oct. 1, 2014).

this case, become effective in base rates on January 1, 2016. The Company is filing the 2016 TAM on a stand-alone basis without a general rate case at this time. Exhibit PAC/101 shows that the 2016 TAM results in an increase to Oregon rates of approximately $11.8 million (unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis). As explained in Ms. Ridenour's testimony, the 2016 TAM results in an overall average rate increase of approximately 0.9 percent.

Q. What are the estimated NPC in the TAM for calendar year 2016?

A. As shown on Exhibit PAC/101, the forecasted normalized NPC for calendar year 2016 are $374.5 million.[2] This is approximately $10.8 million higher than the NPC of $363.7 million in the 2015 TAM. On a total-company basis, the normalized NPC for calendar year 2016 are $1.537 billion, which is approximately $64.8 million higher than the $1.473 billion reflected in the 2015 TAM. Details of the 2016 total-company NPC are provided in Exhibit PAC/102.

Q. Does the Company's initial filing include the benefits and costs associated with participation in the EIM during the 2016 test year?

A. Yes. The Company's initial filing complies with the stipulation resolving the 2015 TAM, in which the Company agreed to address EIM-related costs and benefits in the 2016 TAM filing.

Q. Does the proposed rate increase for the 2016 TAM reflect changes in Oregon load since the 2015 TAM?

A. Yes. The 2016 load forecast used in the Company's calculation of NPC reflects

[2] PAC/101, Dickman/1, line 39.

an increase in Oregon load compared to the 2015 forecast loads in the 2015 TAM. Due to the increased Oregon load, the Company anticipates it will collect $0.8 million more for NPC based on the rates approved in the 2015 TAM, reducing the overall rate change for the 2016 TAM.

Q. Have Oregon's allocation factors changed since the 2015 TAM?

A. Yes. Despite the increase in projected Oregon load, higher load in other states served by the Company caused a decrease in Oregon's allocation factors and the corresponding share of total-company NPC allocated to Oregon compared with the 2015 TAM. This reduction in allocation factors is reflected in the Company's requested rate increase.

Q. Because this is a stand-alone TAM filing, did the Company include an update to Other Revenues for certain items related to NPC, as stipulated in docket UE 216?

A. Yes. Exhibit PAC/103 shows the update to "Other Revenues" compared to the level set in the 2015 TAM. Other Revenues are expected to decrease in 2016 due to the termination of the Bonneville Power Administration (BPA) South Idaho Exchange in June 2016 and the termination of the James River Royalty Offset in December 2015. This is partially offset by an increase in revenue from an ancillary services contract with Seattle City Light for the Stateline wind farm. Projected Other Revenues are approximately $2.3 million lower in 2016, causing a corresponding increase in the TAM rate change.

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 and refined various inputs to the GRID model to improve the accuracy of the NPC calculation for the 2016 test period.

Q. Is the Company using the same version of the GRID model as used in its 2015 TAM?

A. Yes.

Q. What inputs were updated for this filing?

A. All inputs have been updated since the 2015 TAM, including system load; wholesale sales and purchase contracts for electricity, natural gas and wheeling; market prices for electricity and natural gas; fuel expenses; and the characteristics and availability of the Company's generation facilities. In addition, the impact of integrating intermittent resources and load was updated to be consistent with the

Company's 2014 Wind Integration Study[3] that is part of the 2015 Integrated Resource Plan (IRP).

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 heavy load hours (HLH) and light load hours (LLH).

DISCUSSION OF MAJOR COST DRIVERS IN NPC

Q. Please generally describe the changes in NPC compared to the 2015 TAM.

A. Table 1 illustrates the change in total-company NPC by category from the NPC baseline in the 2015 TAM:

Table 1
Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2015	**$1,473**	**$24.58**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	$41	
Purchased Power Expense	$13	
Coal Fuel Expense	$4	
Natural Gas Fuel Expense	$2	
Wheeling and Other Expense	$5	
Total Increase/(Decrease) to NPC	**$65**	
OR TAM 2016	**$1,538**	**$25.21**

[3] Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/2015IRP-AppendixH_WIS_2014_10-25_FinalDraft.pdf.

As shown in Table 1, the increase in NPC is driven mainly by a reduction in wholesale sales revenue, along with smaller increases in expenses for purchased power, coal and natural-gas fuel, and wheeling.

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is driven by lower prices for wholesale market sales transactions. Market sales (represented in GRID as short-term firm and system balancing sales) in the 2015 TAM were included at an average price of $35.25/MWh, while market sales in the current case are included at an average price of $31.05/MWh, a 12 percent decline in price. Revenue from market transactions is approximately $38 million lower on a total-company basis than in the 2015 TAM.

Q. Why did purchased power expense increase?

A. The increase in purchased power expense is mainly attributable the addition of 14 new power purchase agreements (PPAs) with qualifying facilities (QFs). As discussed later in my testimony, all of these PPAs are expected to reach commercial operation in 2016. Increases in purchased power expenses are partially offset by the expiration of two long-term purchase agreements, one for half of the output of the Hermiston power plant and the other for the output from a turbine located at the Georgia Pacific paper mill in Camas, Washington.

Q. Please explain the increase in coal expense in the current proceeding.

A. The increase in coal fuel expense is driven mainly by higher costs at the Company's Bridger Coal facility and higher contract coal costs to supply the Naughton power plant. Cost increases are partially offset by lower expenses due to the closure of the Carbon power plant in May 2015 and cost reductions at other plants. Excluding the Carbon plant, projected coal generation is approximately 63 GWh, or 0.1 percent, higher than the 2015 TAM. Additional details regarding the cost of coal during the test year are provided in the direct testimony of Mr. Larsen.

Q. Please discuss the change in natural gas fuel expense compared to the 2015 TAM.

A. Natural gas expense is higher than in the 2015 TAM due to increased generation output at the Company's natural-gas-fired plants. The average cost of natural gas generation decreased from $33.95/MWh in the 2015 TAM to $29.61/MWh in the current case, a 13 percent reduction. The reduction in natural gas prices relative to the 12 percent reduction in the market price of electricity means there are more hours when the natural gas fired plants will be used for generation. Consequently, projected natural gas generation increased by 1,534 GWh, or 15 percent, compared to the 2015 TAM.

Q. Please describe the increase in the wheeling and other expense category.

A. Expenses in this category are higher due to an increase in wheeling expense resulting from use of the Bonneville Power Administration (BPA) transmission system. The Company's initial filing incorporates BPA's December 11, 2014 Initial Rates Proposal for the 24-month period beginning October 2015, which increases wheeling expense approximately $2.8 million. BPA's draft Record of Decision (ROD) in its rate case will be released June 12, 2015, and its final ROD will be released July 24, 2015. Consistent with past TAM dockets, the Company plans to update the BPA wheeling expense during the proceeding to reflect the final ROD. Inter-hour wind integration charges also increased due to higher wind generation in the 2016 TAM and the updated costs included in the 2014 Wind Integration Study.

EIM COSTS AND BENEFITS

Summary and Background

Q. Please summarize the EIM costs and benefits included in this case.

A. The Company adjusted the NPC forecast for 2016 to reflect EIM benefits from inter-regional dispatch (i.e., exports and imports between PacifiCorp and CAISO) and reduced flexibility reserves. The Company included approximately $9.4 million of benefits on a total-company basis as a reduction to the NPC forecast. The Company also included $5.1 million of total-company costs related to EIM participation during 2016. Table 2 below summarizes the EIM-related benefits and costs included in the 2016 TAM and shows the increase in EIM benefits and decrease in EIM costs compared to the 2015 TAM.

Table 2
Total-Company EIM-Related Benefits and Costs

$ millions	**UE 287/UM 1689**	**2016 TAM**
Inter-regional dispatch	Not specified	$8.4
Intra-regional dispatch		N/A
Flexibility Reserves		$1.0
Within-hour dispatch		N/A
Test-period EIM benefits	**$6.7**	**$9.4**
Test-period EIM costs	**$6.7**	**$5.1**

Q. Did the Company confer with parties to the 2015 TAM in developing its approach to reflecting EIM costs and benefits in rates?

A. Yes. Before filing the 2016 TAM, the Company participated in two workshops with parties to the 2015 TAM to discuss operation of the EIM, the methodology for calculating EIM-related benefits, and potential options for addressing EIM-related costs and benefits from January 1, 2016, forward.[4]

Q. Please describe the EIM and the Company's participation in the EIM.

A. The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and between the PacifiCorp and the CAISO balancing authority areas (BAAs). EIM operation went live October 1, 2014, with financially binding operations effective November 1, 2014. By participating in the EIM, the Company's participating generation units are optimally dispatched using the CAISO's computerized security constrained economic dispatch model. The EIM's automated, expanded footprint, co-optimized dispatch replaces the Company's largely isolated and manual dispatch within its two BAAs. Participation in the EIM produces benefits to customers in the form of reduced NPC, partially offset by costs for initial start-up and ongoing operation.

Q. What is the primary change in the Company's day-to-day operations as a result of EIM?

A. Before EIM operation, the Company manually dispatched most of its regulating resources to balance the system within the hour, generally via phone calls to plant personnel. As a result, requests would typically be sent to the fastest responding

[4] The two workshops were held in accordance with the stipulation in the 2015 TAM. Order No. 14-331, Appendix A at 6, ¶ 12.

and most flexible units first, to ensure system balance and reliability was maintained. As the balance returned to normal, additional requests would be sent to dispatch up lower-cost units and dispatch down higher-cost units. This approach could result in dispatch of higher cost units than strictly necessary in a computer-optimized world. Under EIM, dispatch instructions are automatically sent to all participating resources every five minutes. This helps minimize costs by ensuring the lowest cost resources that are available are dispatched.

The changes in Company operations align with how the Company forecasts NPC. The GRID model has always assumed perfectly optimized hourly dispatch within PacifiCorp's BAAs (i.e., intra-regional dispatch) and does not reflect any intra-hour imbalance or intra-hour dispatch costs (i.e., within-hour dispatch).

Q. Does EIM help to reduce another aspect of the Company's intra-hour imbalance costs?

A. Yes. Before joining the EIM, the Company was dependent on its own resources for all intra-hour balancing. Under the EIM, the CAISO's resources can also be used for intra-hour balancing. In the past, if the Company's loads were less than expected (or if wind generation unexpectedly increased) the Company would work to dispatch down its most expensive available resource. Now, if the highest cost CAISO resource currently dispatched is more expensive than the highest cost Company resource, then the CAISO will back that resource down and the Company will export the output of its most expensive resource to the CAISO (subject to the availability of transmission capacity between PacifiCorp and

CAISO). The same is true in reverse if PacifiCorp has an unexpected need for resources (because, for example, load increases or wind generation decreases).

Q. How does participation in EIM reduce the Company's actual NPC?

A. Participation in EIM is expected to reduce the Company's actual NPC in three ways: (1) optimizing the automated dispatch of participating units in PacifiCorp's BAAs, subject to transmission constraints, using the CAISO's system model; (2) facilitating transactions between the CAISO and PacifiCorp BAAs on a five- and 15-minute basis, using PacifiCorp's transmission rights between CAISO and PacifiCorp on the California Oregon Intertie (COI); and (3) reducing the amount of flexible generating capacity required to be held in reserve by PacifiCorp due to the collective reduction of reserves for the larger and more diversified EIM footprint rather than the individual sum of reserves for the independent CAISO and PacifiCorp BAAs. Benefits realized for the last two categories are highly dependent on the amount of transfer capacity between CAISO and PacifiCorp at the COI available for EIM. Each of these elements is described in more detail below.

Q. Does each of these benefits cause a corresponding reduction to the GRID NPC forecast?

A. No. The GRID NPC forecast already reflects the optimized (i.e., lowest cost) dispatch of PacifiCorp's generating units within its two BAAs, so there are no additional benefits from EIM optimized dispatch (i.e., intra-regional and within-hour dispatch benefits). The other two NPC benefits—inter-regional transactions with CAISO and reduced flexibility reserves—do produce NPC savings relative to the optimized GRID NPC forecast.

Q. Did the Company use actual EIM operations to develop the forecasted EIM benefits applicable to the 2016 TAM?

A. Yes. The Company based its forecast of EIM benefits on actual results from December 2014 and January 2015 because this was the most recent, representative actual data available at the time NPC was prepared. These actual results flow readily from data generated by the operation of the EIM and provide a good baseline for quantification of EIM benefits. The EIM benefit estimates and data to support those estimates will be improved with additional experience, and the Company intends to update the calculations during this case to include more historical results.

The results from December 2014 and January 2015 demonstrate several factors which are critical to calculate benefits realized through EIM. The results should be derived from actual data for five- and 15-minute intervals, reflect contemporaneous actual market prices for electricity and natural gas, and reflect contemporaneous generation and transmission capabilities and constraints. During periods of transmission congestion on the COI, even if the Company has economic resources and transmission available to the California-Oregon Border (COB), the CAISO may not be able to import EIM volumes. Such operational details are difficult to account for in a model but are captured in the actual results.

Recognizing that December and January are only two months during the winter season, the Company expects additional operational data to provide insight into the benefits that can be achieved in other months. For example, during the spring runoff period the Company expects additional congestion on the COI as power moves from hydro units in the northwest to the California market. This congestion will limit the availability of transmission for use in EIM, and updating the 2016 TAM with this data as it becomes available will produce the most accurate forecast possible.

Q. Why didn't the Company use November 2014 results given that financially binding transactions began in November?

A. The Company did not use data from November 2014 because of data integration and modeling errors that were discovered during that month. The CAISO has tools in its tariff to correct prices after the fact for identified software and data errors and has also received additional accommodations from the Federal Energy Regulatory Commission to mitigate anomalous prices for special circumstances associated with the start-up of the EIM.

Q. On February 11, 2015, the CAISO published a report quantifying the estimated EIM benefits during November and December 2014.[5] What were the results of that report?

A. The CAISO report indicated that total EIM benefits during November and December 2014 were approximately $5.97 million for the CAISO and PacifiCorp, or approximately $4.73 million for PacifiCorp. The CAISO indicated its calculation included the impact of more efficient dispatch, both inter- and intra-

[5] http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf.

regional, and reduced renewable energy curtailment (applicable to the CAISO). The report did not include benefits from reduced flexibility reserves.

Q. Are the benefits in the CAISO report comparable to the EIM benefits in the GRID NPC forecast?

A. No. The report issued by the CAISO is intended to quantify the EIM benefits realized by the CAISO and PacifiCorp relative to a counterfactual scenario that mimics system operation before EIM implementation. As a result, the CAISO report includes the benefit of improved PacifiCorp system dispatch compared to the more manual dispatch used before EIM. As noted, because this benefit is already reflected in the GRID model, the CAISO report overstates EIM benefits compared to PacifiCorp's GRID NPC forecast.

Q. Are the benefits from the CAISO report directly comparable to the actual NPC included in the Company's power cost adjustment mechanism (PCAM)?

A. Yes. The benefits reported by the CAISO are reflected in the Company's actual NPC included in the PCAM beginning November 2014.

Q. Please describe the EIM-related costs included in the 2016 TAM.

A. Consistent with the structure of the settlement reached in the 2015 TAM (which matched costs and benefits of EIM participation), the Company included $5.1 million of total-company EIM-related costs in the 2016 TAM. These costs consist of the return on net rate base from the capital investment required to participate in EIM, depreciation expense, and ongoing operations and maintenance (O&M) expenses. A summary of the various cost components is provided as Exhibit PAC/104. Including all EIM-related costs in the 2016 TAM is necessary to ensure that customer rates reflect a proper matching of EIM benefits and costs. Rates set in the Company's most recent general rate case, docket UE 263, do not include any EIM-related costs. Until these costs are included in base rates, EIM benefits included in the Company's TAM filings should be net of the ongoing cost of participation.

Inter-Regional Dispatch Benefits

Q. Did the Company adjust the GRID NPC forecast in the 2016 TAM to reflect savings from exporting and importing energy between PacifiCorp's and the CAISO's BAAs?

A. Yes. The costs and benefits associated with EIM exports and imports are relatively direct, with known historical transaction prices and volumes, and those volumes can be tied to the Company resources that are on the margin. The export benefit is the difference between the export revenue and the expense of the Company generation that was dispatched to support the transaction. The import benefit is the difference between the import expense and the expense of the Company generation that would have been dispatched but for the transaction.

Q. Are the benefits of transacting with the CAISO affected by transmission constraints?

A. Yes. The southbound transfer capability between the Company's west balancing authority area (PACW) and the CAISO has a significant impact on the available benefits. The transmission available for EIM use is limited by two factors. First, the COI path rating is influenced by the status of a large number of interdependent components and is frequently de-rated due to forced and planned outages. Second, the Company's forward transactions delivered at COB also use the Company's available transmission rights—if the Company has scheduled forward transactions that use COI capacity, there is less transfer capacity available for EIM transactions.

Even if transmission is available for the EIM, actual historical data shows that not all of the capacity is used to support exports from the Company to the CAISO. In some periods, the Company imports from the CAISO and exports are zero. In other periods, the Company may not have sufficient resources that are economic at the CAISO market price to fill the entire available path.

Q. How is the EIM export benefit calculated for the forecast period?

A. As noted above, the Company's forecast EIM export benefit is derived from the results of EIM operation during December 2014 and January 2015 as reflected in the CAISO invoices and the cost of the Company's resources that were expected to be on the margin.

Q. Please provide detail on the EIM export benefits included in the 2016 TAM.

A. As shown in Confidential Exhibit PAC/105, the Company's EIM exports in December 2014 and January 2015 averaged 115 megawatts (MW) and had an estimated margin (transaction revenue minus generation expense) totaling approximately $1.3 million. The transmission available to EIM averaged 278 MW. This works out to benefits of $7.81 per megawatt-hour exported or $3.22 per megawatt-hour of transmission available to EIM.

The transmission available to EIM in the forecast period is based on the

Company's COI transmission rights, after accounting for path de-rates, and hourly volumes delivered to COB as calculated by GRID. The COI capacity remaining unused after de-rates and after accounting for forward sales at COB is available to EIM and is valued at $3.22 per megawatt-hour of available transmission. The resulting EIM export benefits total $7.5 million (total-company) for the test period. The Company included these benefits as incremental wholesale sales revenue to the GRID results.

Q. How is the EIM import benefit calculated for the 2016 TAM?

A. The Company's forecasted EIM import benefit is derived in a manner similar to that for exports, based on the results from December 2014 and January 2015, and the Company plans to update its analysis of imports based on additional months of operation during this case. The Company's EIM imports in December 2014 and January 2015 averaged 18 MW and had an estimated margin (avoided generation expense minus transaction expense) totaling approximately $162,000.

Prices in the CAISO BAA are normally higher than in the Company's BAAs, resulting from higher natural gas prices along with a carbon tax. As a result, southbound flows on the COI are typical and face constraints, but northbound counter-flows are not normally constrained. This indicates that transmission may not be a limiting factor for EIM imports. Instead, the relatively infrequent periods when prices in the CAISO BAA are lower than in PACW are likely driven by rapid increases in wind or solar output in the CAISO BAA. Because transmission availability does not appear to be a factor in south to north transfers, the 2016 TAM NPC forecast includes EIM import benefits equal to the average of the benefits in December 2014 and January 2015 multiplied by twelve. Total EIM import benefits in 2016 are $1.0 million (total-company), which is included as a reduction to purchase expense.

Flexibility Reserve Benefits

Q. Does the Company's forecast include flexibility reserve benefits from its participation in EIM?

A. Yes. The Company reduced the regulating reserve requirement modeled in GRID to account for the Company's share of the reserve benefit based on the larger and more diversified footprint of the EIM. Flexibility reserve benefits are a function of the transmission available for EIM dispatch, similar to the EIM export benefit. During December 2014, the Company's share of the reserve diversity benefit amounted to approximately six MW of reserves per 100 MW of EIM transfer capability, as calculated by the CAISO. During the forecast period this amounts to a reserve reduction of roughly 12 MW. Similar to imports and exports, the Company plans to update its analysis of diversity benefits to improve forecast accuracy based on additional months of operation.

Q. How does the CAISO calculate the reduction in flexibility reserves?

A. The CAISO calculates the reduction in ramp reserves for the combined CASIO and PacifiCorp system as compared to the stand-alone ramp reserve need for the CAISO and PacifiCorp separately.

Q. What are ramp reserves?

A. Ramp reserves measure the expected change in load net wind from the beginning of the hour to the end of the hour.

Q. Why are ramp reserves of the combined systems of the CAISO and PacifiCorp lower than the sum of the separate ramp reserves of the CAISO and PacifiCorp?

A. Because of the diversity of the combined load net wind.

Q. Did the Company include additional diversity benefits as a result of NV Energy joining the EIM in October 2015?

A. Yes. The Company's share of this incremental diversity benefit is estimated to amount to three MW of reserves per 100 MW of EIM transfer capability over the COI. During the forecast period this amounts to an additional reserve reduction of roughly six MW. In total, the flexible reserve benefit in the forecast period associated with NV Energy joining the EIM reduces total-company NPC $1.0 million.

Q. Will the addition of NV Energy result in incremental EIM import or export benefits?

A. The impact of NV Energy on the Company's EIM import and exports is uncertain at this time. In the E3 Study of NV Energy's EIM benefits, no direct connection was assumed between the Company and NV Energy, so any benefits would have to flow through the CAISO system.[6]

Q. Have any other parties expressed interest in joining the EIM in the future?

A. Yes. On March 5, 2015, Puget Sound Energy (PSE) announced it intends to begin participating in the EIM in October 2016. Initial reports indicate that PSE's participation in EIM is expected to produce annual benefits to existing

[6] http://www.caiso.com/Documents/NV_Energy-ISO-EnergyImbalanceMarketEconomicAssessment.pdf.

participants (including PacifiCorp and CAISO) ranging from $3.5 million to $4.2 million.[7] The Company's share of these benefits during the 2016 test year is expected to be minimal and, as a result, no adjustment was made to the 2016 TAM. If PSE does begin participating in EIM as planned, any incremental benefits to Oregon customers in 2016 would flow through the PCAM.

GRID MODELING CHANGES TO IMPROVE NPC FORECAST ACCURACY

Q. Did the Company make any changes to improve the accuracy of its NPC modeling since the OR TAM 2015?

A. Yes. The Company made various modifications to the GRID inputs to improve the accuracy of forecast NPC, including changes to reflect:

- Previously unrecognized costs related to day-ahead and real-time balancing transactions;
- Thermal plant forced outage events (heat rate and minimum capacity de-rate);
- Natural gas unit start-up costs and energy;
- Hourly regulation reserve requirements;
- Compliance curtailment of certain Company-owned wind facilities for avian protection; and
- Actual performance of wind PPAs.

Details supporting each modeling change are provided below.

Q. Why is the Company proposing changes to NPC modeling in this case?

A. In previous cases, the Public Utility Commission of Oregon (Commission) has encouraged improvements to NPC modeling to improve forecast accuracy. The Company's proposed modeling changes capture costs and benefits that have not

[7] http://pse.com/aboutpse/EnergySupply/Documents/PSE-ISO_EIM_Report_wb.pdf.

been recognized in the Company's past NPC forecasts. Mr. Graves supports the need for NPC modeling changes, testifying that modifications are needed so that rates reflect the real costs of balancing PacifiCorp's system.

Q. Does the Company's past under-recovery of NPC support the need for changes in its NPC modeling?

A. Yes. Since at least 2007, the Company's actual NPC required to serve customers have exceeded the forecast included in TAM filings.[8] Recovery of any excess actual NPC required to serve customers is limited and, to date, the Company has not recovered any of its prudently incurred excess NPC because of the restrictions on NPC recovery in the PCAM design. A more accurate NPC forecast will minimize this under-recovery and send appropriate price signals to customers so they can make informed decisions regarding their energy consumption, balancing the interests of the Company and customers.

Q. Did the Company provide advance notice to the parties regarding the modeling changes proposed in this case?

A. Yes. In compliance with the TAM Guidelines, the Company provided notice of substantial changes to the Company's modeling of NPC in the 2016 TAM. This notice was provided on February 27, 2015.

Day-Ahead and Real-Time Balancing Transactions

Q. Please summarize the Company's proposal to more accurately model system balancing transactions in GRID NPC.

A. To more accurately model system balancing transactions, the Company adjusted

[8] *See In the Matter of PacifiCorp d/b/a Pacific Power Request for a General Rate Revision*, Docket No. UE 246, Direct Testimony of Gregory N. Duvall, PAC/900, Duvall/16 (Mar. 1, 2012).

forward market prices to reflect historical variations from average actual market prices for purchases and sales. The Company also adjusted system balancing transaction volume to reflect transacting on a forward basis using standard block products, balanced on an hourly basis in the real-time markets.

Q. Please explain how the GRID model currently balances load and resources on an hourly basis.

A. The GRID model calculates the least-cost solution to balance the Company's load and resources to fractions of a megawatt for each hour. The model makes purchases in the wholesale market (labeled as "system balancing purchases" in the NPC report) in the hours for which the Company does not have enough owned or contracted resources to meet its load. The model also makes wholesale market sales (labeled as "system balancing sales" in the NPC report) when it has excess resources for a given hour. These system balancing transactions are calculated for each hour independently and are for the precise volume required by the model. Wholesale market prices for the system balancing sales are based on an hourly forward price curve that is developed from monthly HLH and LLH prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. The prices are input into the model and do not change based on the volume of the system balancing transactions.

Q. How do actual operations differ from the GRID model logic?

A. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The monthly and daily position is calculated as the average for the respective time horizon during HLH and LLH periods; for example, the average HLH position during the month of January or the average LLH position on a given day in February. The monthly and daily products used to balance the Company's position in the wholesale market are available in flat 25 MW blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. In real-time operations, the Company balances its hourly position in the hourly real-time market. At that point, the Company must transact to maintain a balanced system and, as a result, becomes a price-taker subject to whatever price is available at the time.

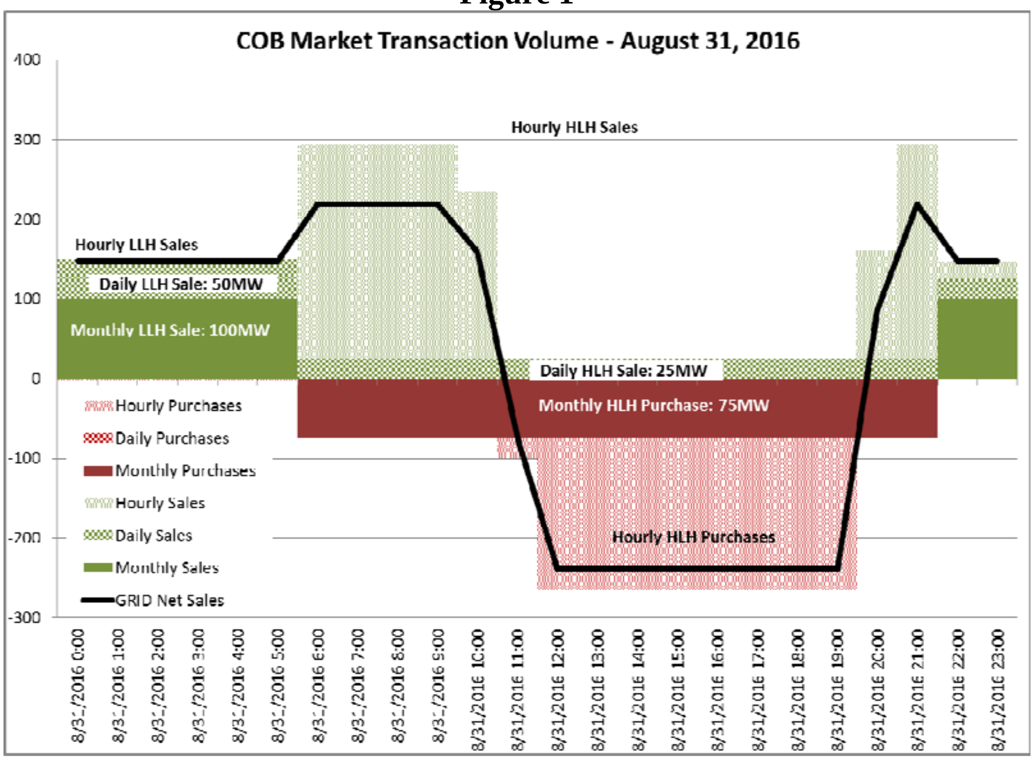
Q. How do the system balancing volumes in GRID compare to the Company's actual volumes?

A. The volume of system balancing transactions generated by GRID is smaller than the volume of similar transactions in actual results. Because GRID balances the Company's load and resources to fractions of a megawatt for each hour in a single step, it avoids the additional purchase and sale transactions that occur in actual operations as the Company progresses through balancing its system on a monthly, daily, and real-time system basis.

For instance, when the Company buys a monthly product that aligns with the Company's average open position for the month, one can expect that roughly half of the days will still have a remaining position to be covered by additional daily purchases. On the other days, the Company will have to make daily sales to unwind the excess volume. The same is true for daily transactions—in some hours the volume acquired will be too low, while in others it will be too high, and additional purchases and sales will be required to cover the Company's actual position.

In addition, buying or selling standard block products for monthly and daily average requirements will not result in a perfect balance of load and resources. This difference then must be closed out in the real-time market where the Company is a price-taker. Figure 1 below illustrates this effect for transactions at the COB market hub during a sample day in the NPC forecast. The solid line represents the hourly sales and purchases generated by the GRID model, and the shaded areas represent monthly and daily standard block products.

Figure 1



Q. Please describe the difference between the hourly price forecast used in GRID and the actual prices for day-ahead and real-time transactions.

A. The GRID model uses an hourly forward price curve that is developed from monthly HLH and LLH prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. In reality, prices vary within each month, and the Company has historically bought more during higher-than-average price periods in each month and sold more during lower-than-average price periods. As a result, the average cost of the Company's daily and hourly short-term firm purchases has been consistently higher than the average actual monthly market price, while the average revenues from its daily and hourly short-term firm sales has been consistently lower than the average actual monthly market price.

Q. Did the Company quantify the impact of this on the Company's past NPC?

A. Yes. In the 36 months ended June 2014, the Company's day-ahead and real-time transactions increased NPC by an average of $7.1 million per year compared to the historical monthly average market prices. Approximately $4.3 million of this impact was a result of higher-than-average purchase prices, while $2.8 million was due to lower-than-average sales prices.

Q. How did the Company calculate the impact of higher short-term purchase power costs and lower short-term sales revenues?

A. The calculation is based on the Company's short-term firm transactions at a given market hub, with deliveries spanning less than one week.[9] The total cost and volume of these transactions is broken down into purchases and sales by month and by HLH or LLH periods. The actual cost of the Company's transactions is then compared against the historical monthly average HLH or LLH market price

[9] Transactions that have deliveries spanning more than a week are excluded because they will contain a price hedging component because both market price and the Company's demand are increasingly uncertain over longer time frames.

at that market. This process is repeated for the other market hubs at which the Company transacts.

Q. Did the price impact of day-ahead and real-time balancing transactions always increase NPC?

A. No. In some periods, the Company was able to sell at higher average prices than it purchased at a given market over the course of a month. The $7.1 million in historical day-ahead and real-time balancing costs is net of $0.8 million from these periods.

Q. Why does the Company buy when prices are high and sell when prices are low?

A. The Company buys when it needs additional resources and sells when it has excess resources. Much of the Company's resource need is determined by its load and wind generation, which vary both throughout the day and throughout the month. The Company's firm loads must be met regardless of price.

The Company's load and wind, which are affected by weather, are correlated with market prices. For instance, during the hottest week in July for the Company's load areas, other market participants are also likely to be experiencing hotter-than-average temperatures and higher-than-average loads. As a result, the marginal cost of the resources other market participants have available is higher than in the coolest week in July, when the Company would likely have extra resources available to sell. The day-ahead and real-time prices the Company experiences during these periods reflect those differences. Similarly, when the wind blows in the Columbia River Gorge and the Company's wind resources generate near their nameplate capacity, the thousands of other turbines in the gorge also generate, pushing down prices in the Mid-Columbia (Mid-C) market. When wind generation in the gorge is low, prices at Mid-C will be higher than average.

Q. Is some of the unfavorable price impact already reflected in GRID due to the hourly price scalars?

A. Yes. However, the effect of the price scalars in GRID is significantly smaller than the $7.1 million historical price impact, with costs totaling just $0.5 million in the forecast period. The hourly scalars only capture the costs associated with the Company buying more in the highest load hours around the daily peak, and less in the shoulder hours when loads are well below the peak. They do not capture the impact of buying more on the highest cost days in a month and selling more on the lowest cost days, since every weekday has the same prices.

Q. How does the Company propose to capture the cost of day-ahead and real-time balancing transactions in the NPC forecast for the test period?

A. To better reflect the market prices available to the Company when it has volumes to transact in the real-time market, the Company has included in GRID separate prices for purchases and sales. These prices are adjusted to account for the historical price differences between the Company's purchases and sales compared to the average market prices. For instance, the Mid-C HLH price in January is increased by $2.20/MWh for purchases and decreased by $3.45/MWh for sales.

The price adjustment need not be positive for purchases and negative for sales. For instance, the Mid-C LLH price in August is increased by $3.58/MWh for purchases, but is also increased by $0.42/MWh for sales. Thus sales at Mid-C in light load hours in August result in incremental revenue compared with the average market prices, reducing NPC.

As described above, in some periods the Company's average purchase costs were lower than its average sales prices. If the inputs to the GRID model for a single market showed a purchase price that was less than the sales price, then the GRID model would buy and sell arbitrarily large volumes of power under this situation, but in reality the volumes in question would be very limited. To prevent this, when the average monthly sales price exceeds the monthly purchase price in the same market, a single price adjustment is used for both sales and purchases based on the volume-weighted average of the historical sales and purchases.

Q. Did the Company also calculate a forecast of additional purchase and sale volumes that arise from using monthly, daily, and hourly products to meet the balancing position determined by GRID?

A. Yes. The system balancing sales volume determined by GRID would need to be increased by 2.6 million MWh, or roughly 28 percent, to account for the use of monthly, daily, and hourly products. System balancing purchase volume would be increased by an equal and offsetting amount as the net position determined by GRID is unchanged.

Q. Did the Company include these additional volumes in the 2016 TAM NPC forecast?

A. Yes. The Company added to its NPC forecast the incremental balancing volumes associated with using standard products to cover the open position determined by

GRID. These volumes are priced so the overall cost of the Company's day-ahead and real-time balancing transactions relative to the forecasted monthly market prices is equal to the historical average.

Q. What is the impact to NPC when GRID is adjusted to reflect the historical impact of day-ahead and real-time balancing transactions?

A. When the adjustments to reflect the impact of historical day-ahead and real-time transactions are included in GRID, 2016 TAM NPC increase by approximately $8.0 million.

Q. How does the resulting short-term firm sales volume in the Company's forecast compare to the historical level?

A. The Company's forecast includes 11.7 million MWh of short term wholesale market sales, whereas the Company's 48 month average is 12.0 million MWh per year. In actual operations, the Company's net position is a forecast and varies over time with changes in forecasts of load, wind, hydro, unit outages, and the economics of the Company's thermal fleet compared with market. As these forecasts change, the Company will buy and sell to limit or cover its revised open position.

Thermal Plant Forced Outages

Q. Please summarize the Company's proposal to more accurately model thermal plant forced outages.

A. The Company previously modeled forced outages at thermal units using a percentage de-rate or "haircut" to nameplate capacity in all hours. In this case, the Company modeled forced outages and unit de-rates as discrete events, rather than applying a uniform de-rate to the plant operating characteristics across all hours. In addition, because outages are no longer modeled as de-rates, the Company removed the corresponding adjustments to heat rates and minimum operating levels.

Q. Please provide background on modeling thermal plant forced outages.

A. The Commission evaluated the calculation of the appropriate forced outage rate and the modeling of outages in docket UM 1355. In Order No. 10-414, the Commission concluded that the forecasted forced outage rate should be based on a four-year average of actual events, adjusted to remove the impact of extraordinarily lengthy events.

Q. Did the Commission provide any specific direction in Order No. 10-414 regarding capacity de-rates and heat rate adjustments in the Company's forced outage modeling?

A. Yes. In Order No. 10-414, the Commission directed the Company to apply corresponding haircuts to the minimum generation levels and heat rates of thermal generating units to better align these unit characteristics with the expected impact of forced outages. The Commission noted that there are different methods of representing forced outages in production cost models, however, and encouraged the Company and other parties to explore these alternatives in the future. Specifically, the Commission stated:

> When modeling forced outages using the capacity deration approach, utilities are directed to derate a unit's capacity over its entire range of operation…We note that ICNU points out that the current deration approach to modeling forced outages is outdated and that there are more sophisticated methods of representing forced outages in production cost models. We

> encourage the utilities, ICNU, CUB, and Staff to explore these modeling alternatives in future rate cases involving net variable power costs.[10]

When addressing the heat rate adjustment, the Commission stated,

> Given the current deration approach to modeling forced outages, a corresponding adjustment to the unit's modeled heat rate curve is necessary. However, again we emphasize the lack of sophistication and realism associated with the deration approach.[11]

Q. Please explain the basis for the Company's prior modeling of forced outages on thermal units in GRID.

A. Under the Company's previous methodology, forced outages and unit de-rates were modeled in GRID as a percentage reduction to the maximum capacity of each unit. The percentage reduction was calculated using a four-year average of actual outage events. In GRID, this approach constrained unit output between minimum operating level and a de-rated maximum, with a slice of each unit being unavailable for dispatch in every hour. Because thermal units typically operate most efficiently near full capacity, a low cost operating segment was thus unavailable to GRID. In TAM filings since docket UM 1355, this issue has been addressed by applying a uniform de-rate to the heat rate and minimum operating levels in GRID.

Q. How are thermal plant outages modeled in the Company's current filing?

A. To more realistically reflect the impact of outages on the Company's operations in the forecast period, the uniform deration has been removed and replaced with an hourly schedule of outages. The revised modeling better reflects the range of

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[10] *In the Matter of Public Utility Commission of Oregon Investigation into Forecasting Forced Outage Rates for Electric Generating Units*, Order No. 10-414 at 7 (Oct. 22, 2010).
[11] Order No. 10-414 at 8.

system operating conditions faced by the Company in actual operations. During intervals without outage events, units are 100 percent available, and can be used over their full operating range. Because outages are no longer modeled as de-rates, adjustments to heat rates and minimum operating levels are no longer necessary.

Q. Does the Company's approach change the heat rates used in this filing?

A. Yes. This adjustment increases the heat rate of the coal fleet slightly, indicating that the prior method overstated the heat rate impact associated with the forced outage haircut. During the forecast period, the overall average heat rate of the Company's coal plants increases by 0.1 percent, and the heat rate of the Company's gas plants decreases by 0.1 percent. Balancing the system under a range of outage conditions and applying more accurate heat rates results in a $0.2 million increase in NPC.

Q. Was the increase in heat rate associated with this change previously anticipated by the Company?

A. Yes. In Mr. Gregory N. Duvall's supplemental testimony in docket UM 1355,[12] the Company identified how the typical difference in heat rate between operation at a unit's rated maximum and de-rated maximum was relatively small. As a result, much of the reduction in NPC associated with the heat rate deration methodology adopted in docket UM 1355 was a result of changes to heat rate when units were operated in the middle or lower end of their range. If a unit is backed down due to economics or transmission constraints, a deration to its

[12] Supplemental Testimony of Gregory N. Duvall, PPL/405, Duvall/16-20, Docket No. UM 1355.

maximum capacity is irrelevant because without the deration, the unit would not have operated at the higher, more efficient level. Under the Company's new method, units appropriately receive the benefits of improved heat rates only when they are dispatched near their maximum capacity.

Q. How did the Company determine the timing and duration of outage events in the 2016 TAM?

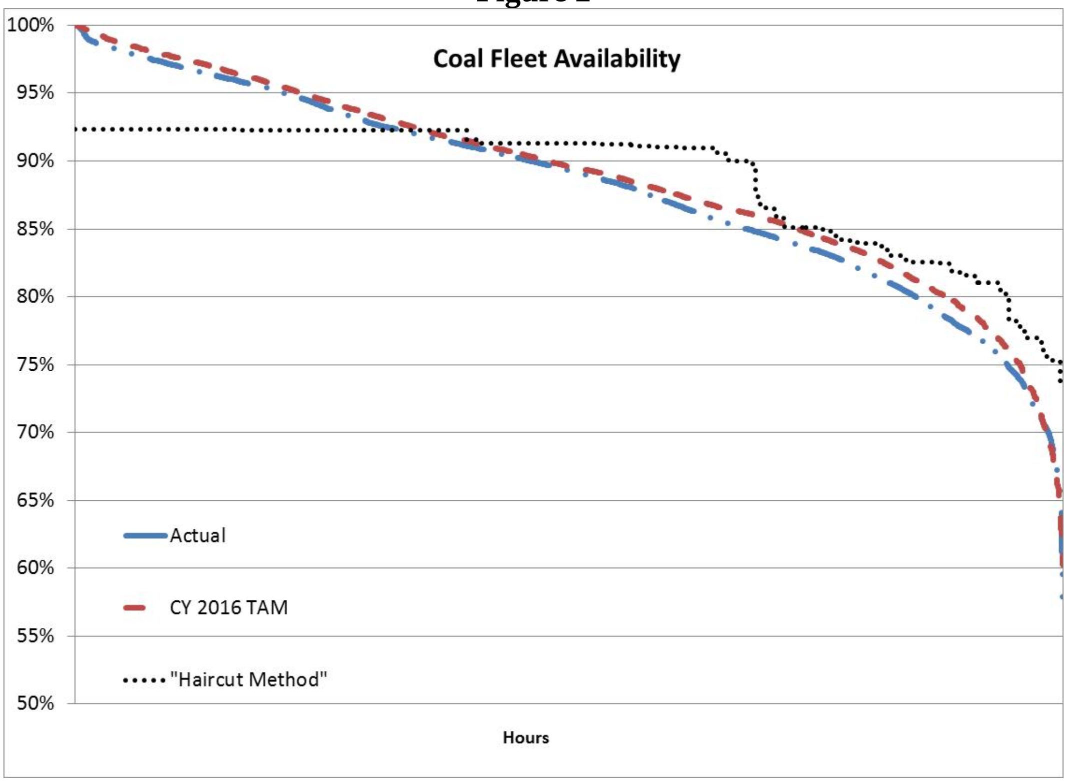
A. The Company did not change the basis for determining the timing and duration of outage events in this case. Consistent with the Commission's order in docket UM 1355, the Company continued to use a four-year average of actual outage events to determine outages during the test year. Lengthy individual outages were capped at 28 days, and the 48-month average was adjusted using the "collar" adopted in Order No. 10-414.

Because the timing and duration of forced outages are not predictable, the 48-month history of actual events was used to develop a schedule during the forecast test year. Forecasted outage and de-rate events were created by compressing the 48-month history of outage events for each unit into an annual period (i.e., the relative timing and duration of each event in the four-year history was divided by four and placed in the forecast test year in the same sequence the events occurred).

Q. How does the distribution of plant availability across the forecast period compare against the historical distribution?

A. As shown in Figure 2 below, the distribution of coal plant availability (including the impact of forced and planned outages) in the forecast period is quite similar to the historical distribution and much better aligned with actual plant operations than under the prior method.

Figure 2



Start-Up Energy

Q. Please summarize the Company's proposal to improve the modeling of start-up energy.

A. Previously, the Company included the cost of natural gas consumed during plant start-up, but did not include energy produced. This meant that natural gas plants were immediately available at up to maximum capacity during the first hour after being offline. In this case, the Company proposes to include both energy produced and plant availability during ramp periods.

Q. Please describe the modeling of combined cycle combustion turbine (CCCT) start-ups.

A. In GRID, when a CCCT is dispatched after being offline it is immediately available at no less than its minimum capacity. In reality, when a unit is dispatched after being offline, there is a start-up period while the generator ramps up from zero generation to its minimum operating level. In previous filings, the Company modeled the minimum down-time constraints for gas units as the time a unit was offline (i.e., no fuel input), and the cost of fuel consumed during start-up was added to NPC.

Q. Why didn't the Company include the energy produced during start-up in past cases?

A. Start-up energy was not included in past cases because the GRID model assumed the gas units were available at minimum capacity immediately after start-up, overstating the energy produced during the ramping period. Furthermore, the minimum down-times were modeled consistent with the technical specifications for the Company's CCCTs, which define down-time as the period between the last heat input before shutdown and the first heat input during start-up. As a result, the time needed to ramp the unit down from its minimum operating level and ramp it up to its minimum operating level was not included in GRID.

Q. How has the Company accounted for the characteristics of its CCCTs during start-up in the 2016 TAM?

A. The Company has measured the energy, fuel input, and shutdown time as each of its units goes from minimum operating level to zero, as well as the energy, fuel input, and start-up time as each of its units goes from zero to minimum operating level. These components are now included in the Company's modeled NPC forecast. The additional start-up and shutdown time is added to the minimum down-time constraint in the Company's modeling. If units are to be shut down, they are offline in GRID for a longer minimum period, whereas in the prior modeling they could have been available sooner for dispatch and reserves. The energy produced during start-up and shutdown is included in GRID in the hours immediately before the unit returning to service, and the heat rate during the start-up and shutdown periods is used to determine the fuel input and corresponding cost.

Q. What are the results of this revised modeling?

A. In total, the Company's forecast includes 104,031 MWh of start-up and shutdown energy with an average heat rate of roughly 10,500 BTU/kWh. As expected, generator efficiency during start-up and shutdown is somewhat lower than in the normal operating range for CCCTs. Compared to the Company's prior modeling, the inclusion of start-up and shutdown energy slightly increases NPC, with the value of start-up energy being more than offset by the increased time to cycle each unit. This change increases NPC in this case by approximately $0.3 million.

Hourly Regulation Reserve Requirement

Q. Please summarize the Company's proposal to improve the modeling of the hourly regulation reserve requirement in NPC.

A. The Company proposes to reflect regulation reserve requirements on an hourly basis, not as flat monthly amounts.

Q. Please explain the modeling of regulation reserves in GRID.

A. Regulation reserves represent generation capacity that must be held in reserve to compensate for fluctuations in load and variable energy resources (e.g., wind resources) within an hour. In the 2015 TAM, the Company included the regulation reserve requirement in GRID as a flat monthly requirement regardless of variations in load and wind output during the period. The total reserve requirement was consistent with the amounts reported in the Company's 2012 Wind Integration Study.

Q. How did the Company change the modeling of regulation reserves in this case?

A. In this case, the Company applied the results of the 2014 Wind Integration Study to calculate hourly regulation reserve requirements for its east and west balancing authority areas based on the hourly wind and load in the forecast period. Modeling reserves on an hourly basis appropriately matches the reserve capacity required in each hour with the forecasted load and wind.

Q. Does modeling reserves on an hourly basis impact the forecast NPC in GRID?

A. Yes. Because the Company's forecasted load and wind generation varies each hour during the test period, modeling the corresponding reserve requirement on an hourly basis results in a more variable requirement in GRID compared to a flat monthly shape. This variability is consistent with how the Company actually operates its system. This change increases NPC by approximately $0.5 million due to more hours where the required reserve capacity is higher than the monthly average, causing additional generation capacity to be held in reserve.

Avian Compliance

Q. What adjustment did the Company make related to compliance curtailment of its owned wind generation for avian protection?

A. In this case, the Company has reduced generation output at its Glenrock/Rolling Hills wind site[13] and its Seven Mile Hill wind site[14] to reflect expected energy lost from compliance curtailment for avian protection.

Q. Is the Company required to curtail these wind facilities for avian protection?

A. Yes. The Company recently received an order from the United States District Court for the District of Wyoming (Court Order) that included the requirement to curtail the Glenrock/Rolling Hills site and the Seven Mile Hill site to reduce the risk of eagle interaction with wind turbines. As part of the Court Order, an on-site observer will use their professional judgment to identify risky eagle flight behavior/pathways during specified time periods and notify plant personnel to implement turbine curtailment.

Q. Is the Court Order designed to ensure compliance with environmental laws?

A. Yes. The Court Order includes the requirement to implement measures that will ensure compliance with the requirements of the Migratory Bird Treaty Act and the Bald and Golden Eagle Act.

Q. How did the Company estimate the energy lost due to avian curtailment?

A. The Company has been curtailing wind output for avian protection at these

[13] For the 2016 TAM, compliance curtailment is reflected at Glenrock and Glenrock III. Rolling Hills is not included in the Company's NPC forecast.
[14] Seven Mile Hill and Seven Mile Hill II.

facilities since November 2012. To estimate the expected lost energy during the test period, the Company used data associated with actual historical curtailments from November 2012 through June 2014. The historical data informed the estimated lost energy associated with prospective curtailments expected during the time periods specified in the Court Order. The Company began implementing the Court ordered curtailments on January 1, 2015. The reduced wind output projected during the test period increases NPC by approximately $0.1 million.

Q. Has the Company continued to exclude the Rolling Hills facility and adjust the capacity factor of Glenrock 1 in accordance with prior Commission orders?

A. Yes. In docket UE 200, the Commission excluded the Rolling Hills facility from Oregon rates and adjusted the capacity factor of the Glenrock 1 facility to account for the effect of Rolling Hills on Glenrock's availability. These adjustments continue to be reflected in the Company's current filing.

Wind Power Purchase Agreements

Q. Please describe the adjustment made to generation from wind PPAs.

A. Previously, the generation from the Company's wind PPAs was based on long-range forecasts provided to the Company by the project owners. Actual wind generation at these facilities has varied somewhat from those forecasts, causing the Company to incur higher purchased power expenses. To better align forecasted NPC with actual results, the Company modeled the forecasted wind generation for each of its wind PPAs to match the levels in the 48-month historical period. For those projects with less than 48 months of history, the project owner's forecast is used for the period when actual results are not available. This change brings the modeling of these contracts in line with the Company's other purchase contracts, which are generally based on 48 months of historical results.

Q. What is the impact of using the 48-month historical generation rather than the project owners' forecast?

A. In this case, reflecting the generation output as described above increases NPC approximately $1.5 million.

CHANGES TO THE COMPANY'S RESOURCE PORTFOLIO

Q. Have changes been made to the modeling of the Company's resources since the 2015 TAM?

A. Yes. The Company's modeling incorporates a number of resource changes to account for operational differences between the 2015 TAM and the end of the test period in this case.

- *Carbon Plant Closure*—The Carbon plant is expected to stop operating in April 2015 and will not operate during the forecast period.
- *Georgia-Pacific Camas Generation*—The operating agreements for the Company's generation plant at Georgia-Pacific's paper mill in Camas, Washington, expire in December 2015. The generation assets are being sold to Georgia-Pacific, who will use the generation assets to offset a portion of their load during the test period.
- *Thermal Upgrades/Environmental Controls*—Environmental upgrades will reduce plant capacity at Jim Bridger 3 in November 2015, Jim Bridger 4 in November 2016, Hayden 1 in May 2015, and Hayden 2 in May 2016.
- *Interruptible Load*—In December 2014, the Company signed a new contract with US Magnesium that enabled its interruptible load to be used to meet load following requirements. In the past, this interruptible load contributed non-spinning reserves which could be credited against up to half of the Company's contingency reserve requirement. Under the new

contract, using interruptions to meet load following requirements as well as during contingency events means less reserves need to be held on other Company resources.

Q. Please describe changes to the Company's long-term purchase and sale contracts since the 2015 TAM.

A.
- *BPA South Idaho Exchange*—Under an exchange agreement with BPA, the Company supplies energy to serve BPA's load in South Idaho and is returned energy in its PACW. This contract terminates June 30, 2016.
- *Hermiston Purchase*—The Company's Hermiston purchase contract for the output of the 50 percent share of the Hermiston plant not owned by the Company terminates on June 30, 2016. Starting July 1, 2016, the NPC forecast includes only the Company's 50 percent ownership share of the Hermiston units.

Q. The Company has agreed to exchange certain of its transmission assets with Idaho Power, subject to regulatory approvals. Is the impact of this transaction included in the NPC forecast?

A. Yes. Once approved and finalized, the Idaho Power asset exchange agreement will result in lower wheeling expenses paid by the Company to Idaho Power. The transaction is currently expected to close by the end of 2015. The test period wheeling expense has been reduced by $0.6 million to reflect the transaction.

Q. Does this case include new QF PPAs that are not yet operational, but that are expected to achieve commercial operation before the end of the forecast period?

A. Yes. At the time the Company prepared the 2016 TAM NPC, 14 new PPAs with QFs had been signed that have not previously been included in rates—12 that are expected to reach commercial operation in 2015, and two that are expected to reach commercial operation in 2016. Based on the information known to the Company when this case was prepared, the Company has a commercially reasonable good faith belief that these QFs will reach commercial operation before or during the forecast period. In addition to the QF PPAs that are included in the initial filing, several more QF PPAs either have been signed or are expected to be signed as the TAM progresses. The Company will update the status of these pending PPAs as new information becomes available. The Company is aware of three QF PPAs in this category.

Q. What type of information does the Company rely on to support the expected commercial operation dates for these contracts?

A. There are several sources of information. First, the scheduled commercial operation date is set forth in the PPA for each project. As part of the negotiations, various milestones are included in the PPA that are documented and support the commercial operation date. Second, counterparties provide project status updates on a monthly basis that document progress toward milestones and the commercial operation date. Third, the Company monitors the status of the generator interconnection process, which is posted on the publicly available transmission provider's OASIS website, to ensure project output can be brought onto the Company's transmission system consistent with the commercial operation date.

Q. Does the Company have any updates to the expected commercial operation dates of new QFs based on updated information since the NPC forecast was prepared?

A. Yes. Latigo Wind Park and Champlin Blue Mountain have provided notice that they may incur delays in their commercial operation dates due to litigation that affected their ability to secure financing for their projects and finalize turbine purchases. Latigo Wind Park is included in the TAM for all of 2016, but is now expected to be online in first quarter 2016. Champlin Blue Mountain is included in the TAM beginning October 2016. The Company's updates in this docket will incorporate updated online dates for these QFs based on available information.

Q. Did the Company extend any PPAs in its NPC study that are scheduled to expire during the forecast period?

A. Yes. Several existing QF PPAs terminate before the end of the forecast period, and the Company assumed that these customers will execute PPAs to continue selling to the Company at the most recent avoided cost rates. The Company will update the status of these PPAs as new information becomes available.

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 later orders?

A. Yes. The Company has complied with the TAM Guidelines applicable to the initial filing in a stand-alone TAM.

Q. Did the Company make changes to GRID in this case?

A. No.

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

A. Yes.

Q. Did the Company provide information regarding its anticipated TAM updates?

A. Yes. Exhibit PAC/106 contains a list of known contracts and other items 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.

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 296
Exhibit PAC/101
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Oregon-Allocated Net Power Costs

April 2015

PacifiCorp
Oregon - CY 2016 TAM

Line no		ACCT.	Total Company UE-287 Final TAM CY 2015	Total Company TAM CY 2016	Factor	Factors CY 2015	Factors CY 2016	Oregon Allocated UE-287 Final TAM CY 2015	Oregon Allocated TAM CY 2016
1	**Sales for Resale**								
2	Existing Firm PPL	447	14,460,450	14,516,523	SG	25.687%	25.464%	3,714,489	3,696,443
3	Existing Firm UPL	447	29,139,801	26,803,485	SG	25.687%	25.464%	7,485,207	6,825,157
4	Post-Merger Firm	447	414,915,695	376,599,095	SG	25.687%	25.464%	106,580,340	95,896,037
5	Non-Firm	447	-	-	SE	24.484%	24.074%	-	-
6	**Total Sales for Resale**		458,515,946	417,919,102				117,780,036	106,417,637
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	3,538,604	4,635,674	SG	25.687%	25.464%	908,969	1,180,414
10	Existing Firm Demand UPL	555	52,672,295	53,565,725	SG	25.687%	25.464%	13,530,052	13,639,812
11	Existing Firm Energy	555	28,521,106	33,338,675	SE	24.484%	24.074%	6,983,099	8,026,082
12	Post-merger Firm	555	537,557,343	535,787,067	SG	25.687%	25.464%	138,083,579	136,431,173
13	Secondary Purchases	555	-	-	SE	24.484%	24.074%	-	-
14	Other Generation Expense	555	3,522,855	6,262,777	SG	25.687%	25.464%	904,924	1,594,734
15	**Total Purchased Power**		625,812,203	633,589,918				160,410,624	160,872,215
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	27,165,030	21,064,818	SG	25.687%	25.464%	6,977,943	5,363,880
19	Existing Firm UPL	565	-	-	SG	25.687%	25.464%	-	-
20	Post-merger Firm	565	112,170,725	118,768,709	SG	25.687%	25.464%	28,813,550	30,242,899
21	Non-Firm	565	6,904,205	8,415,001	SE	24.484%	24.074%	1,690,424	2,025,860
22	**Total Wheeling Expense**		146,239,960	148,248,527				37,481,916	37,632,640
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	760,067,707	766,272,808	SE	24.484%	24.074%	186,094,753	184,475,497
26	Fuel Consumed - Coal (Cholla)	501	60,047,431	58,220,045	SSECH/SE	24.484%	24.074%	14,701,995	14,016,120
27	Fuel Consumed - Gas	501	3,732,974	5,004,816	SE	24.484%	24.074%	913,980	1,204,879
28	Natural Gas Consumed	547	333,797,813	334,547,426	SE	24.484%	24.074%	81,726,958	80,540,249
29	Simple Cycle Comb. Turbines	547	5,273,378	4,853,712	SSECT/SE	24.484%	24.074%	1,291,132	1,168,501
30	Steam from Other Sources	503	4,328,145	4,797,463	SE	24.484%	24.074%	1,059,702	1,154,960
31	**Total Fuel Expense**		1,167,247,450	1,173,696,270				285,788,521	282,560,207
32									
33	**Net Power Cost (Per GRID)**		1,480,783,666	1,537,615,613				365,901,025	374,647,425
34									
35									
36	Settlement Adjustment		(1,300,000)		SG	25.687%	25.464%	(333,934)	
37	EIM Benefits*		(6,700,000)		SG	25.687%	25.464%	(1,721,044)	
38	Oregon Situs Solar Project Benefit		(141,066)	(131,143)	OR	100.000%	100.000%	(141,066)	(131,143)
39	**Total NPC Net of Adjustments**		1,472,642,600	1,537,484,470				363,704,981	374,516,282
40									
41	EIM Costs		6,700,000	4,612,380	SG	25.687%	25.464%	1,721,044	1,174,482
42	**Total TAM Net of Adjustments**		1,479,342,600	1,542,096,849				365,426,026	375,690,764
43									
44							Increase Absent Load Change		10,264,739
45									
46				Oregon-allocated NPC Baseline in Rates from UE-287				$365,426,026	
47				$ Change due to load variance from UE-287 forecast				822,040	
48				2016 Recovery of NPC in Rates				$366,248,066	
49	*EIM Benefits for the 2016 TAM are reflected in net power costs								
50							**Increase Including Load Change**		**9,442,698**
51									
52							Add Other Revenue Change		2,309,696
53									
54							**Total TAM Increase**		**11,752,395**

Docket No. UE 296
Exhibit PAC/102
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Net Power Costs Report

April 2015

PacifiCorp

_ORTAM16 NPC Study _2015 03 17 GOLD

Net Power Cost Analysis

$

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Special Sales For Resale													
Long Term Firm Sales													
Black Hills s27013/s28160	14,516,523	1,221,600	1,183,316	1,221,669	1,195,609	1,218,829	1,196,722	1,218,948	1,219,325	1,209,413	1,204,442	1,201,551	1,225,098
BPA Wind s42818	2,631,751	334,752	288,687	279,742	194,794	187,665	172,685	115,191	111,139	117,826	238,821	295,404	295,045
Hurricane Sale s393046	12,152	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013
LADWP (IPP Layoff)	26,803,485	2,259,411	1,894,946	1,769,697	1,189,888	2,237,017	2,568,975	2,658,253	2,657,940	2,534,044	2,545,057	2,136,582	2,351,676
Leaning Juniper Revenue	100,622	5,999	6,206	9,361	6,641	7,866	7,721	11,314	12,268	10,301	8,503	6,972	7,469
UMPA II s45631	9,606,329	593,283	572,367	593,283	582,825	593,283	929,263	1,779,848	1,400,150	792,640	593,283	582,825	593,283
Total Long Term Firm Sales	53,670,861	4,416,058	3,946,535	3,874,764	3,170,770	4,245,672	4,876,378	5,784,565	5,401,835	4,665,236	4,591,118	4,224,346	4,473,583
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	2,162,160	702,000	702,000	758,160	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	2,162,160	702,000	702,000	758,160	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	21,131,358	4,201,108	1,208,138	1,258,071	778,771	397,415	740,152	1,584,441	2,206,533	2,588,996	2,155,403	2,226,988	1,785,341
Four Corners	56,514,085	4,624,354	3,559,911	4,952,590	4,158,815	3,512,634	2,468,020	4,216,069	7,022,940	5,330,915	7,080,324	5,149,820	4,437,696
Mead	33,544,823	2,720,253	1,342,952	1,697,663	2,362,809	1,759,528	1,507,358	3,528,091	3,517,335	3,844,068	3,682,257	3,702,986	3,879,524
Mid Columbia	14,429,438	1,349,927	416,682	1,482,722	1,006,443	305,918	337,104	905,417	1,940,256	2,477,484	2,146,150	1,364,148	697,188
Mona	21,413,783	2,043,117	364,011	535,264	2,141,171	3,319,479	1,619,466	1,333,677	1,339,227	2,653,874	1,805,087	2,179,218	2,080,192
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	129,124,266	10,498,738	11,133,245	10,881,896	10,753,382	9,121,133	9,026,508	10,775,613	8,937,823	12,766,566	12,790,548	11,826,802	10,612,012
EIM Exports	7,473,033	449,520	520,623	532,427	604,791	782,969	828,769	827,779	755,133	553,900	520,085	441,511	655,527
Trapped Energy	323,048	-	-	-	-	3,831	300,134	-	-	2,975	-	16,108	-
DA-RT Balancing	78,132,247	5,728,904	4,614,584	6,915,413	5,555,827	6,249,160	6,503,216	9,382,671	11,097,092	5,537,958	4,668,745	4,846,472	7,032,205
Total System Balancing Sales	362,086,081	31,615,921	23,160,146	28,256,045	27,362,009	25,452,067	23,330,728	32,553,757	36,816,337	35,756,736	34,848,597	31,754,051	31,179,686
Total Special Sales For Resale	417,919,102	36,733,979	27,808,681	32,888,969	30,532,779	29,697,739	28,207,106	38,338,323	42,218,172	40,421,972	39,439,716	35,978,398	35,653,269

PacifiCorp

_ORTAM16 NPC Study _2015 03 17 GOLD

Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental p27875	904,316	70,865	126,672	197,802	96,264	-	-	-	170,136	101,412	-	141,165	-
Combine Hills Wind p160595	5,226,273	414,665	462,908	560,424	551,989	467,464	487,360	400,205	385,055	298,718	361,361	419,818	416,305
Deseret Purchase p194277	36,467,814	3,104,118	3,017,274	3,060,696	3,060,696	2,626,470	3,060,696	3,104,118	3,104,118	3,060,696	3,104,118	3,060,696	3,104,118
Douglas PUD Settlement p38185	2,413,195	115,379	92,743	198,338	316,668	368,702	363,721	313,097	236,603	106,999	98,975	101,440	100,531
Gemstate p99489	3,191,800	261,000	257,700	261,800	257,700	257,700	257,700	257,700	276,000	257,700	280,200	305,600	261,000
Hermiston Purchase p99563	34,590,660	6,947,479	6,655,863	6,230,648	5,202,517	4,455,852	5,098,301	-	-	-	-	-	-
Hurricane Purchase p393045	126,266	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522	10,522
IPP Purchase	26,803,485	2,259,411	1,894,946	1,769,697	1,189,888	2,237,017	2,568,975	2,658,253	2,657,940	2,534,044	2,545,057	2,136,582	2,351,676
MagCorp Reserves p510378	6,877,150	561,400	553,380	581,450	593,480	573,430	561,400	569,420	573,430	581,450	589,470	581,450	557,390
Nucor p346856	6,018,000	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500
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	235,042	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587	19,587
Rock River Wind p100371	5,034,554	680,576	454,611	562,529	481,643	324,287	283,350	190,216	188,086	281,844	506,704	511,662	569,044
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Three Buttes Wind p460457	21,900,784	2,950,042	2,048,922	2,268,067	1,790,156	1,522,263	1,376,527	915,605	1,110,451	1,208,578	1,763,698	2,344,477	2,602,000
Top of the World Wind p522807	43,163,842	5,675,352	4,007,657	4,588,167	3,723,277	3,180,993	2,809,599	1,990,205	2,035,002	2,244,343	3,532,172	4,592,308	4,784,770
Tri-State Purchase p27057	10,409,372	852,422	768,608	785,922	782,892	882,603	723,041	1,022,769	969,567	915,894	940,409	864,739	900,507
Wolverine Creek Wind p244520	10,581,890	769,966	927,019	1,223,945	1,077,890	870,483	924,641	707,826	699,677	690,703	828,162	982,254	879,322
Long Term Firm Purchases Total	233,958,729	26,862,122	23,467,790	24,488,933	21,324,507	19,966,773	20,714,789	14,328,913	14,605,543	14,481,810	16,749,758	18,241,676	18,726,115
Seasonal Purchased Power													
Constellation 2013-2016	5,512,192	-	-	-	-	-	-	1,884,600	2,000,592	1,627,000	-	-	-
Seasonal Purchased Power Total	5,512,192	-	-	-	-	-	-	1,884,600	2,000,592	1,627,000	-	-	-

PacifiCorp

_ORTAM16 NPC Study _2015 03 17 GOLD

Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Qualifying Facilities													
QF California	7,126,982	655,677	754,337	820,422	1,045,929	1,061,305	822,623	388,861	290,451	268,239	269,515	300,789	448,834
QF Idaho	6,205,778	433,226	410,763	481,037	521,123	653,245	716,679	609,003	496,858	463,343	489,225	478,375	452,901
QF Oregon	26,970,288	2,211,749	2,127,184	2,405,344	2,757,425	2,858,041	2,561,614	2,175,047	2,057,407	2,109,199	1,889,557	1,671,841	2,145,879
QF Utah	9,102,693	585,580	616,681	720,017	744,707	811,720	873,429	857,572	893,007	835,407	801,128	713,438	650,008
QF Washington	228,931	-	-	-	3,931	18,303	37,636	52,497	56,609	45,055	14,901	-	-
QF Wyoming	214,412	22,234	21,945	24,923	17,973	14,891	12,066	14,669	15,427	14,157	14,216	20,346	21,566
Biomass One QF	14,859,547	1,384,512	1,338,960	1,387,295	808,736	820,398	808,737	1,441,275	1,469,283	1,432,225	1,456,705	1,217,783	1,293,636
Champlin Blue Mtn Wind QF	3,895,424	-	-	-	-	-	-	-	-	-	1,082,799	1,323,345	1,489,280
Chevron Wind p499335 QF	1,264,235	192,890	116,666	127,238	83,200	63,471	54,652	56,428	73,676	75,976	93,561	157,369	169,108
Chopin Wind QF	870,683	-	-	-	-	-	146,555	115,369	116,162	78,566	127,908	143,957	142,167
DCFP p316701 QF	163,158	11,345	7,900	11,022	12,915	18,002	16,517	15,734	14,377	12,517	21,490	14,736	6,602
Enterprise Solar I QF	1,113,187	-	-	-	-	-	-	-	-	-	27,465	595,928	489,795
Escalante Solar I QF	1,063,686	-	-	-	-	-	-	-	-	-	26,763	565,845	471,078
Escalante Solar II QF	1,017,582	-	-	-	-	-	-	-	-	-	25,574	541,277	450,732
Escalante Solar III QF	930,688	-	-	-	-	-	-	-	-	-	23,218	494,927	412,543
Evergreen BioPower p351030 QF	2,723,029	221,309	195,150	188,234	170,667	181,666	206,205	282,649	280,180	262,093	290,298	216,608	227,970
Five Pine Wind QF	7,640,280	599,313	713,852	683,662	647,143	506,349	463,950	558,000	649,010	598,347	648,793	758,578	813,282
Foote Creek III Wind QF	1,729,763	192,266	182,002	222,913	120,638	106,254	87,405	95,791	98,307	109,828	153,015	168,056	193,289
Latigo Wind Park QF	9,707,709	1,007,477	950,837	1,126,955	897,120	856,897	745,979	668,253	572,323	616,686	799,252	709,690	756,240
Mountain Wind 1 p367721 QF	9,949,548	1,612,132	1,166,440	986,656	826,048	592,688	583,881	461,435	499,200	459,680	756,781	877,647	1,126,961
Mountain Wind 2 p398449 QF	15,336,994	2,324,070	1,716,181	1,505,837	1,234,690	911,192	1,035,503	849,897	822,420	765,825	1,104,885	1,397,691	1,668,805
North Point Wind QF	16,747,038	1,292,141	1,544,384	1,477,966	1,432,441	1,074,831	1,071,697	1,254,510	1,476,276	1,330,317	1,432,288	1,637,599	1,722,589
Oregon Wind Farm QF	12,464,585	909,025	965,807	1,161,572	1,408,837	1,322,282	1,333,282	1,196,105	1,095,605	829,468	753,163	719,974	769,467
Pioneer Wind Park I QF	4,983,236	-	-	-	-	-	22,008	650,952	683,005	451,955	820,623	1,259,003	1,095,690
Power County North Wind QF p5756	4,674,158	381,157	466,179	440,071	444,493	317,036	307,270	312,183	308,299	321,132	418,650	415,580	542,108
Power County South Wind QF p5756	4,324,174	354,458	477,423	377,396	418,997	277,180	289,555	253,681	294,086	291,607	366,405	405,506	517,881
Roseburg Dillard QF	941,190	87,975	96,082	69,190	70,969	53,248	59,425	125,632	102,729	80,628	32,444	72,663	90,205
Spanish Fork Wind 2 p311681 QF	2,669,093	212,578	171,283	187,689	137,362	146,005	192,759	312,100	340,089	279,407	230,785	238,518	220,515
Sunnyside p83997/p59965 QF	28,752,568	2,518,536	2,440,635	2,507,593	1,715,887	2,540,943	2,459,285	2,526,996	2,464,774	2,444,680	2,132,025	2,450,145	2,551,069
Tesoro QF	895,479	76,374	88,584	98,771	73,409	78,254	66,197	65,380	64,697	59,658	55,366	79,207	89,582
Threemile Canyon Wind QF p50013	1,743,670	100,301	143,911	147,786	197,456	194,882	214,833	177,367	165,071	108,524	99,562	98,312	95,665
Utah Pavant Solar QF	4,205,934	156,620	209,161	340,630	372,298	408,203	467,079	567,085	543,247	428,669	331,137	213,551	168,254
Utah Red Hills Solar QF	6,474,642	301,183	358,203	461,929	658,529	672,972	652,600	839,943	814,585	592,515	505,379	316,761	300,043
Qualifying Facilities Total	210,990,363	17,844,129	17,280,550	17,962,145	16,822,923	16,560,257	16,309,420	16,924,415	16,757,160	15,365,702	17,294,873	20,275,047	21,593,743
Mid-Columbia Contracts													
Douglas - Wells p60828	3,698,661	308,222	308,222	308,222	308,222	308,222	308,222	308,222	308,222	308,222	308,222	308,222	308,222
Grant Reasonable	(3,067,851)	(255,654)	(255,654)	(255,654)	(255,654)	(255,654)	(255,654)	(255,654)	(255,654)	(255,654)	(255,654)	(255,654)	(255,654)
Grant Surplus p258951	2,039,032	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919	169,919
Mid-Columbia Contracts Total	2,669,842	222,487	222,487	222,487	222,487	222,487	222,487	222,487	222,487	222,487	222,487	222,487	222,487
Total Long Term Firm Purchases	453,131,126	44,928,738	40,970,827	42,673,565	38,369,917	36,749,517	37,246,697	33,360,415	33,585,782	31,696,998	34,267,117	38,739,210	40,542,345

PacifiCorp

_ORTAM16 NPC Study _2015 03 17 GOLD

Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Storage & Exchange													
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
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	2,032,800	660,000	660,000	712,800	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	2,032,800	660,000	660,000	712,800	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	17,396,279	147,796	264,370	2,096,021	3,202,808	2,499,855	2,427,127	1,061,845	2,799,530	1,737,949	287,826	187,911	683,241
Four Corners	4,042,829	79,418	812,467	677,719	473,808	32,136	729,783	197,099	297,987	122,890	439,593	135,528	44,401
Mead	3,904	-	3,904	-	-	-	-	-	-	-	-	-	-
Mid Columbia	46,396,223	702,411	149,481	3,953,112	2,784,237	4,741,402	3,224,264	15,140,027	8,333,702	967,306	3,881,083	1,009,512	1,509,688
Mona	5,935,783	399,767	445,623	1,650,981	417,513	414,070	229,578	429,857	380,826	168,468	363,033	498,355	537,714
NOB	1,157,450	3,339	229,392	11,692	42,756	87,684	277,678	122,022	8,442	21,034	-	58,723	294,688
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
EIM Imports	(970,632)	(80,886)	(80,886)	(80,886)	(80,886)	(80,886)	(80,886)	(80,886)	(80,886)	(80,886)	(80,886)	(80,886)	(80,886)
Emergency Purchases	133,004	6,470	5	58,152	10,533	96	-	-	-	17,231	38,809	1,708	-
DA-RT Balancing	92,668,375	6,336,360	4,836,629	8,469,576	6,556,826	7,904,200	8,076,752	11,216,554	13,023,076	6,579,682	5,736,559	5,832,213	8,099,948
Total System Balancing Purchases	166,763,215	7,594,676	6,660,985	16,836,367	13,407,594	15,598,557	14,884,294	28,086,518	24,762,675	9,533,675	10,666,017	7,643,063	11,088,794
Total Purchased Power & Net Inte	627,327,141	53,633,413	48,741,812	60,672,732	52,227,511	52,798,074	52,580,991	61,896,933	58,798,457	41,680,673	45,383,134	46,832,273	52,081,139

PacifiCorp

_ORTAM16 NPC Study _2015 03 17 GOLD

Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Wheeling & U. of F. Expense													
Firm Wheeling	147,716,221	12,658,681	13,128,481	13,525,792	12,710,892	11,793,419	11,940,245	12,014,725	11,437,886	11,865,747	12,055,424	11,952,610	12,632,321
C&T EIM Admin fee	496,083	43,880	39,352	37,994	36,057	37,459	39,686	45,311	46,346	43,595	41,697	41,078	43,628
ST Firm & Non-Firm	36,223	6,169	4,936	580	19	5,475	1,397	923	1,933	3,174	1,699	2,544	7,374
Total Wheeling & U. of F. Expense	148,248,527	12,708,730	13,172,770	13,564,366	12,746,969	11,836,353	11,981,328	12,060,959	11,486,165	11,912,516	12,098,820	11,996,231	12,683,322
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	58,220,045	4,724,607	5,296,058	5,391,889	3,356,499	4,537,707	4,129,051	4,984,799	5,054,323	5,432,076	5,471,885	4,853,984	4,987,167
Colstrip	17,555,088	1,614,915	1,442,078	1,665,898	1,523,017	927,484	922,636	1,634,969	1,648,983	1,570,131	1,455,718	1,575,135	1,574,126
Craig	25,109,564	2,251,262	2,058,376	2,155,387	2,203,242	2,100,128	2,105,229	2,287,574	2,273,232	2,156,351	1,621,216	1,732,806	2,164,760
Dave Johnston	62,240,102	4,614,041	4,880,935	4,588,696	5,067,641	5,540,051	5,426,159	5,751,930	5,792,967	5,509,837	5,173,464	4,864,888	5,029,492
Hayden	12,872,538	1,210,623	1,143,172	1,198,181	456,322	673,498	955,698	1,165,152	1,251,936	1,169,292	1,241,938	1,205,227	1,201,500
Hunter	149,626,086	12,358,135	11,570,163	8,825,804	11,361,825	13,059,338	12,496,954	13,809,616	13,136,754	13,319,838	13,898,603	12,824,718	12,964,338
Huntington	122,075,914	11,308,320	9,588,179	11,330,560	10,671,327	8,741,156	10,113,994	10,543,700	11,607,777	9,162,981	8,131,226	9,625,780	11,250,914
Jim Bridger	235,622,719	19,747,396	19,386,756	19,014,231	16,717,390	14,808,731	17,488,945	22,081,713	23,027,894	21,414,600	21,231,777	19,625,409	21,077,877
Naughton	112,111,247	9,902,906	9,322,956	9,935,331	7,547,493	8,088,135	9,358,308	9,368,965	9,964,689	9,523,907	10,157,221	9,132,403	9,808,934
Wyodak	29,059,552	2,601,294	2,512,563	1,502,145	2,140,024	2,135,457	2,596,101	2,668,951	2,724,438	2,581,297	2,697,875	2,207,082	2,692,325
Total Coal Fuel Burn Expense	824,492,853	70,333,499	67,201,237	65,608,121	61,044,779	60,611,685	65,593,076	74,297,369	76,482,993	71,840,311	71,080,923	67,647,430	72,751,431
Gas Fuel Burn Expense													
Chehalis	50,206,071	2,923,268	2,833,730	2,118,106	3,013,223	3,624,389	3,770,630	6,886,091	5,684,074	6,488,003	6,979,217	2,355,689	3,529,654
Currant Creek	45,589,812	4,125,360	1,584,008	3,139,295	2,322,897	3,899,921	3,820,194	5,591,154	5,497,844	5,057,367	2,570,585	4,015,545	3,965,644
Gadsby	4,448,726	-	-	-	59,467	-	-	1,429,255	2,061,261	898,743	-	-	-
Gadsby CT	3,483,374	248,566	25,763	176,876	106,439	221,307	277,331	552,869	516,585	514,752	393,603	243,866	205,416
Hermiston	36,507,538	3,221,514	2,956,403	2,525,190	1,534,906	804,111	1,434,255	3,507,720	4,046,888	3,905,222	3,607,241	4,197,653	4,766,434
Lake Side 1	65,977,869	6,528,800	4,570,574	3,543,777	4,108,747	5,067,000	5,611,339	6,838,002	6,980,272	5,375,153	3,988,198	6,633,796	6,732,211
Lake Side 2	81,947,002	7,948,423	6,570,456	5,853,775	4,626,063	6,045,812	6,218,516	7,448,992	7,725,151	7,186,545	7,117,304	7,423,380	7,782,585
Total Gas Fuel Burn	288,160,393	24,995,932	18,540,935	17,357,017	15,771,741	19,662,540	21,132,263	32,254,082	32,512,076	29,425,785	24,656,147	24,869,930	26,981,944
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	19,781,000	1,718,950	1,624,725	1,840,238	1,829,025	1,908,670	1,784,250	1,528,920	1,584,333	1,657,050	1,654,393	1,498,875	1,151,573
Clay Basin Gas Storage	25,914	(93,151)	(93,468)	(85,132)	53,143	53,143	53,143	53,143	53,143	53,143	53,143	(12,583)	(61,753)
Pipeline Reservation Fees	36,438,647	3,054,646	2,957,884	3,054,646	3,006,265	3,054,646	3,006,265	3,077,184	3,077,184	3,029,979	3,077,184	2,997,779	3,044,984
Total Gas Fuel Burn Expense	344,405,954	29,676,376	23,030,076	22,166,769	20,660,175	24,678,999	25,975,922	36,913,329	37,226,735	34,165,957	29,440,867	29,354,001	31,116,748
Other Generation													
Blundell	4,797,463	448,520	376,265	451,281	375,046	300,958	391,032	386,046	401,839	382,599	419,324	433,160	431,393
Integration Charge	6,262,777	585,186	505,150	582,279	515,600	497,698	488,700	444,804	438,755	426,452	514,400	628,788	634,966
Total Other Generation	11,060,240	1,033,707	881,414	1,033,560	890,646	798,655	879,732	830,851	840,594	809,051	933,724	1,061,948	1,066,360
Net Power Cost	**1,537,615,613**	130,651,746	125,218,628	130,156,579	117,037,299	121,026,026	128,803,941	147,661,118	142,616,772	119,986,535	119,497,752	120,913,486	134,045,730
Net Power Cost/Net System Load	**25.21**	**24.28**	**25.51**	**26.38**	**25.08**	**25.24**	**25.95**	**26.00**	**25.76**	**24.64**	**24.54**	**24.35**	**24.68**

Docket No. UE 296
Exhibit PAC/103
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Update to Other Revenues

April 2015

PacifiCorp
Oregon - CY 2016 TAM
Other Revenues - Stand Alone TAM Adjustment

		Total Company					**Oregon Allocated**	
Line no		UE-287 Final	CY 2016	Factor	Factors CY 2015	Factors CY 2016	UE-287 Final	CY 2016
1	Seattle City Light - Stateline Wind Farm	(9,932,463)	(9,811,103)	SG	25.687%	25.464%	(2,551,374)	(2,498,269)
2	Non-company owned Foote Creek	(1,106,372)	(900,697)	SG	25.687%	25.464%	(284,196)	(229,351)
3	BPA South Idaho Exchange	(9,240,627)	(4,691,490)	SG	25.687%	25.464%	(2,373,661)	(1,194,627)
4	Little Mountain Steam Revenues	-	-	SG	25.687%	25.464%	-	-
5	James River Royalty Offset	(3,926,947)	-	SG	25.687%	25.464%	(1,008,724)	-
6								
7	Total Other Revenue	(24,206,409)	(15,403,291)				(6,217,955)	(3,922,247)
8								
9				Decrease (Increase) in Other Revenues Absent Load Change				2,295,709
10								
11				Baseline Other Revenues in Rates			(6,217,955)	
12				$ Change due to load variance from UE 287 CY 2015 forecast			(13,988)	
13				Other Revenues in Rates using 2016 load forecast			(6,231,943)	
14								
15				**Decrease (Increase) in Other Revenues Including Load Change**				**2,309,696**

Docket No. UE 296
Exhibit PAC/104
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Energy Imbalance Market Costs

April 2015

PacifiCorp
Oregon 2016 TAM
Energy Imbalance Market Costs

$ dollars

	CY 2016 EIM Costs			
	Total Company	**Factor**	**Factors CY 2016**	**Oregon Allocated**
Capital Investment	16,291,370			
Accumulated Deferred Income Taxes	(3,049,556)			
Depreciation Reserve	(3,810,701)			
Net Rate Base (13-month average)	$9,431,113			
	10.75%			
Pre-Tax Return on Rate Base	$1,014,212	SG	25.464%	$258,256
Operation & Maintenance (Ongoing)	1,259,600	SG	25.464%	320,741
Depreciation Expense	2,338,567	SG	25.464%	595,486
Total Revenue Requirement	$4,612,380			$1,174,482
CAISO Fee in Net Power Costs	$496,083	SG	25.464%	$126,321
Total EIM Costs	$5,108,463			$1,300,803

CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER
Docket No. UE 296
Exhibit PAC/105
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Brian S. Dickman

Energy Imbalance Market Import and Export Summary

April 2015

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 296
Exhibit PAC/106
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

List of Expected or Known Contract Updates

April 2015

List of Known Items Expected to be Updated During the 2016 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. The Company has entered power purchase agreements with the Utah Municipal Power Authority (UMPA) and Utah Associated Municipal Power Systems (UAMPS) associated with its acquisition of the Eagle Mountain municipal electric utility.
3. Changes in contract terms of existing electricity sales and purchase and exchange contracts.
4. New natural gas sales and purchase contracts, physical and financial.
5. Changes in contract terms of existing natural gas sales and purchase contracts.
6. Contracts whose prices are linked to market indexes and inflation rates.
7. Sales contract with Black Hills Company for energy price and fixed payments.
8. Purchase contracts for generation and fixed costs from the Mid Columbia projects.
9. Purchase contract with Tri-State Generation and Transmission Association Inc. for energy price.
10. Potential new qualifying facility purchase contracts with Ewauna, Arlington, Bonanza, Eagle Point, Falvey, Neff, Granite Mountain East, Granite Mountain West, Iron Springs Solar, Pavant II, and BYU-Idaho.
11. Potential new power purchase agreements with Bevans Point and Old Mill Solar for compliance with the Oregon Solar Capacity Standard.
12. Purchase expenses of PGE Cove based on PGE projection.
13. Election decision for Grant Meaningful Priority.

Transportation and Storage of Natural Gas

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

Wheeling Expenses and Transmission

17. New transmission contracts to wheel power to serve the Company's load obligations.
18. Changes in contract terms of existing transmission contracts.
19. Wheeling expenses that are impacted by changes in third-parties' transmission tariff rates.
20. The Company plans to update the Bonneville Power Administration (BPA) wheeling expenses to reflect BPA's final Record of Decision in its rate case, which is expected to be released July 24, 2015.
21. Contracts whose prices are linked to market indexes and inflation rates.

Other

22. Energy Imbalance Market benefit estimates, including import and export margins and volumes, as well as flexibility reserve diversity credits.

Coal Expense Update Items

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

		Captive		Fixed Price Contracts		Escalating Contracts		Transportation Contracts	
Plant	Supplier/Mine	Volume	Price	Volume	Price	Volume	Price	Volume	Price
Bridger	Bridger Coal Company	√							
	Black Butte								
	Union Pacific Railway							√	√
Cholla	Peabody Coalsales - Lee Ranch Mine					√	√		
	BNSF Railway							√	√
Colstrip	Westmoreland - Rosebud Mine					√	√	√	√
Craig	Trapper Mine	√							
	Tri-State - Colowyo Mine						√		
	Union Pacific Railway								√
Hayden	Twentymile Mine					√	√		
	Union Pacific							√	√
Hunter	Arch - Sufco			√	√				
	Utah American Energy - West Ridge			√	√				
	Utah Trucking							√	√
Huntington	Arch - Sufco			√	√				
	Rhino Energy - Castle Valley			√	√				
	Utah Trucking							√	√
D Johnston	Open Position					√	√		
	Western Fuels - Dry Fork Mine								
	Cloud Peak - Cordero Rojo Mine								
	BNSF Railway							√	√
Naughton	Chevron Mining - Kemmerer Mine					√	√		
Wyodak	Black Hills - Wyodak Mine					√	√		

Docket No. UE 296
Exhibit PAC/200
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Frank C. Graves

April 2015

DIRECT TESTIMONY OF FRANK C. GRAVES

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ATTACHED EXHIBITS

Exhibit PAC/201—Resume of Frank C. Graves

Exhibit PAC/202—Daily Spot vs. Forward Prices for Mid-Columbia

Q. Please state your name and present position.

A. My name is Frank C. Graves. I am a Principal at the economic consulting firm *The Brattle Group*, where I am also the leader of the utility practice group. I am testifying in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I specialize in regulatory and financial economics, especially for electric and gas utilities. I have assisted utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, supply procurement and cost recovery mechanisms, network flow modeling, renewable asset selection and contracting, and hedging strategies. I have testified before the Federal Energy Regulatory Commission (FERC) and many state regulatory commissions, as well as in state and federal courts, on such matters as integrated resource planning, the prudence of prior investment and contracting decisions, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions. I am the author of several publications in risk management. I received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975. I have included my detailed resume in Exhibit PAC/201.

Q. Have you previously testified on behalf of PacifiCorp regarding its energy cost recovery mechanisms?

A. Yes. I filed testimony on behalf of the Company in Wyoming, Docket No. 20000-405-ER-15 regarding recovery of gains and losses on hedging and whether and how to share hedging gains or losses between customers and the utility. In Docket No. 20000-469-ER-15, I filed testimony supporting changes to the energy cost adjustment mechanism. I also filed testimony in the Company's request for a power cost adjustment mechanism in Utah, Docket No. 09-035-15 and in Docket No. 10-035-124 regarding the recovery of gains and losses from hedging as well as the treatment of option costs.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I have been asked by the Company to review its pattern of systematic under-recovery of net power costs (NPC) that arise largely from system balancing transactions.

SYSTEMATIC NPC UNDER-RECOVERY

Q. Has NPC been under-recovered in Oregon in recent years?

A. Yes. Oregon's load share of incurred total NPC costs above forecasted costs has ranged from $15.6 million to $33.7 million per year during the last three years, or about 5-10 percent of total actuals. Figure 1 below shows the annual details for PacifiCorp.

Figure 1: PacifiCorp's NPC Annual Actual vs. NPC Recovered in Oregon

Year	OR NPC Collected Through Rates	OR Actual NPC	Under-Recovery of OR NPC
2011	$301,662,279	$333,544,839	$31,882,559
2012	$336,201,734	$351,814,385	$15,612,651
2013	$348,474,235	$382,126,867	$33,652,632

Q. Have you identified any consistent drivers of under-recovered NPC in recent years you would consider to be systematic?

A. Yes. These variances between forecasted and actual NPC have occurred largely because the numerous and essential "balancing" wholesale activities of PacifiCorp in the spot market are very large and unpredictable. If these variances tend to "wash out" over time, with some being negative losses to the Company (as above) but others being positive gains, they would merely be a source of noise in company financial performance but not an expected impairment or handicap for the Company. However, these loss patterns have persisted throughout periods of falling and rising power prices and appear to be systematic; they do not wash out.

Q. Please explain why PacifiCorp's NPC variances could occur systematically.

A. A likely reason is that system planning models used to forecast NPC costs do not reflect the extent and cost of realized volatility in prices and demand, nor can they readily capture the way unexpected demands and short-term price changes tend to be correlated, thereby leading to a net adjustment (balancing) cost that is not reflected in the modeling results. These limitations arise because no system planning model can include all of the uncertain factors that affect actual market operations.

For instance, it is extremely unusual for power systems models to include possible transmission system disruptions, nonstandard generation outages, or load variances due to multi-day persistent abnormal weather. In principle, virtually any one of these kinds of risk factors could be simulated in a Monte Carlo fashion, but doing so would require statistical evidence on their distributions that would be very hard to obtain and verify, and because there are so many such factors, it would be impossible to span all possible combinations of all of them. Importantly, it is also unlikely that such risk factors would occur in isolation, leaving all other expected conditions unchanged. For instance, higher than expected loads may occur in summer because it is hotter than normal, which might be associated with more solar renewable output but perhaps less wind production, while in winter, unexpected loads may correspond to cold snaps that also drive up gas prices. So in order to model these factors, all of their joint interactions would need to be well understood and recurring, at least statistically.

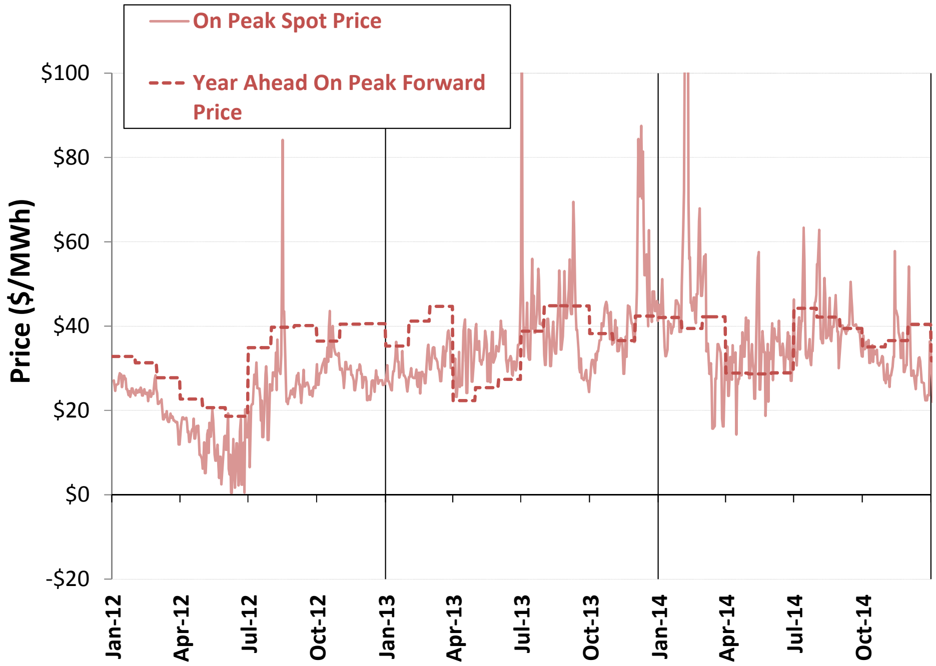
Q. So this is partly a product of practical limitations in forecasting models?

A. Yes, power system planning models tend to be "too smooth" or too perfect, basically only able to simulate how a specific set of assumed future likely conditions affect the costs of system operations if it were optimally deployed for those conditions. These models do not simulate what will happen if those conditions do not materialize, nor how system operators may conditionally manage their systems conservatively to defend against unforeseen circumstances, e.g., committing more fast response resources than would be required if there were no such uncertainties.

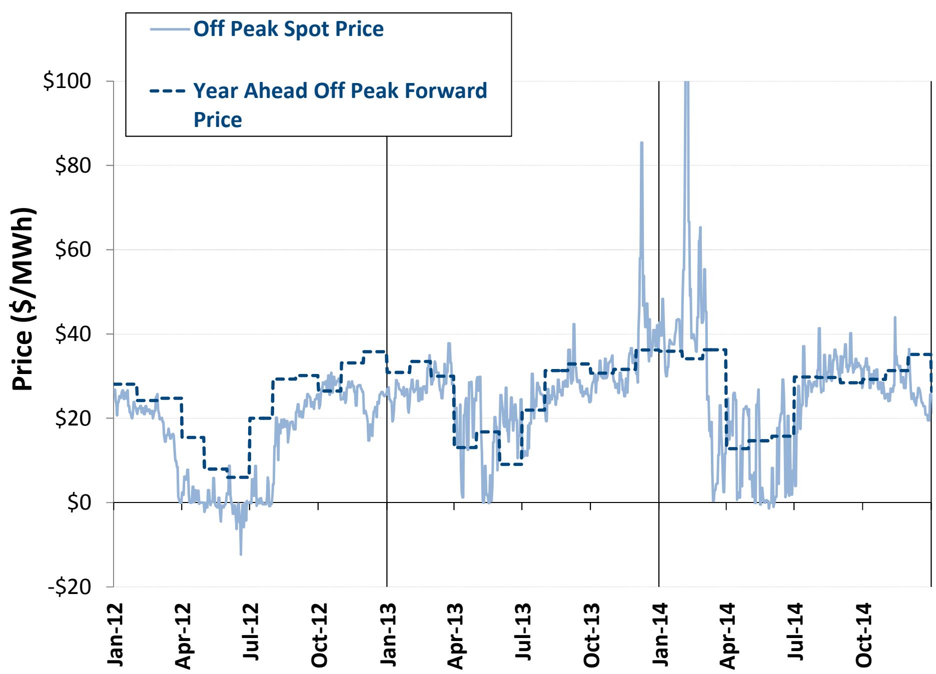
To demonstrate this, Figure 2 below shows that daily average spot prices at Mid-Columbia (Mid-C) are very volatile and have had several recent past dramatic spikes that are several times larger for short periods of time than the year-ahead forward price. Exhibit PAC/202 shows the same data for Palo Verde. Hourly prices within each day can be even more volatile than these daily averages, and balancing transactions often involve only a few hours of purchases or sales each day. While technically not a forecast, the traded forward prices are the market's consensus view of what is reasonable to expect realized spot prices to average, hence are somewhat like a forecast (and many traders may have used a forecasting model to decide what forward prices they were comfortable trading). Thus, the observed daily and annual average variance from forwards is evidence of how difficult it is to accurately forecast the spot price going forward. Moreover, even if you are right on average, you will inevitably be off by a significant amount from day to day and hour to hour. This complexity is part of why the realized NPC always differs from the forecast NPC.

Figure 2: Daily Spot vs. Forward Prices

(a) Mid-Columbia, On Peak



(b) Mid-Columbia, Off-Peak



Notes:

[1] Calculated based on data compiled by Ventyx, the Velocity Suite and SNL (as of March 23, 2015).
[2] Spot prices reflect day-ahead prices.
[3] Forward prices are as of the beginning of each month, and held constant throughout the month.

The typical forecasting model does not capture the volatility illustrated in Figure 2, so inherently the realized prices will exhibit greater volatility than the forecasted prices. Further, models typically do not simulate any kind of intra-hour constraints or uncertainty (including the GRID model used by PacifiCorp). Yet, intra-hour constraints and uncertainty cause many of the daily average spikes in Figure 2 above. The short time frames have recently become increasingly important to actual power system operations in the past decade (and will be even more so in the future) because of the increasing reliance on intermittent, renewable resources that are subject to rapid, very short-term changes in performance (if the wind or sunshine should change, as is common).[1]

As a result, even the most detailed of power industry simulation models typically underestimate short-term price and load volatility, though they may forecast average prices and loads over longer time periods fairly well.

Q. Are these volatility forecasting limitations to blame for the underestimation of NPC?

A. Not by themselves. Forecasting limitations in capturing volatility are not a source of persistent (or expected) cost shortfalls <u>unless</u> there is a pattern in the unforeseen price and volume variances from the model projections that causes those variances to have an additional, expected cost. That can arise if there is a consistent relationship between the direction of unexpected (not forecasted) demand and corresponding movements in spot prices of power or fuel relative to

[1] In the past two to three years, a new generation of system planning models have been developed that do simulate very short-term operating horizons and corresponding renewable resource performance uncertainty (or forecasting error). However, these are new and sometimes very cumbersome, and the data they require to capture these short-term effects is voluminous and not yet widely or conveniently available.

expectations. Specifically, if the relationship between movements in the unforeseen demand and spot prices is positive, then the variability in net purchase and sale revenues will tend to be both greater than the apparent price or volume volatilities by themselves, and there will tend to be a systematic, expected cost (above forecasts) as well. This occurs because these balancing transactions tend to involve a loss whether they are purchases or sales:

- If purchases, they tend to occur because demand is higher than expected (or renewable output is lower than expected) and prices are correspondingly higher than forecasted.
- If they are unplanned sales (because retail demand is unexpectedly low), the realized price tends to be depressed and below the forwards, again resulting in a loss relative to closing the expected volumes at the expected or forward price.

Q. Do PacifiCorp's balancing transactions tend to involve a pattern of losses?

A. Yes. Company studies of short-term transactions (less than one week in duration of committed volumes) at trading hubs in the last three years indicate this situation is occurring. At every trading hub, and for both on and off peak purchases and sales, in nearly every month for 36 months, it has been the case that purchases tend to cost more per MWh than average spot prices and sales tend to have occurred below the average monthly spot price (ignoring volumetric causes of revenue variance, i.e. just focusing on the price effects even if realized sales volumes had been known with certainty).

These average annual deviations are shown below in Confidential

Figure 3, by trading hub, for short-term transactions in July 2011 through June 2014. In this figure the MWh purchased each month at a given hub was multiplied by the historical average spot price at the respective hub and month. This amount was summed for the period starting July 2011 and ending June 2014. This total was then subtracted from the total actual dollar amount purchased at the same hub. Finally, this resulting difference was divided by the total amount of MWh purchased in the same time interval to yield a volume weighted average price deviation for all purchases at a given hub. The analogous calculation was performed for sales. Finally, the figure shows the transacted volume, which shows that while the volume-weighted price variation per MWh is large at, for example, Mona, the trading volume is small.

Confidential Figure 3: NPC Variability Breakdown

[redacted]

This graph shows that purchases have occurred at a premium to average prices and sales at a discount per MWh. When looking at the month-by-month source data for this graph, a somewhat more complex pattern emerges that is partly seasonal and varies by trading hub, and that is erratic year on year in absolute magnitudes. However, on average there is a monthly balancing price error of a few $/MWh in each direction, with purchases tending to occur at prices above the monthly average and sales below, to an extent not foreseen in the NPC forecasting models (even if they had been completely accurate about monthly average prices). Collectively, these balancing price variances seem to explain an average of about $27.8 million of PacifiCorp's annual shortfalls.

Q. Is there any way for the Company to avoid the types of transactions causing these systematic losses?

A. No. There is no possibility of operating in the complex power markets without unforecasted transactions to balance the Company's system on an hourly basis, and these must be done at whatever prices are then available in the market, subject to WECC market practices that dictate buying in 25MW blocks on a forward basis. This constraint on discrete block sizes further contributes to some unavoidable volume variances. That is, as described in Mr. Brian S. Dickman's testimony, the balancing transactions done on a forward basis utilize standard block products that are not a perfect match for the Company's hourly position shortfalls or slack supply. On a real-time basis the company must transact to balance then-current requirements (load) with available resources, including balancing positions taken previously on a week- or day-ahead forward basis.

Q. Why doesn't the Company leave all of its balancing to the hour-ahead market?

A. On a day-ahead basis, counterparties can nominate gas and bring additional gas generation online. Similarly, many hydro projects have flow and ramping constraints that limit hour to hour changes in output. Likewise, generation and transmission outage scheduling may be adjusted based on prices in the daily and monthly markets. Each of these results in lower resource flexibility on an hour-ahead basis than over longer time frames, and that reduced flexibility results in greater price premiums on purchases and reduced revenues on sales.

Q. How does this systematic pattern of losses on balancing transactions affect the Company financially?

A. These shortfalls unduly harm the Company and also imply that the NPC price in base rates is under-estimating true costs. As a result, the company proposes to reduce its expected exposure to this kind of systematic losses on balancing transactions by applying forecasting adjustment factors based on the monthly hub shortfalls observed over the past three years in average balancing prices per MWh. Assuming that this degree of bias persists, this correction will roughly restore base NPC rates to being fair estimates of actual average costs per MWh. This will also make overall variances much closer to zero, hence less burdensome on customers to absorb lagged over/under cost allocations. Thus, there are two advantages to this approach: (1) it makes base rates a better predictor of actual average costs per MWh and hence avoids customer surprises; and (2) it makes PacifiCorp's recovery of NPC more timely and accurate, requiring less true-up.

Of course, these factors have not been precisely stable in the past three years. They vary considerably from year to year in this historical period from which they are estimated, and they are unlikely to perfectly echo their history in the next few years, so there will still be variances.

Q. Could PacifiCorp reduce its exposure to these variances with better or alternative hedging?

A. No. First, most hedging takes place over longer time frames (weeks to months or years).[2] Nor could different hedge targets eliminate the persistent shortfalls for which remedy is sought here. Imbalances are inevitable at any level of target hedging—e.g., if peak demand was fully hedged, there would be a need to sell off when the peak was not reached; if the average need was hedged, the realized load would vary about that level and there would be a need for both purchases and sales. There also are no hedges available for the elements of balancing costs that are incurred, such as marginal losses, ancillary services for procuring or using spot market reserves, load uncertainty. In addition, PacifiCorp's hedging practices have been debated and modified over the past few years in settings that aired and compared customer needs and concerns with practical limitations on hedging analysis and reporting, and I believe those arrangements should be left in place.

Q. Does this conclude your direct testimony?

A. Yes.

[2] Day-ahead transactions are technically a hedge on day-of, real time operations, but their prices are subject to considerable variability, and most planning models do not consider real time differences from day-ahead prices, so the day-ahead prices are essentially expected spot prices for planning purposes.

Docket No. UE 296
Exhibit PAC/201
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Frank C. Graves

Resume of Frank C. Graves

April 2015

RESUME OF FRANK C. GRAVES

Mr. Frank C. Graves is a Principal of The Brattle Group and the leader of its Utility Practice Area line of business. He specializes in regulatory and financial economics, especially for electric and gas utilities, and in litigation matters related to securities litigation, damages from breached energy contracts, and risk management.

He has over 30 years of experience assisting utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, supply procurement and cost recovery mechanisms, network flow modeling, renewable asset selection and contracting, and hedging strategies. He has testified before the FERC and many state regulatory commissions, as well as in state and federal courts, on such matters as integrated resource planning (IRPs), the prudence of prior investment and contracting decisions, risk management, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions

In the area of financial economics, he has assisted and testified in civil cases in regard to contract damages estimation, securities litigation suits, special purpose audits, tax disputes, risk management, and cost of capital estimation, and he has testified in criminal cases regarding corporate executives' culpability for securities fraud.

He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

AREAS OF EXPERTISE

- *Financial Analysis and Commercial Litigation*
- *Utility Planning and Operations*
- *Regulated Industry Policy and Restructuring*
- *Energy Market Competition*
- *Electric and Gas Transmission*

PROFESSIONAL AFFILIATIONS

- IEEE Power Engineering Society
- Mathematical Association of America
- American Finance Association
- Stanford Energy Modeling Forum

REPRESENTATIVE ENGAGEMENTS

Financial Analysis and Commercial Litigation

- For an international energy company seeking to expand its operations in the US, Mr. Graves lead an assessment of the market performance risks facing a possible acquisition target, in order to determine what contingencies or market shifts were critical to it being an attractive target. Uncertain long run wholesale energy conditions, tightening environmental regulations, and disruptive technology development prospects were considered.
- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Mr. Graves developed a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops he lead with the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- For a For an international technology firm that had experienced a recent bankruptcy, Mr. Graves assisted in the design of a study of how the remaining valuable assets could be deemed assignable to disparate country-specific claims. Company operating practices for research and development risk and profit sharing were evaluated to identify an equitable approach.
- For a merchant power company with a prematurely terminated development contract, Mr. Graves co-lead a team to value the lost contract. The contract included several different kinds of revenue streams of different risks, for which Brattle developed different discount rates and debt carrying-capacity assessments. The case was settled with a very large award consistent with the Brattle valuations.
- Holding company utilities with many subsidiaries in different states face differing kinds of regulatory allowances, balancing accounts with differing lags and allowed returns for cost recovery, possibly different capital structures, as well as different (and varying) operating conditions. Given such heterogeneity, it can be difficult to determine which subsidiaries are performing well vs. poorly relative to their regulatory and operational challenges. Mr. Graves developed a set of financial

reporting normalization adjustments to isolate how much of each subsidiary's profitability was due to financial, vs. managerial, vs. non-recurring operational conditions, so that meaningful performance appraisal was possible.

- Many banks, insurance firms and capital management subsidiaries of large multinational corporations have entered into long term, cross border leases of properties under sale and leaseback or lease in, lease out terms. These have been deemed to be unacceptable tax shelters by the IRS, but that is an appealable claim. Mr. Graves has assisted several companies in evaluating whether their cross border leases had legitimate business purpose and economic substance, above and beyond their tax benefits, due to likelihood of potentially facing a role as equity holder with ownership risks and rewards. He has shown that this is a case-specific matter, not per se determined by the general character of these transactions.

- For a private energy hedge fund providing risk management contracts to industrial energy users, a breach of contract from one industrial customer was disputed as supposedly involving little or no loss because the fund had not been forced to liquidate positions at a loss that corresponded precisely to the abruptly terminated contract. Mr. Graves provided analysis demonstrating how the portfolio loss was borne, but other fund management metrics used to control positions, and other unrelated hedging positions, also changed roughly concurrently in a manner that disguised the way the economic damage was realized over time. The case was settled on favorable terms for Mr. Graves' client.

- Many utilities have regulated and unregulated subsidiaries, which face different types and degrees of risk. Mr. Graves lead a study of the appropriate adjustments to corporate hurdle rates for the various lines of business of a utility with many types of operations.

- A company that incurred Windfall Tax liabilities in the U.K. regarded those taxes as creditable against U.S. income taxes, but this was disputed by the IRS. Mr. Graves lead a team that prepared reports and testimony on why the Windfall Tax had the character of a typical excess profits tax, and so should be deemed creditable in the U.S. The tax courts concurred with this opinion and allowed the claimed tax deductions in full.

- For a defendant in a sentencing hearing for securities' fraud, Mr. Graves prepared an analysis of how the defendant's role in the corporate crisis was confounded by other concurrent events and disclosures that made loss calculations unreliable. At trial, the Government stipulated that it agreed with Mr. Graves' analysis.
- For the U.S. Department of Justice, Mr. Graves prepared an event study quantifying bounds on the economic harm to shareholders that had likely ensued from revelations that Dynegy Corporation's "Project Alpha" had been improperly represented as a source of operating income rather than as a financing. The event study was presented in the re-sentencing hearing of Mr. Jamie Olis, the primary architect of Project Alpha.
- Mr. Graves has assisted leasing companies with analyses of the tax-legitimacy of complex leasing transactions. These analyses involved reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent, purpose and cost of defeasance, and compliance with prevailing guidelines for true-lease status.
- For a utility facing significant financial losses from likely future costs of its Provider of Last Resort (POLR) obligations, Mr. Graves prepared an analysis of how optimal hindsight coverage would have compared in costs to a proposed restructuring of the obligation. He also reviewed the prudence of prior, actual coverage of the obligation in light of conventional risk management practices and prevailing market conditions of credit constraints and low long-term liquidity.
- Several banks were accused of aiding and abetting Enron's fraudulent schemes and were sued for damages. Mr. Graves analyzed how the stock market had reacted to one bank's equity analyst's reports endorsing Enron as a "buy," to determine if those reports induced statistically significant positive abnormal returns. He showed that individually and collectively they did not have such an effect.
- Mr. Graves lead an analysis of whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil" of limited liability. The analysis investigated the presence of untenable debt capitalization in the subsidiary,

overlapping management staff, the adherence to normal corporate governance protocols, and other kinds of evidence of excessive parental control.

- As a tax-revenue enhancement measure, the IRS was considering a plan to recapture deferred taxes associated with generation assets that were divested or reorganized during state restructurings for retail access. Mr. Graves prepared a white paper demonstrating the unfairness and adverse consequences of such a plan, which was instrumental in eliminating the proposal.
- For a major electronics and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.
- In a dispute over damages from a prematurely terminated long-term power tolling contract, Mr. Graves presented evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. The amount of damages was dramatically larger under a two-discount rate calculation, which was the position adopted by the court.
- The energy and telecom industries have been plagued by allegations regarding trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded financial collapse and subsequent shareholder suits. Mr. Graves lead research on accounting and financial evidence, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.
- Dramatic natural gas price increases in the U.S. have put several natural gas and electric utilities in the position of having to counter claims that they should have hedged more of their fuel supplies at times in the past. Mr. Graves developed testimony to rebut this hindsight criticism and risk management techniques for

fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.

- As a means of calculating its stranded costs, a utility used a partial spin-off of its generation assets to a company that had a minority ownership from public shareholders. A dispute arose as to whether this minority ownership might be depressing the stock price, if a "control premium" was being implicitly deducted from its value. Using event studies and structural analyses, Mr. Graves identified the key drivers of value for this partially spun-off subsidiary, and he showed that value was not being impaired by the operating, financial and strategic restrictions on the company. He also reviewed the financial economics literature on empirical evidence for control premiums, which he showed reinforced the view that no control premium de-valuation was likely to be affecting the stock.
- A large public power agency was concerned about its debt capacity in light of increasing competitive pressures to allow its resale customers to use alternative suppliers. Mr. Graves lead a team that developed an Economic Balance Sheet representation of the agency's electric assets and liabilities in market value terms, which was analyzed across several scenarios to determine safe levels of debt financing. In addition, new service pricing and upstream supply contracting arrangements were identified to help reduce risks.
- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to valuation and development decisions. Mr. Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.
- A major telecommunications firm was concerned about when and how to reenter the Pacific Rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together

should it face financial distress, while offering strong returns under good performance.

- There are many risks associated with operations in a foreign country, related to the stability of its currency, its macro economy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.
- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan of reorganization, which was approved. Testimony was provided on cost-of-service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.
- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reappraisal of these assets. Traditional valuation methods, e.g., based on the replacement costs of comparable assets, can be misleading because they do not consider market conditions. Mr. Graves testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.
- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spin-off of transmission, and new marketing programs were among the many components of the proposed new business plan.

- As a means of reducing supply commitment risk, some utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves assisted several of these utilities in the development of valuation models for comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power.
- For the World Bank and several investor-owned electric utilities, Mr. Graves presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as price caps and floors) for natural gas pipelines.
- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.
- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.
- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the

company. This defined an economic priority ladder for efforts to reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.

- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to the risks of bonds and stocks to estimate project-specific discount rates and their probable bounds.

Utility Planning and Operations

- Mr. Graves co-lead a team of Brattle analysts to assess the relative influence of different factors that were affected by the "Polar Vortex" cold snap of early 2013 that caused dramatic spikes in local power and gas prices in parts of the mid-Atlantic and northeastern US. The risks of similar recurring events were assessed in light of pending expansions of the electric and gas transmission grids, as well as likely coal plant retirements.
- For the Board of Directors or executive management teams of several utilities, Mr. Graves has lead strategic retreats on disruptive issues facing the electric industry in the future and how a utility should choose which risks and opportunities to embrace vs. avoid.
- Air quality and other power plant environmental regulations are being tightened considerably in the period from about 2014-2018. Mr. Graves has co-developed a market and financial model for determining what power plants are most likely to retire vs. retrofit with new environmental controls, and how much this may alter their profitability. This has been used to help several power market participants assess future capacity needs, as well as to adjust their price forecasts for the coming decade.

- Successful merchant power plant development and financing depends in part on obtaining a long term power purchase agreement. Mr. Graves directed a study of what pricing points and risk-sharing terms should be attractive to potential buyers of long-term power supply contracts from a large baseload facility.
- Many utilities are pursuing smart meters and time-of-use pricing to increase customer ability to consume electricity economically. Mr. Graves has led a study of the costs and benefits of different scales and timing of installation of such meters, to determine the appropriate pace. He has also evaluated how various customer incentives to increase conservation and demand response might be provided over the internet, and how much they might increase the participation rates in smart meter programs.
- Wind resources are a critical part of the generation expansion plans and contracting interests of many utilities, in order to satisfy renewable portfolio standards and to reduce long run exposure to carbon prices and fuel cost uncertainty. Mr. Graves has applied Brattle's risk modeling capabilities to simulate the impacts of on- and off-shore wind resources on the potential range of costs for portfolios of wholesale power contracts designed to serve retail electricity loads. These impacts were compared to gas CCs and CTs and to simply buying more from the wholesale market to identify the most economical supply strategy.
- For a municipal utility with an opportunity to invest in a nuclear power plant expansion, Mr. Graves lead an analysis of how the proposed plant fit the needs of the company, what market and regulatory (environmental) conditions would be required for the plant to be more economical than conventional fossil-fired generation, and how the development risks could be shared among co-owners to better match their needs and risk tolerances. He also assessed the market for potential off-take contracts to recover some of the costs and capacity that would be available for a few years, ahead of the needs of the municipal utility.
- The potential introduction of environmental restrictions or fees for CO_2 emissions has made generation expansion decisions much more complex and risky. He helped one utility assess these risks in regard to a planned baseload coal plant, finding that the value of flexibility in other technologies was high enough to prefer not building a conventional coal plant.

- Mr. Graves helped design, implement, and gain regulatory approvals for a natural gas procurement hedging program for a western U.S. gas and electric utility. A model of how gas forward prices evolve over time was estimated and combined with a statistical model of the term structure of gas volatility to simulate the uncertainty in the annual cost of gas at various times during its procurement, and the resulting impact on the range of potential customer costs.
- Generation planning for utilities has become very complex and risky due to high natural gas prices and potential CO2 restrictions of emission allowances. Some of the scenarios that must be considered would radically alter system operations relative to current patterns of use. Mr. Graves has assisted utilities with long range planning for how to measure and cope with these risks, including how to build and value contingency plans in their resource selection criteria, and what kinds of regulatory communications to pursue to manage expectations in this difficult environment.
- For a Midwestern utility proposing to divest a nuclear plant, Mr. Graves analyzed the reasonableness of the proposed power buyback agreement and the effects on risks to utility customers from continued ownership vs. divestiture. The decommissioning funds were also assessed as to whether their transfer altered the appropriate purchase price.
- Several utilities with coal-fired power plants have faced allegations from the U.S. EPA that they have conducted past maintenance on these plants which should be deemed "major modifications", thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. For another utility, Mr. Graves developed retrospective estimates of changes in emissions before and after repairs using production costing simulations. In a third, he reviewed contemporaneous corporate planning documents to show that no increase in emissions would have been expected from the repairs, due to projected reductions in future use of the plant as well as higher efficiency. In all three cases, testimony was presented.
- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but it has not fulfilled this duty. As a

result, nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared developed an economic model of the performance that could have reasonably been expected of the government, had it not breached its contract to remove the spent fuel.

- Capturing the full value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable market prices.

- Mr. Graves led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of its traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas program also included numerous adjustments to the gas company’s rate design, such as designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.

- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.

- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive. Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.

- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.
- Mr. Graves has helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probable need.
- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. Alternative balancing valuation and accounting methods were shown to be cheaper, more efficient, and simpler to administer. This analysis helped the parties reach a settlement based on a cash-in/cash-out design.
- The Clean Air Act Amendments authorized electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers or SCRs, until the present value cost of such investments is significantly below that projected from relying on EAs.
- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a major reorganization.

The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.

- Mr. Graves helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.
- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.
- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves designed and supervised market analyses to identify resale opportunities by comparing the marginal operating costs of all this company’s power plants not needed to meet target reserves to the marginal costs for almost 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.

- Mr. Graves specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.
- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies affect the relative attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe "front end load" while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This "value of service" framework was generalized for the Electric Power Research Institute.
- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.
- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.
- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. Planning tools were developed for balancing gas portfolios to customer group demands.

- For a Midwestern electric utility, Mr. Graves extended a regulatory pro forma financial model to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).
- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.
- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial pro forma simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.
- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and local taxpayers.

Regulated Industry Policy and Restructuring

- For a group of utilities responding to a state mandate to consider means of encouraging distributed technologies to be assessed and incentivized in parity with central station generation, Mr. Graves and others at Brattle prepared alternative means of incorporating marginal cost and externality value considerations into new cost/benefit assessment tools, procurement mechanisms, and supply contracting.

- For a mid-Atlantic gas distribution utility, Mr. Graves assessed mark to market losses that had occurred from gas supply hedges entered before spot prices declined precipitously. Concerns were voice that this outcome indicated the company's hedging practices were no longer attune to market conditions, so Mr. Graves developed and lead workshop between the company, intervener groups, and state commission staff to define new appropriate goals, mechanisms and review standards for revised risk management approach.
- For a major participant in the Japanese power industry contemplating reorganization of that country's electric sector following Fukushima, Mr. Graves lead a research project on the performance of alternative market designs around the US and around the world for vertical unbundling, RTO design, and retail choice.
- For several utilities facing the end of transitional "provider of last resort" (or POLR) prices, Mr. Graves developed forecasts and risk analyses of alternative procurement mechanisms for follow-on POLR contracts. He compared portfolio risk management approaches to full requirements outsourcing under various terms and conditions.
- For a large municipal electric and gas company considering whether to opt-in to state retail access programs, Mr. Graves lead an analysis of what changes in the level and volatility of customer rates would likely occur, what transition mechanisms would be required, and what impacts this would have on city revenues earned as a portion of local electric and gas service charges.
- Many utilities experienced significant "rate shock" when they ended "rate freeze" transition periods that had been implemented with earlier retail restructuring. The adverse customer and political reactions have lead to proposals to annual procurement auctions and to return to utility-owned or managed supply portfolios. Mr. Graves has assisted utilities and wholesale gencos with analyses of whether alternative supply procurement arrangements could be beneficial.
- The impacts of transmission open access and wholesale competition on electric generators risks and financial health are well documented. In addition, there are substantial impacts on fuel suppliers, due to revised dispatch, repowerings and retirements, changes in expansion mix, altered load shapes and load growth under

more competitive pricing. For EPRI, Mr. Graves co-authored a study that projected changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.

- As a result of vertical unbundling, many utilities must procure a substantial portion of their power from resources they do not own or operate. Market prices for such supplies are quite volatile. In addition, utilities may face future customer switching to or from their supply service, especially if they are acting as provider of last resort (POLR). This problem is a blending of risk management with the traditional least-cost Integrated Resource Planning (IRP). Regulatory standards for findings of prudence in such a hybrid environment are often not well understood or articulated, leaving utilities at risk for cost disallowances that can jeopardize their credit-worthiness. Mr. Graves has assisted several utilities in devising updated procurement mechanisms, hedging strategies, and associated regulatory guidelines that clarify the conditions for approval and cost recovery of resource plans, in order to make possible the expedited procurement of power from wholesale market suppliers.
- Public power authorities and cooperatives face risks from wholesale restructuring if their sales-for-resale customers are free to switch to or from supply contracting with other wholesale suppliers. Such switching can create difficulties in servicing the significant debt capitalization of these public power entities, as well as equitable problems with respect to non-switching customers. Mr. Graves has lead analyses of this problem, and has designed alternative product pricing, switching terms and conditions, and debt capitalization policies to cope with the risks.
- As a means of unbundling to retain ownership but not control of generation, some utilities turned to divesting output contracts. Mr. Graves was involved in the design and approval of such agreements for a utility's fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.
- Mr. Graves contributed to the design and pricing of unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of

possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundlings that were insensitive to system operations.

- For several natural gas pipeline companies, Mr. Graves evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.
- Mr. Graves assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and they have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves has assisted a leasing company with analyses of the tax-legitimacy of complex leasing transactions by reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

Market Competition

- Mr. Graves assisted a nuclear plant owner with an assessment of whether a proposed merger of a company in whom it had a partial investment interest would alter the co-owner’s incentives to manage the plant for maximum stand-alone value of the asset. Structural and behavioral models of the relevant market were developed to determine that there would be no material changes in incentive or ability to affect the value of the asset.

- Mr. Graves has testified on the quality of retail competition in Pennsylvania and on whether various proposals for altering Default Service might create more robust competition.
- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power. Mr. Graves assisted several utilities in evaluating the competitive impacts of potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, along with mechanisms for incorporating physical flow limits in FERC's Delivered Price Test (DPT) for mergers. He has also assessed the adequacy of mitigation measures (divestitures and conduct restrictions) under the DPT, Market-Based Rates, and other tests of potential market power arising from proposed mergers.
- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the quality of competition in the wholesale generation markets can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves helped one of the largest ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.
- Vertical market power arises when sufficient control of an upstream market creates a competitive advantage in a downstream market. It is possible for this problem to arise in power supply, in settings where the likely marginal generation is dependent on very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.
- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of a proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of the process for soliciting and ranking bids to buy tranches of capacity over the line.

- Many regions have misgivings about whether the preconditions for retail electric access are truly in place. In one such region, Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak transmission grid made adequate competition among numerous generation suppliers very implausible.
- Mr. Graves assisted one of the early ISOs with its initial market performance assessment and its design of market monitoring tests for diagnosing the quality of prevailing competition.

Electric and Gas Transmission

- Substantial fleets of wind-based generation can impose significant integration costs on power systems. Mr. Graves assisted in assessing what additional amounts and costs for ancillary services would be needed for a Western utility with a large renewable fleet. The approach included a statistical analysis of how wind output was correlated with demand, and how much forecasting error in wind output was likely to be faced over different scheduling horizons. Benefits of geographic diversity of the wind fleet were also assessed.
- For a utility seeking FERC approval for the purchase of an affiliate's generating facility, Mr. Graves analyzed how transmission constraints affecting alternative supply resources altered their usefulness to the buyer.
- As part of a generation capacity planning study, he lead an analysis of how congestion premiums and discounts relative to locational marginal prices (LMPs) at load centers affected the attractiveness of different potential locations for new generation. At issue was whether the prevailing LMP differences would be stable over time, as new transmission facilities were completed, and whether new plants could exacerbate existing differentials and lead to degraded market value at other plants.
- Mr. Graves assisted a genco with its involvement in the negotiation and settlement of "regional through and out rates" (RTOR) that were to be abolished when MISO joined PJM. His team analyzed the distribution of cost impacts from several competing proposals, and they commented on administrative difficulties or advantages associated with each.

- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to assess the inadequacies in the physical capabilities and economic incentives to manage voltages at adequate levels. The Brattle team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.
- Mr. Graves conducted a cost-of-service analysis for the pricing of ancillary services provided by the New York Power Authority.
- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves wrote a primer on how to define and measure the cost of electric utility transmission services for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the estimation of marginal costs of transmission. The implications for a variety of policy issues are also discussed.
- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves worked to develop alternative pricing mechanisms and service mixes for pipelines that would provide more dynamically efficient signals and incentives.
- Mr. Graves analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result from a proposed unbundling of services.

TESTIMONY

Direct testimony on behalf of Rocky Mountain Power in regard to recovery of gains and losses on hedging before the Wyoming Public Service Commission, Docket No. 20000-405-ER-15, March 2, 2015.

Direct testimony on behalf of Hope Gas, Inc., in regard to the prudence of its gas hedging, before the West Virginia Public Service Commission, Case No. 12-1070-G-30C, June 24, 2013.

Direct testimony on behalf of Public Service Company of New Mexico before the NM Public Regulation Commission re appropriate profit incentives for energy conservation activities, Case No. 12-00317-UT, October 5, 2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Utah in regard to hedging practices for natural gas supply, Docket 11-035-200, July 2012.

Rebuttal testimony on behalf of Rocky Mountain Power Company before the Public Service Commission of Wyoming in regard to gas supply hedging and loss-sharing, Docket No. 20000-405-ER-11, June 2012.

Direct testimony on behalf of Ohio Power Company before the PUC of Ohio in regard to performance of PJM capacity markets, in Ohio Power's application for its ESP service charges, Case No. 10-2929-EL-UNC, March 30, 2012.

Expert report and oral testimony on behalf of Pepco Holdings, Inc. before the Maryland Public Service Commission in regard to inadequacies in the MD PSC's RFP for new combined cycle generation development in SWMAAC, Case No. 9214, January 31, 2012.

Direct testimony on behalf of Columbus Southern Power Company and Ohio Power Company before the Public Utilities Commission of Ohio in the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, Case No. 10-2929 -EL-UNC, August 31, 2011.

Rebuttal report on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 07-876C, No. 07-875C, No. 07-877C, August 5, 2011.

Direct Testimony on rehearing regarding the allowance of swaps in Rocky Mountain Power's fuel adjustment cost recovery mechanism, on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, July 2011.

Comments and Reply Comments on capacity procurement and transmission planning on behalf of New Jersey Electric Distribution Companies before the State of New Jersey Board of

Public Utilities in the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning, NJ BPU Docket No. EO11050309, June 17, 2011; July 12, 2011.

Rebuttal testimony regarding Rocky Mountain Power's hedging practices on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, Docket No. 10-035-124, June 2011.

Expert and Rebuttal reports regarding contract termination damages, on behalf of Hess Corporation before the United States District Court for the Northern District of New York, Case No. 5:10-cv-587 (NPM/GHL), April 29, 2011, May 13, 2011.

Expert and Rebuttal reports on spent fuel removal at Rancho Seco nuclear power plant, on behalf of Sacramento Municipal Utility District before the U.S. Court of Federal Claims, No. 09-587C, October 2010, July 1, 2011.

Rebuttal testimony on the Impacts of the Merger with First Energy on retail electric competition in Pennsylvania, on behalf of Allegheny Power before the Pennsylvania Public Utility Commission, Docket Numbers A-2010-2176520 and A-2010-2176732, September 13, 2010.

Expert and Rebuttal reports on the interpretation of pricing terms in a long term power purchase agreement, on behalf of Chambers Cogeneration Limited Partnership before the Superior Court of New Jersey, Docket No. L-329-08, August 23, 2010, September 21, 2010.

Expert and Rebuttal reports on spent fuel removal at Trojan nuclear facility, on behalf of Portland General Electric Company, The City of Eugene, Oregon, and PacifiCorp before the United States Court of Federal Claims No. 04-0009C, August 2010, June 29, 2011.

Rebuttal and Rejoinder testimonies on the approval of its Smart Meter Technology Procurement and Installation Plan before the Pennsylvania Public Utility Commission on behalf of West Penn Power Company d/b/a Allegheny Power, Docket Number M-2009-2123951, October 27, 2009, November 6, 2009.

Supplemental Direct testimony on the need for an energy cost adjustment mechanism in Utah to recover the costs of fuel and purchased power, on behalf of Rocky Mountain Power before the Public Service Commission of Utah, Docket No. 09-035-15, August 2009.

Expert and Rebuttal reports on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 98-126C, No. 98-154C, No. 98-474C, April 24, 2009, July 20, 2009.

Expert report in regard to opportunistic under-collateralization of affiliated trading companies, on behalf of BJ Energy, LLC, Franklin Power LLC, GLE Trading LLC, Ocean

Power LLC, Pillar Fund LLC and Accord Energy, LLC before the United States District Court for the Eastern District of Pennsylvania, No. 09-CV-3649-NS, March 2009.

Rebuttal report in regard to appropriate discount rates for different phases of long-term leveraged leases, on behalf of Wells Fargo & Co. and subsidiaries, Docket No. 06-628T, January 15, 2009.

Oral and written direct testimony regarding resource procurement and portfolio design for Standard Offer Service, on behalf of PEPCo Holdings Inc. in its Response to Maryland Public Service Commission, Case No. 9117, October 1, 2008 and December 15, 2008.

Direct testimony regarding considerations affecting the market price of generation service for Standard Service Offer (SSO) customers, on behalf of Ohio Edison Company, et al., Docket 08-125, July 24, 2008.

Direct testimony in support of Delmarva's "Application for the Approval of Land-Based Wind Contracts as a Supply Source for Standard Offer Service Customers," on behalf of Delmarva Power & Light Company before the Public Service Commission of Delaware, July 24, 2008.

Oral direct testimony in regard to the Government's performance in accepting spent nuclear fuel under contractual obligations established in 1983, on behalf of plaintiff Dairyland Power Cooperative before the United States Court of Federal Claims (No. 04-106C), July 17, 2008.

Direct testimony for Delmarva Power & Light on risk characteristics of a possible managed portfolio for Standard Offer Service, as part of Delmarva's IRP filings (PSC Docket No. 07-20), March 20, 2008 and May 15, 2008.

Oral direct testimony regarding the economic substance of a cross-border lease-to-service contract for a German waste-to-energy plant on behalf of AWG Leasing Trust and KSP Investments, Inc before U. S. District Court, Northern District of Ohio, Eastern Division, Case No. 1:07CV0857, January 2008.

Direct testimony regarding portfolio management alternatives for supplying Standard Offer Service, on behalf of Potomac Electric Power Company and Delmarva Power & Light Company before the Public Service Commission of Maryland, Case No. 9117, September 14, 2007.

Direct testimony in regard to preconditions for effective retail electric competition, on behalf of New West Energy Corporation before the Arizona Commerce Commission, Docket No. E-03964A-06-0168, August 31, 2007.

Direct and rebuttal testimonies regarding the application of OG&E for an order of commission granting preapproval to construct Red Rock Generating Facility and authorizing a recovery rider, on behalf of Oklahoma Gas & Electric Company (OG&E) before the

Corporation Commission of the State of Oklahoma, Case No. PUD 200700012, January 17, 2007 and June 18, 2007.

Testimony in regard to whether defendant's role in accounting misrepresentations could be reliably associated with losses to shareholders, on behalf of defendant Mark Kaiser before U.S. District Court of New York SI:04Cr733 (TPG).

Rebuttal testimony on proposed benchmarks for evaluating the Illinois retail supply auctions, on behalf of Midwest Generation EME L.L.C. and Edison Mission Marketing and Trading before the Illinois Commerce Commission Docket Number 06-0800, April 6, 2007.

Direct and rebuttal testimonies on the shareholder impacts of Dynegy's Project Alpha for the sentencing of Jamie Olis, on behalf of the U.S. Department of Justice before the United States District Court, Southern District of Texas, Houston Division, Criminal Number H-03-217, September 12, 2006.

Direct and rebuttal testimony on the need for POLR rate cap relief for Metropolitan Edison and Pennsylvania Electric and the prudence of their past supply procurement for those obligations, on behalf of FirstEnergy Corp before the Pennsylvania Public Utility Commission, Docket Nos. R-00061366 and R-00061367, August 24, 2006.

Direct testimony regarding Deutsche Bank Entities' opposition to Enron Corp's amended motion for class certification, on behalf of the Deutsche Bank Entities before the United States District Court, Southern District of Texas, Houston Division, Docket No. H-01-3624, February 2006.

Expert and Rebuttal reports regarding the non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract, on behalf of Pacific Gas and Electric Company before the United States Court of Federal Claims, Docket No. 04-0074C, into which has been consolidated No. 04-0075C, November 2005.

Direct testimony regarding the appropriate load caps for a POLR auction, on behalf of Midwest Generation EME, LLC before the Illinois Commerce Commission, Docket No. 05-0159, June 8, 2005.

Affidavit regarding unmitigated market power arising from the proposed Exelon – PSEG Merger, on behalf of Dominion Energy, Inc. before the Federal Energy Regulatory Commission, Docket No. EC05-43-000, April 11, 2005.

Expert and rebuttal reports and oral testimonies before the American Arbitration Association on behalf of Liberty Electric Power, LLC, Case No. 70 198 4 00228 04, December 2004, regarding damages under termination of a long-term tolling contract.

Oral direct and rebuttal testimony before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, Docket No. 98-154 C, July 2004 (direct) and August 2004 (rebuttal), regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Direct, supplemental and rebuttal testimony before the Public Service Commission of Wisconsin, on behalf of Wisconsin Public Service Corporation and Wisconsin Power and Light Company, Docket No. 05-EI-136, February 27, 2004 (direct), May 4, 2004 (supplemental) and May 28, 2004 (rebuttal) in regard to the benefits of the proposed sale of the Kewaunee nuclear power plant.

Testimony before the Public Utility Commission of Texas on behalf of CenterPoint Energy Houston Electric LLC, Reliant Energy Retail Services LLC, and Texas Genco LP, Docket No. 29526, March 2004 (direct) and June 2004 (rebuttal), in regard to the effect of Genco separation agreements and financial practices on stranded costs and on the value of control premiums implicit in Texas Genco Stock price.

Rebuttal and additional testimony before the Illinois Commerce Commission, on behalf of Peoples Gas Light and Coke Company, Docket No. 01-0707, November 2003 (rebuttal) and January 2005 (additional rebuttal), in regard to prudence of gas contracting and hedging practices.

Rebuttal testimony before the State Office of Administrative Hearings on behalf of Texas Genco and CenterPoint Energy, Docket No. 473-02-3473, October 23, 2003, regarding proposed exclusion of part of CenterPoint's purchased power costs on grounds of including "imputed capacity" payments in price.

Rebuttal testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Ameren Energy Generating Company and Union Electric Company, Docket No. EC03-53-000, October 6, 2003, in regard to evaluation of transmission limitations and generator responsiveness in generation procurement.

Rebuttal testimony before the New Jersey Board of Public Utilities on behalf of Jersey Central Power & Light Company, Docket No. ER02080507, March 5, 2003, regarding the prudence of JCP&L's power purchasing strategy to cover its provider-of-last-resort obligation.

Oral testimony (February 17, 2003) and expert report (April 1, 2002) before the United States District Court, Southern District of Ohio, Eastern Division on behalf of Ohio Edison Company and Pennsylvania Power Company, Civil Action No. C2-99-1181, regarding coal plant maintenance projects alleged to trigger New Source Review.

Expert Report before the United States District Court on behalf of Duke Energy Corporation, Docket No. 1:00CV1262, September 16, 2002, regarding forecasting changes in air pollutant emissions following coal plant maintenance projects.

Direct testimony before the Public Utility Commission of Texas on behalf of Reliant Energy, Inc., Docket No. 26195, July 2002, regarding the appropriateness of Reliant HL&P's gas contracting, purchasing and risk management practices, and standards for assessing HL&P's gas purchases.

Direct and rebuttal testimonies before the Public Utilities Commission of the State of California on behalf of Southern California Edison, Application No. R. 01-10-024, May 1, 2002, and June 5, 2002, regarding Edison's proposed power procurement and risk management strategy, and the regulatory guidelines for reviewing its procurement purchases.

Rebuttal testimony before the Texas Public Utility Commission on behalf of Reliant Resources, Inc., Docket No. 24190, October 10, 2001, regarding the good-cause exception to the substantive rules that Reliant Resources, Inc. and the staff of the Public Utility Commission sought in their Provider of Last Resort settlement agreement.

Direct testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Northeast Utilities Service Company, Docket No. ER01-2584-000, July 13, 2001, in regard to competitive impacts of a proposed merchant transmission line from Connecticut to Long Island.

Direct testimony before the Vermont Public Service Board on behalf of Vermont Gas Systems, Inc., Docket No. 6495, April 13, 2001, regarding Vermont Gas System's proposed risk management program and deferred cost recovery account for gas purchases.

Affidavit on behalf of Public Service Company of New Mexico, before the Federal Energy Regulatory Commission (FERC), Docket No. ER96-1551-000, March 26, 2001, to provide an updated application for market based rates.

Affidavit on behalf of the New York State Electric and Gas Corporation, April 19, 2000, before the New York State Public Service Commission, In the Matter of Customer Billing Arrangements, Case 99-M-0631.

Supplemental Direct and Reply Testimonies of Frank C. Graves and A. Lawrence Kolbe (jointly) on behalf of Southern California Edison Company, Docket Nos. ER97-2355-00, ER98-1261-000, ER98-1685-000, November 1, 1999, regarding risks and cost of capital for transmission services.

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Docket No. UE 296
Exhibit PAC/202
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

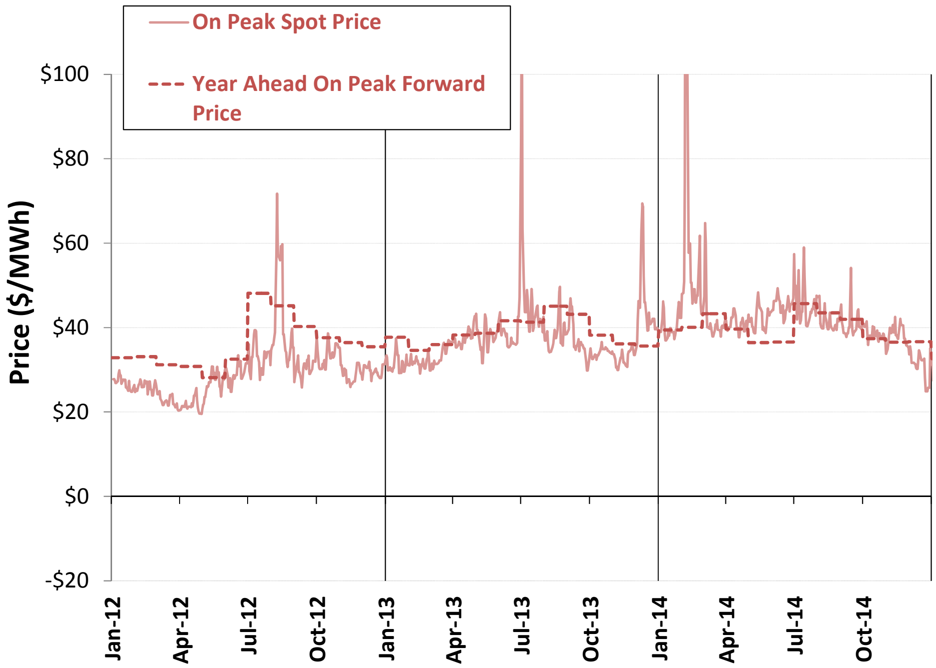
Exhibit Accompanying Direct Testimony of Frank C. Graves

Daily Spot vs. Forward Prices

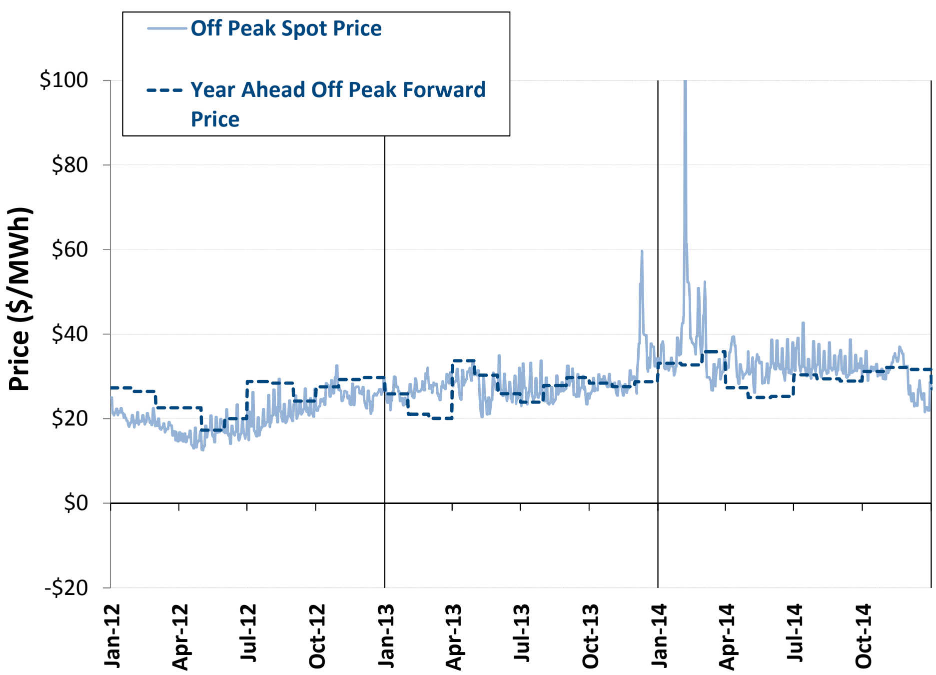
April 2015

Daily Spot vs. Forward Prices

(a) Palo Verde, On Peak



(b) Palo Verde, Off Peak



Notes:

[1] Calculated based on data compiled by Ventyx, the Velocity Suite and SNL (as of March 23, 2015).
[2] Spot prices reflect day-ahead prices.
[3] Forward prices are as of the beginning of each month, and held constant throughout the month.

Docket No. UE 296
Exhibit PAC/300
Witness: Stephen A. Larsen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Stephen A. Larsen

April 2015

DIRECT TESTIMONY OF STEPHEN A. LARSEN

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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 Stephen A. Larsen. 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.

QUALIFICATIONS

Q. Briefly describe your professional experience.

A. I joined Berkshire Hathaway Energy (BHE, f/k/a MidAmerican Energy Holdings Company) in 1999 and have held positions of increasing responsibility including Plant Engineer at Saranac Power Partners, General Manager of Yuma Cogeneration, General Manager of Imperial Valley Operations, President of CalEnergy Operating Company, and Vice President Construction for BHE Renewables. In November 2014, I was appointed to my present position as Vice President of Interwest Mining Company and Fuel Resources. 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 in this proceeding?

A. I explain the Company's overall approach to coal supply for the Company's coal-fired generating plants and provide support for the level of coal prices included in coal fuel expense in the 2016 TAM.

Q. Please summarize your testimony.

A. My testimony:

- Explains the primary causes of changes to the total-company coal fuel expense reflected in the 2016 TAM;
- Provides background on third-party coal contracts and current contract price re-openers; and
- Reviews the Company's affiliate mine coal prices and compares them to other supply alternatives.

OVERVIEW OF THE COMPANY'S COAL SUPPLIES

Q. How does the Company plan to meet fuel supplies for its coal plants in 2016?

A. As reflected below in confidential Table 1, the Company employs a diversified coal supply strategy. The Company will supply approximately 82.0 percent of its 2016 coal requirements with third-party coal supplies and 18.0 percent with coal from the Company's affiliate mines. More specifically: (1) approximately 50.9 percent of the Company's total coal requirement will be supplied under fixed-price contracts; (2) approximately 28.5 percent will be supplied under contracts that escalate or de-escalate based on changes to producer and consumer price indices; and (3) approximately 2.6 percent of the total coal requirement will be supplied to the Dave Johnston plant from currently unidentified Powder River Basin (PRB) mines.

Confidential Table 1: Coal Sourcing

[redacted]

Q. Please explain how the Company's Utah plants are supplied with coal, taking into consideration the Company's proposed closure of the Deer Creek mine.

A. The Utah plants are sourced collectively through a diversified portfolio of coal supplies under four different coal supply agreements. The Hunter plant receives coal under two different coal supply agreements. The primary coal supply for Hunter is provided through a long-term coal supply agreement with Bowie Coal Sales, LLC (Bowie). A second coal supply agreement is with West Ridge Resource, Inc. With the proposed closure of the Deer Creek mine, the primary coal supply to the Huntington plant will be a new long-term contract with Bowie. The Huntington plant also receives coal under a coal supply agreement with Rhino Energy, LLC. Two of the coal supply agreements, West Ridge Resources, Inc. and Rhino Energy, LLC, are interchangeable between Hunter and Huntington. The flexibility to move coal between the two plants helps to ensure that the targeted coal quality blends are met for each plant and helps minimize transportation costs between the mines and the plants. In April 2015, the Carbon plant will be closed. Coal which has been directed and delivered to Carbon will now be redirected to the Hunter and Huntington plants.

Q. Confidential Table 1 includes spot/unidentified coal for the Dave Johnston plant. Please explain.

A. The Dave Johnston plant is projected to consume approximately 3.7 million tons in 2016; the Company currently has 3.0 million tons of coal for the plant under contract. The Company intends to solicit multi-year coal supplies from PRB mines through a request for proposal during the second quarter of 2015.

COAL COST CHANGES

Q. Has total coal fuel expense in the 2016 TAM decreased from the level reflected in the Company's 2015 TAM?

A. Yes. As stated in the testimony of Mr. Brian S. Dickman, coal fuel expense has increased by $4.4 million, from $820.1 million in the 2015 TAM update to $824.5 million in the 2016 TAM (all dollar amounts stated in my testimony are on a total-company basis). This increase represents an increase related to higher coal prices of approximately [redacted], offset by a decrease relating to reduced coal-fired generation of approximately [redacted].

Q. What are the primary drivers of the [redacted] increase in coal prices?

A. Approximately [redacted] of the increase in coal prices is associated with third-party coal purchases and transportation costs and approximately [redacted] is associated with the Company's affiliated mines. These increases are offset by a decrease of [redacted] associated with the proposed sale of the preparation plant to Bowie.

THIRD-PARTY COAL CONTRACTS

Q. Please discuss the change in third-party coal supplies.

A. The Company expects a net increase in third-party coal supply costs as shown in confidential Table 2 below:

Confidential Table 2: Coal Transportation Contract Price Increases/Decreases

[redacted]

Coal Supply Agreements for the Wyoming Plants

Naughton

Q. Has the Naughton plant's coal cost changed from the 2015 TAM?

A. Yes, delivered coal costs have increased [redacted] compared to the 2015 TAM or [redacted]. The increase includes the expected impact of the 2016 contract price reset, estimated at [redacted]. The remainder of the increase, [redacted], is the result of a change in the amount of coal purchased under each price tier, namely fewer Tier 2 tons.

Q. Please describe the coal supply arrangements and contract purchase price reset.

A. The Naughton plant is supplied via an overland conveyor by Westmoreland's adjacent Kemmerer mine under a long-term coal supply agreement. The current coal supply agreement was renegotiated in 2010 and will terminate December 31, 2021. The contract includes tiered pricing: (1) Tier 1 includes the first 2.4 million tons purchased in a contract year; and (2) Tier 2 purchases in excess of 2.4 million tons. The contract calls for the price to be reset starting January 2016 based on 2015 mine costs. The Company expects the purchase price to increase [redacted] on January 1, 2016 as a result of increased mine costs at Westmoreland's mine.

Wyodak

Q. Please describe the price increase related to the Wyodak contract.

A. The company was in the midst of contract negotiations to settle the July 1, 2014 price reopener during the 2015 TAM. A price reopener settlement was reached with Wyodak Resources Development Corp. on October 30, 2014, after the Company filed its rebuttal TAM update. Delivered coal costs have increased [redacted] compared to the 2015 TAM [redacted]. The 2016 TAM includes an increase for final settlement terms of approximately [redacted]. The remainder of the cost increase, approximately [redacted], is the result of the escalation of contract indices.

Jim Bridger

Q. Please explain the increase in third-party coal prices for the Jim Bridger plant.

A. The Company's previous agreement with Black Butte Coal Company will expire in 2015 with the delivery of the 2010 contract's deferred tons. The Company issued a request for proposals (RFP) coal solicitation on June 9, 2014, to evaluate the least-cost fueling replacement option for the Black Butte coal supply. The RFP was issued to all coal suppliers in Southwest Wyoming and to the suppliers of 8,800 Btu PRB coal. Five of the coal suppliers responded with proposals. A new coal supply agreement for Black Butte coal was executed in December 2014.

The Company's previous agreement for third-party coal transportation with Union Pacific Railroad Company (UPRR) expires concurrently with the coal supply agreement. The Company entered into negotiations with UPRR in the latter half of 2014 to secure a rail agreement to transport Black Butte and PRB coal to the plant. The new agreement with UPRR was signed in January 2015.

Bridger plant third-party coal prices increase [redacted] compared to the 2015 TAM or [redacted]. The price of Black Butte coal delivered to the Jim

Bridger plant has increased from [redacted] This price increase is the result of the increase in the price of coal for this niche coal supply as determined by the RFP. The increase attributable to the Black Butte contract price is approximately [redacted]. The increase attributable to the UPRR rail agreement is approximately [redacted].

Dave Johnston

Q. Does the 2016 TAM reflect an increase in Dave Johnston generating plant coal supply costs?

A. Yes. Dave Johnston plant delivered coal costs have increased by [redacted] compared to the 2015 TAM or [redacted]. An increase in coal costs of approximately [redacted] is partially offset by a decline in rail cost of approximately [redacted].

Q. What are the coal supply arrangements for Dave Johnston in the 2016 TAM?

A. Following an April 2014 RFP for PRB coal supplies, the Company executed a three-year coal supply agreement for the purchase of additional Dry Fork mine coal from Western Fuels through 2016. At that time, the Company also entered into a two-year agreement with Cloud Peak Energy for the purchase of Cordero Rojo mine coal for 2015 and 2016. For 2015 and 2016, a total of [redacted] tons per year (approximately 67 percent of the plant's annual requirements) will be supplied from Western Fuels' Dry Fork mine. Cloud Peak Energy's Cordero mine will supply [redacted] tons (approximately 28 percent of the plant's requirements) in 2015 and [redacted] tons (approximately 14 percent of the plant's requirements) in 2016. The Company intends to solicit the remainder of the plant's requirements through an RFP during the second quarter of 2015. The coal price for Dave Johnston's open position in the 2016 TAM reflects the average 2016 forward price for PRB 8400 Btu coal as published in Coal Daily in February 2015.

Coal Supply Agreements for the Utah Plants

Q. Which non-affiliated mines currently supply coal to the Utah plants?

A. The Company has a diversified portfolio of multi-year coal supply agreements with Bowie's Sufco mine (Sufco), Utah American Energy's West Ridge mine (West Ridge), and Rhino Energy's Castle Valley mine (Castle Valley).

Q. Have prices for coal supply to the Utah plants changed from levels reflected in the 2015 TAM?

A. Yes. Purchased coal and transportation costs for the Utah plants (Hunter and Huntington) have decreased by approximately [redacted]. This is the result of a decrease of [redacted] at the Hunter plant offset by a [redacted] increase at the Huntington plant. The decrease is primarily associated with an expected price reduction for Sufco coal resulting from a January 2016 contract price re-opener. In addition to this expected price reduction, with the increased tonnage volume of coal being delivered to the Hunter plant, there is a further price discount associated with "Tier 2" coal under the agreement

Q. Please explain how the proposed Deer Creek mine closure is expected to affect fuel supply to the Utah plants.

A. The Deer Creek mine was the primary coal supplier for the Huntington plant. The

Company has executed a new long-term coal supply agreement with Bowie through 2029, contingent on approval from the Public Utility Commission of Oregon (Commission) in docket UM 1712. Coal received under this agreement is designated for the Huntington plant. The agreement is a "delivered to plant" agreement, and Bowie is responsible for the transportation of the coal from the mine to the plant.

In addition, the Company has a long-term coal supply agreement with Bowie for Sufco coal delivered to the Hunter plant. This agreement, which was amended as a part of the Deer Creek mine transaction, expires in December 2020. This is also a "delivered to the plant" agreement.

Q. Based on the proposed transaction to close the Deer Creek mine, what fuel supply costs for the Hunter and Huntington plants are included in the 2016 TAM?

A. For the Hunter plant, delivered coal prices will decrease from [redacted] per ton in the 2015 TAM to [redacted] per ton in the 2016 TAM, a reduction of [redacted] per ton or [redacted]. Third-party coal purchases will decrease [redacted] and Energy West costs will decrease [redacted]. For the Huntington plant, delivered coal prices will increase from [redacted] per ton in the 2015 TAM to [redacted] per ton in the 2016 TAM, an increase of [redacted] per ton or [redacted]. Third-party coal purchases will increase [redacted], and Energy West costs will increase [redacted].

Q. Does the 2016 TAM reflect Energy West pension costs?

A. Yes. Consistent with the Company's application in docket UM 1712, the 2016

TAM includes [redacted] for contributions to the 1974 United Mine Workers Association pension plan and a credit of [redacted] in pension costs associated with management employees. Approximately [redacted] is included in Huntington plant costs and [redacted] in Hunter plant costs.

Q. Have other Energy West Mining Company costs decreased in the 2016 TAM compared to the 2015 TAM?

A. Yes. Preparation plant operating costs have decreased by approximately [redacted]. Contingent upon Commission approval, the preparation plant will be sold to Bowie and Bowie will deliver coal to the Hunter plant consistent with contract coal quality specifications. Operating costs for the preparation plant are therefore eliminated in the 2016 TAM. In addition, cost savings associated with Deer Creek coal shipped directly to Hunter plant and from the preparation plant result in a cost reduction of [redacted].

Q. Please discuss the coal supply arrangements with Castle Valley, West Ridge, and Sufco.

A. The Company has a long-term coal supply agreement with Castle Valley mine. The mine is required to supply [redacted] tons of coal annually through 2017 for the Company's Utah plants. The coal pricing under this coal supply agreement is specified fixed pricing for each year under the agreement. The mine price decreased from [redacted] per ton in 2014 to [redacted] per ton in 2015 as a result of a contract price re-opener. Additionally, the Company negotiated a favorable option to purchase an additional [redacted] tons of coal in both 2015 and 2016 for [redacted] per ton and [redacted] per ton, respectively.

The Company negotiated a new two-year coal supply agreement in 2014 with the West Ridge mine. The prior coal supply agreement expired December 31, 2014. The new coal supply agreement results in significant savings to the Company. The 2015 free-on-board (FOB) mine price is [redacted] per ton. This represents a [redacted] per ton savings against the 2014 price in the prior agreement. The 2016 FOB mine price is [redacted] per ton.

Coal Supply Agreements for the Jointly Owned Plants

Cholla

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 and El Segundo mine complex through 2024, which includes two price re-openers: the first price re-opener was January 1, 2013; the second price re-opener is January 1, 2018.

Q. What price has the Company assumed for the Cholla coal supply in the 2016 TAM?

A. With quarterly escalation and de-escalation based on producer and consumer price indices, the average clean coal price under the new agreement is projected to decrease from the [redacted] per ton price assumed in the 2015 TAM to [redacted] per ton in the 2016 TAM, or [redacted] per ton. The decrease is mainly attributable to a reduction in diesel fuel and natural gas indices under the agreement. Including royalties, taxes and transportation, the Company forecasts that delivered coal prices will decrease from [redacted] per ton in the 2015 TAM to [redacted] per ton in the current 2016 TAM, a reduction of [redacted] per ton or [redacted].

Hayden

Q. Has the Hayden plant's coal cost changed from the 2015 TAM?

A. Yes. Delivered coal prices have decreased from [redacted] per ton in the 2015 TAM to [redacted] per ton in the 2016 TAM, a reduction of [redacted] per ton or [redacted]. The contract price adjusts with changes in producer and consumer price indices.

Colstrip

Q. Please explain the increase in coal fuel expense for Colstrip in the 2016 TAM.

A. Coal prices for the Colstrip plant have increased from [redacted] per ton in the 2015 TAM to [redacted] per ton in the 2016 TAM, or [redacted] per ton or [redacted]. 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 owners of Colstrip Units 3 and 4. The increase in 2016 is primarily attributable to an increase in Rosebud's variable production cost.

Craig

Q. Please describe the coal supply arrangements for the Craig plant.

A. The Craig plant is supplied with two long-term coal supply agreements. One agreement is with Tri-State's Colowyo mine through 2017. Pricing under this agreement adjusts quarterly based upon the escalation and de-escalation of specific producer and consumer price indices. The agreement also has a market price adjustment effective July 2016. The second agreement is a long-term agreement with the Trapper Mine that runs through 2020. The Trapper mine is a captive mine owned by the several owners of the Craig plant. The pricing under the agreement is based upon the annual mine cost associated with the Trapper mine.

Q. Has the Craig plant's third-party coal cost changed from the 2015 TAM?

A. Yes. Delivered coal prices have increased from [redacted] per ton in the 2015 TAM to [redacted] per ton in the 2016 TAM, an increase of [redacted] per ton or [redacted]. The primary reason for the increase is an estimated market price adjustment in 2016 under the Colowyo coal supply agreement.

CAPTIVE MINE COAL COSTS

Q. Please explain the major changes associated with coal supply from PacifiCorp's captive mines in the 2016 TAM.

A. Bridger Coal Company mine costs have increased by [redacted] per ton or [redacted] million. As described above, Energy West Mining Company costs decreased [redacted]. Trapper mine costs have decreased from [redacted] per ton in the 2015 TAM to [redacted] per ton in the 2016 TAM, or [redacted] per ton or [redacted].

Q. In Order No. 13-387, the Commission ordered the Company to remove certain operations and maintenance costs embedded in the costs of coal from its affiliate mines.[1] Did the Company adjust the price of coal from Bridger Coal Company consistently with Order No. 13-387?

A. Yes. In the 2016 TAM, the Company reduced Bridger Coal Company costs by approximately $1.2 million to reflect removal of management overtime and 50 percent of annual incentive plan (AIP) awards.

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[1] *In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism,* Docket UE 264, Order No.13-387 (Oct. 28, 2013).

Q. In Order No. 13-387, the Commission also directed the Company to prepare a periodic fuel supply plan for plants supplied by affiliate mines. Is the Company in the process of developing the required plan for the Jim Bridger plant?

A. Yes. In the 2015 TAM, the Company made a proposal for the timing and contents of the periodic fuel supply plan, to which no party objected. Consistent with that proposal, the Company intends to file a fuel supply plan for the Jim Bridger plant by the end of 2015.

Bridger Coal Company

Q. Please describe the change in Bridger Coal Company coal costs in the 2016 TAM.

A. Bridger Coal Company costs increased from the 2015 TAM by approximately [redacted]. Bridger Coal Company costs increased from [redacted] per ton in the 2015 TAM to [redacted] per ton in the 2016 TAM, or by [redacted] per ton or [redacted]. A decrease in Bridger Coal's heat content from [redacted] per pound of coal accounts for [redacted] of the increase, and changes in volume reduced costs by [redacted]

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

A. Yes, as reflected in confidential Table 3 below, Bridger Coal Company's production has decreased from [redacted] tons in the 2015 TAM to [redacted] tons in the 2016 TAM, and Bridger Coal Company deliveries have decreased from [redacted] tons to [redacted] tons. The decrease in Bridger Coal Company deliveries corresponds with increased coal deliveries from Black Butte Coal Company during 2016.

Confidential Table 3: Bridger Coal Production

[redacted]

Q. Please explain the decrease in production from the Bridger Coal Company's underground mine.

A. There are three significant factors contributing to less underground mine production in the 2016 TAM:

- A reduction in the number of continuous miner production shifts due to changes in workforce schedules for underground mine employees. The underground mine is currently operating three continuous miner sections, two 10-hour shifts per day, four days per week. In the 2015 TAM, two continuous miner sections were projected to operate two 12-hour shifts per day, six days per week. The third continuous miner section was projected to operate two 12-hour shifts per day, four days per week. Workforce schedule and shift changes are driven by limited workforce availability at the underground mine.

- A reduction in the amount of coal produced by the longwall. Longwall production is reduced as the mine balances longwall system retreat and continuous miner development. In addition, fewer tons are extracted from each panel due to utilizing a lower profile longwall machine in the 2016 TAM.

- Longwall panels were shortened beginning with the 14 Right panel due to geological conditions and changes in the ventilation plan mandated by the Mine Safety and Health Administration.

Q. Please describe the major drivers of the increase in cost of Bridger Coal Company deliveries to the Bridger plant.

A. The reduced coal production from the underground mine has had a significant impact of delivered costs in the 2016 TAM. Primary cost drivers expressed on a cost per ton basis for the Bridger Coal Company are: (1) increased depreciation; (2) reduced coal inventory expense; (3) increased final reclamation expense; and (4) increased controllable costs.

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

A. The delivered cost of coal from Bridger Coal Company is [redacted] per ton in the 2016 TAM, which is comparable to the forecasted Black Butte cost of [redacted] per ton and Kemmerer cost of [redacted] per ton for calendar year 2016.

Trapper Mine

Q. Have Trapper mine costs changed from the 2015 TAM?

A. Yes. Trapper mine costs have decreased from [redacted] per ton in the 2015 TAM to [redacted] per ton in the 2016 TAM, or by [redacted] per ton. This decrease is primarily attributable to less stripping costs in the coal mining process.

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

A. Trapper remains the least-cost fuel supply in Colorado. Trapper's costs in the 2016 TAM are roughly [redacted] per ton less than the delivered price of Colowyo coal to the Craig plant.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 296
Exhibit PAC/400
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

April 2015

DIRECT TESTIMONY OF JUDITH M. RIDENOUR

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ATTACHED EXHIBITS

Exhibit PAC/401—Proposed TAM Rate Spread and Rates

Exhibit PAC/402—Proposed TAM Adjustment for Other Revenues

Exhibit PAC/403—Proposed Tariff Schedules

Exhibit PAC/404—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 and 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.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present the Company's proposed rate spread, rates, and revised tariff pages for the 2016 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) and the TAM adjustment for Other Revenues identified by Mr. Brian S. Dickman. I also provide a summary of the impact of the proposed rate change on customers' bills.

PROPOSED RATE SPREAD AND RATE DESIGN

Q. Please describe the Company's tariff rate schedule that collects 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 test period for this TAM?

A. In accordance with the TAM Guidelines adopted in Order No. 09-274, the test period for the TAM is the year during which the Schedule 201 rates will be effective, which is the 12 months ending December 31, 2016.

Q. How did the Company allocate NPC to the rate schedule classes?

A. The Company allocated forecast NPC to the customer classes based on the present spread of NPC revenue, which is consistent with the TAM Guidelines and consistent with the generation allocation factors agreed to the stipulation in the Company's last general rate case, docket UE 263, approved in Order No. 13-474, updated for the change in load.

Q. Did you prepare an exhibit showing the rate spread and present and proposed Schedule 201 rates and revenues?

A. Yes. Exhibit PAC/401 shows present Schedule 201 rates and revenues and the associated rate spread and revenue targets for each rate schedule based on the Oregon-allocated forecast NPC identified by Mr. Dickman. The final columns in the exhibit show the proposed Schedule 201 rates and revenues. As explained by Mr. Dickman, forecast NPC is subject to updates throughout this proceeding.

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 proposed rate spread 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 201 rates.

Q. How does the Company propose to reflect in rates the amount related to Other Revenues associated with this TAM filing?

A. The Company's Schedule 205, TAM Adjustment for Other Revenues, is used to collect or distribute the adjustment related to Other Revenues in a stand-alone TAM filing. Present rates for this tariff were established in the Company's 2015 TAM, docket UE 287. The amount for the TAM Adjustment for Other Revenues in the 2016 TAM results in a rate increase from the 2015 TAM, since the Oregon-allocated revenues for the 2016 test period are less than the final amounts reflected in the 2015 TAM. The proposed rate spread and rate design for Schedule 205 parallels the generation-based rate spread and rate design of Schedule 201 for NPC as described above, consistent with past treatment of this adjustment.

Q. Did you prepare an exhibit showing proposed Schedule 205 rates and revenues?

A. Yes. Exhibit PAC/402 shows the proposed adjustment to Schedule 205 rates and revenues based on the amounts in this 2016 TAM along with the total combined Schedule 205 rates for the tariff, which reflect the adjustments for both the 2015 TAM and 2016 TAM.

Q. Please describe Exhibit PAC/403.

A. Exhibit PAC/403 contains the proposed revised Schedules 201 and 205.

Q. Is the Company proposing changes to its transition adjustment tariff schedules at this time?

A. No. The Company will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—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 rate effects of the changes proposed in this filing?

A. The overall proposed effect is a rate increase of 0.9 percent on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/404 shows the estimated effect of the Company's proposed prices by delivery service schedule both excluding (base) and including (net) 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. Did you prepare an exhibit that shows the impact on customer bills as a result of the proposed changes to Schedule 201 and Schedule 205?

A. Yes. Exhibit PAC/404, beginning on page 2, 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 increase of $0.80.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 296
Exhibit PAC/401
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Rate Spread and Rates

April 2015

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2016

		Present Schedule 201		Present Rate	Target	Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Spread	Revenues	Rates	Revenues
Schedule 4, Residential							
First Block kWh (0-1,000)	3,906,072,873	2.677 ¢	$104,565,571		$107,261,547	2.746 ¢	$107,260,761
Second Block kWh (> 1,000)	1,377,924,557	3.657 ¢	$50,390,701		$51,689,906	3.751 ¢	$51,685,950
	5,283,997,430		$154,956,272	42.438%	$158,951,452		$158,946,711
						Change	$3,990,439
Employee Discount							
First Block kWh (0-1,000)	11,290,332	2.677 ¢	$302,242			2.746 ¢	$310,033
Second Block kWh (> 1,000)	5,315,117	3.657 ¢	$194,374			3.751 ¢	$199,370
	16,605,449		$496,616				$509,403
Discount			-$124,154				-$127,351
						Change	-$3,197
Schedule 23, Small General Service							
Secondary Voltage							
1st 3,000 kWh, per kWh	900,821,085	2.965 ¢	$26,709,345		$27,397,982	3.041 ¢	$27,393,969
All additional kWh, per kWh	247,078,348	2.199 ¢	$5,433,253		$5,573,337	2.256 ¢	$5,574,088
	1,147,899,433		$32,142,598	8.803%	$32,971,319		$32,968,057
						Change	$825,459
Primary Voltage							
1st 3,000 kWh, per kWh	788,479	2.872 ¢	$22,645		$23,229	2.946 ¢	$23,229
All additional kWh, per kWh	355,294	2.131 ¢	$7,571		$7,766	2.186 ¢	$7,767
	1,143,773		$30,216	0.008%	$30,995		$30,996
						Change	$780
Schedule 28, General Service 31-200kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	1,425,838,082	2.900 ¢	$41,349,304		$42,415,398	2.975 ¢	$42,418,683
All additional kWh, per kWh	581,965,329	2.820 ¢	$16,411,422		$16,834,552	2.893 ¢	$16,836,257
	2,007,803,411		$57,760,726	15.819%	$59,249,950		$59,254,940
						Change	$1,494,214
Primary Voltage							
1st 20,000 kWh, per kWh	9,764,536	2.792 ¢	$272,626		$279,655	2.864 ¢	$279,656
All additional kWh, per kWh	8,839,791	2.717 ¢	$240,177		$246,369	2.787 ¢	$246,365
	18,604,327		$512,803	0.140%	$526,024		$526,021
						Change	$13,218
Schedule 30, General Service 201-999kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	175,688,856	3.100 ¢	$5,446,355		$5,586,776	3.180 ¢	$5,586,906
All additional kWh, per kWh	1,041,475,343	2.688 ¢	$27,994,857		$28,716,638	2.757 ¢	$28,713,475
	1,217,164,199		$33,441,212	9.159%	$34,303,414		$34,300,381
						Change	$859,169
Primary Voltage							
1st 20,000 kWh, per kWh	11,969,659	3.065 ¢	$366,870		$376,329	3.144 ¢	$376,326
All additional kWh, per kWh	77,508,031	2.650 ¢	$2,053,963		$2,106,920	2.718 ¢	$2,106,668
	89,477,690		$2,420,833	0.663%	$2,483,248		$2,482,994
						Change	$62,161
Schedule 41, Agricultural Pumping Service							
Secondary Voltage							
Winter, 1st 100 kWh/kW, per kWh	2,618,553	4.141 ¢	$108,434		$111,230	4.248 ¢	$111,236
Winter, All additional kWh, per kWh	2,314,472	2.821 ¢	$65,291		$66,974	2.894 ¢	$66,981
Summer, All kWh, per kWh	221,393,752	2.821 ¢	$6,245,518		$6,406,544	2.894 ¢	$6,407,135
	226,326,777		$6,419,243	1.758%	$6,584,748		$6,585,352
						Change	$166,109
Primary Voltage							
Winter, 1st 100 kWh/kW, per kWh	7,933	4.010 ¢	$318		$326	4.112 ¢	$326
Winter, All additional kWh, per kWh	45,374	2.732 ¢	$1,240		$1,272	2.803 ¢	$1,272
Summer, All kWh, per kWh	282,020	2.732 ¢	$7,705		$7,904	2.803 ¢	$7,905
	335,327		$9,263	0.003%	$9,502		$9,503
						Change	$240
Schedule 47, Large General Service, Partial Requirements 1,000kW and over							
Primary Voltage							
On-Peak, per on-peak kWh	24,778,886	2.536 ¢	$628,393			2.601 ¢	$644,499
Off-Peak, per off-peak kWh	8,999,847	2.486 ¢	$223,736			2.550 ¢	$229,496
	33,778,733		$852,129		$873,995		$873,995
						Change	$21,866
Transmission Voltage							
On-Peak, per on-peak kWh	8,612,187	2.381 ¢	$205,056			2.442 ¢	$210,310
Off-Peak, per off-peak kWh	7,766,653	2.331 ¢	$181,041			2.391 ¢	$185,701
	16,378,840		$386,097		$396,011		$396,011
						Change	$9,914

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2016

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Present Rate Spread	Target 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	361,489,356	2.734 ¢	$9,883,119		$10,137,932	2.804 ¢	$10,136,162
Off-Peak, per off-peak kWh	199,021,762	2.684 ¢	$5,341,744		$5,479,468	2.753 ¢	$5,479,069
	560,511,118		$15,224,863	4.170%	$15,617,400		$15,615,231
						Change	$390,368
Primary Voltage							
On-Peak, per on-peak kWh	1,067,203,994	2.536 ¢	$27,064,293		$27,762,082	2.601 ¢	$27,757,976
Off-Peak, per off-peak kWh	671,514,994	2.486 ¢	$16,693,863		$17,124,275	2.550 ¢	$17,123,632
	1,738,718,988		$43,758,156	11.984%	$44,886,356		$44,881,608
						Change	$1,123,452
Transmission Voltage							
On-Peak, per on-peak kWh	420,559,376	2.381 ¢	$10,013,519		$10,271,694	2.442 ¢	$10,270,060
Off-Peak, per off-peak kWh	316,970,565	2.331 ¢	$7,388,584		$7,579,081	2.391 ¢	$7,578,766
	737,529,941		$17,402,103	4.766%	$17,850,775		$17,848,826
						Change	$446,723
Schedule 15, Outdoor Area Lighting Service							
Secondary Voltage							
All kWh, per kWh	9,154,109	2.235 ¢	$204,590		$209,865	2.293 ¢	$209,678
	9,154,109		$204,590	0.056%	$209,865		$209,678
						Change	$5,088
Schedule 50, Mercury Vapor Street Lighting Service							
Secondary Voltage							
All kWh, per kWh	8,783,001	1.838 ¢	$161,687		$165,855	1.888 ¢	$165,420
	8,783,001		$161,687	0.044%	$165,855		$165,420
						Change	$3,734
Schedule 51, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	19,673,713	2.901 ¢	$571,824		$586,567	2.981 ¢	$585,734
	19,673,713		$571,824	0.157%	$586,567		$585,734
						Change	$13,910
Schedule 52, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	406,889	2.222 ¢	$9,041		$9,274	2.279 ¢	$9,273
	406,889		$9,041	0.002%	$9,274		$9,273
						Change	$232
Schedule 53, Street Lighting Service, Consumer-Owned System							
Secondary Voltage							
All kWh, per kWh	9,363,960	0.948 ¢	$88,770		$91,059	0.972 ¢	$91,018
	9,363,960		$88,770	0.024%	$91,059		$91,018
						Change	$2,247
Schedule 54, Recreational Field Lighting							
Secondary Voltage							
All kWh, per kWh	1,211,340	1.634 ¢	$19,793		$20,303	1.676 ¢	$20,302
	1,211,340		$19,793	0.005%	$20,303		$20,302
						Change	$509
Total before Employee Discount			**$366,372,220**	100.000%	$375,818,115		**$375,802,051**
Employee Discount			-$124,154		-$127,351		-$127,351
TOTAL	**13,128,263,000**		**$366,248,066**		$375,690,764		**$375,674,700**
						Change	**$9,426,635**
Schedule 47 Unscheduled kWh	2,050,352						
Total Forecast kWH	13,130,313,352						

Docket No. UE 296
Exhibit PAC/402
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Rate Spread and Rates

April 2015

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Revenues
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2016

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Proposed Change Rates	Proposed Change Revenues	Total Proposed Schedule 205 Rates
Schedule 4, Residential					
First Block kWh (0-1,000)	3,906,072,873	-0.004 ¢	0.017 ¢	$664,032	0.013 ¢
Second Block kWh (> 1,000)	1,377,924,557	-0.006 ¢	0.023 ¢	$316,923	0.017 ¢
	5,283,997,430			$980,955	
Employee Discount					
First Block kWh (0-1,000)	11,290,332		0.017 ¢	$1,919	
Second Block kWh (> 1,000)	5,315,117		0.023 ¢	$1,222	
	16,605,449			$3,141	
Discount				-$785	
Schedule 23, Small General Service					
Secondary Voltage					
1st 3,000 kWh, per kWh	900,821,085	-0.005 ¢	0.019 ¢	$171,156	0.014 ¢
All additional kWh, per kWh	247,078,348	-0.003 ¢	0.014 ¢	$34,591	0.011 ¢
	1,147,899,433			$205,747	
Primary Voltage					
1st 3,000 kWh, per kWh	788,479	-0.004 ¢	0.018 ¢	$142	0.014 ¢
All additional kWh, per kWh	355,294	-0.003 ¢	0.013 ¢	$46	0.010 ¢
	1,143,773			$188	
Schedule 28, General Service 31-200kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	1,425,838,082	-0.005 ¢	0.019 ¢	$270,909	0.014 ¢
All additional kWh, per kWh	581,965,329	-0.004 ¢	0.017 ¢	$98,934	0.013 ¢
	2,007,803,411			$369,843	
Primary Voltage					
1st 20,000 kWh, per kWh	9,764,536	-0.004 ¢	0.018 ¢	$1,758	0.014 ¢
All additional kWh, per kWh	8,839,791	-0.004 ¢	0.017 ¢	$1,503	0.013 ¢
	18,604,327			$3,261	
Schedule 30, General Service 201-999kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	175,688,856	-0.005 ¢	0.020 ¢	$35,138	0.015 ¢
All additional kWh, per kWh	1,041,475,343	-0.004 ¢	0.017 ¢	$177,051	0.013 ¢
	1,217,164,199			$212,189	
Primary Voltage					
1st 20,000 kWh, per kWh	11,969,659	-0.005 ¢	0.019 ¢	$2,274	0.014 ¢
All additional kWh, per kWh	77,508,031	-0.004 ¢	0.017 ¢	$13,176	0.013 ¢
	89,477,690			$15,450	
Schedule 41, Agricultural Pumping Service					
Secondary Voltage					
Winter, 1st 100 kWh/kW, per kWh	2,618,553	-0.006 ¢	0.026 ¢	$681	0.020 ¢
Winter, All additional kWh, per kWh	2,314,472	-0.004 ¢	0.018 ¢	$417	0.014 ¢
Summer, All kWh, per kWh	221,393,752	-0.004 ¢	0.018 ¢	$39,851	0.014 ¢
	226,326,777			$40,949	
Primary Voltage					
Winter, 1st 100 kWh/kW, per kWh	7,933	-0.006 ¢	0.025 ¢	$2	0.019 ¢
Winter, All additional kWh, per kWh	45,374	-0.004 ¢	0.017 ¢	$8	0.013 ¢
Summer, All kWh, per kWh	282,020	-0.004 ¢	0.017 ¢	$48	0.013 ¢
	335,327			$58	
Schedule 47, Large General Service, Partial Requirements 1,000kW and over					
Primary Voltage					
On-Peak, per on-peak kWh	24,778,886	-0.004 ¢	0.016 ¢	$3,965	0.012 ¢
Off-Peak, per off-peak kWh	8,999,847	-0.004 ¢	0.016 ¢	$1,440	0.012 ¢
	33,778,733			$5,405	
Transmission Voltage					
On-Peak, per on-peak kWh	8,612,187	-0.004 ¢	0.015 ¢	$1,292	0.011 ¢
Off-Peak, per off-peak kWh	7,766,653	-0.004 ¢	0.015 ¢	$1,165	0.011 ¢
	16,378,840			$2,457	

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Revenues
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2016

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Proposed Change Rates	Proposed Change Revenues	Total Proposed Schedule 205 Rates
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
On-Peak, per on-peak kWh	361,489,356	-0.004 ¢	0.017 ¢	$61,453	0.013 ¢
Off-Peak, per off-peak kWh	199,021,762	-0.004 ¢	0.017 ¢	$33,834	0.013 ¢
	560,511,118			$95,287	
Primary Voltage					
On-Peak, per on-peak kWh	1,067,203,994	-0.004 ¢	0.016 ¢	$170,753	0.012 ¢
Off-Peak, per off-peak kWh	671,514,994	-0.004 ¢	0.016 ¢	$107,442	0.012 ¢
	1,738,718,988			$278,195	
Transmission Voltage					
On-Peak, per on-peak kWh	420,559,376	-0.004 ¢	0.015 ¢	$63,084	0.011 ¢
Off-Peak, per off-peak kWh	316,970,565	-0.004 ¢	0.015 ¢	$47,546	0.011 ¢
	737,529,941			$110,630	
Schedule 15, Outdoor Area Lighting Service					
Secondary Voltage					
All kWh, per kWh	9,154,109	-0.003 ¢	0.014 ¢	$1,282	0.011 ¢
	9,154,109			$1,282	
Schedule 50, Mercury Vapor Street Lighting Service					
Secondary Voltage					
All kWh, per kWh	8,783,001	-0.003 ¢	0.012 ¢	$1,054	0.009 ¢
	8,783,001			$1,054	
Schedule 51, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	19,673,713	-0.005 ¢	0.018 ¢	$3,541	0.013 ¢
	19,673,713			$3,541	
Schedule 52, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	406,889	-0.003 ¢	0.014 ¢	$57	0.011 ¢
	406,889			$57	
Schedule 53, Street Lighting Service, Consumer-Owned System					
Secondary Voltage					
All kWh, per kWh	9,363,960	-0.001 ¢	0.006 ¢	$562	0.005 ¢
	9,363,960			$562	
Schedule 54, Recreational Field Lighting					
Secondary Voltage					
All kWh, per kWh	1,211,340	-0.003 ¢	0.010 ¢	$121	0.007 ¢
	1,211,340			$121	
Total before Employee Discount				**$2,327,231**	
Employee Discount				-$785	
TOTAL	**13,128,263,000**			**$2,326,446**	
Schedule 47 Unscheduled kWh	2,050,352				
Total Forecast kWH	13,130,313,352				

Docket No. UE 296
Exhibit PAC/403
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedules

April 2015

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 201

NET POWER COSTS
COST-BASED SUPPLY SERVICE

Available

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

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-270, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

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

Monthly Billing

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

Delivery Service Schedule No.			**Delivery Voltage** Secondary	Primary	Transmission	
4	Per kWh	0-1000 kWh	2.746¢			(I)
		> 1000 kWh	3.751¢			(I)
5	Per kWh	0-1000 kWh	2.746¢			(I)
		> 1000 kWh	3.751¢			(I)

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

Schedule		Secondary	Primary	Transmission	
23	First 3,000 kWh, per kWh	3.041¢	2.946¢		(I)
	All additional kWh, per kWh	2.256¢	2.186¢		(I)
28	First 20,000 kWh, per kWh	2.975¢	2.864¢		(I)
	All additional kWh, per kWh	2.893¢	2.787¢		(I)
30	First 20,000 kWh, per kWh	3.180¢	3.144¢		(I)
	All additional kWh, per kWh	2.757¢	2.718¢		(I)
41	Winter, first 100 kWh/kW, per kWh	4.248¢	4.112¢		(I)
	Winter, all additional kWh, per kWh	2.894¢	2.803¢		(I)
	Summer, all kWh, per kWh	2.894¢	2.803¢		(I)

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

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Secondary	Primary	Transmission	
		Delivery Voltage			
47/48	Per kWh On-Peak	2.804¢	2.601¢	2.442¢	(I)
	Per kWh, Off-Peak	2.753¢	2.550¢	2.391¢	(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	2.279¢	(I)
	For dusk to midnight operation, per kWh	2.279¢	(I)
54	Per kWh	1.676¢	(I)

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
Mercury Vapor	7,000	76	$ 1.74	(I)
Mercury Vapor	21,000	172	$ 3.94	(I)
Mercury Vapor	55,000	412	$ 9.45	(I)
High Pressure Sodium	5,800	31	$ 0.71	(I)
High Pressure Sodium	22,000	85	$ 1.95	(I)
High Pressure Sodium	50,000	176	$ 4.04	(I)

50 **A. Company-owned Overhead System**

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
Horizontal, per lamp	$1.43	$3.25	$7.78	(I)
Vertical, per lamp	$1.43	$3.25		(I)

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.43			(I)
On 26-foot poles, vertical, per lamp	$1.43			(I)
On 30-foot poles, horizontal, per lamp		$3.25		(I)
On 30-foot poles, vertical, per lamp		$3.25		(I)
On 33-foot poles, horizontal, per lamp			$7.78	(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

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

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.43			(I)
On 26-foot poles, vertical, per lamp	$1.43			(I)
On 30-foot poles, horizontal, per lamp		$3.25		(I)
On 30-foot poles, vertical, per lamp		$3.25		(I)
On 33-foot poles, horizontal, per lamp			$7.78	(I)

51

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
LED	4,000	100 (comp)		$0.57	(I)
LED	6,200	150 (comp)		$0.80	
LED	13,000	250 (comp)		$1.52	
LED	16,800	400 (comp)		$2.06	
High Pressure Sodium	5,800	70	31	$0.92	
High Pressure Sodium	9,500	100	44	$1.31	
High Pressure Sodium	16,000	150	64	$1.91	
High Pressure Sodium	22,000	200	85	$2.53	
High Pressure Sodium	27,500	250	115	$3.43	
High Pressure Sodium	50,000	400	176	$5.25	
Metal Halide	12,000	175	68	$2.03	
Metal Halide	19,500	250	94	$2.80	(I)

53

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
High Pressure Sodium	5,800	70	31	$0.30	(I)
High Pressure Sodium	9,500	100	44	$0.43	
High Pressure Sodium	16,000	150	64	$0.62	
High Pressure Sodium	22,000	200	85	$0.83	
High Pressure Sodium	27,500	250	115	$1.12	
High Pressure Sodium	50,000	400	176	$1.71	
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	$1.45	
Metal Halide	107,800	1,000	354	$3.44	(I)

Non-Listed Luminaire, per kWh 0.972¢ (I)

(continued)

Purpose

This schedule adjusts rates for Other Revenues as authorized by Order No. 10-363.

Applicable

To all Residential Consumers and Nonresidential Consumers.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule and Direct Access Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0-1000 kWh	0.013¢			(I)
		> 1000 kWh	0.017¢			(I)
5	Per kWh	0-1000 kWh	0.013¢			(I)
		> 1000 kWh	0.017¢			(I)

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

		Secondary	Primary	Transmission	
23, 723	First 3,000 kWh, per kWh	0.014¢	0.014¢		(I)
	All additional kWh, per kWh	0.011¢	0.010¢		(I)
28, 728	First 20,000 kWh, per kWh	0.014¢	0.014¢		(I)
	All additional kWh, per kWh	0.013¢	0.013¢		(I)
30, 730	First 20,000 kWh, per kWh	0.015¢	0.014¢		(I)
	All additional kWh, per kWh	0.013¢	0.013¢		(I)
41, 741	Winter, first 100 kWh/kW, per kWh	0.020¢	0.019¢		(I)
	Winter, all additional kWh, per kWh	0.014¢	0.013¢		(I)
	Summer, all kWh, per kWh	0.014¢	0.013¢		(I)

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

(continued)

Energy Charge (continued)

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	0.013¢	0.012¢	0.011¢	(I)
747/748	Per kWh, Off-Peak	0.013¢	0.012¢	0.011¢	(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, 752	For dusk to dawn operation, per kWh	0.011¢	(I)
	For dusk to midnight operation, per kWh	0.011¢	(I)
54,754	Per kWh	0.007¢	(I)

15	**Type of Luminaire**	**Nominal Rating**	**Monthly kWh**	**RatePer Luminaire**	
	Mercury Vapor	7,000	76	$0.01	(I)
	Mercury Vapor	21,000	172	$0.02	
	Mercury Vapor	55,000	412	$0.05	
	High Pressure Sodium	5,800	31	$0.00	
	High Pressure Sodium	22,000	85	$0.01	
	High Pressure Sodium	50,000	176	$0.02	(I)

50 **A. Company-owned Overhead System**

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
Horizontal, per lamp	$0.01	$0.02	$0.04	(I)
Vertical, per lamp	$0.01	$0.02		(I)

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$0.01			(I)
On 26-foot poles, vertical, per lamp	$0.01			(I)
On 30-foot poles, horizontal, per lamp		$0.02		(I)
On 30-foot poles, vertical, per lamp		$0.02		(I)
On 33-foot poles, horizontal, per lamp			$0.04	(I)

(continued)

Energy Charge (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	$0.01			(I)
On 26-foot poles, vertical, per lamp	$0.01			(I)
On 30-foot poles, horizontal, per lamp		$0.02		(I)
On 30-foot poles, vertical, per lamp		$0.02		(I)
On 33-foot poles, horizontal, per lamp			$0.04	(I)

51, 751

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
LED	4,000	100 (comp)		$0.00	
LED	6,200	150 (comp)		$0.00	
LED	13,000	250 (comp)		$0.00	
LED	16,800	400 (comp)		$0.00	
High Pressure Sodium	5,800	70	31	$0.00	
High Pressure Sodium	9,500	100	44	$0.01	(I)
High Pressure Sodium	16,000	150	64	$0.01	
High Pressure Sodium	22,000	200	85	$0.01	
High Pressure Sodium	27,500	250	115	$0.01	
High Pressure Sodium	50,000	400	176	$0.02	
Metal Halide	12,000	175	68	$0.01	
Metal Halide	19,500	250	94	$0.01	(I)

53, 753

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.00	
High Pressure Sodium	9,500	100	44	$0.00	
High Pressure Sodium	16,000	150	64	$0.00	
High Pressure Sodium	22,000	200	85	$0.00	
High Pressure Sodium	27,500	250	115	$0.01	(I)
High Pressure Sodium	50,000	400	176	$0.01	
Metal Halide	9,000	100	39	$0.00	
Metal Halide	12,000	175	68	$0.00	
Metal Halide	19,500	250	94	$0.00	
Metal Halide	32,000	400	149	$0.01	
Metal Halide	107,800	1,000	354	$0.02	(I)

Non-Listed Luminaire, per kWh 0.005¢ (I)

Docket No. UE 296
Exhibit PAC/404
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed TAM Price Change

April 2015

TAM

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 ENDING DECEMBER 31, 2016

					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	484,847	5,283,998	$599,886	$4,914	$604,800	$604,858	$4,914	$609,772	$4,972	0.8%	$4,972	0.8%	1
2	**Total Residential**		484,847	5,283,998	$599,886	$4,914	$604,800	$604,858	$4,914	$609,772	$4,972	0.8%	$4,972	0.8%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	76,799	1,149,043	$124,706	$5,159	$129,865	$125,738	$5,159	$130,897	$1,032	0.8%	$1,032	0.8%	3
4	Gen. Svc. 31 - 200 kW	28	9,753	2,026,408	$182,635	$2,978	$185,613	$184,517	$2,978	$187,495	$1,882	1.0%	$1,882	1.0%	4
5	Gen. Svc. 201 - 999 kW	30	888	1,306,642	$104,811	$929	$105,740	$105,959	$929	$106,888	$1,148	1.1%	$1,148	1.1%	5
6	Large General Service >= 1,000 kW	48	203	3,036,760	$212,674	($9,438)	$203,236	$215,118	($9,438)	$205,680	$2,444	1.1%	$2,444	1.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	7	52,208	$5,418	($173)	$5,245	$5,457	($173)	$5,284	$39	1.1%	$39	1.2%	7
8	Agricultural Pumping Service	41	7,969	226,662	$26,037	($1,274)	$24,763	$26,244	($1,274)	$24,970	$207	0.8%	$207	0.8%	8
9	**Total Commercial & Industrial**		95,619	7,797,723	$656,281	($1,819)	$654,462	$663,033	($1,819)	$661,214	$6,752	1.0%	$6,752	1.0%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,475	9,154	$1,171	$219	$1,390	$1,177	$219	$1,396	$6	0.5%	$6	0.4%	10
11	Street Lighting Service	50	230	8,783	$972	$194	$1,166	$977	$194	$1,171	$5	0.5%	$5	0.4%	11
12	Street Lighting Service HPS	51	746	19,674	$3,436	$717	$4,153	$3,453	$717	$4,170	$17	0.5%	$17	0.4%	12
13	Street Lighting Service	52	26	407	$53	$9	$62	$53	$9	$62	$0	0.0%	$0	0.0%	13
14	Street Lighting Service	53	248	9,364	$587	$116	$703	$590	$116	$706	$3	0.5%	$3	0.4%	14
15	Recreational Field Lighting	54	107	1,211	$101	$19	$120	$102	$19	$121	$1	1.0%	$1	0.8%	15
16	**Total Public Street Lighting**		7,832	48,593	$6,320	$1,274	$7,594	$6,352	$1,274	$7,626	$32	0.5%	$32	0.4%	16
17	**Total Sales before Emp. Disc. & AGA**		588,298	13,130,314	$1,262,487	$4,369	$1,266,856	$1,274,243	$4,369	$1,278,612	$11,756	0.9%	$11,756	0.9%	17
18	Employee Discount				($466)	($3)	($469)	($470)	($3)	($473)	($4)		($4)		18
19	**Total Sales with Emp. Disc**		588,298	13,130,314	$1,262,021	$4,366	$1,266,387	$1,273,773	$4,366	$1,278,139	$11,752	0.9%	$11,752	0.9%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		588,298	13,130,314	$1,264,460	$4,366	$1,268,826	$1,276,212	$4,366	$1,280,578	$11,752	0.9%	$11,752	0.9%	21

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

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

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

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.61	$20.70	$0.09	0.44%
200	$30.60	$30.77	$0.17	0.56%
300	$40.58	$40.85	$0.27	0.67%
400	$50.58	$50.93	$0.35	0.69%
500	$60.57	$61.01	$0.44	0.73%
600	$70.54	$71.08	$0.54	0.77%
700	$80.54	$81.16	$0.62	0.77%
800	$90.53	$91.24	$0.71	0.78%
900	**$100.51**	**$101.31**	**$0.80**	**0.80%**
950	$105.51	$106.36	$0.85	0.81%
1,000	$110.50	$111.39	$0.89	0.81%
1,100	$123.10	$124.11	$1.01	0.82%
1,200	$135.68	$136.80	$1.12	0.83%
1,300	$148.28	$149.52	$1.24	0.84%
1,400	$160.87	$162.23	$1.36	0.85%
1,500	$173.47	$174.95	$1.48	0.85%
1,600	$186.04	$187.66	$1.62	0.87%
2,000	$236.42	$238.51	$2.09	0.88%
3,000	$362.34	$365.63	$3.29	0.91%
4,000	$488.25	$492.75	$4.50	0.92%
5,000	$614.17	$619.88	$5.71	0.93%

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

Note: Assumed average billing cycle length of 30.42 days.

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

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$71	$80	$71	$80	0.69%	0.62%
	750	$97	$106	$98	$107	0.75%	0.70%
	1,000	$124	$132	$125	$133	0.79%	0.74%
	1,500	$176	$185	$178	$187	0.83%	0.79%
10	1,000	$124	$132	$125	$133	0.79%	0.74%
	2,000	$229	$238	$231	$240	0.85%	0.82%
	3,000	$335	$344	$338	$347	0.88%	0.85%
	4,000	$425	$433	$428	$437	0.86%	0.85%
20	4,000	$451	$460	$455	$464	0.81%	0.80%
	6,000	$630	$639	$636	$644	0.81%	0.80%
	8,000	$810	$818	$816	$825	0.82%	0.81%
	10,000	$989	$997	$997	$1,005	0.81%	0.81%
30	9,000	$953	$962	$960	$969	0.77%	0.76%
	12,000	$1,221	$1,230	$1,231	$1,240	0.78%	0.77%
	15,000	$1,490	$1,499	$1,502	$1,510	0.79%	0.78%
	18,000	$1,758	$1,767	$1,772	$1,781	0.79%	0.79%

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

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

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$69	$78	$70	$79	0.69%	0.61%
	750	$95	$104	$96	$105	0.76%	0.68%
	1,000	$121	$130	$122	$131	0.79%	0.74%
	1,500	$172	$181	$174	$182	0.83%	0.80%
10	1,000	$121	$130	$122	$131	0.79%	0.74%
	2,000	$224	$232	$226	$234	0.86%	0.83%
	3,000	$327	$335	$329	$338	0.88%	0.86%
	4,000	$414	$423	$417	$426	0.86%	0.85%
20	4,000	$440	$449	$444	$452	0.81%	0.80%
	6,000	$614	$623	$619	$628	0.81%	0.80%
	8,000	$789	$798	$795	$804	0.81%	0.80%
	10,000	$963	$972	$971	$980	0.81%	0.80%
30	9,000	$929	$938	$936	$945	0.76%	0.75%
	12,000	$1,190	$1,199	$1,199	$1,208	0.77%	0.76%
	15,000	$1,452	$1,461	$1,463	$1,472	0.78%	0.77%
	18,000	$1,713	$1,722	$1,727	$1,735	0.78%	0.78%

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

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	3,000	$344	$347	0.85%
	4,500	$453	$458	0.96%
	7,500	$673	$680	1.08%
31	6,200	$691	$697	0.87%
	9,300	$917	$926	0.98%
	15,500	$1,370	$1,385	1.10%
40	8,000	$886	$894	0.87%
	12,000	$1,178	$1,190	0.99%
	20,000	$1,763	$1,782	1.10%
60	12,000	$1,320	$1,332	0.88%
	18,000	$1,759	$1,776	0.99%
	30,000	$2,619	$2,648	1.09%
80	16,000	$1,749	$1,764	0.89%
	24,000	$2,327	$2,350	0.99%
	40,000	$3,470	$3,508	1.09%
100	20,000	$2,177	$2,197	0.89%
	30,000	$2,892	$2,920	0.99%
	50,000	$4,320	$4,367	1.09%
200	40,000	$4,263	$4,301	0.89%
	60,000	$5,691	$5,748	0.99%
	100,000	$8,548	$8,642	1.09%

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

Pacific Power
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	$441	$445	0.95%
	6,000	$541	$546	1.03%
	7,500	$641	$648	1.08%
31	9,300	$885	$894	0.97%
	12,400	$1,092	$1,103	1.05%
	15,500	$1,298	$1,312	1.11%
40	12,000	$1,135	$1,146	0.98%
	16,000	$1,401	$1,416	1.06%
	20,000	$1,668	$1,686	1.11%
60	18,000	$1,692	$1,709	0.99%
	24,000	$2,085	$2,107	1.06%
	30,000	$2,475	$2,503	1.11%
80	24,000	$2,236	$2,258	0.99%
	32,000	$2,756	$2,785	1.06%
	40,000	$3,276	$3,312	1.11%
100	30,000	$2,776	$2,804	0.99%
	40,000	$3,426	$3,463	1.06%
	50,000	$4,076	$4,122	1.11%
200	60,000	$5,442	$5,497	1.00%
	80,000	$6,743	$6,815	1.07%
	100,000	$8,043	$8,133	1.12%

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

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,602	$2,622	0.79%
	30,000	$3,179	$3,208	0.93%
	50,000	$4,333	$4,380	1.09%
200	40,000	$4,563	$4,602	0.84%
	60,000	$5,718	$5,774	0.98%
	100,000	$8,026	$8,118	1.14%
300	60,000	$6,695	$6,751	0.84%
	90,000	$8,427	$8,509	0.98%
	150,000	$11,890	$12,026	1.14%
400	80,000	$8,709	$8,782	0.85%
	120,000	$11,017	$11,127	0.99%
	200,000	$15,635	$15,815	1.15%
500	100,000	$10,753	$10,844	0.85%
	150,000	$13,639	$13,775	1.00%
	250,000	$19,411	$19,635	1.16%
600	120,000	$12,797	$12,906	0.85%
	180,000	$16,260	$16,423	1.00%
	300,000	$23,186	$23,455	1.16%
800	160,000	$16,886	$17,030	0.86%
	240,000	$21,503	$21,719	1.00%
	400,000	$30,738	$31,095	1.16%
1000	200,000	$20,974	$21,154	0.86%
	300,000	$26,746	$27,015	1.00%
	500,000	$38,290	$38,735	1.16%

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

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$3,117	$3,146	0.93%
	40,000	$3,683	$3,721	1.02%
	50,000	$4,249	$4,295	1.09%
200	60,000	$5,609	$5,664	0.98%
	80,000	$6,741	$6,814	1.08%
	100,000	$7,873	$7,964	1.15%
300	90,000	$8,261	$8,343	0.99%
	120,000	$9,959	$10,067	1.08%
	150,000	$11,657	$11,791	1.15%
400	120,000	$10,818	$10,926	1.00%
	160,000	$13,083	$13,225	1.09%
	200,000	$15,347	$15,525	1.16%
500	150,000	$13,388	$13,522	1.00%
	200,000	$16,218	$16,396	1.10%
	250,000	$19,048	$19,270	1.16%
600	180,000	$15,957	$16,118	1.00%
	240,000	$19,354	$19,567	1.10%
	300,000	$22,750	$23,015	1.17%
800	240,000	$21,097	$21,309	1.01%
	320,000	$25,625	$25,908	1.10%
	400,000	$30,153	$30,506	1.17%
1000	300,000	$26,236	$26,501	1.01%
	400,000	$31,896	$32,249	1.11%
	500,000	$37,557	$37,997	1.17%

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

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

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December- March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$195	$222	$155	$196	$225	$155	0.96%	1.03%	0.00%
	3,000	$292	$319	$155	$295	$323	$155	0.97%	1.02%	0.00%
	5,000	$486	$514	$155	$491	$519	$155	0.96%	1.00%	0.00%
Three Phase										
20	4,000	$389	$444	$309	$393	$449	$309	0.96%	1.04%	0.00%
	6,000	$584	$639	$309	$589	$645	$309	0.96%	1.02%	0.00%
	10,000	$973	$1,028	$309	$982	$1,038	$309	0.96%	1.00%	0.00%
100	20,000	$1,945	$2,222	$1,349	$1,964	$2,245	$1,349	0.96%	1.04%	0.00%
	30,000	$2,918	$3,195	$1,349	$2,946	$3,227	$1,349	0.96%	1.02%	0.00%
	50,000	$4,863	$5,140	$1,349	$4,910	$5,191	$1,349	0.96%	1.00%	0.00%
300	60,000	$5,835	$6,667	$3,409	$5,892	$6,736	$3,409	0.96%	1.04%	0.00%
	90,000	$8,753	$9,585	$3,409	$8,837	$9,682	$3,409	0.96%	1.02%	0.00%
	150,000	$14,588	$15,420	$3,409	$14,729	$15,574	$3,409	0.96%	1.00%	0.00%

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

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

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$283	$310	$155	$285	$313	$155	0.96%	1.01%	0.00%
	4,000	$377	$404	$155	$381	$408	$155	0.96%	1.00%	0.00%
	5,000	$471	$498	$155	$476	$503	$155	0.96%	0.99%	0.00%
Three Phase										
20	6,000	$565	$619	$309	$571	$626	$309	0.96%	1.01%	0.00%
	8,000	$754	$808	$309	$761	$816	$309	0.96%	1.00%	0.00%
	10,000	$942	$996	$309	$952	$1,006	$309	0.96%	0.99%	0.00%
100	30,000	$2,827	$3,096	$1,339	$2,855	$3,128	$1,339	0.96%	1.01%	0.00%
	40,000	$3,770	$4,039	$1,339	$3,806	$4,079	$1,339	0.96%	1.00%	0.00%
	50,000	$4,712	$4,981	$1,339	$4,758	$5,031	$1,339	0.96%	0.99%	0.00%
300	90,000	$8,482	$9,289	$3,399	$8,564	$9,383	$3,399	0.96%	1.01%	0.00%
	120,000	$11,310	$12,116	$3,399	$11,418	$12,237	$3,399	0.96%	1.00%	0.00%
	150,000	$14,137	$14,944	$3,399	$14,273	$15,092	$3,399	0.96%	0.99%	0.00%

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

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

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$26,043	$26,311	1.03%
	500,000	$37,068	$37,514	1.20%
	650,000	$45,336	$45,916	1.28%
2,000	600,000	$51,654	$52,190	1.04%
	1,000,000	$72,323	$73,215	1.23%
	1,300,000	$88,295	$89,455	1.31%
6,000	1,800,000	$151,296	$152,902	1.06%
	3,000,000	$215,186	$217,863	1.24%
	3,900,000	$263,103	$266,583	1.32%
12,000	3,600,000	$301,267	$304,480	1.07%
	6,000,000	$429,047	$434,402	1.25%
	7,800,000	$524,882	$531,843	1.33%

Notes:

On-Peak kWh	64.49%
Off-Peak kWh	35.51%

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

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

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$24,611	$24,860	1.01%
	500,000	$34,832	$35,247	1.19%
	650,000	$42,498	$43,037	1.27%
2,000	600,000	$48,749	$49,247	1.02%
	1,000,000	$67,810	$68,641	1.22%
	1,300,000	$82,577	$83,657	1.31%
6,000	1,800,000	$142,178	$143,673	1.05%
	3,000,000	$201,246	$203,737	1.24%
	3,900,000	$245,547	$248,785	1.32%
12,000	3,600,000	$283,001	$285,990	1.06%
	6,000,000	$401,137	$406,119	1.24%
	7,800,000	$489,739	$496,216	1.32%

Notes:

On-Peak kWh	61.38%
Off-Peak kWh	38.62%

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

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

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	500,000	$34,542	$34,931	1.13%
	650,000	$41,663	$42,169	1.21%
2,000	1,000,000	$66,818	$67,596	1.16%
	1,300,000	$80,496	$81,508	1.26%
6,000	3,000,000	$198,444	$200,779	1.18%
	3,900,000	$239,479	$242,514	1.27%
12,000	6,000,000	$394,740	$399,410	1.18%
	7,800,000	$476,809	$482,880	1.27%
50,000	25,000,000	$1,637,946	$1,657,406	1.19%
	32,500,000	$1,979,902	$2,005,199	1.28%

Notes:

On-Peak kWh	57.02%
Off-Peak kWh	42.98%

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