MRG
McDOWELL RACKNER GIBSON PC

ADAM LOWNEY
Direct (503) 595-3926
adam@mrg-law.com

August 25, 2016

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: UE 307– In the Matter PACIFICORP, dba PACIFIC POWER, 2017 Transition Adjustment Mechanism

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic copy of PacifiCorp's Cross-Examination Exhibits.

Please contact this office with any questions.

Very truly yours,

Adam Lowney

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Cross-Exhibits in Docket UE 307 on the parties listed below via e-mail and/or overnight delivery with OAR 860-001-0180.

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

Michael Goetz
Citizens' Utility Board of Oregon
610 Broadway, Suite 400
Portland, OR 97205
mike@oregoncub.org

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

Bradley Mullins
Mountain West Analytics
333 SW Taylor, Suite 400
Portland, OR 97204
brmullins@mwanalytics.com

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

S. Bradley Van Cleve
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
bvc@dvclaw.com

Gregory M. Adams
Richardson Adams, PLLC
PO Box 7218
Boise, ID 83702
greg@richardsonadams.com

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

Kevin Higgins
Energy Strategies LLC
215 State Street, Suite 200
Salt Lake City, UT 84111-2322
khiggins@energystrat.com

Oregon Dockets
Pacific Power
825 NE Multnomah St, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

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

John Crider
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088
john.crider@state.or.us

Matthew McVee
Pacific Power
825 NE Multnomah Street, Suite 1800
Portland, OR 97232
matthew.mcvee@pacificorp.com

Sommer Moser
PUC Staff – Department of Justice
1162 Court Street NE
Salem, OR 97301
sommer.moser@doj.state.or.us

Dated this 25th day of August 2016.

Wendy McIndoo

Wendy McIndoo
Office Manager
McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205
(503) 595-3922
(503)595-3928 (facsimile)
wendy@mrg-law.com

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

In the Matter of: PACIFICORP, dba PACIFIC POWER 2017 Transition Adjustment Mechanism	**PACIFICORP'S LIST OF EXHIBITS TO BE ENTERED INTO THE RECORD**

PREFILED EXHIBITS

Exhibit PAC/100	CONFIDENTIAL Direct Testimony of Brian S. Dickman, dated April 1, 2016.
Exhibit PAC/101	Exhibit Accompanying Direct Testimony of Brian S. Dickman (Oregon Allocated Net Power Costs).
Exhibit PAC/102	Exhibit Accompanying Direct Testimony of Brian S. Dickman (Net Power Costs Report).
Exhibit PAC/103	Exhibit Accompanying Direct Testimony of Brian S. Dickman (Update to Other Revenues).
Exhibit PAC/104	Exhibit Accompanying Direct Testimony of Brian S. Dickman (Energy Imbalance Market Import and Export Summary).
Exhibit PAC/105	Exhibit Accompanying Direct Testimony of Brian S. Dickman (Energy Imbalance Market Costs).
Exhibit PAC/106	Exhibit Accompanying Direct Testimony of Brian S. Dickman (Update to Renewable Energy Production Tax Credits).
Exhibit PAC/107	Exhibit Accompanying Direct Testimony of Brian S. Dickman (List of Expected or Known Contract Updates).
Exhibit PAC/200	CONFIDENTIAL Direct Testimony of Dana M. Ralston, dated April 1, 2016.
Exhibit PAC/300	Direct Testimony of Judith M. Ridenour, dated April 1, 2016.
Exhibit PAC/301	Exhibit Accompanying Direct Testimony of Judith M. Ridenour (Proposed TAM Rate Spread and Rates).
Exhibit PAC/302	Exhibit Accompanying Direct Testimony of Judith M. Ridenour (Proposed TAM Adjustment for Other Items).
Exhibit PAC/303	Exhibit Accompanying Direct Testimony of Judith M. Ridenour (Proposed Tariff Schedules).
Exhibit PAC/304	Exhibit Accompanying Direct Testimony of Judith M. Ridenour (Estimated Effect of Proposed TAM Price Change).

Exhibit PAC/400	CONFIDENTIAL Reply Testimony of Brian S. Dickman, dated August 1, 2016.
Exhibit PAC/401	Exhibit Accompanying Reply Testimony of Brian S. Dickman (TAM Allocation Reply Filing 2017).
Exhibit PAC/402	Exhibit Accompanying Reply Testimony of Brian S. Dickman (Results of Updated NPC Study Reply Filing 2017).
Exhibit PAC/403	Exhibit Accompanying Reply Testimony of Brian S. Dickman (Corrections and Updates Summary Reply Filing 2017).
Exhibit PAC/404	Exhibit Accompanying Reply Testimony of Brian S. Dickman (Other Revenue Reply Filing 2017).
Exhibit PAC/405	Exhibit Accompanying Reply Testimony of Brian S. Dickman (EIM Costs Reply Filing 2017).
Exhibit PAC/406	Exhibit Accompanying Reply Testimony of Brian S. Dickman (EIM Inter-Regional Benefits Reply Filing 2017).
Exhibit PAC/407	Exhibit Accompanying Reply Testimony of Brian S. Dickman (Staff Response to PacifiCorp Data Request 2).
Exhibit PAC/408	Exhibit Accompanying Reply Testimony of Brian S. Dickman (Staff Response to PacifiCorp Data Request 12).
Exhibit PAC/409	CONFIDENTIAL Exhibit Accompanying Reply Testimony of Brian S. Dickman (Staff Response to PacifiCorp Data Request 4).
Exhibit PAC/410	Exhibit Accompanying Reply Testimony of Brian S. Dickman (CUB Response to PacifiCorp Data Request 1).
Exhibit PAC/411	Exhibit Accompanying Reply Testimony of Brian S. Dickman (CAISO Technical Bulletin "Quantifying the Benefits of Participating in EIM").
Exhibit PAC/412	Exhibit Accompanying Reply Testimony of Brian S. Dickman (CAISO 2016 Q1 Report "Benefits for Participating in EIM").
Exhibit PAC/413	Exhibit Accompanying Reply Testimony of Brian S. Dickman (CUB Response to PacifiCorp Data Request 7).
Exhibit PAC/500	CONFIDENTIAL Reply Testimony of Dana M. Ralston, dated August 1, 2016.
Exhibit PAC/501	Exhibit Accompanying Reply Testimony of Dana M. Ralston (PacifiCorp Compliance Proposal for Periodic Long-Term Plans).
Exhibit PAC/502	Exhibit Accompanying Reply Testimony of Dana M. Ralston (Staff Response to PacifiCorp Data Request 11).

Exhibit PAC/600	CONFIDENTIAL Reply Testimony of R. Bryce Dalley, dated August 1, 2016.
Exhibit PAC/601	Exhibit Accompanying Reply Testimony of R. Bryce Dalley (Staff's 2009 Pre-GRC Audit).
Exhibit PAC/602	Exhibit Accompanying Reply Testimony of R. Bryce Dalley (Staff's Discovery Response from docket UE 264).
Exhibit PAC/603	Exhibit Accompanying Reply Testimony of R. Bryce Dalley (Staff's Response to PacifiCorp Data Requests 6-10).
Exhibit PAC/604	Exhibit Accompanying Reply Testimony of R. Bryce Dalley (Production Tax Credit details).
Exhibit PAC/700	Reply Testimony of Judith M. Ridenour, dated August 1, 2016.
Exhibit PAC/701	Exhibit Accompanying Reply Testimony of Judith M. Ridenour (Proposed Adjustment to Schedule 200, Base Supply Service).
Exhibit PAC/702	Exhibit Accompanying Reply Testimony of Judith M. Ridenour (Proposed Reply TAM Rate Spread and Rates).
Exhibit PAC/703	Exhibit Accompanying Reply Testimony of Judith M. Ridenour (Proposed Reply TAM Adjustment for Other Items).
Exhibit PAC/704	Exhibit Accompanying Reply Testimony of Judith M. Ridenour (Proposed Reply Tariff Schedules).
Exhibit PAC/705	Exhibit Accompanying Reply Testimony of Judith M. Ridenour (Estimated Effect of Proposed Reply TAM Price Change).
Exhibit PAC/800	CONFIDENTIAL Surrebuttal Testimony of Brian S. Dickman, dated August 22, 2016.
Exhibit PAC/801	Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman (List of Staff and Intervenor Adjustments).
Exhibit PAC/802	Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman (Staff Response to PacifiCorp Data Request 47).
Exhibit PAC/803	CONFIDENTIAL Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman (Staff Response to PacifiCorp Data Request 50).
Exhibit PAC/804	CONFIDENTIAL Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman (Staff Response to PacifiCorp Data Request 48).
Exhibit PAC/805	CONFIDENTIAL Exhibit Accompanying Surrebuttal Testimony of Brian S. Dickman (PacifiCorp Response to CUB Data Request 79).
Exhibit PAC/900	Surrebuttal Testimony of Kelcey A. Brown, dated August 22, 2016.

Exhibit PAC/1000	CONFIDENTIAL Surrebuttal Testimony of Dana M. Ralston, dated August 22, 2016.
Exhibit PAC/1001	HIGHLY CONFIDENTIAL Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston (Union Pacific Railroad Contract).
Exhibit PAC/1002	CONFIDENTIAL Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston (Black and Veatch 2013 Study).
Exhibit PAC/1003	CONFIDENTIAL Exhibit Accompanying Surrebuttal Testimony of Dana M. Ralston (Comparison of Base Case and a Market Case).
Exhibit PAC/1100	CONFIDENTIAL Surrebuttal Testimony of R. Bryce Dalley, dated August 22, 2016.

CROSS-EXAMINATION EXHIBITS

Exhibit PAC/1200	PacifiCorp ISO EIM Benefits Report Q1 2015.
Exhibit PAC/1201	PacifiCorp ISO EIM Benefits Report Q4 2014.
Exhibit PAC/1202	CAISO Presentation–Benefits for Participating in EIM.
Exhibit PAC/1203	Staff's Response to PacifiCorp's Data Requests Nos. 37, 38, 39, and 44.
Exhibit PAC/1204	PacifiCorp ISO EIM Benefits Report Q2 2015.
Exhibit PAC/1205	Opening Testimony of Lance Kaufman in Docket UE 308.
Exhibit PAC/1206	Opening Testimony of John Crider in Docket UE 283.
Exhibit PAC/1207	Excerpt from Staff's Comments in Docket LC 57.
Exhibit PAC/1208	Excerpt from CONFIDENTIAL Direct Testimony of Cindy A. Crane in Docket UE 216.
Exhibit PAC/1209	Excerpt from CONFIDENTIAL Opening Testimony of John Crider and Jorge Ordonez in Docket UE 264.
Exhibit PAC/1210	CONFIDENTIAL Comparison of Exhibits Staff/403 and PAC/1003.

DATED: August 25, 2016

MCDOWELL RACKNER & GIBSON PC

Adam Lowney

Katherine McDowell
Adam Lowney
Attorneys for PacifiCorp

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1200

PacifiCorp ISO EIM Benefits Report Q1 2015

August 25, 2016

Benefits for Participating in EIM

April 30, 2015

Revision History

Date	Version	Description	Author
4/30/2015	1.0		Lin Xu

Table of Contents

Executive Summary

The Energy Imbalance Market (EIM) began financially-binding operation on November 1, 2014 by optimizing resources across the California Independent System Operator (ISO) and PacifiCorp balancing authority areas (BAAs). The ISO published the first EIM benefit report for November and December 2014 in February 2015.[1]

This second report quantifies the estimated gross benefits for January, February, and March 2015 to be $5.26 million, which remains in line with pre-launch projections. The benefit report reflects the EIM's ability to select the lowest cost resource across the PacifiCorp and ISO BAAs to serve demand. The report analysis considers the following categories as described in an earlier study conducted by Energy + Environmental Economics (E3)[2] for PacifiCorp and the ISO.

- ***More efficient dispatch, both inter- and intra-regional***, by automating dispatch every five minutes within PacifiCorp's two BAAs and between the PacifiCorp and California ISO BAAs.
- ***Reduced renewable energy curtailment*** by allowing BAAs to export or reduce imports of renewable generation when it would otherwise need to be economically curtailed.
- ***Reduced flexibility reserves needed in PacifiCorp BAAs,*** which saves cost by aggregating the load, wind and solar variability and forecast errors of the combined EIM footprint. This report introduces the flexibility reserve benefits for PacifiCorp but defers measurement of reduced flexibility reserve benefits for the ISO to future reports due to the need to develop additional measurement techniques.

The ISO made the following enhancements in this report from the 2014 Q4 report.

- ***Benefit calculations this report included all fifteen minute market intervals.*** In the previous report, the intervals with price differences larger than $50/MWh were excluded to reasonably represent, but not overstate, the benefits from after-the-fact price corrections or changes as a result of the pricing waiver.[3]
- ***Calculations for this quarter used relevant prices including any corrections, rather than raw market prices.*** This not only allows the benefit to be calculated with better accuracy, but also eliminated the need to exclude intervals that may be corrected for prices after the fact.
- ***2015 Q1 calculations included avoided renewable curtailments (in MWh) in the ISO BAA,which contributed to the total EIM benefit.*** This is when a renewable resource is supporting the

[1] California ISO, http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf
[2] PacifiCorp, Energy Imbalance Markets Summary, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf
[3] Dec 1, 2014 Order Granting Waiver - EIM Pricing Parameters (ER15-402)
http://www.caiso.com/Documents/Dec1_2014_OrderGrantingWaiver_EIMPricingParameters_ER15-402.pdf

transfer from the ISO to PacifiCorp such that without the EIM the renewable generation in the ISO has to be curtailed.

These enhancements improved the accuracy of the benefit calculation. This report, though, has not quantified the benefits in the 5-minute market because the simplified benefit methodology has not been expanded to quantify 5-minute and 5-minute transfers between PacifiCorp and ISO started on February 4, 2015., The ISO plans to add the 5-minute components to future benefits reports

The table below shows the estimated benefits summary for the first quarter of 2015 in millions of dollars per BAA. The EIM benefit is calculated based on the methodology discussed in an earlier ISO technical bulletin with the simplifications described in the 2014 Q4 report.

BAA	January	February	March	Total
ISO	$0.48	$0.49	$0.48	$1.44
PACE	$0.88	$0.83	$0.91	$2.63
PACW	$0.42	$0.49	$0.28	$1.19
Total	$1.78	$1.81	$1.67	$5.26

Table 1: Estimated benefits shown are in millions and accrued in the first quarter of 2015.

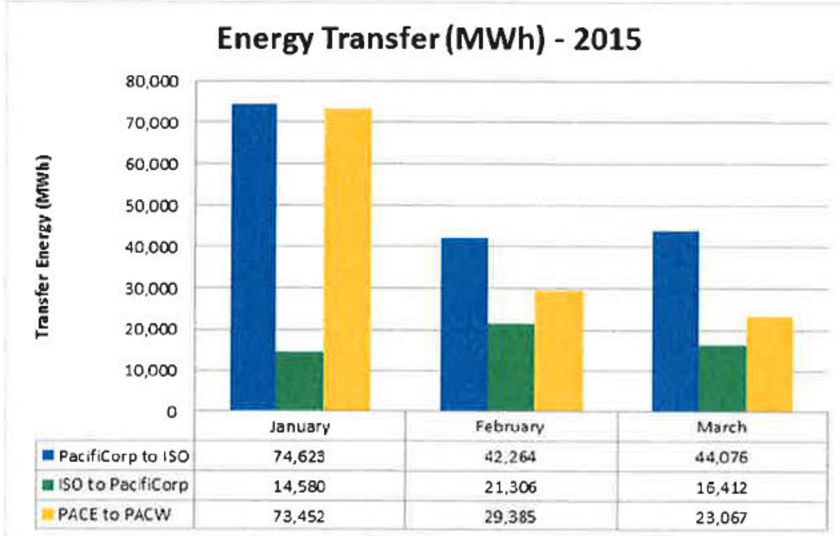
One of the most important contributions to the EIM benefit is the EIM transfer, which allows lower cost supply from one BAA to meet demand in another BAA. As such, the transfer volume is a good indicator of the EIM benefit. The highest level of energy transfers dispatched by the EIM in the 15-minute intervals for this quarter were 421 megawatts (MW) between the PacifiCorp West BAA (PACW) and the ISO, 321 MW from the ISO to PACW, and 200 MW from PacifiCorp East BAA (PACE) to PACW. The level of transfers reflect the economic opportunity between the regions.

PacifiCorp used a large portion of its Interchange Rights Holder mechanism for EIM transfers between PACW and the ISO. This report does not consider PacifiCorp's opportunity cost that the utility considered when using its transfer rights for the EIM.

Total 15-minute market transfers for January through March 2015 are approximately 160,963 megawatt hours (MWh) from PacifiCorp to the ISO and 52,297 MWh from the ISO to PacifiCorp (Figure 1). For the same period, average monthly transfers from PacifiCorp to the ISO and PACE to PACW decreased when compared to November and December 2014. Average monthly transfers from PacifiCorp to the ISO increased for the period January through March 2015 when compared to November and December 2014.

Five-minute incremental transfers were introduced between PacifiCorp and ISO starting on February 4, 2015. Since then, about 6,000 MWh in February and 13,000 MWh in March of incremental energy was transferred above that which was transferred in the 15-minute transfer reflected in Figure 1. This implies that there may be additional benefits in the 5-minute market, which the ISO has planned to quantify in future reports.

Figure 1: Energy transfers in the 15-minute market



	January	February	March
PacifiCorp to ISO	74,623	42,264	44,076
ISO to PacifiCorp	14,580	21,306	16,412
PACE to PACW	73,452	29,385	23,067

While market conditions vary, the EIM continues to provide benefits to participating entities and their customers as demonstrated in this report.

Background

The EIM began financially-binding operation on November 1, 2014 by optimizing resources across the ISO and PacifiCorp BAAs, which includes California, Oregon, Washington, Utah, Idaho and Wyoming. The EIM improves the integration of renewable resources and increases reliability by sharing information between balancing authorities on electricity delivery conditions across the entire EIM region. The ISO published the first EIM benefits report for November and December 2014 in February 2015.[4] This 2015 Q1 report is the second quarterly EIM benefits. As other entities such as NV Energy begin participating in the EIM, future reports will assess those additional balancing authorities and associated benefits.

Enhancements

The ISO continues to use the simplified method discussed in the 2014 Q4 report, but has implemented several enhancements to improve the accuracy of calculation.

Flexibility reserve procurement benefit

The net uncertainty from aggregating the load, wind and solar variability and forecast errors of the combined EIM footprint is typically smaller than the sum of each BAA's individual uncertainty in supply and demand. This is because the one BAA's uncertainty may offset another BAA's uncertainty, so that

[4] California ISO Q4 2014 EIM Benefits Report,
http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf

the net uncertainty is reduced. The reduction of uncertainty in the EIM means less flexibility reserve would be needed to maintain the same level of operational standard. The EIM flexibility reserve reduction is calculated as the sum of each EIM participating BAA's flexibility reserve requirement minus the net total flexibility reserve requirement for the whole EIM footprint.

The EIM co-optimizes the flexibility reserve with energy. Providing flexibility reserve may result in opportunity cost from not being able to provide energy, and the flexibility reserve is priced at the marginal opportunity cost in the EIM. The cost savings from the reduced flexibility reserve requirement, which is part of the total EIM benefit, is estimated to be $74,000 for Q1 2015. The calculation methodology is described below.

> In the counter factual dispatch for PacifiCorp BAAs, its flexible ramp requirement is reset to the standalone BAA's flexible ramping requirement, which does not reflect the diversity benefit. The available supply will be first used to meet the energy demand.
>
> After the BAA's energy demand is met, the remaining unloaded capcity will be used to meet the flexibile ramping. If the BAA does not have enough capacity to meet the flexible ramp requirement on top of its energy demand, then it implies that getting additional flexibility reserve capacity will incur an opportunity cost.
>
> The ISO estimated the per MW opportunity cost by the corresponding flexible ramping price in the EIM. Then the flexibility reserve cost, which equals the extra flexibility reserve needed multiplied by the EIM flexible ramping price, is added to the counter factual dispatch cost for each BAA.
>
> The added flexible ramping cost will increase the EIM benefit by the same amount because the EIM benefit is calculated as the total counter factual dispatch cost minus the total EIM cost.

In summary, by aggregating the load, wind and solar variability and the forecast errors of the combined EIM footprint, PacifiCorp can reduce its procurement of flexibility reserves. This reduction was calculated and averaged as high as 13.8 MW per hour in Q1 2015 at a savings of $74,000. The ISO may also benefit in a similar way, but the dollar savings were not quantified due to the complexity of binding transmission constraints and co-optimization in the ISO's market. The simplified calculation does not support considering these binding constraints.

The flexibility reserve benefit calcuated as above represents only the cost savings due to reduced procurement in the EIM. There may be additional benefits when the flexibility reserve is deployed in the five-minute market. The deployment benefit will be included in future reports.

Reduced Renewable Curtailment

Included in the EIM benefit is the avoided renewable curtailment in the ISO. This occurs when a renewable resource is supporting the transfer from the ISO to PacifiCorp such that without the EIM the renewable generation in the ISO would need to be curtailed. In addition to the cost saving benefit that is quantified in the report, avoided renewable curtailment may have additional benefit in reducing greenhouse gas emissions and renewable credits. The the avoided renewable curtailment volume for Q1 2015 was 8,860 MWh .

Other enhancements

The ISO made the following enhancements in the 2015 Q1 report. First, the ISO used relevant prices that included corrections in the benefit calculation rather than the raw market output prices. Second, all intervals have been included in the benefit calculation. In the 2014 Q4 report, the EIM benefits were calculated from the intervals where the absolute price difference between MALIN 500 KV bus and PacifiCorp was below $50/MWh. That was to avoid misrepresenting the benefit stemming from after-the-fact price corrections as under the existing pricing waiver[5]. No exclusion was applied in the 2015 Q1 report because the ISO moved to using relevant prices that corrections. These enhancements are expected to improve the benefit calculation accuracy and quality.

EIM Benefits in Q1 2015

The gross estimated EIM benefit is about $1.78 million for January, $1.81 million for February and $1.67 million for March for a total of $5.26 million. The details are provided in Table 3. These numbers represent benefits from all the intervals and include the flexibility reserve benefits discussed above.

BAA	January	February	March	Total
ISO	$0.48	$0.49	$0.48	$1.44
PACE	$0.88	$0.83	$0.91	$2.63
PACW	$0.42	$0.49	$0.28	$1.19
Total	$1.78	$1.81	$1.67	$5.26

Table 3: Estimated benefits shown are in millions and accrued for the first quarter of 2015.

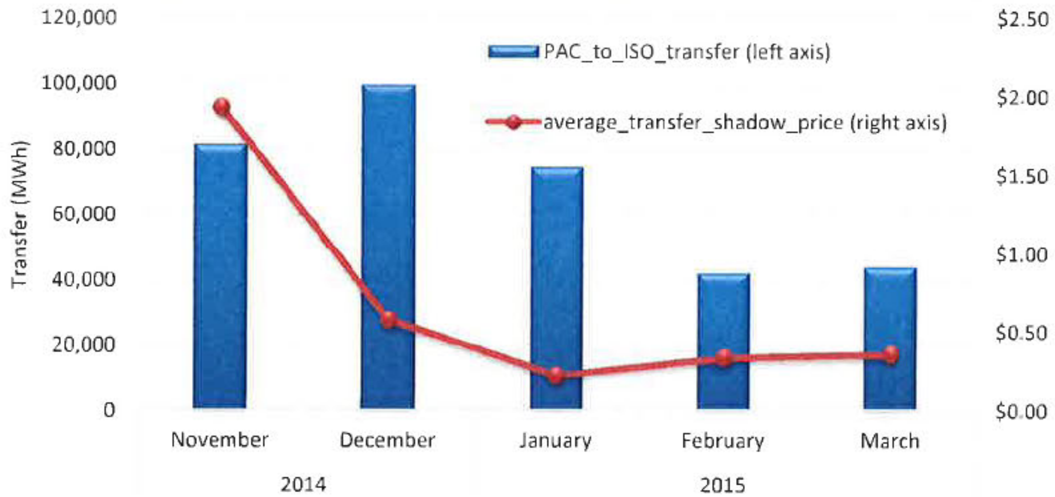
Compared with 2014 Q4, the monthly average EIM benefit was reduced by about $1.23 million. This may be due to the following reasons.

First, the volume of EIM transfers from PacifiCorp to the ISO were less than November and December 2014. As shown in Figure 2, the monthly average transfer volume from PacifiCorp to the ISO decreased by approximately 40 percent from 2014 Q4 to 2015 Q1. Coincidentally, the monthly average transfer shadow price also dropped from $0.60/MW-$1.90/MW range in 2014 Q4 to $0.20/MW-$0.40/MW range in 2015 Q1. The transfer shadow price is the marginal cost difference between the supply in PacifiCorp and the supply in the ISO deliverable to the MALIN 500 KV bus. PacifiCorp's marginal supply cost was lower than that of the ISO when EIM transferred energy from PacifiCorp to the ISO, however,

[5] Dec 1, 2014 Order Granting Waiver - EIM Pricing Parameters (ER15-402)
http://www.caiso.com/Documents/Dec1_2014_OrderGrantingWaiver_EIMPricingParameters_ER15-402.pdf

the marginal cost difference between PacifiCorp and the ISO tightened in 2015 Q1. Note that the EIM transfer benefit captures the total cost difference between PacifiCorp's supply and the ISO's supply for the transferred energy, but not the marginal cost difference. Yet empirically, marginal cost and total cost usually trend the same way. The downward trend of EIM benefit from 2014 Q4 to 2015 Q1 corellated well with decrease in marginal cost difference, which may be related to changes in supply and demand conditions in both the ISO and PacifiCorp.

Figure 2: Energy transfer in the 15-minute market from PacifiCorp to the ISO



Second, as the EIM stabilizes with less price excursions, the benefit resulting from extreme market conditions may reduce. We expect these extreme market outcomes to decrease over time as offers submitted into the EIM increase, and with improvements in the market clearing engine.

Third, improved scheduling practices may also lead to less EIM benefit being quantifiable under the current approach. As EIM BAAs gain more experience with the market, they may start to improve their base scheduling practices. More optimized base schedules will leave less room for the EIM to optimize, and thus less EIM benefit being calculated. However, these improvements would not materialize but for the EIM. We just cannot quantify such benefits through the current calculations.

Conclusion

The benefit continued to accrue in the EIM for the first quarter of 2015 at about $1.75 million per month, which is in line with pre-launch projections. Comparing with 2014 Q4, there was a reduction in the monthly average benefit. This is can be attributable to multiple reasons that includes seasonal transfer reductions, a more stable market and improved scheduling practices. The ISO made several enhancements in this report to improve the benefit accuracy and quality including quantifying the flexibility reserve benefit.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1201

PacifiCorp ISO EIM Benefits Report Q4 2014

August 25, 2016

Benefits for Participating in EIM

February 11, 2015

Revision History

Date	Version	Description	Author
2/10/2015	1.0		Lin Xu

Table of Contents

Executive Summary

The Energy Imbalance Market (EIM) began financially-binding operation on November 1, 2014 by optimizing resources across the California Independent System Operator (ISO) and PacifiCorp balancing authority areas (BAAs).

This first report quantifies the estimated gross benefits from the first two months of EIM operation to be $5.97 million, which is in line with pre-launch projections. This benefit report reflects EIM's ability to select the lowest cost resource across the PacifiCorp and ISO BAAs to serve demand and accounts for the following categories as described in an earlier study conducted by Energy + Environmental Economics (E3) [1] for PacifiCorp and the ISO:

- ***More efficient dispatch, both inter- and intra-regional***, by automating dispatch every five minutes within PacifiCorp's two BAAs and between the PacifiCorp and California ISO BAAs; and
- ***Reduced renewable energy curtailment*** by allowing BAAs to export or reduce imports of renewable generation when it would otherwise need to be economically dispatched down or manually curtailed.

This report does not calculate the ***reduced flexibility reserves*** needed by the ISO and PacifiCorp BAAs, which provides additional savings by aggregating the load, wind, and solar variability and forecast errors of the combined EIM footprint. It also does not calculate the benefits in the 5-minute market. The ISO plans to add this component to future benefits reports.

The table below shows the estimated benefits summary for November and December 2014 in millions of dollars per BAA. The EIM benefit is calculated based on the methodology discussed in an earlier ISO Technical Bulletin with some practical simplifications described later in this report.

BAA	November	December	Total
ISO	$0.65	$0.59	$1.24
PACE	$1.05	$1.26	$2.31
PACW	$1.39	$1.03	$2.42
Total	$3.09	$2.88	$5.97

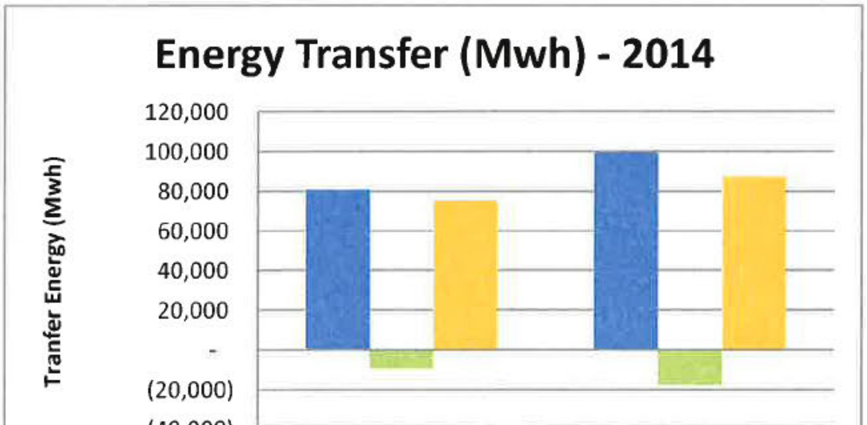
Table 1: Estimated benefits shown are in the millions and accrued for the last two months in 2014.

The EIM dispatched energy transfers up to 421 megawatts (MW) in a 15-minute interval between the PacifiCorp West BAA (PACW) and ISO, up to 220 MW from ISO to PACW, and up to 200 MW from PAC East BAA (PACE) to PACW, which were consistent with economic pricing between the regions.

[1] PacifiCorp, Energy Imbalance Markets Summary, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

PacifiCorp consistently exercised its Interchange Rights Holder mechanism for EIM transfers to use a large percentage of its transfer rights between PACW and the ISO. Congestion within the ISO-controlled grid also factored into the amount of capacity available for EIM transfers.

This report does not consider PacifiCorp's opportunity cost that the utility considered when deciding to use its transfer rights. Although subject to continuously varying market conditions, the benefits are expected to increase as system operations continue to improve with new resources participating and as transfer capability increases or is available during 5-minute intervals. Preliminary estimates for November and December 2014 reflect approximately 180,786 megawatt hours (MWh) transferred to ISO from PacifiCorp and 27,361 MWh transferred to PacifiCorp from the ISO (Figure 1).



	November	December
PacifiCorp to ISO	80,973	99,813
ISO to PacifiCorp	(9,830)	(17,531)
PACE to PACW	75,169	87,420

Figure 1: Energy Transfer

The estimated benefits in the first two months of operation are consistent with the March 2013 study conducted by E3 [2] for PacifiCorp and the ISO that projected annual savings in 2017 in the range of $21 million to $129 million.

While market conditions will vary, the benefits demonstrated in EIM's first two months indicate that EIM has the potential to provide benefits to participating entities and their customers for the long term.

[2] PacifiCorp, Energy Imbalance Markets Summary, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

Background

The EIM began financially binding operation on November 1, 2014 by optimizing resources across the ISO and PacifiCorp BAAs, which includes California, Oregon, Washington, Utah, Idaho and Wyoming. The EIM improves the integration of renewable resources and increases reliability by sharing information between balancing authorities on electricity delivery conditions across the entire EIM region. This first quarterly report outlines the estimated benefits from the first two months of EIM operation. Future reports will examine EIM customer savings and benefits on a three month quarterly basis. As other entities such as NV Energy begin participating in the EIM, future reports will assess those additional balancing authorities and associated benefits.

During the design, development, and implementation over the last two years, EIM has been supported by a broad range of stakeholders, government officials and energy policy organizations. EIM participants expect to benefit from more efficient dispatch of resources both within and between BAAs, and the ability to share flexible resources to accommodate variable energy resources. A joint PacifiCorp and ISO study performed by E3 predicted the EIM's annual benefit in the range of $21 million to $129 million in 2017.[3] Likewise, a study conducted for NV Energy showed incremental benefits to all EIM participants from $9 million to $29 million.[4] In addition, the ISO built the EIM model on an existing, proven market platform that gives EIM entities a low-cost, low-risk option to participate in EIM.

In a Technical Bulletin provided to stakeholders on August 28, 2014,[5] the ISO proposed a systematic way to quantify benefits for each region served by EIM. In both the Technical Bulletin and in this report, the ISO refers to EIM benefits compared to a "counterfactual" or "business without EIM" approach. Cost savings are calculated by comparing the cost of the EIM optimized dispatch to the counterfactual cost of dispatch without EIM optimization and without intra-hour transfers between PacifiCorp and ISO that would not occur but for the EIM.

Simplified Method of Calculating Benefits

This report quantifies the estimated benefit of participating in the EIM for November and December 2014. Because of the complexity in automating the counterfactual reruns and validating the results, the ISO was unable to complete the counterfactual reruns for fourth quarter of 2014 by the publication date of this first report. However, the ISO has developed a simplified process to produce the optimized counterfactual dispatch. This method only quantifies benefits from the 15-minute market and does not attempt to quantify additional benefits from 5-minute market or diversification affecting flexible ramping requirements. The ISO will explore quantifying these benefits in future reports.

[3] PacifiCorp, Energy Imbalance Markets Summary, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf
[4] NV Energy-ISO Energy Imbalance Market Economic Assessment http://www.caiso.com/Documents/NV_Energy-ISO-EnergyImbalanceMarketEconomicAssessment.pdf
[5] Quantifying the Benefits for Participating in EIM, published August 28, 2014 posted at http://www.caiso.com/Documents/TechnicalBulletin_EnergyImbalanceMarket-Benefits.pdf

The major difference from the approach discussed in the Technical Bulletin is that the counterfactual dispatches without EIM are based on the off line optimization of production data rather than re-running the EIM market clearing engine with modifications to simulate pre-EIM practice. The simplified approach provides reasonable counterfactual dispatches when no transmission constraints are binding in the PacifiCorp regions.

Counterfactual dispatch

The counterfactual dispatch for the ISO mimics ISO market operations without importing from or exporting to PacifiCorp through EIM transfers. The counterfactual dispatch for PacifiCorp mimics PacifiCorp's pre-EIM manual dispatch to meet demand with limited ability for intra-hour transfers between PacifiCorp and the ISO prior to EIM.

In cases where a counterfactual dispatch could not be produced for a balancing area using available bids, a conservative assumption was made by extending the highest bid dispatched.

ISO counterfactual dispatch

The ISO would need to meet demand without EIM transfers between PacifiCorp and the ISO. The ISO counterfactual dispatch will be constructed in the following ways.

Scenario 1: ISO counterfactual dispatch without EIM transfer from PacifiCorp to the ISO

1. Find ISO's undispatched supply (not including supply from PacifiCorp) with bids greater than or equal to the transfer point price (MALIN 500 KV);
2. Sort and stack them from low to high bid; and
3. Clear the supply stack from low to high bid up to the transfer megawatts.

The supply resources that are dispatched up to the volume of transferred megawatts are the counterfactual dispatches that the ISO would have to dispatch without importing through the EIM transfer. The counterfactual dispatch cost represents the cost of meeting demand in the ISO without economic EIM transfers from PacifiCorp.

Scenario 2: ISO counterfactual dispatch without EIM transfer from the ISO to PacifiCorp

1. Find ISO's dispatched supply with bids less than or equal to the transfer point price (MALIN 500 KV);
2. Sort and stack them from high to low bid; and
3. Clear the supply stack from high to low bid up to the transfer megawatts.

The supply resources that are dispatched down to the volume of transferred megawatts are the counterfactual dispatches that the ISO would have realized but for the EIM export transfer.

PacifiCorp counterfactual dispatch

PacifiCorp East and PacifiCorp West BAAs would need to meet demand without EIM optimization and without intra-hour transfers between PacifiCorp and the ISO. The PacifiCorp counter factual dispatch will be constructed in the following way:

1. Calculate the demand change for each BAA;
2. If the demand change results in violations of the transfer limitations between PACE and PACW, then adjust base schedules from the limited pool in each BAA to resolve the overloads in the right economic order; and
3. Economically dispatch resources from the limited pool on top of the changed base schedules from step 2 to meet PacifiCorp demand without violating the transfer limitations between PACE and PACW.

The economic clearing in step 2 and step 3 are performed the same way as in the ISO's counterfactual dispatch by going through the sorted supply stacks. The limited pool of resources reasonably approximates PacifiCorp's manual resource dispatch prior to EIM to meet intra-hour system imbalances.

This process is expected to result in the following:

- No intra-hour transfers between the ISO and PacifiCorp;
- The allowance of intra-hour transfer changes between PACE and PACW subject to directional transfer capability limitations;
- Meeting PacifiCorp's total demand (PACE and PACW) change from base schedule from a limited pool of resources; and
- The disallowance of intra-hour dispatch instructions to economically clear against each other unless it is for congestion management purposes.

EIM benefit calculation steps

For each interval and each BAA, the EIM benefit is calculated in the following way:

1. Use the simplified method to determine the optimized counterfactual dispatches would be without EIM;
2. For each region, calculate the total EIM dispatch cost as the sum of bid cost associated with the dispatch difference between the EIM dispatch and the base schedule, the EIM transfer cost (volume and price), and the greenhouse gas (GHG) cost;
3. For each region, calculate the total counterfactual dispatch cost as the sum of bid cost associated with the dispatch difference between the counterfactual dispatch and the base schedule, and the counterfactual transfer cost between PACE and PACW; and
4. Calculate each region's cost saving as the difference between the total counterfactual dispatch cost and the total EIM dispatch cost.

EIM benefits in Q4 2014

The total estimated EIM benefit is about $3.09 million for November and $2.88 million for December for a total of $5.97 million with details provided in Table 2. These numbers represent benefits from 79 percent of all the intervals where the largest absolute price difference between the Malin500 and PACE or between the Malin500 and PACW is less than $50/MWh. The intervals with price differences larger than $50/MWh are excluded to reasonably represent, but not overstate, the benefits from after-the-fact price corrections or changes as a result of the pricing waiver[6].

BAA	November	December	Total
ISO	$0.65	$0.59	$1.24
PACE	$1.05	$1.26	$2.31
PACW	$1.39	$1.03	$2.42
Total	$3.09	$2.88	$5.97

Table 2: Estimated benefits shown are in the millions and accrued for the last two months in 2014.

Conclusion

The estimated benefits calculation was developed through a thorough analysis and is a reasonable representation of the benefits accrued by both balancing authorities. Results are in line with expectations given market conditions and the first two months of operating the new market. Future reports will include assessing flexibility reserve benefits and 5-minute dispatch benefits that were not included in this report. Prospects for increases in customer benefits remain bright with improvements to market operations, expanding of the market with more participants, and expanding of renewables and transmission within the EIM footprint.

[6] Dec 1, 2014 Order Granting Waiver - EIM Pricing Parameters (ER15-402)
http://www.caiso.com/Documents/Dec1_2014_OrderGrantingWaiver_EIMPricingParameters_ER15-402.pdf

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1202

CAISO Presentation–Benefits for Participating in EIM

August 25, 2016

California ISO
Shaping a Renewed Future

Benefits for Participating in EIM

Mark Rothleder, VP Market Quality and Renewable Integration
Lin Xu, Lead Market Development Engineer

Informational call

February 11, 2015

Agenda

- Summary of results
- Summary of March 2013 benefit study
- Method of calculating benefits
- EIM benefits for November and December 2014

Summary of results

- Report estimates benefits accrued in November and December 2014 from EIM operation
- Total estimated benefit to EIM footprint is $5.97M
- Benefits are consistent with earlier benefit study
- Benefits reflect:
  - More efficient dispatch, both inter- and intra-regional in the 15-minute market
  - Reduced economic renewable energy curtailment
- Subsequent reports will quantify the reduced flexibility reserves needed by both Balancing Authority Areas (BAAs) and 5-minute dispatch benefits

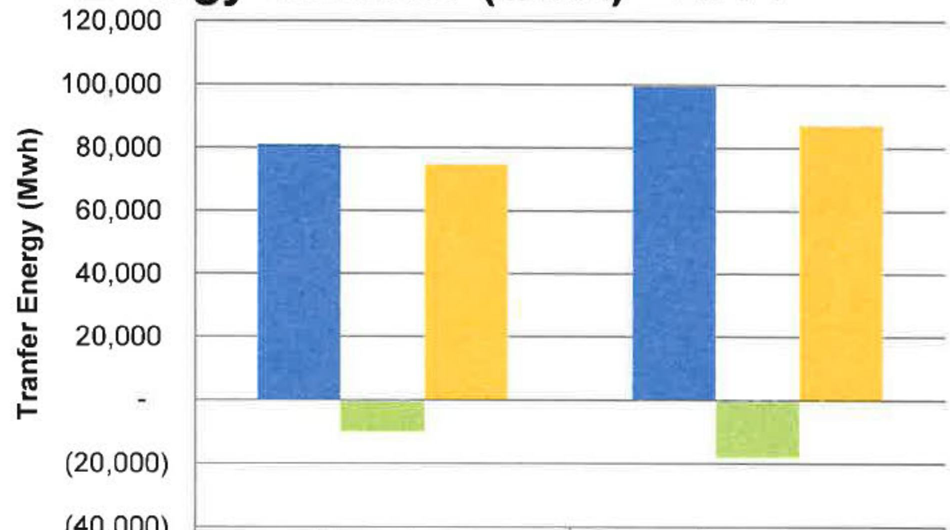
Summary of results for 4th Quarter 2014

BAA	November	December	Total (millions)
ISO	$0.65	$0.59	$1.24
PACE	$1.05	$1.26	$2.31
PACW	$1.39	$1.03	$2.42
Total	**$3.09**	**$2.88**	**$5.97**

- Results represent benefits from 79% of all the intervals where the largest absolute price difference between the Malin500 and PACE or between the Malin500 and PACW is less than $50/MWh.

Summary of transfer results for 4th Quarter 2014

Energy Transfer (Mwh) - 2014



	November	December
PacifiCorp to ISO	80,973	99,813
ISO to PacifiCorp	(9,830)	(17,531)
PACE to PACW	75,169	87,420

- The EIM dispatched energy transfers up to:
  - 421 megawatts (MW) in a 15-minute interval between the PacifiCorp West BAA (PACW) and ISO
  - 220 MW from ISO to PACW
  - 200 MW from PAC East BAA (PACE) to PACW

Pre-launch projections reflected prompt return on investment

	ISO/ PacifiCorp study (in millions)	**ISO/NV Energy study on incremental benefits** (in millions)
annual benefits	$21.4 - $129.0	$9.0 - $18.0 (2017) $15.0 - $29.0 (2022)
start-up costs	approx. $20.0 ($2.5 to ISO)	approx. $11.20 ($1.10 to ISO)
annual on-going costs	approx. $3.00 ($1.35 to ISO)	approx. $2.60 ($0.75 to ISO)

March 2013 study by Energy + Environmental Economics (E3) for PacifiCorp and the ISO can be viewed here: http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

Method of calculating benefits

COMPARE:

cost of the EIM optimized dispatch

- In the 15 minute market
- Excludes benefits from flexible ramping

TO:

counterfactual cost of dispatch without EIM optimization

- without intra-hour transfers between PacifiCorp and ISO that would not occur but for the EIM.

Counterfactual dispatch:

- Mimics imbalance operation without optimization within PacifiCorp and without transfers between PacifiCorp and ISO.
- The ISO would need to meet demand without EIM transfers between PacifiCorp and the ISO.
- PacifiCorp East/PacifiCorp West BAAs (PACE/PACW) would need to meet demand without EIM optimization and without intra-hour transfers between PacifiCorp and the ISO.

In summary, benefits are consistent with earlier benefit analysis and are reasonable

BAA	November	December	Total
ISO	$0.65	$0.59	$1.24
PACE	$1.05	$1.26	$2.31
PACW	$1.39	$1.03	$2.42
Total	**$3.09**	**$2.88**	**$5.97**

- Benefits reflect:
  - More efficient dispatch, both inter- and intra-regional in the 15-minute market
  - Reduced renewable energy economic or manual curtailment
- Subsequent reports will quantify the reduced flexibility reserves needed by both Balancing Authority Areas (BAAs) and 5-minute dispatch benefits

Questions

Please address any questions regarding this report to EIM@caiso.com

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1203

Staff's Response to PacifiCorp's Data Requests Nos. 37, 38, 39 and 44

August 25, 2016

PacifiCorp Data Request 37

Refer to Staff/300, Crider/3, line 20. Please provide the basis for the statement that all Energy Imbalance Market (EIM) participants submit optimized base schedules, including PacifiCorp.

Response to PacifiCorp Data Request 37

According to the Company as stated in "PACIFICORP'S ENERGY IMBALANCE MARKET ENTITY PROPOSAL, September 13, 2013" :

"The EIM Entity Scheduling Coordinator will coordinate and facilitate the EIM for the EIM Entity. The EIM Entity Scheduling Coordinator will compile generation and load schedules for each of the EIM Entity BAAs and submit balanced base schedules to the Market Operator. A balanced base schedule consists of hourly forecasts of load, generation, and interchange, which net to zero."

Staff interprets a perfectly balanced base schedule with a net imbalance of zero to be optimized at an hourly level.

PacifiCorp Data Request 38

Refer to Staff/300, Crider/5, lines 15-16
a. Does Staff agree that the California Independent System Operator (CAISO) counterfactual is intended to model PacifiCorp's system as it operated pre- EIM, which meant that its resources were dispatched manually?

b. Please quantify the costs that the Company incurred pre-EIM that are now avoided, and included in Staff's intra-regional benefits adjustment.

c. If Staff disagrees with either (a) or (b), please provide an explanation for Staff's position.

Response to PacifiCorp Data Request 38

a. Staff's understanding is that the counterfactual is intended to model PacifiCorp's dispatch as it operated prior to the EIM.

b. Staff understands that GRID is an economic dispatch model that simulates the operation and dispatch of generation units. Staff is not aware of GRID modeling being dependent on the physical means of actual operational dispatch of units. Staff is not aware of GRID being dependent on the mode of communications between dispatcher and the generation asset, but only that GRID assigns generation levels to the units on an hourly basis in an optimized fashion. Please also see Staff Data Response 40 (b).

c. Please see response to (b) above.

PacifiCorp Data Request 39

Refer to Staff/300, Crider/6 lines 1-9. Please confirm that the description of the CAISO security constrained economic dispatch model (SCED) model Staff quotes from the Company's response to data request CUB 72 (Staff/301) is not describing the CAISO counterfactual scenario. If Staff cannot confirm, please provide the basis for Staff's position.

Response to PacifiCorp Data Request 39

The scenario described in lines 1-9 is not the counterfactual scenario. Staff understands the SCED described therein as used in the EIM scenario is the same SCED used in the counterfactual scenario. As stated in the EIM technical bulletin (exhibit to PAC reply testimony), the counterfactual requires an economic dispatch solution:

> PacifiCorp counterfactual dispatch
> PacifiCorp East BAA and PacifiCorp West BAA would need to meet demand without intra-hour transfers between PacifiCorp and the ISO, but transfers could occur between PACE and PACW in the counterfactual dispatch. The PacifiCorp counter factual dispatch will be constructed in the following way:
> 1. Calculate the real-time net load imbalance for each BAA;
> 2. **Economically dispatch** resources from the limited pool on top of the base schedules to meet net PacifiCorp load imbalance without violating the transfer limitations between PACE and PACW.

PacifiCorp Data Request 44

Refer to Staff/300, Crider/8, lines 18-22. Please identify, by exhibit, page, and line number, which portions of Staff's opening testimony have been superseded by Staff's new understanding of the terms used by CAISO.

Response to PacifiCorp Data Request 44

Nothing of substance in Staff/100 has been "superseded" by the CAISO terminology discussion in Staff/300, Crider/7-8.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1204

PacifiCorp ISO EIM Benefits Report Q2 2015

August 25, 2016

California ISO

Benefits for Participating in EIM

July 30, 2015

Revision History

Date	Version	Description	Author
7/30/2015	1.0		Lin Xu

Table of Contents

Executive Summary

This is the third "Quantifying EIM Benefits" report released and it quantifies the estimated gross benefits for April, May, and June 2015 to be $10.18 million, which is consistent with pre-launch projections. The increase in benefits reflects the inclusion of the five-minute granularity, increased transfer volumes from PacifiCorp, the first Energy Imbalance Market (EIM) participant, to the ISO, and higher prices in the market.

This analysis continues to prove EIM's ability to select the lowest cost resource across the PacifiCorp and ISO balancing authority areas (BAAs) to serve demand and measures benefits within the following categories, which were described in an earlier study conducted by Energy + Environmental Economics (E3)[1] for PacifiCorp and the ISO.

- ***More efficient dispatch, both inter- and intra-regional, in the Fifteen-Minute Market (FMM) and Real-Time Dispatch (RTD)*** by automating dispatch every fifteen minutes and every five minutes within PacifiCorp's two BAAs and between the PacifiCorp and California ISO BAAs.
- ***Reduced renewable energy curtailment*** by allowing BAAs to export or reduce imports of renewable generation when it would otherwise need to be economically curtailed.
- ***Reduced flexibility reserves needed in PacifiCorp BAAs,*** which saves cost by aggregating the load, wind, and solar variability and forecast errors of the combined EIM footprint. This report introduces the flexibility reserve benefits for PacifiCorp but defers measurement of reduced flexibility reserve benefits for the ISO to future reports due to the need to develop additional measurement techniques.

Comparing with past reports, the ISO made the following enhancements in this report:

- ***Quantify benefits on a five-minute market interval basis.*** In the previous reports, the ISO quantified EIM benefits on a fifteen-minute market interval basis. In this report, the ISO quantified the EIM benefits using the five-minute EIM interval results.
- ***Enhanced benefits accounting of greenhouse gas (GHG) allocation method.*** In this report, the ISO enhanced the GHG allocation accounting method to divide the benefits between BAAs more precisely.

Table 1 below shows the estimated benefits summary for the second quarter of 2015 in millions of dollars per BAA. The EIM benefit is calculated based on the methodology discussed in an earlier ISO Technical Bulletin with the practical simplifications described in the 2014 Q4 report, and on five-minute market interval basis.

[1] PacifiCorp, Energy Imbalance Markets Summary, http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

BAA	April	May	June	Total
ISO	$0.62	$1.00	$0.84	$2.46
PACE	$0.62	$0.97	$1.67	$3.26
PACW	$0.66	$1.21	$2.59	$4.46
Total	**$1.90**	**$3.18**	**$5.10**	**$10.18**

Table 1: Estimated benefits shown are in millions and accrued in the second quarter of 2015

One of the important contributors to the EIM benefit are transfers, which allows lower cost supply from one BAA to meet demand in another. As such, the transfer volume is a good indicator of a portion of the EIM benefit. Transfers can take place in both the FMM and RTD. The transfer limits between PACW and the ISO in the FMM are based on the Interchange Rights PacifiCorp utilized for EIM transfers. This report does not consider PacifiCorp's opportunity cost that the utility considered when using its transfer rights for the EIM.

The transfer limits in the five-minute RTD market are dynamically determined based on allocated dynamic transfer capability limiting the five-minute transfers around the fifteen-minute transfer scheduled in the FMM, and system operating conditions. Table 2 below provides the FMM transfer volume as well as the RTD dynamic transfer volume. The total EIM transfer for both fifteen-minute transfers and five-minute dynamic transfers for April through June 2015 were approximately 260,452 megawatt hours (MWh) from PacifiCorp to the ISO and 35,368 MWh from the ISO to PacifiCorp.

Negative RTD dynamic transfer values, such as those realized in May and June and shown in Table 2, can occur when the RTD dynamic transfer flows in the opposite direction of the FMM transfer. For example, for a particular hour, the FMM transfer can be 100 MWh from the ISO to PacifiCorp, and the RTD dynamic transfer can be 20 MWh from PacifiCorp to the ISO, resulting in a 80 MWh total transfer from the ISO to PacifiCorp. In this case, they will be reported as transfer from ISO to PacifiCorp with FMM = 100 Mwh, RTD (dynamic) = -20 MWh, and total = 80 MWh.

market	Month	PAC_ISO	ISO_PAC	PACE_PACW
FMM	April	38,688	14,094	22,111
	May	75,382	13,134	58,954
	June	98,742	7,489	77,234
RTD (dynamic)	April	12,924	1,033	4,275
	May	14,191	292	-404
	June	20,525	-674	-8,335
Total	**All**	**260,452**	**35,368**	**153,835**

Table 2: Energy transfers (MWh) in the FMM and RTD for the second quarter of 2015

While market conditions will vary, the EIM continues to provide benefits to participating entities and their customers as demonstrated in this report.

Background

The EIM began financially-binding operation on November 1, 2014 by optimizing resources across the ISO and PacifiCorp BAAs, which includes California, Oregon, Washington, Utah, Idaho and Wyoming. The EIM improves the integration of renewable resources and increases reliability by sharing information between balancing authorities on electricity delivery conditions across the entire EIM region. The ISO published the first EIM benefit report for November and December 2014 in February 2015,[2] and the second EIM benefit report for the first quarter of 2015 in April 2015.[3] This third report outlines the estimated benefits from the second quarter of 2015. When other entities such as NV Energy begin participating in the EIM, future reports will assess those additional balancing authorities and associated benefits.

Enhancements

The ISO continues to use the simplified method discussed in the last two reports, but has implemented two major enhancements, namely quantifying the benefits of the 5-minute market and improving the GHG revenue accounting method. Both will be explained below.

Separately, the ISO also quantified the benefits using the fifteen minute market results only for comparative purposes to prior quarterly reports.

Five-minute granularity EIM benefit

In the last two reports, the ISO quantified the EIM benefits for each fifteen-minute market interval using the FMM results and counter factual dispatch constructed with fifteen-minute granularity to match the FMM imbalance. The total bid cost difference between the fifteen-minute counter factual dispatch and the FMM dispatch is the fifteen-minute EIM benefit. In this report, the ISO quantifies the benefits for each five-minute market interval using the RTD market results, relevant information from the FMM market and counter factual dispatch constructed with five-minute granularity. The total EIM benefit in terms of cost saving is the total bid cost difference between the five-minute counter factual dispatch and RTD dispatch.

On a high level, constructing the five-minute counter factual dispatch is no different from constructing the fifteen-minute counter factual dispatch except for the market interval granularity. The five-minute counter factual dispatch in PacifiCorp is to meet the five-minute imbalance from the limited resource pool that were used for real-time balancing prior to EIM. ISO assumes each BAA plans to balance real-time energy in a time frame similar to the FMM but with five-minute granularity. Therefore, in the five-

[2] California ISO, http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf
[3] California ISO, http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ1_2015.pdf

minute counter factual dispatch, ISO uses the supply bids subject to the same ramp limitation perceived in the FMM instead of the ramp limitation perceived in the RTD. As discussed the Q4 2014 report, the ramp limitations perceived in the FMM may still be too restrictive for the counter factual dispatch. This is because the ramp limitations are calculated from the actual generation level of previous EIM dispatch, so the ramp limitation in the FMM may not apply for the counter factual dispatch. To mitigate this, ISO extends the last supply segment with highest bid cost in the same BAA to the extent that there is infeasibility in a BAA in the counter factual dispatch.

After the five-minute counter factual dispatch is constructed, the ISO calculates the total EIM benefit by taking the difference between the total counter factual dispatch cost and the total EIM dispatch cost on a five-minute granularity level. In order to divide the total benefit among the BAAs, the ISO models the transfer as supply or demand for each BAA depending on whether it is transferring in or transferring out of the BAA, and assigns the corresponding transfer price to it. As discussed in the Technical Bulletin-Appendix 1, the transfer price will be the BAA's locational marginal price (LMP), plus or minus half of the congestion shadow price on the transfer. As discussed earlier, transfers can take place in both the FMM and the RTD market, and are settled at different prices. In the benefit calculation, the ISO prices the transfer in the same way as it is being settled. For example, if the FMM transfer is 100 MW at transfer price $50, and the RTD dynamic transfer is 50 MW at price $60, then the transfer dollar amount is 100*50 + 50*60 = $8,000 for a total of 150 MWh transfer.

Improved GHG revenue accounting

When the ISO is importing power from PacifiCorp, the imported energy is being allocated to individual resources subject to bid-in GHG adder costs. The allocated GHG awards will also receive a GHG payment at the marginal GHG price. Note that the GHG transfer could be allocated to resources in both PACE and PACW. In the last two reports, ISO did not explicitly calculate the GHG revenue for individual BAAs. Instead, all of the GHG revenue was allocated to PACW. While the total benefit is the same, this tends to overestimate the benefit in PACW, and underestimate the benefit in PACE.

In this report, ISO refined the GHG revenue accounting method so that the GHG revenue will be explicitly calculated based on the individual allocations. Details about this enhancement can be found at the updated EIM Technical Bulletin-Appendix 1.

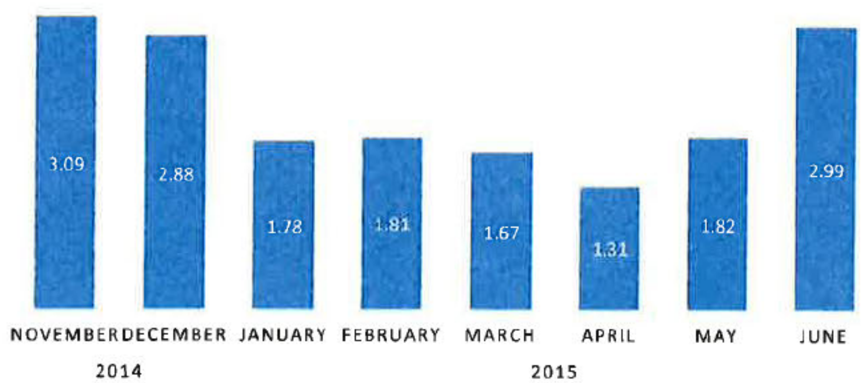
In addition, the GHG allocation awards also have two settlements, the FMM settlement and the RTD settlement. ISO also calculates the GHG revenue in the same way as they are settled.

EIM Benefits in Q2 2015

Figure 2 illustrates the make-up of the Q2 estimated EIM benefit of $10.18 million, which includes $1.90 million for April, $3.18 million for May, and $5.10 million for June. Further details by individual BAA are provided in in Table 1. As stated previously, this is significantly higher than the Q1 2015 benefits due to fact that the Q2 2015 benefits were quantified based on the five-minute interval basis while the Q1 2015 benefits were quantified on a fifteen-minute market interval basis.

For comparison to previous reports, the ISO separately calculated the benefits using the previously fifteen-minute interval results as well. For Q2 2015 this benefit was $6.12 million, which compares to the Q1 2015 number of $5.26 million. The ISO plotted the monthly fifteen-minute EIM benefit since November 2014 in Figure 2. The fifteen-minute benefit is trending upward from April to June, which is likely related to an increase in real-time demand through the quarter and more resources participating in EIM.

Figure 2: Monthly fifteen-minute EIM benefit trend (in million dollars)



The total EIM benefit calculated on a five-minute granularity is about 66 percent more than the EIM benefit quantified on fifteen-minute market intervals in Q2 2015. The increased benefits seen on a five-minute granularity level can be attributable to both the added transfer volume and the larger price difference between PacifiCorp and the ISO in the five-minute intervals. The PacifiCorp to ISO dynamic five-minute transfer is about 22 percent of the fifteen-minute transfer in volume, which is only accounted for in the five-minute EIM benefit calculation. Economic transfers take place as a result of cost difference between PacifiCorp and the ISO until the transfer limit is reached or the marginal cost difference diminishes. When the transfer constraint is not binding, it implies the marginal cost difference has diminished after making the transfer, but the cost difference associated with the transfer is generally not zero. When the transfer constraint is binding, it implies the transfer limit has been reached, then the shadow price of the transfer is the marginal cost difference. In this case, the cost difference associated with the transfer may be higher than the shadow price of the transfer.

To summarize, the benefit of the transfer is the cost difference times the transfer volume. The ISO uses the average transfer shadow price as the indicator of cost difference between PacifiCorp and the ISO. The average transfer shadow price in RTD is 34 percent more than that of FMM. So combining the transfer volume and shadow price, we expect the benefit at the five-minute granularity would be about $(1+22\%)*(1+34\%) = 1.63$ times of the fifteen-minute benefit. This simple method estimates that the five-minute benefit would be 63 percent more than the fifteen-minute benefit, which is very close to the observed 66 percent.

Reduced Renewable Curtailment

Included in the EIM benefit is the avoided renewable curtailment in the ISO. This occurs when a renewable resource is supporting the transfer from the ISO to PacifiCorp such that without the EIM the renewable generation in the ISO would need to be curtailed. In addition to the cost saving benefit that is quantified in the report, avoided renewable curtailment may have additional benefit in reducing greenhouse gas emissions and renewable credit. The total avoided renewable curtailment volume in MWh for Q2 2015 was quantified to be 1,474 (April) + 1,253 (May) + 902 (June) = 3,629 MWh. Assuming the avoided renewable curtailement displaces production from other resources at a default emission rate of of 0.428 metric-tons CO2/Mwh, the avoided curtailment displaced an estimated 1553 metric-tons of CO2.

Conclusion

EIM continued to show significant benefits during the second quarter of 2015. The total benefit for Q2 of $10.18 million based on the five minute market results is consistent with pre-launch studies.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1205

Opening Testimony of Lance Kaufman
Docket UE 308

August 25, 2016

CASE: UE 308
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

REDACTED
Opening Testimony

June 20, 2016

Q. Please state your name, occupation, and business address.

A. My name is Lance Kaufman. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit staff/301.

Q. What is the purpose of your testimony?

A. I discuss two issues related to the Company's power cost projection.

Q. Other than your witness statement, did you prepare an exhibit for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, CALIFORNIA – OREGON TRADING MARGIN

Q. Please describe the issue related to the Oregon-California Trading Margin?

A. In PGE's last AUT proceeding, the Commission ordered PGE to propose a methodology to capture, for purposes of the AUT, the value of benefits PGE obtains through transactions at the California-Oregon Border (COB) made possible by transmission rights paid for by PGE ratepayers. (Order No. 15-356.)

Q. What is PGE's proposed methodology?

A. PGE calculates an incremental benefit to power costs associated with transactions at COB. The benefit exists at times when PGE has excess transmission capacity between COB and MidC and a price differential between the two markets exists. The benefit is incremental because sales at the COB market are not explicitly modeled by MONET. Instead, PGE calculates the benefit for each month based on the forecasted COB volumes times the forecasted price difference between COB and MidC.

Q. Why is the price difference between MidC and COB an appropriate value for COB transactions?

A. The market price at each trading hub represents the marginal cost and benefit of transmitting power to and from COB. The difference between these prices is the gain that PGE realizes when it purchases energy at one hub and sells at the other.

Q. Has PGE appropriately estimated the COB transaction benefits?

A. No. I have two concerns. First, PGE is only modeling 87 percent of normal transactions at COB. Second, the method used to estimate monthly transaction volumes is not consistent with the method used to estimate the price difference between COB and MidC.

Q. Please explain why PGE is only modeling 87 percent of normal COB transactions.

A. PGE estimates normal COB transactions by calculating the three year rolling average of purchases and sales in each month, split for high load hours and low load hours. However, when calculating the monthly benefit in each month, PGE only counts sales at COB. This ignores [redacted] hours of purchases at COB and sales at MidC. PGE has apparently not recognized the marginal gain on these sales.

Q. Is it normal for PGE both buy and sell at COB in the same month?

A. Yes. PGE has made both purchases and sales at COB in every month in 2013, 2014, and 2015. This is understandable, given that while the *average* monthly margin may be always positive, the *actual* margin at a particular time can be either positive or negative within the month.

Q. Please provide an example.

A. Assume that in one month there are 15 days where the MidC price is $30 per MWh and the COB price is $20 per MWh. Assume on the other 15 days that the MidC price is $45 per MWh and the COB price is $15 per MWh. In this case, there are 15 days where the margin at COB is minus $10 and 15 days where the margin at COB is plus $30. The monthly average is (15 x (-10) + 15 x 30)/30 = $10 per month. However, even though the monthly average is positive representing an incremental margin at COB, there are half the days in the month where it is better economically to sell at COB and half where it is better to buy at COB. The important point is that the Company can realize an incremental benefit on both purchases and sales, within the same month, by arbitraging between the appropriate markets. PGE will likely have 2017 purchases at COB even though the COB forecast price is higher than the MidC forecast price. This will happen because the forecasted margin is equivalent to an average price. In actual normal operations PGE will have profitable purchases. Therefore excluding normal COB purchases from the valuation of the COB transactions is inappropriate.

Q. What is an appropriate solution to this issue?

A. PGE should include both purchases and sales in the calculation of the COB trading benefit. PGE should maintain the margin estimate as the absolute price difference between COB and MidC.

Q. Does Staff's proposal allow the power cost forecast to capture all the benefits of arbitraging between the COB and MidC markets?

A. Staff's proposal is only a partial solution. To understand why Staff's proposal is a partial solution, consider the scenario presented in the Q&A above, where there are 15 days in the month with a negative margin of ($10) per MWh, 15 days in the month with a positive margin of $30 per MWh, and the average margin is $10 per month. Suppose further that there is 1 MWh of transmission available in every day. The table below summarizes the actual operations that would minimize power cost.

Margin	Transaction	MWh	Profit
-10	Purchase at COB	15	$150
30	Sell at COB	15	$450
		Total Profit	**$600**

PGE's modeling approach to COB transactions for this example would result in the following estimate.

Avg. Margin	Transaction	MWh	Profit
10	Sell at COB	15	$150
		Total Profit	$150

Staff's modeling approach to COB transactions for this example would result in the following estimate.

Avg. Margin	Transaction	MWh	Profit
10	Buy/Sell at COB	30	$300
		Total Profit	$300

Q. Does Staff propose other adjustments to the methodology?

A. Staff's approach results in a cost estimate that is closer to reality than PGE's approach, but that remains conservatively small. However, Staff is not sure whether the benefit obtained by introducing more complexity into the methodology is warranted. In reality purchase and sale MWh are split closer to 90/10. In addition, the actual margin likely has a continuous distribution around the forecasted COB MidC spread.

Q. What is the dollar impact of Staff's method in this AUT?

A. Staff's proposal [redacted] hours to the benefit calculation. This results in an additional power cost reduction of [redacted].[1]

Q. What is Staff's recommendation regarding the margin calculation?

A. Staff recommends that the Commission adopt Staff's method to calculate the net benefits obtained from PGE's access to the COB market. Staff's methodology is simple and can be easily integrated into PGE's modeling and produces more accurate results than the methodology proposed by PGE. Staff plans to undertake more complête analysis of the Company's valuation method in next year's AUT in order to obtain more precise valuation of the trading margin.

[1] *See* Exhibit Staff/302 Kaufman/1.

ISSUE 2, BOARDMAN COAL MANAGEMENT

Q. Why has PGE changed the way it models coal costs at the Boardman plant?

A. The Boardman plant receives coal through transportation agreements with BNSF Railway Company (BNSF) and Union Pacific Railroad Company (UP). Both contracts require [redacted] tons of coal be shipped in 2017. If PGE does not meet minimum shipping requirements PGE will be subject to liquidated damage charges. PGE has an ability to partially manage liquidated damages through coal stockpiling and, for the BNSF contract only, by rolling shipments into future years.

The forecasted market conditions are such that PGE will likely incur liquidated damages associated with Boardman coal transportation. Previous MONET models have not had the capability of incorporating liquidated damages into dispatch logic. PGE proposes a model change that dispatches based on the marginal cost of coal, inclusive of liquidated damages.

Q. What are forecasted damages if PGE does not modify the MONET model to account for liquidated damages?

A. Boardman burns [redacted] tons when liquidated damages are not accounted for. However, PGE expects to enter 2017 with [redacted] tons of coal in inventory, and has a target of 500,000 tons of inventory (60 days of coal burn). In order to reduce the coal stockpile, PBE would ship no coal in 2017. PGE would accrue an incremental shipping shortfall of [redacted]

[redacted] tons. In addition, PGE anticipates having a shortfall liability for 2016. PGE expects to rollover of [redacted] tons of this liability into 2017 and [redacted] tons into 2018. The rollover is only available for BNSF damages, and not for UP damages. Because of the reduction in rollover, BNSF shortfall increases from of [redacted] tons.

This results in liquidated damages for [redacted] tons through the BNSF contract and [redacted] tons through the UP contract, for a total of [redacted] in damages.[2]

Q. What would the liquidated damages be if PGE did not reduce its coal inventory or roll 2016 shortfall into 2017?

A. If the stockpile and rollover were held fixed in 2017, PGE would ship [redacted] tons, shortfall would only be [redacted] tons and liquidated damages would only be [redacted]. See the table below for the detailed calculations.

---

[2] *See* Staff/303 Kaufman/1.

[redacted]

Q. Is it possible that PGE could minimize damages in 2017 without modifying Boardman dispatch?

A. Yes. If PGE chooses to enter 2017 with low stockpile and no rollover, PGE could take its minimum coal requirements for BNSF by increasing the stockpile by [redacted] tons, having a 2018 shortfall rollover of [redacted] tons and burning [redacted] tons. This would result in no damages for BNSF, and only [redacted] in damages for UP. See the table below for detailed calculations.

[redacted]

Q. Why is PGE modeling a reduction in the coal stockpile?

A. PGE states that the 2017 target stockpile inventory is set 27 percent below the historical Boardman average inventory level. The purpose of this is to position PGE to "more easily mitigate safety and operational risks if low power prices continue to displace the Boardman plant in 2017 and beyond."[3] This means that the purpose of the abnormally low stockpile target is to absorb the impact of the minimum coal transportation requirements. However, PGE intends to enter 2017 with a stockpile of 94 days, and will not achieve the target until the end of 2017. Thus the large reduction in the coal stockpile during 2017 is intended to mitigate risks for 2018 and beyond.

PGE's stated goal to "more easily mitigate safety and operational risks if low power prices continue" is essentially shifting uncertain transportation shortfalls of 2018 and beyond into 2017. This means that PGE is pushing costs

[3] PGE/400, Niman-Peshka-Hager/26.

associated with the minimum transportation requirements into 2017 from both 2016 and 2018.

Q. PGE is also proposing to reduce the UP transportation shortfall rollover. Does PGE provide a reason for this in testimony?

A. No. PGE's testimony does not provide a rational for reducing the transportation shortfall rollover from [redacted].

Q. Please evaluate the risk that "low power prices continue to displace the Boardman plant in [2018] and beyond."

A. PGE is forecasting gas prices to increase five to seven percent per year between 2017 and 2020. This should put upward pressure on power prices and cause less displacement of Boardman generation. In addition, the minimum transportation requirements for Boardman are reducing from [redacted] tons per year to [redacted] tons per year in 2018 and 2019, then to [redacted] tons in 2020. These factors combined make the likelihood and magnitude of the 2017 transportation shortfall much greater than in 2018 and beyond.

Q. What are the safety risks on which PGE bases its decision to reduce the coal stockpile in 2017?

A. PGE raises a concern that high coal inventory could lead to spontaneous combustion. Staff has requested additional information on the operational limits and safety limits of the coal inventory. In 2015 PGE maintained coal inventory above [redacted] days for six months.[4] PGE takes measures to reduce inventory before it reaches unsafe levels.[5] Based on these two facts, an inventory of above [redacted] days must be an acceptably save inventory. The safe inventory is well above PGE's January 1, 2017 inventory target. Therefore PGE should be able to maintain the January 1, 2017 level without compromising safety.

Q. Do you propose any alternative modeling method related to coal stockpile and shortfall rollover?

A. For the current AUT, I agree with PGE's method of modeling liquidated damages. However, PGE should not model liquidated damages attributable to 2016 or 2018. To accomplish this, I propose that inventory stockpile be modeled without change from January 1, 2017 to December 31, 2017. I also propose that zero rollover be modeled entering and leaving 2017. The purpose of this change is that it will correctly attribute liquidated damage liabilities to the year in which they are accrued. This prevents actual 2016 operations from inflating cost estimates for 2017.

Q. Does your proposal shift any shortfall liability from 2017 into 2018?

A. No. My proposal contains all 2017 transportation liability in 2017. Given the reduced likelihood of a shortfall in 2018, it may be reasonable to shift the liability from 2017 into 2018 (i.e., roll over a portion of any 2017 shortfall into

[4] *See* Staff 304 Kaufman/3 response to OPUC DR 13.
[5] *See* Staff 305 Kaufman/2 response to OPUC DR 12 part d.

2018). Shifting liability into 2018 may be the least cost least risk approach. However, for consistency across time I have decided not to propose this.

Q. Do you have an estimated impact of your proposed change to liquidated damages?

A. Yes, my proposed change will reduce 2017 coal use by [redacted] tons and reduce annual net power costs by approximately [redacted] Staff has submitted a data request to the Company to establish a more precise figure.[6]

Q. Does this conclude your testimony?

A. Yes.

[6] *See* Staff/ 306 Kaufman/1.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1206

Opening Testimony of John Crider
Docket UE 283

August 25, 2016

CASE: UE 283
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1200

Opening Testimony

June 11, 2014

Q. Please state your name, occupation, and business address.

A. My name is John Crider. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Staff Exhibit 1201.

Q. What is the purpose of your testimony?

A. To address the prudence of the Company's acquisition of 10 percent of the Boardman power plant ownership from Power Resources Cooperative (PRC)

Q. Did you prepare an exhibit for this docket other than your qualification statement?

A. No.

Discussion

Q. Please summarize the agreement under review.

A. The Company is the majority owner of the Boardman coal generation plant with an eighty percent share. The Company has negotiated the purchase of an additional ten percent share of the plant from the current share owner, PRC. For an agreed upon cash amount, PGE will assume ownership and responsibilities related to the plant from PRC.

Q. Please summarize the terms of the agreement with PRC.

A. The agreement has five components:

- PRC's "Boardman purchase payment" to PGE in exchange for PGE assuming all PRC's obligations relating to Boardman;
- PGE's purchase of PRC's equipment and fuel inventory;
- Settlement of a third party PPA with Western System Power Pool for the energy output in 2019 and 2020;
- PGE's purchase of PRC's interest in two associated power lines; and
- An "operating risk payment" from PRC to PGE

Q. Have you examined these components for prudence?

A. Yes. Staff conducted a thorough review of the Company's initial and supplemental testimony, received additional information through eight data requests, and held several discussions with the Company to understand the flow of finances and the financial analysis.

Q. What is the result of your analysis?

A. The first four components of the agreement are related to items whose costs and benefits are known or can be accurately estimated. For example, calculation of the value of the pre-existing coal inventory and equipment are known, and the value of the power purchase agreement obligations can be accurately estimated. The Company's Confidential workpaper "PRC_Economics_2-18-2014" provides a thorough spreadsheet model that calculates the necessary compensation to completely cover anticipated costs to ratepayers due to the first four components. These calculations are summarized in the Company's Confidential Exhibit 1502. In addition, the terms of the agreement allow for a true-up to actual costs for the estimated values,[1] which results in very little risk to customers.

Q. Please explain the purpose of the spreadsheet model cited above.

A. The spreadsheet details the costs and expected value of inventory and energy on an annual basis for the years 2014 through 2020 when coal generation ceases at Boardman. These costs and benefits are calculated and tabulated by five payment components. The payment components are described by the Company as the Boardman Purchase Payment, the Inventory Purchase, the Operating Risk Payment, the 2011 Power Purchase Agreement Settlement, and the Two Power Lines. I will explain how each component is calculated.

Q. Please describe the Boardman Purchase Payment.

A. This item reflects the net economic value of PRC's ten percent portion of the Boardman plant through 2020. The net economic value is calculated as the

[1] UE283-UE286/PGE/1500, Pope-Tooman/6 at 11-16

difference between the total operating cost of the plant and the revenues realized through the sale of energy. The Company first estimates net variable power costs (NVPC) and operations & maintenance (O&M) costs on an annual basis. The NVPC cost estimates are based primarily on projected fuel cost, rail car expenses, and transmission costs and offset by revenue from wholesale sales. O&M costs are estimated based on an extrapolation of actual O&M costs at an annual inflation rate of 1.93 percent. The total cost to operate the PRC portion of the plant offset by the wholesale value of the energy produced yields a negative net economic value for the plant. This is the amount that PRC is required to pay to PGE to make the net economic value of the plant equal to zero on a net present value basis. The amount of this Boardman Purchase Payment is also subject to true-up at the closing of the transaction. Taking into consideration both the validity of the estimates and the existence of the true-up, ratepayers assume virtually no risk for the Boardman Purchase Payment.

Q. Please describe the Inventory Purchase component.

A. PGE will pay PRC for the ten percent ownership PRC has in fuel stock and materials and supplies. This payment is based on actual material costs and is subject to true-up based on existing inventory at the time of closing. Since this inventory payment is based on actual costs and is subject to true-up, there is no risk to ratepayers.

Q. Please describe the 2011 Power Purchase Agreement (PPA) Settlement.

A. PRC and PGE had previously executed a PPA for PRC to deliver their portion of the plant output to PGE in 2019 and 2020, after PRC's PPA with the Turlock

Irrigation District expires in 2018.This payment component will compensate PGE for the value of the estimated wheeling expenses and line losses that were previously avoided under the original 2011 agreement. PGE will return the revenue from this settlement to customers via Schedule 105 (Regulatory Adjustments). This component represents a return of revenue to customers.

Q. Please describe the Two Power Lines.

A. PRC currently has partial ownership of two power transmission lines used to transmit power from the Boardman plant. PGE will assume PRC's ownership interest in these two lines and PGE will use the lines for both Boardman and its Carty generation plant. Recovery of costs related to these power lines will not be included in this rate case, and will be considered along with other Carty cost recovery.

Q. Please describe the Operating Risk Payment.

A. PGE will assume the additional decommissioning costs associated with the PRC ten percent share of the Boardman plant. The Company has estimated this cost based on a study by Black & Veatch which estimated the total decommissioning cost at about $68 million. The ten percent assumed cost ($6.8 million) is accounted for as part of the Boardman Purchase Payment. However, there are potential additional cost elements not included in the decommissioning estimate. PGE has recognized this and has calculated an additional risk payment required from PRC in order to cover these potential costs.

Q. Do you find a concern with the Operating Risk Payment?

A. Yes. This is the one item in the agreement that is difficult to value since it reflects the potential costs associated with decommissioning the plant. The purpose of this payment is to cover costs (and relieve risk) associated with both known and as-yet unknown potential costs associated with decommissioning.

Q. Is there a possibility for as-yet unknown costs associated with decommissioning the Boardman plant?

A. Yes. Although the Company has a reasonable analysis and estimate of the decommissioning costs performed by a reputable engineering firm, there is still potential for unforeseen costs due to potential environmental remediation. Some of these potential costs are already recognized – primarily the potential of additional cost for coal ash remediation. However, there may be other potential costs that are simply unrecognized at this time and will not be discovered until the time of decommissioning.

Q. Has the Company attempted to mediate this risk?

A. Yes. The operating risk premium has been calculated to provide financial insurance against these unknown and unforeseen costs.

Q. Is the operating risk premium adequate in light of the cost risk involved?

A. Staff has not yet reached a conclusion on this question. Staff is awaiting further information from the Company regarding the calculation of the operating risk premium.

Q. What are the next steps Staff will take to determine the adequacy of the risk premium payment?

A. To date the Company's testimony and discovery responses have not clearly identified the assumptions and calculation steps involved in determining the operating risk payment. Staff has requested data regarding these assumptions and a detailed description of the process the Company has used to determine the value of the payment. Upon receiving the required data and information, Staff will evaluate the Company's process and make a determination about whether the amounted collected is commensurate with the potential cost risk.

Q. If Staff determines that the amount PRC will pay to PGE as an operating risk premium is commensurate with the cost risk, will Staff have a recommendation regarding the entire transaction?

A. Yes. If Staff determines the operating risk premium is commensurate with the cost risk involved, Staff will recommend that the Commission accept the transaction as prudent and in the best interest of ratepayers .

Q. Does this conclude your testimony?

A. Yes

PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1207

Excerpt from Staff's Comments
Docket LC 57

August 25, 2016

ELLEN F. ROSENBLUM
Attorney General

MARY H. WILLIAMS
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

August 22, 2013

Public Utility Commission of Oregon
Filing Center
3930 Fairview Industrial Dr. SE
Salem, OR 97302-1166

Re: In the Matter of PacifiCorp, dba Pacific Power, 2013 Integrated Resource Plan
Docket No: LC 57 – STAFF OPENING COMMENTS

Dear Filing Center:

Enclosed for filing find Staff's Opening Comments submitted by Juliet Johnson.

Sincerely,

Neoma Lane

Neoma Lane
Legal Secretary
Business Activities Section

NAL:nal/4537340-v1
Enclosure
cc: Service List

PUBLIC UTILITY COMMISSION OF OREGON

LC 57

STAFF OPENING COMMENTS

In the Matter of PACIFICORP, dba PACIFIC POWER 2013 INTEGRATED RESOURCE PLAN

August 22, 2013

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 57

In the Matter of PACIFICORP, dba PACIFIC POWER, 2013 Integrated Resource Plan.	STAFF'S OPENING COMMENTS

The Public Utility Commission of Oregon's (Commission) adopted Integrated Resource Plan (IRP) guideline 1.c. states:

> The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.

In this IRP the Public Utility Commission of Oregon Staff (Staff) recognizes the existence of both traditional resource planning risks associated with market and system operations (i.e., load growth, gas prices, energy prices, and coal prices) and those risks that are more regulatory and political (i.e., uncertainties related to regional haze requirements based on state or federal implementation plans, carbon costs, future regulation of carbon pollution from existing power plants, and the willingness of regulatory agencies to approve alternative compliance actions based on early retirement of coal power plants). Both must be considered in the selection of the optimum portfolio of resources.

Pollution Control Investments

Staff is evaluating the potential shut down scenarios at Hunter 1 and Dave Johnston 3. Staff issued data requests to PacifiCorp (Company) to obtain additional System Optimizer and Planning and Risk (PaR) runs for shut down scenarios.[1] Staff continues to evaluate these and other alternatives to potential pollution control investments at the Company's owned coal plants.

Staff recognizes that the economics of shut down scenarios are largely dependent upon Environmental Protection Agency (EPA) potential actions related to regional haze and carbon regulation. We cannot wait until future regulatory decisions are finalized (into laws), before detailed economic analyses of potential outcomes should be performed. By the time such regulatory actions become final, it well may be too late. Future actions are not entirely unpredictable and, therefore, it is prudent for the Company to continue to plan

[1] Staff OPUC Data Requests 154-157.

In future IRPs, including the 2013 IRP Update, the Company should be required to provide a detailed elaboration of its "forward market view," including more analysis and justification for the Company's assumptions relative to market depth and liquidity.

Direct Access Loads

The Commission's Guideline 9: Direct Access Loads states:

> An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

Consistent with its treatment of direct access under the 2010 Multi-State Protocol, "PacifiCorp [states on page 44 of Appendix B in Volume 2] that it continues to plan for load for direct access customers" (i.e., as if the load were to continue on a standard cost-of-service, retail basis). In UE 267, PacifiCorp filed a tariff allowing for permanent direct access whereby customers are permanently served by an electric service supplier and not PacifiCorp for generation services given five-year's notice. Going forward and in the next IRP, PacifiCorp will need to project future permanent direct access loads and remove such loads from system generation requirements.

Natural Gas and Electricity Prices

Staff is investigating the forecasted prices used in the Monte Carlo draws. These are not specifically included in the IRP, but are more meaningful than the prices used in System Optimizer because they determine the level and spread of the PVRR's that decide which the preferred portfolio is. Specifically, Staff is taking a closer look at how the prices at the different hubs are correlated and how gas prices and electricity prices are correlated with each other at the hub level.

Staff would recommend that going forward, the specific Monte Carlo time paths be included in the IRP document.

Staff finds that when looking at each of the Hub prices used in System Optimizer separately, the level and spread of the prices are consistent with those of other utilities, government bodies and additional third parties, but again stresses that these are not the most important forecasts.

Coal Price Forecasts

High, low and medium coal cost forecasts have a very tight dispersion over time indicating very stable coal pricing through the planning period. Although this is a reasonable forecast based on the stable history of coal prices, there may be more price variability in the future as coal-related regulatory activity increases. Also, in recent years rail transport prices have risen and both contract terms and price fluctuations have introduced more risk into coal procurement than has been typical in the past.

PacifiCorp's "high" coal forecast price is only 10 percent over the "medium" forecast after ten years (2024) and less than 20 percent higher 20 years out. In future IRPs, it would be beneficial for PacifiCorp to analyze the effect of a larger change in the coal price forecast due to the risk of uncertainty around coal mining regulation, coal transport regulation, carbon regulation, and the changing resource mix both nationally and internationally which may drastically change the worldwide demand for coal. Further, because of the expected competition between coal and natural gas for electricity generation as gas prices remain low and coal plants continue to be subject to increased pollution control regulations, PacifiCorp needs to engage in continued analysis of the economics of fuel conversion opportunities.

RPS Compliance and RECs

Page 32 of PacifiCorp 2013 IRP Volume 2, cites OPUC Order 11-2035-01. This Order states that the Company should identify the additional costs associated with addressing the non-modeled objectives cited by the Company. One such objective is compliance with Washington's Renewable Portfolio Standard (RPS). The preferred portfolio does not meet Washington's RPS. The Company's stated method of meeting the standard is to purchase Renewable Energy Certificates (RECs). The Company's analysis sufficiently demonstrates that this is an appropriate approach.

However, the IRP does not report on the expected cost of meeting this objective. Staff finds that placing no price on REC's is not sufficient for planning purposes. While REC prices are currently very low and the overall impact of purchasing REC's is currently quite small, current prices are not always indicative of future prices (if they were, there would be no need to have CO_2 in the analysis, either). Additionally, many regions of the country currently have REC prices much higher than is currently found in the Pacific Northwest. Staff would like to see additional analysis if the Company continues with this form of RPS modeling in future IRPs. First, PacifiCorp should provide an expected cost of meeting RPS requirements through RECs. Second, PacifiCorp should establish the factors causing REC price variability and provide an expected range for REC prices over time.

The PacifiCorp modeling approach relative to RPS compliance appears to be computationally intensive. Seven portfolios, C01, C02, C04, C06, C08, C10, and C12, do not satisfy state and federal RPS. The Planning and Risk results for these portfolios do not pass pre-screening because they do not satisfy state or federal RPS. Time and resource constraints limit the number of portfolios that can be thoroughly analyzed. The time spent generating non-compliant portfolios may be better spend exploring portfolios that are considered feasible.

One outcome of developing both non-RPS and RPS compliant portfolios is an estimate of the cost of complying with RPS. The costs associated with complying with RPS may be important data, however it does not appear to inform PacifiCorp's portfolio selection decision. Staff looks forward to working with the Company as they develop future IRPs

PUBLIC UTILITY COMMISSION
OF OREGON

UE 307

PACIFICORP

PAC/1208

Excerpt from Direct Testimony of Cindy A. Crane
Docket UE 216

REDACTED

August 25, 2016

REDACTED
Docket No. UE-216
Exhibit PPL(TAM)/300
Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Cindy A. Crane

February 2010

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

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

Qualifications

Q. Briefly describe your business experience.

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

Purpose and Summary

Q. What is the purpose of your testimony?

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

level in 2010 was the result of the rebuild/replacement of the longwall system during the latter half of 2010.

Q. Did customers benefit from the longwall rebuild?

A. Yes. The longwall shields had reached their maximum life of 40,000 cycles. Continued mining required either purchase of a new longwall system or rebuild of the existing system. While the rebuild/replacement option was cheaper than purchasing a new longwall, both options were significantly superior to the alternative of purchasing replacement coal. Even with the cost increase in 2010, the Deer Creek mine was the least-cost supply for the Utah plants. The longwall rebuild allows the Deer Creek mine to extract the remaining economic coal reserves at a substantial savings relative to market. Like any major capital addition, the costs of the Deer Creek mine longwall rebuild caused 2010 costs to be higher than they otherwise would have been. However, customers will reap the benefit of the longwall rebuild for an extended period of time. This long-term view of mining operations is imperative, rather than a focus on a single-year view.

Q. Please explain the change in Bridger Coal costs between 2010 and 2011.

A. The 2011 TAM reflects a significant decrease in Bridger Coal Company costs from [redacted]. Underground operating costs [redacted] and surface operating costs [redacted]. The decrease in underground costs is largely due to a combination of increased coal production and reductions in contract services, royalties and transfers from inventory. The royalty reduction is a result of the Company's renegotiation of a royalty agreement with Anadarko in

2009. The decrease in Bridger surface costs, approximately [redacted], is mostly due to the accounting impact of the Emerging Issues Task Force 04-6 (EITF 04-6) pronouncement. Without EITF 04-6, surface costs are similar, approximately [redacted], in both 2010 and 2011.

Q. Are the Bridger surface and underground separate operations?

A. No. Bridger Coal Company is an integrated mine complex and, as was discussed in the 2010 TAM, the surface operation is the swing coal supply for the Bridger plant. Both operations share common assets such as conveyors, scrapers, dozers, light duty vehicles, maintenance shops, administrative buildings, etc. Mine administration personnel including purchasing, planning, engineering, environmental services, information technology, safety, human resources, administration services, government relations and surveying support both operations.

Q. Would Bridger Coal Company costs increase if surface mining ceased?

A. Yes. Without the surface operation, Bridger mine costs would increase. Shared costs, services and assets would be assigned entirely to the underground operations or final reclamation. The increase in final reclamation costs would require increased funding of the reclamation trust. Additionally, the Bridger mine would continue to absorb the depreciation expense for surface operation equipment such as draglines, scrapers, trucks, and other assets that will still be utilized in final reclamation activities.

Q. What other benefits does the Bridger surface operation provide?

A. The Bridger surface operation is critical to coal blending. All coal, surface and underground, has an assigned coal quality. Mine plans are developed on a monthly basis to ensure that the delivered coal product to the Bridger plant meets specific coal quality constraints. On a daily basis surface operation and deliveries are adjusted to meet specification. All coal blending is performed by the surface operation.

Q. Do other mines in the Southwest Wyoming blend coal?

A. Yes. Both the Kemmerer and Black Butte mines blend coal. Both mining operations blend coal from multiple pits to meet specific contract parameters. With underground mining, however, operations are limited to the mining of a single coal seam. Without the surface operation, Bridger Coal could not deliver a coal stream that would meet the requirements of Jim Bridger plant's operations.

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

A. Bridger mine costs remain considerably less than any available market alternative. Though Kiewit Mining recently notified the Company that the Black Butte mine has [redacted] tons of uncommitted production capacity through 2014, this amount is insufficient to replace the coal supply from the Bridger mine. In any event, the delivered cost of this uncommitted tonnage to the Jim Bridger plant is approximately [redacted] in 2011, over [redacted] higher than Bridger mine costs in the test period. The projected delivered cost of PRB coal in 2011 is over $[redacted] than Bridger mine costs in the test period without considering the costs of capital modifications required for the Bridger plant to switch to PRB coal supply.

Q. What is the least cost supply for the Jim Bridger plant?

A. It is the supply approach that is being pursued by the Company. A combination of the current Black Butte agreement and the combined Bridger surface and underground operations continue to be the optimum coal supply for the Jim Bridger plant. Without the Bridger surface operation, the Jim Bridger plant test period costs would be higher. The decremental cost of Bridger surface production, mine costs less fixed costs, is approximately [redacted] in 2011 which remains considerably less than the delivered cost of either Black Butte or PRB coals.

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

A. The 2011 Trapper price is [redacted] delivered to the Craig plant. This price is considerably less than the Company's other Colorado coal supplies. The price is over [redacted] less than the delivered price under the Company's long-term coal supply agreement with the Colowyo mine.

Summary

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

A. Coal costs in 2010 and 2011 vividly demonstrate the value of the Company's diversified coal supply strategy. In 2010, affiliate coal costs increased significantly, in large part due to operation of EITF 04-6 and the longwall rebuild at the Deer Creek mine, while third-party coal supply costs increased more moderately. In 2011, third-party coal supply costs are increasing more significantly, due to the timing of long-term coal contract re-openers. At the same time, these cost increases are offset by reductions in affiliate mining costs, associated with increased production capacity and the operation of EITF 04-6. Thus, in both 2010 and 2011, customers will benefit from the Company's diversified strategy by more balanced and less extreme cost increases.

Q. Does the nature of the Company's coal cost increases in 2010 and 2011 demonstrate the importance of reviewing the reasonableness of the Company's coal costs on a multiple year basis, instead of a single year?

A. Yes. A least-cost fueling strategy cannot be based on annual determination of the Company's captive mines relative to other available supply options. Decisions to invest in the affiliate operations are made on the same basis the Company makes with respect to investment in its service territory. Such analysis is based on an extended period over a mine's life. While mine production costs will typically fluctuate more than contract prices, it is unreasonable to limit recovery of production costs in a particular year when the captive operations are superior to other supply options over the extended period and consistently provide benefits to customers. This is especially true in a case such as this where there is no risk of cross subsidization between the utility and the affiliate.

Q. Please summarize your testimony.

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

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1209

Excerpt from Opening Testimony of John Crider and Jorge Ordonez
Docket UE 264

REDACTED

August 25, 2016

CASE: UE 264
JOINT WITNESSES: John Crider &
Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

JOINT STAFF EXHIBIT 100

Opening Testimony

June 4, 2013

CERTAIN INFORMATION CONTAINED IN JOINT STAFF

EXHIBIT 100 OF UE 264

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 10-069 in UE 216.

YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 216 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is John Crider. I am employed by the Oregon Public Utility Commission (OPUC) as a Senior Utility Analyst in the Energy Resources and Planning Section of the Energy Division. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

My name is Jorge Ordonez. I am employed by the Oregon Public Utility Commission (OPUC) as a Senior Financial Economist in the Energy Resources and Planning Section of the Energy Division. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. Our Witness Qualification Statements are found in Exhibit Staff/101 and Staff/102

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to first summarize Pacific Power's (Company) 2013 Transition Adjustment Mechanism (TAM) for Net Power Costs (NPC) for the test year of 2014, and then to discuss four specific issues related to the TAM.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, we summarize the Company's filing in the Introduction section. Following the introduction summary, we discuss four specific issues regarding the filing: an increase in coal costs; the effect of interruptible power contracts on the

NPC; proposed changes to the Company's modeling of hydro; and the Company's proposed changes related to wind modeling.

I. INTRODUCTION

Q. PLEASE SUMMARIZE PACIFICORP'S 2013 TRANSITION ADJUSTMENT MECHANISM (TAM) FILING.

A. The Company's March 1, 2013, filing requested an overall decrease of $15.5 million in NPC for calendar year 2014 over what is currently collected in rates. The Company's total forecasted system-wide NPC is calculated as $1.457 billion compared to $1.473 billion currently included in rates. Due to an increase in Oregon load, this translates to a $0.4 million increase in Oregon allocated NPC from $362.7 million in 2013 to $363.1 million in 2014.

Q. WHAT IS THE EFFECT ON OREGON RATES?

A. The slight increase in Oregon load resulted in a corresponding decrease in the overall rate, from $27.68 per MWh in 2013 to $27.57 per MWh in 2014. These rates are calculated based on the Oregon load forecast presented by the Company in its current general rate case (UE 263).

Q. WHAT ARE THE MAJOR DRIVERS FOR THE 2014 NPC?

A. The Company explains the major cost drivers as a decrease in overall system load of 0.85 percent and a decrease of purchased power expense of $69 million, offset by an increase in coal expenses of $41 million, an increase in natural gas fuel expense of $6 million, an increase in wheeling, hydro and other expenses of $10 million, and a decrease in wholesale sales revenue of $4 million. The overall effect is a decrease of $16 million in system-wide NPC.

Q. WHAT IS THE PRIMARY COST DRIVER FOR THE $10 MILLION INCREASE IN WHEELING, HYDRO AND OTHER EXPENSES?

A. The increase in this category is due to increases in BPA's transmission rates. New rates are scheduled to go into effect in October of 2013 and will result in increases ranging from 15% to 20%. The Company has estimated the cost increase based on proposed rates and will update these values to reflect BPA's final Record of Decision (ROD), expected in late July 2013.

Q. ARE ANY SIGNIFICANT SYSTEM CHANGES MODELED IN THIS YEAR'S TAM?

A. Yes. The 2014 TAM incorporates the benefits and power costs for the Company's new 637 MW Lake Side 2 natural gas plant. The plant will come online in the second quarter of 2014. The TAM includes the variable costs and benefits of Lake Side 2 from June 2014 forward.

Q. DID THE COMPANY INTRODUCE ANY OTHER CHANGES INTO THE MODELING FOR THIS YEAR'S TAM?

A. Yes. The Company incorporated modeling changes in accordance with Commission Order 12-409 issued in last year's TAM proceeding (UE 245).

Q. PLEASE EXPLAIN THE CHANGES OUTLINED IN ORDER NO. 12-409.

A. Order No. 12-409 included four specific modeling changes which the Company has included in this year's TAM.

a) Market Caps – wholesale market caps were kept in the modeling, but the caps are now calculated based on the highest of the four most recently available averages for each trading hub

b) Arbitrage and Revenue Credit – no adjustment is made to impute revenue

c) Third Party Wind Integration – the cost of integrating third-party wind is included.

d) Hydro Forced Outages – The Commission did not have a specific requirement regarding this issue, but urged the Company and Parties in UE 245 to review the modeling and make necessary changes. The Company has proposed a corresponding revision of their modeling of hydro outages that is consistent with Order No. 12-409.

Q. IN THIS FILING DID THE COMPANY COMPLY WITH ORDER NO. 10-414 (DOCKET UM 1355), WHICH DIRECTED THE COMPANY TO CALCULATE FORCED OUTAGE RATES ACCORDING TO A SPECIFIC METHODOLOGY?

A. Yes. Order No. 10-414 prescribed the method for calculating forced outage rates for coal plants. Staff examined the documentation that PacifiCorp provided for its coal plant forced outage rate calculations and determined that the methodology used in this filing is consistent with Order No. 10-414.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. There are four specific issues that Staff presents testimony on in this proceeding. The second part of our testimony explores each of these issues in more detail.

II. DISCUSSION OF ISSUES

Q. WHAT ARE THE FOUR ISSUES DISCUSSED IN THIS SECTION?

A. Staff provides testimony on the following four specific issues in this TAM. The four issues discussed below include:

A. Increase in Coal Costs

B. Effect of Interruptible Power Contracts

C. Hydro Modeling Changes

D. Wind Modeling Changes

SECTION A – INCREASE IN COAL COSTS

Q. PLEASE DESCRIBE THE INCREASE IN COAL COSTS.

A. The Company proposes an overall increase of $53.5 million in coal costs for the test year. This total includes $16.5 million increase in third-party coal costs, and a $37 million increase in captive[1] mine costs.

Q. WHAT ARE THE PRIMARY COST DRIVERS FOR THE THIRD-PARTY COAL CONTRACTS?

A. Contract price re-openers are responsible for increases of $[redacted] at Wyodak and $[redacted] at Cholla. Higher diesel and equipment operating costs have increased costs at the Kemmerer mine (which serves the Naughton power plant) by $[redacted]. The remaining increases in third-party contract costs are due to increases in consumer price index, production taxes and royalties.

[1] "Captive coal mine" refers to a coal mine that satisfies the needs of a mine owner rather than for open market sale.
Source: www.teachmefinance.com/Scientific_Terms/Captive_coal.html

Q. WHAT ARE THE COST INCREASES RELATED TO THE COMPANY'S CAPTIVE MINES?

A. The Company has ownership of two captive mines with significant cost increases in this TAM. Bridger Coal Company, which serves Jim Bridger plant, has an increase of $[redacted] over 2013 expenses, and Deer Creek mine which serves several plants, has an increase of $[redacted]. These increases are partially offset by a $[redacted] cost reduction at the Trapper and Prep Plant plants for a net increase of $[redacted] in captive mine cost.

Q. WHAT ARE THE MAJOR COST DRIVERS FOR THE INCREASE IN BRIDGER COAL COSTS?

A. Most of the increase is associated with funds for reclamation activities which totals approximately $[redacted] dollars.

Q. WHAT ARE THE MAJOR COST DRIVERS FOR THE DEER CREEK MINE?

A. The primary reason for the cost increase is the shortened life span of the mine. Originally, the mine was estimated to remain in operation through 2021 but recent drilling results have concluded that the operational life of the mine will be reduced two years to 2019. The increase in depreciation expense and post-retirement expenses account for $[redacted] of the total. The remaining increase in cost is due to an increase in royalty costs.

Q. DOES STAFF HAVE ANY ADJUSTMENTS TO THE CAPTIVE COAL MINE COSTS?

A. Yes. In previous dockets Staff has identified and Commission has allowed rate-case type adjustments to certain itemized O&M costs related to the captive mines. Specifically, reductions in management overtime, bonuses, donations, fines and meal expenses have been allowed[2, 3]. Staff proposes similar adjustments to the cost calculations for the Bridger and Deer Creek mines.

Q. PLEASE EXPLAIN THE O&M ADJUSTMENTS STAFF PROPOSES FOR THE BRIDGER AND DEER CREEK MINE COSTS.

A. Based on similar adjustments authorized by the Commission in Orders No. 07-527[4] and 99-697[5], Staff proposes a total reduction estimated at $[redacted] on an Oregon basis for certain O&M items. This value is based on Company 2013 cost estimates and includes the following reductions:

a) 100% reduction of management overtime costs

b) 100% reduction of fines

c) 50% reduction of bonuses

d) 50% reduction in meal costs

The costs related to Bridger were adjusted based on costs supplied by the Company.[6] The adjustments to Deer Creek were estimated in a similar manner as the Bridger costs. These estimated values are subject to future

---

[2] In UE 197, the Commission adopted Staff's principle that costs for meals and entertainment are discretionary and should be shared equally by ratepayers and shareholders. (Order 09-020 at 20-21)

[3] In UE 210, the Commission stated: "We find that the Joint Parties have also adequately supported their position with respect to bonus and incentive payments. Pacific Power explained the purpose behind its bonus and incentive programs in detail, and the evidence shows that the stipulated adjustments to these programs generally reflect Staff's proposal (and ICNU's original similar proposal) that 100 percent of officer bonuses and 50 percent of annual incentive plan bonuses be removed from rates. This sharing arrangement has traditionally been supported by the Commission, and we see no reason to deviate from that tradition here." (Order 10-022 at 10-11)

[4] Docket UW-120

[5] Docket UG-132

[6] Crane workpapers

revision based on the Company's outstanding responses to pending data requests from Staff.

SECTION B – EFFECT OF INTERRUPTIBLE CONTRACTS

Q. PLEASE DESCRIBE THE INTERRUPTIBLE CONTRACTS.

A. The Company currently has contracts with three large industrial customers that give the Company the ability to curtail the customer's load for economic purposes. Two of these contracts are due to expire at the end of 2013; the third will continue through 2014. The Company is planning to renegotiate the two expiring contracts and plans for them to be in place for 2014.

Q. HOW HAS THE COMPANY PROPOSED TO MODEL THESE CONTRACTS IN THIS TAM?

A. The Company has assumed that these three contacts will remain in place at current prices and curtailment levels for the 2014 test year. It is possible that the updated contracts would call for a change in curtailed load, which would in turn impact the net system load used to calculate NPC. The revised contract terms may also impact the inter-jurisdictional allocation factors. Incorporating either of these changes would require an exception to the TAM guidelines[7]. The Company proposes that this exception be allowed.

Q. DOES STAFF AGREE WITH THE COMPANY'S PROPOSAL REGARDING THESE CONTRACTS?

A. No. Any significant changes to the contracts may have unanticipated changes to the modeling outcome and calculation of NPC. If introduced late in the

[7] See Order No. 09-274 (UE 199) which adopts the TAM guidelines limiting the nature and scope of modeling updates

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 307

PACIFICORP

PAC/1210

Comparison of Exhibits Staff/403 and PAC/1003

REDACTED

August 25, 2016

THIS PAGE IS CONFIDENTIAL PER PROTECTIVE ORDER IN DOCKET UE 307 AND IS PROVIDED SEPARATELY