McDOWELL RACKNER GIBSON PC

KATHERINE McDOWELL
Direct (503) 595-3924
katherine@mrg-law.com

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VIA ELECTRONIC FILING

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Public Utility Commission of Oregon
PO Box 1088
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Re: UE 323– In the Matter PACIFICORP, dba PACIFIC POWER, 2018 Transition Adjustment Mechanism

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic copy of PacifiCorp's Opening Brief (Redacted). The CONFIDENTIAL copies will be sent via overnight delivery.

Please contact this office with any questions.

Very truly yours,

Katherine McDowell

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of: PACIFICORP d/b/a PACIFIC POWER 2018 Transition Adjustment Mechanism	**UE 323**

PACIFICORP'S OPENING BRIEF

REDACTED

September 14, 2017

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I. INTRODUCTION

PacifiCorp d/b/a Pacific Power respectfully submits this opening brief to the Public Utility Commission of Oregon (Commission), in support of the company's proposed 2018 Transition Adjustment Mechanism (TAM) increase of approximately $7.9 million, or 0.6 percent overall.[1] The increase reflects a decrease in forward market prices for electricity and natural gas, which reduce PacifiCorp's wholesale sales revenue.[2] That reduction in revenue, however, is offset by reductions in coal and natural gas fuel expense and an increase in Energy Imbalance Market (EIM) benefits, producing a relatively small overall rate increase.[3]

PacifiCorp's net power cost (NPC) modeling tracks the Commission's most recent TAM orders— the only modeling changes in the case come from the pre-filing workshops or from the other parties. PacifiCorp worked diligently to ensure the filing's transparency, and the company has accepted a number of parties' proposals to narrow the scope of litigation and reduce controversy. PacifiCorp's filing is substantively identical to the 2017 TAM filing approved last year, and no party has established why the Commission should change its approach here.

Despite the relatively modest 2018 TAM increase and the similarity of the 2016, 2017, and 2018 TAM filings, parties still contest this filing, particularly the day-ahead and real-time system balancing transactions (DA/RT) adjustment. PacifiCorp continues to refine the adjustment, volunteering two changes in this case to address parties' normalization concerns. Ignoring these efforts at compromise, Staff and the Industrial Customers of Northwest Utilities (ICNU) propose modifications that effectively eliminate the DA/RT

[1] PAC/400, Wilding/5. Unless otherwise stated, all values are stated on an Oregon-allocated basis.
[2] PAC/400, Wilding/6.
[3] PAC/400, Wilding/6.

adjustment. Staff presents unclear, unquantified, and only partially developed proposals to modify or replace the DA/RT adjustment. Staff's arguments largely rehash claims made last year that the Commission already found unpersuasive. ICNU proposes two adjustments, both of which the Commission has already rejected, and one of which is directly contradicted by ICNU's position in the 2016 TAM.

After more than a decade of NPC under-recovery, PacifiCorp came close to recovering its actual NPC in 2016. Even though Staff previously questioned the value of backcasting, Staff and ICNU now argue that PacifiCorp must validate its NPC modeling, and specifically the DA/RT adjustment, through a backcast. PacifiCorp supports efficient and useful model validation, instead of time-consuming and potentially controversial backcasting, and proposes workshops to develop the appropriate standards.

For the third year in a row, Staff challenges PacifiCorp's modeling of energy imbalance market (EIM) benefits. PacifiCorp forecasts total-company EIM benefits for 2018 of [redacted]. This is [redacted] than the forecasted benefits in the 2017 TAM, reflecting the expected growth in benefits. Staff's EIM benefit calculation seeks an even higher increase in EIM benefits through an arbitrary growth rate that double-counts certain benefits and produces an unreasonable forecast.

Staff also recommends that PacifiCorp change its modeling to include long-term economic shutdowns of coal plants. But in normal years, the company does not perform economic shutdowns, which is demonstrated in historical data that Staff ignores or mischaracterizes. Staff's ad hoc analysis is too narrowly focused on market prices without considering reliability and system operations, and produces unrealistic results.

Staff challenges PacifiCorp's coal costs at the Cholla plant, which include liquidated damages under its coal supply agreement that reflect the reduction of the coal stockpile instead of purchasing additional coal. PacifiCorp reasonably increased the stockpile above target levels in 2016 to avoid higher liquidated damages in effect at that time and is now drawing down the stockpile at a lower liquidated damage rate. Even though Staff does not challenge the prudence of the company's decision to draw down the stockpile, Staff's adjustment is premised on maintaining high stockpile levels that risk higher future costs.

Staff and the Sierra Club express concerns over how the company analyzes new coal supply agreements. In response, PacifiCorp presented testimony from an outside expert that its contracting practices are prudent and fully consistent with industry standards. To further address parties' concerns, PacifiCorp proposes a workshop on the evaluation of coal supply agreements, and incorporating variable operations and maintenance (O&M) expenses into the TAM. PacifiCorp and Sierra Club agree on the scope of this workshop and on this basis, Sierra Club agrees that the workshop addresses its recommendations in this case.

PacifiCorp has accepted CUB's and Staff's proposals to implement a contract delay rate (CDR) for new Qualifying Facility (QF) contracts. PacifiCorp's proposal reasonably weights the CDR by QF capacity, an approach supported by Staff, and limits the delay days to those within the rate effective period.

Finally, Calpine Energy Solutions, LLC (Calpine) again argues for a renewable energy certificate (REC) credit in the transition adjustment and for a reduction in the consumer opt-out charge to account for accumulated depreciation in years six through 10. PacifiCorp's proposed REC credit is consistent with Order No. 16-482, and the company agrees to a workshop to establish a framework for future RECs transfers in lieu of a credit.

On the consumer opt-out charge, the company produced new evidence which supports the Commission's approval of this charge in three previous cases.

II. ARGUMENT

A. The DA/RT adjustment increases the accuracy of the TAM.

1. The DA/RT adjustment models PacifiCorp's system balancing costs in a fair and reasonable manner.

PacifiCorp's historical data demonstrates that it incurs system balancing costs that are not reflected in the company's forward price curve or modeled in GRID.[4] To incorporate these costs in the TAM, the company uses the two-component DA/RT adjustment.[5] First, to better reflect the market prices available to PacifiCorp when it transacts in the real-time market, the company models separate prices for forecasted system balancing sales and purchases.[6] The company typically makes balancing purchases during higher-than-average periods and balancing sales during lower-than-average periods—a fact that parties do not contest.[7] The price adjustment accounts for the historical price differences between PacifiCorp's purchases and sales compared to the monthly average prices used in GRID.[8]

Second, the DA/RT adjustment reflects additional transaction volumes to account for the market's standard 25 MW block products.[9] The volume component is necessary because GRID assumes that PacifiCorp can transact in flexible increments that perfectly match system need, and it therefore models an unrealistically low volume of transactions.

[4] PAC/100, Wilding/19.
[5] TR. 19-20, 43 (Wilding).
[6] PAC/100, Wilding/20.
[7] *See, e.g.*, PAC/800, Wilding/9.
[8] PAC/100, Wilding/20.
[9] PAC/100, Wilding/21.

PacifiCorp's DA/RT adjustment in the 2018 TAM is virtually identical to the DA/RT adjustment the Commission approved in the 2016 and 2017 TAMs.[10] The only change is that PacifiCorp uses one more year of historical data, for a total of 60 months, to normalize the adjustment. The company proposed this modification in the pre-filing TAM workshops, and it reduces the DA/RT adjustment relative to the previous 48-month historical average. No party objects to this change.[11] PacifiCorp's DA/RT adjustment increases NPC by approximately $6.7 million, $0.3 million less than the DA/RT adjustment approved in the 2017 TAM.

The Commission thoroughly reviewed the DA/RT adjustment before initially approving it in the 2016 TAM in Order No. 15-394. The Commission found that PacifiCorp's short-term purchase prices systematically exceed short-term sales prices. The Commission approved the price component of the DA/RT adjustment to "account for these expected price differences" and to produce "a more accurate [NPC] estimate."[12] Approving the volume component, the Commission found that GRID understated system balancing volumes because it "assume[s] the volumes of purchases and sales matched exact needs."[13]

In the 2017 TAM, the parties fully litigated the DA/RT adjustment for a second time. In Order No. 16-482, the Commission reaffirmed that the DA/RT adjustment "reasonably addresses a deficiency of the GRID model and is likely to more accurately capture PacifiCorp's net variable power costs."[14]

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[10] *In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec. 11, 2015); *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 13 (Dec. 20, 2016).
[11] PAC/100, Wilding/23-24.
[12] Order No. 15-394 at 4.
[13] *Id.*
[14] Order No. 16-482 at 13.

PacifiCorp has worked in good faith to ensure understanding of the DA/RT adjustment.[15] PacifiCorp developed significant new analysis in the 2018 TAM pre-filing workshops to support the DA/RT adjustment, which it included in its initial filing. PacifiCorp analyzed the sensitivity of the adjustment to various scenarios suggested by the parties, including abnormal weather, thermal outages, and hydro conditions.[16] The analysis shows that DA/RT costs are a result of multiple variables across PacifiCorp's system, which allows for proper normalization over a four- or five-year period.[17] PacifiCorp also demonstrated the impact the DA/RT costs would have had in other years. In each case, the costs narrowed (but did not close) the company's under-recovery gap.[18]

2. Overview of parties' positions on the DA/RT adjustment.

CUB does not oppose the DA/RT adjustment. Instead, CUB and PacifiCorp agree to a collar mechanism to exclude outlier years (defined as years in which PacifiCorp's power cost adjustment mechanism (PCAM) is triggered) from the historical data set used to calculate the DA/RT adjustment.[19] The collar does not impact the DA/RT adjustment in this case.

Staff and ICNU propose changes to the DA/RT adjustment that purport to modify it, but effectively eliminate it.[20] Staff and ICNU argue that the DA/RT adjustment is arbitrary, unrealistic, and irrational, without presenting new and persuasive evidence to refute the Commission's findings to the contrary in Order Nos. 15-394 and 16-482.[21] Despite Staff's

[15] PAC/100, Wilding/15-17; PAC/1100.
[16] PAC/107.
[17] PAC/100, Wilding/23.
[18] PAC/107, Wilding/24.
[19] CUB/200, Jenks/16; PAC/400, Wilding/29.
[20] *See, e.g.*, ICNU/200, Mullins/3; Staff/200, Kaufman/19, Staff/500, Kaufman/34.
[21] *See, e.g.*, Staff/200, Kaufman/11; ICNU/100, Mullins/9 (continuing to disagree with the merits of the adjustment).

and ICNU's attempts at repackaging, their arguments are fundamentally indistinguishable from those already considered and rejected by the Commission.[22]

Staff and ICNU have the "burden of producing evidence to support their argument in opposition to the utility's position."[23] In Order No. 16-482, the Commission directed the parties to hold workshops on the DA/RT adjustment to "facilitate parties' deeper understanding" of the adjustment, with the express goal to "create an improved evidentiary record" on the DA/RT adjustment if it was disputed again in this case.[24] Despite this direction, Staff and ICNU have provided even less evidence for their DA/RT adjustment challenges than last year. Indeed, Staff repeatedly cites its testimony in the 2017 TAM as support for its position here, even though (1) the Commission already rejected that evidence as unpersuasive, and (2) this evidence is not included in the record. ICNU's position is directly contrary to the position it took in the 2016 TAM, a fact that it did not even acknowledge and attempt to reconcile until cross-examination at hearing. Faced with a similarly deficient record in last year's TAM, the Commission concluded that the parties had presented "[n]o persuasive evidence . . . to convince us that our decision [in the 2016 TAM] was in error."[25]

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[22] *See, e.g.*, Staff/200, Kaufman/14-16; ICNU/200, Mullins/10.

[23] *In the Matter of Portland General Electric Company Application to Amortize the Boardman Deferral*, Docket No. UE 196, Order No. 09-046 at 7-8 (Feb. 5, 2009); see also *In the Matter of Portland General Electric Company 2012 Annual Power Cost Update Tariff (Schedule 125)*, Docket No. UE 228, Order No. 11-432 at 3 (Nov. 2, 2011) ("To reach a determination on whether proposed rates are just and reasonable, we look at the record as a whole and make a determination based on the preponderance of the evidence. Once a utility has met the initial burden of presenting evidence to support its request, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Although the burden of production shifts, the burden of persuasion is always with the utility.") (internal citations omitted).

[24] Order No. 16-482 at 2.

[25] *Id.* at 13.

3. Staff has not articulated or supported reasonable changes to the DA/RT adjustment.

Staff's position on the DA/RT adjustment is unquantified and unsupported.[26] It consists of some combination of the proposals from Staff's opening and rebuttal testimony: (1) changing the DA/RT adjustment price component to use a single market price, reflecting a five-year correlation of load and market prices;[27] (2) reducing the volume component to account for value of historical arbitrage transactions and residual value of contracts; [28] (3) calculating the DA/RT adjustment using only two years of historical data, excluding either 2011, 2013, 2014 under Staff's new collar approach, or 2013-2015, years with higher DA/RT costs;[29] and (4) eliminating the volume component.[30] At hearing, Staff could not clearly explain its recommendations, how they relate to one another, or how much they reduce PacifiCorp's TAM forecast. Staff summarily asserted that the "impact of the adjustments are reasonable because the methodology is reasonable,"[31] while admitting it had not modeled the operation or impact of its recommendations.[32]

a. Staff did not justify its proposal to replace the price component of the DA/RT adjustment with a modified forward price curve.

In its opening testimony, Staff proposes replacing the price component of the DA/RT adjustment with a single market price that is correlated with PacifiCorp's load over the 60-month normalization period.[33] While Staff made a similar proposal last year, it has never

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[26] *See, e.g.*, TR. 208-09 (Kaufman).
[27] Staff/200, Kaufman/19.
[28] Staff/200, Kaufman/19.
[29] Staff/500, Kaufman/34.
[30] Staff/500, Kaufman/34.
[31] TR. 218 (Kaufman).
[32] TR. 213, 219-20 (Kaufman).
[33] Staff/200, Kaufman/19.

actually modeled a modified forward price curve to explain and demonstrate its proposed methodology.[34]

During discovery, Staff indicated that it would quantify the impact of this adjustment and provide that information, along with any analysis showing that Staff's proposal increases NPC forecast accuracy compared to the DA/RT adjustment.[35] Staff never did so.[36] Staff also failed to include this information in its rebuttal testimony, as it promised in its opening testimony.[37] Indeed, Staff's rebuttal testimony never mentions its price curve recommendation, implying that it had been abandoned.[38] It was not until the hearing that Staff clarified otherwise.[39]

Staff now claims that it has had insufficient time to develop its preferred price curve methodology.[40] The Commission rejected a similar argument from Staff in the 2016 TAM.[41] Staff has had two additional years to develop this analysis; the fact that it has not done so supports PacifiCorp's position that Staff's proposal is fundamentally flawed and unworkable.

PacifiCorp presented unrebutted evidence that while implementing more realistic hourly prices could improve the market prices in GRID, this would still not capture the impact of uncertainty in the company's load and resource position and market prices between the day-ahead and hour-ahead time frame.[42] The company also demonstrated that the DA/RT adjustment reflects demand-related variability by capturing the price differential

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[34] TR. 203, 213 (Kaufman).
[35] PAC/1101.
[36] TR. 217 (Kaufman).
[37] Staff/200, Kaufman/19.
[38] TR. 208-09 (Kaufman).
[39] TR. 208-09 (Kaufman).
[40] TR. 217 (Kaufman) ("I haven't had enough time to do these calculations.").
[41] Order No. 15-394 at 4 (rejecting Staff's proposal for a investigation into GRID because "[p]arties have had sufficient time and opportunity to review and assess" the DA/RT adjustment).
[42] PAC/400, Wilding/13-14.

between purchases and sales—because PacifiCorp typically purchases when demand is higher, the price curve is correlated to demand. [43]

Staff's recommendation to replace the price component is undercut by Staff's acknowledgement in its own hypothetical that GRID does not capture all system balancing costs and the "DART price adder . . . remedies the DART problem."[44] Staff presented a hypothetical where PacifiCorp executes three transactions to balance its system: (1) PacifiCorp buys a monthly product with 10,000 MWh valued at $20 per MWh for a total of $200,000; (2) PacifiCorp sells 5,000 MWh in daily products priced at $10 per MWh, for a total revenue of $50,000; and (3) PacifiCorp keeps the remaining 5,000 MWh in daily products which are valued at $30 per MWh, for a total value of $150,000.[45] Staff agrees that without the DA/RT adjustment, GRID would purchase 5,000 MWh for $20 per MWh, modeling an expense of $100,000, even though PacifiCorp would have actually paid $150,000.[46] Staff further agrees that with the DA/RT adjustment, GRID would purchase 5,000 MWh for $30 per MWh, thus "remedying" the problem.[47] This concession is critical because it undermines Staff's primary basis for opposing the DA/RT adjustment.

b. Staff's proposal to include the value of historical arbitrage transactions and the residual value of monthly contracts in the DA/RT adjustment is unsupported in the record.

Staff's opening testimony also proposes modification of the volume component of the DA/RT adjustment to account for the value of historical arbitrage transactions and the residual value of monthly contracts.[48] This recommendation also has serious flaws.

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[43] PAC/800, Wilding/9-10.
[44] Staff/500, Kaufman/33.
[45] Staff/200, Kaufman/18.
[46] PAC/400, Wilding/19-21 (explaining Staff's hypothetical); Staff/500, Kaufman/33 (accepting PacifiCorp's explanation of the hypothetical).
[47] Staff/500, Kaufman/33.
[48] Staff/200, Kaufman/19; Staff/500, Kaufman/34.

First, in the 2017 TAM, the Commission rejected Staff's argument that the DA/RT adjustment did not fully account for the value of arbitrage transactions.[49] Staff's new evidence in this case consists of two examples and the hypothetical described above. In its reply testimony, PacifiCorp demonstrated that when corrected, Staff's examples prove that the DA/RT adjustment appropriately accounts for arbitrage transactions.[50] In its rebuttal testimony, Staff did not address the errors in its examples, refute the corrections, or contest the conclusion that its examples show the need for the DA/RT adjustment.[51]

Second, Staff failed to model or quantify its proposal in testimony. Staff's opening testimony provided a "preliminary estimate" of its value, but Staff's subsequent testimony never updated this preliminary estimate.[52] Indeed, Staff never mentioned its proposal again until hearing. In addition, Staff never explained how its estimate theoretically accounts for the value of historical arbitrage transactions. Staff simply reduced the NPC forecast by the difference between the company's actual 2016 sales revenue and the sales revenue calculated at the annual average price.[53] Staff's approach assumes that every single sales transaction in 2016 was an arbitrage transaction and that none of the actual benefits of the 2016 arbitrage transactions are accounted for in the DA/RT adjustment. Both of these assumptions are false.

Third, Staff provided virtually no testimony on its proposal related to the residual value of monthly contracts, including how this value would be calculated.[54] At hearing, Staff claimed that its preliminary estimate for the arbitrage adjustment also accounts for the residual value of monthly contracts.[55] But Staff's pre-filed testimony specifically states that

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[49] Order No. 16-482 at 12.
[50] PAC/400, Wilding/16-19.
[51] Staff/500, Kaufman/34.
[52] Staff/200, Kaufman/19-20.
[53] Staff/200, Kaufman/19-20.
[54] PAC/800, Wilding/22.
[55] TR. 216 (Kaufman).

the preliminary estimate "does not include the residual value of monthly and daily contracts."[56]

Fourth, while Staff criticizes the DA/RT adjustment's volume component as an arbitrary fixed-price adder,[57] Staff acknowledges that it is not opposed to fixed-price adders if they have a rational basis.[58] As the Commission has twice found, the volume component is rational and captures incremental costs not modeled in GRID.[59]

c. Contrary to Staff's argument, the volume component of the DA/RT adjustment works together with the price component to capture the total incremental DA/RT costs.

In rebuttal testimony, Staff proposes elimination of the volume component of the DA/RT adjustment, apparently as an alternative to its initial proposal to offset the value of arbitrage transactions and the residual value of monthly contracts.[60] Staff supports this proposal through the same hypothetical discussed above.[61] Staff reasons that because the pricing component fully captures the incremental DA/RT costs in its hypothetical, the volume component is superfluous.[62]

Staff's hypothetical is too limited to support Staff's conclusion—the volume component appears unnecessary in this example only because the difference between the price in parts one (monthly average price of $20 per MWh) and three ($30 per MWh) is the sales price in part two ($10 per MWh). Thus, in this particular hypothetical, the price component of the DA/RT adjustment captures the full incremental costs. Staff's testimony, however, fails to recognize that the volume component is designed to reflect the costs that are

[56] Staff/200, Kaufman/20.
[57] Staff/500, Kaufman/20-21; Staff/200, Kaufman/11 (stating Staff made the same argument last year).
[58] Staff/200, Kaufman/14.
[59] Order No. 16-482 at 13; Order No. 15-394 at 4.
[60] Staff/500, Kaufman/34.
[61] Staff/500, Kaufman/33.
[62] Staff/500, Kaufman/33.

not captured by the price component.[63] Just because there were no additional costs in this hypothetical does not mean the volume component is unnecessary in all cases.[64]

A simple change to the sales price in part two of Staff's hypothetical demonstrates the necessity of the DA/RT adjustment's volume component.[65] If the sales price in part two is changed from $10 per MWh to $5 per MWh, PacifiCorp would incur $175,000 for 5,000 MWh. As Staff concedes, without the DA/RT adjustment GRID would model a single 5,000 MWh transaction at $20 per MWh (for a total cost of $100,000). And, as Staff concedes, the price component would add an additional $50,000 in GRID, so that GRID plus the price adder would model a total cost of $150,000—which is $25,000 *less* than the actual costs incurred by PacifiCorp. Staff's own hypothetical, with only a slight modification, demonstrates that the price and volume component of the DA/RT adjustment work together to reflect all DA/RT costs not modeled in GRID.

d. Staff's proposal to exclude historical DA/RT data is unprincipled, contradictory, and admittedly based on insufficient data.

To smooth year-to-year variations in DA/RT costs and produce a normalized forecast, the DA/RT adjustment relies on a rolling historical average, a methodology the Commission has approved in numerous other contexts.[66] In the 2016 and 2017 TAMs, and in the pre-filing workshops, parties consistently argued that the DA/RT adjustment relied on insufficient historical data to produce a normalized forecast.[67] The Commission rejected

[63] PAC/800, Wilding/20-21.
[64] PAC/800, Wilding/20-21.
[65] PacifiCorp's surrebuttal testimony included a more complicated example that also demonstrated how the price and volume components of the DA/RT adjustment work together to include in the NPC forecast incremental DA/RT costs that are not otherwise included in GRID. PAC/800, Wilding/21-22. That example used the same reasoning as the hypothetical Staff first proposed and then agreed with the company's analysis.
[66] PAC/800, Wilding/11.
[67] PAC/100, Wilding/21, 23-24; PAC/800, Wilding/13-14.

these arguments, and explicitly affirmed that the use of three or four years of historical data produces a reasonable, normalized forecast.[68]

To avoid continued litigation over the normalization issue, PacifiCorp increased the historical data set used in this case to 60 months.[69] PacifiCorp also accepted CUB's proposed collar to exclude years triggering the company's PCAM to further allay the parties' normalization concerns.[70]

Staff now argues that the DA/RT adjustment relies on too much historical data and that PacifiCorp should use only years with low DA/RT costs.[71] Staff proposes to limit the historical data set to only those years "with low real time sales as representative of DART transactions."[72] Staff recommends the exclusion of any year with an NPC variance of $30 million or more, which would exclude 2011, 2013, and 2014.[73] In the alternative, Staff recommends the exclusion of 2013, 2014, and 2015.[74] Both recommendations are arbitrary attempts to unreasonably decrease the DA/RT adjustment—as evidenced by the simple fact that each method identifies different years as "outliers."[75]

First, all the years that Staff recommends eliminating as outliers were previously included in DA/RT adjustments approved by the Commission.[76] Because the Commission has already found that including the supposedly outlier years in the DA/RT calculation produces normalized results, there is no basis now to reverse that determination.

[68] Order No. 16-482 at 13; Order No. 15-394 at 4.
[69] PAC/800, Wilding/14.
[70] PAC/400, Wilding/29.
[71] Staff/500, Kaufman/34.
[72] Staff/500, Kaufman/27-28.
[73] Staff/500, Kaufman/17; PAC/800, Wilding/15.
[74] Staff/500, Kaufman/17.
[75] PAC/800, Wilding/15; TR. 229 (Kaufman) (acknowledging methodologies exclude different years).
[76] TR. 229 (Kaufman).

Second, Staff admits there is insufficient historical data to draw any conclusions about what historical DA/RT costs are normal or abnormal.[77] This admission eliminates any principled basis for Staff's recommendations. Staff seeks to reduce the DA/RT adjustment by claiming merely that certain data "*could* represent abnormal years of DA/RT costs."[78] Without more concrete evidence—evidence Staff agrees does not exist—there is no basis to change the previously approved historical data set.[79]

Third, the fact Staff eliminates so much historical data as abnormal undermines any claim that the excluded years are truly unusual.[80] Of the five years used to calculate the DA/RT adjustment, there are three years with high DA/RT costs, and two years with low DA/RT costs.[81] Staff arbitrarily declares that the three years with high DA/RT costs are outliers based on little more than the fact they are "clustered together."[82] But if three of five years have DA/RT costs that are comparable to one another, and distinct from the other two years, the reasonable inference based on this observation alone (to the extent there is one) is that the three years are normal, and the two years are abnormal.[83] Staff turns this reasonable inference on its head.

Moreover, if both Staff's recommendations are taken together, four of the six historical years with DA/RT data are "outliers."[84] And if the "outliers" Staff identified using ICNU's analysis—which Staff did not dispute—are also excluded, then five of the six

[77] Staff/500, Kaufman/24 ("The length of data are too short to draw conclusions about whether these three years are normal or abnormal.").
[78] Staff/500, Kaufman/24.
[79] PAC/800, Wilding/16-17.
[80] PAC/800, Wilding/17.
[81] Staff/500, Kaufman/25, 27.
[82] Staff/500, Kaufman/24.
[83] PAC/800, Wilding/17.
[84] PAC/800, Wilding/15.

historical years are "outliers."[85] Staff effectively argues there is one normal year, and five abnormal years based on virtually no analysis—a conclusion that is patently unreasonable.

Fourth, Staff presented no evidence that its collar will identify years with abnormal DA/RT costs.[86] Staff argued both here and in past TAMs that the historical variance between forecasted and actual NPC has no relationship to DA/RT costs.[87] If the historical variance is not produced by abnormally high or low DA/RT costs, then applying Staff's proposed collar will do nothing to identify years with abnormal DA/RT costs. Instead, Staff's collar arbitrarily excludes years that Staff does not even claim are outliers.[88]

e. Staff's proposed standard for approval of the DA/RT adjustment is unprecedented and unjustified.

Staff proposes that the Commission require PacifiCorp to validate the GRID model through a backcast before reaffirming the DA/RT adjustment.[89] While the Commission has never previously imposed such a requirement,[90] Staff supports its recommendation by incorrectly claiming that the Commission approved the DA/RT adjustment as a remedy for PacifiCorp's persistent historical NPC under-recovery.[91]

The Commission found that the DA/RT adjustment is necessary to capture costs that are actually incurred but not modeled in GRID.[92] The fact these incremental DA/RT costs are not included in PacifiCorp's historical NPC forecasts certainly contributed to the company's historical under-recovery.[93] PacifiCorp has previously testified that the

[85] Staff/500, Kaufman/24, 26.
[86] PAC/800, Wilding/14-15.
[87] PAC/800, Wilding/15, n. 27.
[88] PAC/800, Wilding/15 (collar produces different outliers from alternative recommendation).
[89] Staff/500, Kaufman/33-34.
[90] *See* Order No. 15-394 at 4; Order No. 16-482 at 13.
[91] Staff/500, Kaufman/15 ("PacifiCorp relies entirely on a comparison of the NPC variance with and without the DART adjustment" to support the accuracy of the adjustment).
[92] Order No. 16-482 at 13; Order No. 15-394 at 4; PAC/800, Wilding/7-9.
[93] PAC/800, Wilding/7-9.

systematic under-recovery of actual system balancing costs has been a consistent driver in the historical variance between actual and forecast NPC.[94] But PacifiCorp has never argued, and the Commission has never found, that the company's historical under-recovery alone is sufficient justification for the DA/RT adjustment or that the adjustment is meant to simply fill the gap between actual and forecast NPC. Staff's argument here is also undermined by its testimony in the 2017 TAM, where Staff correctly testified that PacifiCorp had not actually made the argument that its historical under-recovery is the basis for the DA/RT adjustment.[95]

4. ICNU's proposals repeat previously unpersuasive arguments and produce a non-normalized DA/RT adjustment.

ICNU makes two proposals that together virtually eliminate the DA/RT adjustment, even though neither adjustment alone has a significant impact.[96] ICNU proposes that the DA/RT adjustment include hedging transactions, a recommendation directly contrary to ICNU's position in the 2016 TAM that the DA/RT adjustment must exclude hedges.[97] ICNU also recommends that the DA/RT adjustment rely on only post-EIM data, even though the Commission rejected that same proposal last year.[98]

a. The Commission previously found that the DA/RT adjustment reasonably relies on pre-EIM data.

In the 2017 TAM, CUB argued that the DA/RT adjustment improperly relied on historical data that predated PacifiCorp's participation in the EIM.[99] The Commission rejected this argument in Order No. 16-482, finding that the DA/RT adjustment "is based on

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[94] Staff/716 at 5.
[95] PAC/800, Wilding/8.
[96] TR. 28 (Wilding).
[97] ICNU/100, Mullins/13.
[98] ICNU/100, Mullins/13.
[99] Order No. 16-482 at 12.

an analysis of a reasonable set of transactions," including pre-EIM transactions.[100] This year, ICNU repeats CUB's argument from last year and claims that the adjustment must be based on data from 2015 and 2016 only.[101] Like last year, the record here demonstrates that PacifiCorp's participation in the EIM has not rendered its pre-EIM DA/RT cost data obsolete for purposes of the adjustment.[102] The DA/RT costs in 2015, the first year of the EIM, were 35 percent higher than the previous 48-month average, undermining ICNU's claim that the EIM fundamentally lowered DA/RT costs.[103] Moreover, the average post-EIM DA/RT costs ([redacted]) are within [redacted] of average pre-EIM DA/RT costs ([redacted]), and within [redacted] of the 2011 to 2016 DA/RT costs ([redacted]).[104] Indeed, the 2015 and 2016 DA/RT costs represent the median costs for the entire historical period (2011 to 2016).[105] At hearing, ICNU's witness could only testify that there "*may* be a shift" in DA/RT costs in 2015, confirming the speculative nature of its proposal.

In addition, DA/RT costs were low in 2016, the year both Staff and ICNU suggest is the new normal, because of historically low natural gas prices that allowed PacifiCorp to rely more heavily on its own gas plants to balance the system.[106] And, even though 2016 DA/RT costs were lower than the 2013 to 2015 costs, the 2016 costs were higher than the 2011 and 2012 costs.[107] Further, to the extent that PacifiCorp's participation in the EIM changes the

[100] Order No. 16-482 at 13.
[101] ICNU/100, Mullins/13.
[102] PAC/400, Wilding/27-28.
[103] PAC/400, Wilding/27.
[104] PAC/400, Wilding/24.
[105] PAC/400, Wilding/24; TR. 179-80 (Mullins).
[106] PAC/800, Wilding/18.
[107] PAC/400, Wilding/24.

level of its DA/RT costs, those changes will be reflected in the historical average used to calculate the adjustment.[108]

b. The DA/RT adjustment should not be expanded to include hedges.

ICNU recommends that the calculation of the DA/RT adjustment include transactions that have a delivery time of more than one week, *i.e.*, primarily monthly transactions that have hedging components.[109] Thus, ICNU now recommends that the Commission reverse its previous finding that the DA/RT adjustment appropriately excludes hedging transactions and explicitly include those transactions as part of the DA/RT adjustment.[110] Not only has the Commission already rejected ICNU's position, it is also the *exact opposite* of the position ICNU took in the 2016 TAM.[111] In pre-filed testimony, ICNU neither acknowledges this contradiction nor explains its reversal.[112] The DA/RT adjustment appropriately focuses on only day-ahead and real-time transactions, not hedging transactions, and ICNU has not provided any compelling reason to change this approach.

i. Unlike DA/RT transactions, there are no systematic costs or benefits resulting from hedging transactions.

PacifiCorp has demonstrated, and the Commission has found, that there is a systematic cost incurred in the day-ahead and real-time markets that is not accounted for in

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[108] Although Staff appears supportive of ICNU's general argument that the EIM has rendered pre-EIM data obsolete, Staff's own recommendation relies on pre-EIM data and eliminates post-EIM data as a purported "outlier." Staff/500, Kaufman/34.

[109] ICNU/100, Mullins/13; TR. 176, 182 (Mullins); *see also* ICNU/200, Mullins/4, 8, 9 (acknowledging adjustment may be accounting for hedging benefits). In its briefing in docket UE 296, ICNU explicitly argued that "making forward monthly transactions rather than waiting to make a spot market transaction constitutes a form of hedging," and that the DA/RT adjustment "assigned additional costs to monthly transactions," which means that it "assigns costs to hedging contracts in a normalized NPC forecast." Docket No. UE 296, Response Brief of the Industrial Customers of Northwest Utilities at 7 (Sept. 28, 2015). PacifiCorp requests that the Commission take official notice of ICNU's prior briefing pursuant to OAR 860-001-0460(1)(d) as a record in the files of the Commission that has been made a part of the files in the regular course of performing the Commission's duties.

[110] Order No. 16-482 at 13; ICNU/200, Mullins/9.

[111] PAC/400, Wilding/21; PAC/800, Wilding/30-31.

[112] PAC/800, Wilding/30.

GRID because PacifiCorp tends to sell when market prices are low and buy when market prices are high.[113] ICNU acknowledges that in every year of the historical period, the DA/RT adjustment represents a cost.[114]

In contrast, ICNU argues that hedging costs should be included in the calculation of the DA/RT adjustment because they provide *systematic* benefits to customers.[115] But hedging transaction do not have a systematic bias.[116] Indeed, ICNU's own analysis shows that from 2011 to 2016, hedges represent a cost in some years, and a benefit in others.[117] Over the 60 months used to calculate the DA/RT adjustment, PacifiCorp's hedging transactions netted out to nearly zero, as compared to the DA/RT costs, which averaged $27.7 million.[118]

ICNU's own past arguments confirm that hedges do not have a systematic bias one way or the other.[119] In docket UE 296, ICNU argued that including monthly transactions in the DA/RT adjustment is unreasonable because it incorrectly "assumes there will be systematic losses associated with forward hedging contracts."[120] ICNU claimed that the lack of systematic costs or benefits "is central to power cost forecasting."[121] If hedging produced systematic costs or benefits, then "the basic construct underlying the use of power cost

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[113] Order No. 15-394 at 4.
[114] ICNU/200, Mullins/3 (Confidential Table 1R shows DA/RT costs in every year).
[115] ICNU/100, Mullins/10 ("the Company adds an additional systematic cost for transactions of less than seven days, yet does not consider whether the longer-term transactions are systematically settling favorably, or unfavorably, relative to the market."); *id.* (hedging transactions provide "offsetting systematic benefits"); *id.* at 11 (ICNU analyzed the "systematic" impact of greater than seven-day transactions); ICNU/200, Mullins/9 ("If there is an offsetting systematic benefit associated with these longer-term contracts, those benefits are appropriately applied against the impact of the DA/RT, irrespective of what is causing the benefit.").
[116] PAC/800, Wilding/25-27.
[117] ICNU/200, Mullins/3.
[118] ICNU/200, Mullins/3 (hedging benefits are [redacted], DA/RT costs are $27.7 million).
[119] PAC/800, Wilding/30-31.
[120] PAC/1111 at 2; *id.* at 6 ("it is generally recognized that there is no systematic bias between forward market prices and spot market prices").
[121] PAC/1111 at 7 ("Thus, to the extent that a utility is ultimately required to transact for more or less power in hourly spot markets than previously sold or purchased in forward markets, it is expected to be no better or worse off than if it had solely purchased its power requirements in spot markets.").

forecasting for ratemaking purposes begins to unravel, leading to a conclusion that a power cost forecast may no longer meet the standard to be used for ratemaking." [122]

At hearing, ICNU failed to distinguish its past position and, in fact, conceded that it has now taken the opposite position.[123] ICNU's witness claimed that his past testimony was based on an incorrect "assumption that the volume portion of the Company's adjustment included costs associated with [] monthly transactions."[124] Thus, according to ICNU, when it understood that the DA/RT adjustment included monthly transactions, it was improper for assuming a systematic cost. But, now that ICNU understands that the DA/RT adjustment does not include monthly transactions, the adjustment must include monthly transactions because they provide a systematic benefit. ICNU's explanation makes no sense and provides no justification for the inconsistency of its positions.

In docket UE 296, ICNU also claimed that if there were opportunities for profit in a forward market, "the mechanics of supply and demand would . . . eliminate the opportunity for a risk-free return."[125] Without explanation, ICNU now claims that since 2015, PacifiCorp is able to systematically generate risk-free profits through its monthly transactions, and that the "mechanics of supply and demand" will no longer eliminate that opportunity.[126]

More importantly, ICNU provides no plausible explanation of what changed in 2015 such that PacifiCorp is now systematically profiting from its hedging transactions. ICNU argues that the company's participation in the EIM has apparently enabled it to systematically profit from hedges.[127] But the only basis for this claim is that the hedging

[122] PAC/1111 at 7-8.
[123] TR. 195 (Mullins) ("I've kind of reached a different conclusion.").
[124] TR. 190 (Mullins).
[125] PAC/1111 at 8.
[126] TR. 192 (Mullins).
[127] ICNU/100, Mullins/12.

benefits in 2015 and 2016 are larger than the other years in the historical period.[128] ICNU provides no evidence that there is a correlation between the EIM and larger hedging benefits.

ICNU also speculates that since 2015, there may be a risk premium embedded in forward prices.[129] But ICNU previously argued that a risk premium would be "evidence of systematic hedging *costs*" that customers should not pay.[130] Here, ICNU provides no explanation of why there is a risk premium now when there was not one two years ago, why a risk premium today produces benefits when it produced costs two years ago, or why customers should receive those benefits when shareholders should bear the costs.

ii. The inclusion of hedging transactions in the DA/RT adjustment fundamentally changes its nature.

Unlike the DA/RT adjustment, ICNU's hedging adjustment does not model a systematic difference between the average market price and the average purchase and sales price.[131] Instead, ICNU's hedging adjustment effectively measures the difference between the forward price curve at the time PacifiCorp executes a hedge and the point in time when the energy is delivered.[132] In this way, ICNU's hedging adjustment measures something completely different from the DA/RT adjustment.

In docket UE 296, ICNU argued against including hedges in the DA/RT adjustment specifically because the costs and benefits resulting from historical hedges are "indicative of changing market conditions between the time that the hedge is entered into and the prompt period" and "will not correspond to the market conditions" in the test period.[133] If historical hedges are not indicative of the costs and benefits of future hedges, as ICNU previously

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[128] ICNU/100, Mullins/12.
[129] ICNU/200, Mullins/8.
[130] PAC/1108 (emphasis added).
[131] PAC/800, Wilding/25, 31.
[132] PAC/800, Wilding/25, 31.
[133] PAC/800, Wilding/31; PAC/1111 at 12-13.

testified and did not refute here, then there is no basis to include historical hedges in the NPC forecast.[134] While ICNU characterizes its hedging adjustment as a simple application of the DA/RT adjustment to a broader array of system balancing transactions, hedges are fundamentally different from DA/RT transactions and the logic and principles underlying the DA/RT adjustment are inapplicable.[135]

iii. ICNU's inclusion of only two years of hedging transactions produces an anomalous DA/RT adjustment.

ICNU recommends an 89 percent reduction in the DA/RT adjustment based on two previously rejected changes to the Commission-approved methodology: including hedges and using only post-EIM data.[136] Notably, neither recommendation on its own produces a significant change in the DA/RT adjustment. Including hedges reduces the adjustment from $27.7 million to [redacted], a change of only [redacted].[137] Limiting the adjustment to only post-EIM data reduces the adjustment to [redacted], a change of [redacted].[138] It is only when these two changes are made together, that the DA/RT adjustment is virtually eliminated.[139] ICNU's hedging adjustment does not result in a normalized forecast because it uses only two years of historical data—years with by far the largest hedging benefits of the entire historical period.[140] In 2015 and 2016, hedges produced a customer benefit of [redacted], which is nearly [redacted] than the benefit over the 60-month period used to calculate the DA/RT adjustment.[141]

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[134] PAC/800, Wilding/25, 31.
[135] ICNU/200 Mullins/3.
[136] ICNU/200, Mullins/3 (reducing DA/RT from $27.7 million to [redacted]); PAC/800, Wilding/25-29; ICNU/100, Mullins/13; Order No. 15-394 at 4; Order No. 16-482 at 12-13.
[137] PAC/800, Wilding/28.
[138] PAC/800, Wilding/28.
[139] PAC/800, Wilding/28.
[140] PAC/800, Wilding/17, 26-27, 28-29.
[141] ICNU/200, Mullins/3 (compare [redacted]).

B. PacifiCorp supports model validation, but backcasting is not a useful or efficient validation technique.

There is no dispute that PacifiCorp has historically under-recovered its NPC in Oregon rates.[142] Despite this fact, the company believes that its GRID model is sound and produces a reasonable NPC forecast. The variance between the forecasted and actual NPC is driven primarily by the fact that forecasted inputs to the NPC model—such as market prices, load, and weather—are inherently uncertain and actual events will nearly always deviate from the forecast.[143] In the 2017 TAM, Staff argued that PacifiCorp's historical under-recovery was "fundamentally grounded in error forecasting the model inputs."[144] In the 2016 TAM, ICNU argued the variance is "ultimately driven by the accuracy of the forecast inputs into the model."[145]

In 2016, PacifiCorp also under-recovered its NPC in Oregon rates. But the 2016 forecast was the most accurate to date.[146] 2016 was also the first year that the DA/RT adjustment was included in the NPC forecast. Now, both Staff and ICNU argue that PacifiCorp should be required to demonstrate the validity of its NPC modeling through a backcast. But Staff's and ICNU's proposed backcast methodology is unclear, with Staff describing it differently in every filing.[147] Without any industry standards or precedent, developing a backcast will require extensive effort by the parties to agree on the parameters and perform GRID runs and sensitivity studies. After that work is complete, the parties will

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[142] PAC/400, Wilding/43.
[143] PAC/800, Wilding/35.
[144] PAC/800, Wilding/36.
[145] PAC/800, Wilding/36.
[146] PAC/400, Wilding/43; PAC/800, Wilding/37; TR. 247 (Kaufman).
[147] Staff/200, Kaufman/4 (referring to its preferred methodology as a backcast or a "within sample test"); Staff/500, Kaufman/2 (recommending "Model Validation" generally, and stating that it has not requested a backcast); TR. 237 (Kaufman).

still be required to engage in the same line-by-line analysis that the company recommends occur in the first instance.

1. PacifiCorp proposes an in-depth analysis of historical data to understand how GRID impacts the variance between forecast and actual results.

PacifiCorp supports all reasonable efforts to validate its NPC modeling.[148] The most efficient and insightful validation process relies on a granular comparison of the actual and forecast NPC from past years, similar to what occurs in the PCAM.[149] By thoroughly analyzing the line-by-line differences between the forecast and actual results, parties can understand why the GRID model produced the results that it did given the forecasted inputs. Parties can then understand how the model itself contributed to the variance between forecast and actual results, as compared to the contribution of input error. Here, the parties performed this type of analysis based on the 2016 results and both Staff and ICNU identified various reasons for the variance between actual and forecasted NPC.[150] A more thorough analysis, using a comparable methodology, can be used to validate the accuracy of the GRID model.

To minimize controversy, PacifiCorp recommends that the parties convene a workshop following the conclusion of this case to discuss a model validation process.[151] Subsequent workshops can then examine the results of any validation analysis. PacifiCorp's proposal would largely mirror the pre-filing workshops in this case, which the parties generally agreed were useful.[152]

2. Backcasting will be burdensome, controversial, and inefficient.

Both Staff and ICNU recommend that the Commission order PacifiCorp to perform a backcast analysis, which consists of re-running the historical NPC model using selected

[148] PAC/800, Wilding/33.
[149] PAC/800, Wilding/34.
[150] *See, e.g.*, Staff/500, Kaufman/4-8; ICNU/100, Mullins/6-8.
[151] PAC/800, Wilding/34-35.
[152] PAC/100, Wilding/15-18.

actual inputs.[153] In theory, if the model is accurate, when known inputs are used, the model should replicate actual events. While backcasting may sound like a reasonable validation technique, it has substantial practical limitations that make it an inefficient methodology for validating PacifiCorp's NPC modeling.

According to Staff, the purpose of a backcast is to control for input error by replacing certain variables in the GRID model with actual historical results.[154] Therefore, the first step in the backcast is to identify which variables will be replaced. In this case, Staff recommends that the backcast replace eight variables with actual historical results.[155] But in the 2017 TAM, Staff recommended different variables, and in this case, ICNU disagrees with Staff's proposed variables.[156] There are hundreds of possible variable combinations that could be replaced in GRID with actual historical data, and the results of the backcast will depend on which combination of variables are replaced with actuals and which are determined by GRID.

Moreover, Staff and ICNU both argue that once an initial GRID backcast is run, the parties can then perform additional sensitivity runs that change the selected inputs to isolate the impact of specific input errors.[157] Each sensitivity requires a new GRID run, and parties may want sensitivities based on additional variables that were not replaced in the initial GRID run.[158] It is possible that a backcast study could require PacifiCorp to perform hundreds of GRID runs depending on the number of years and sensitivities studied.[159] Then, parties will need to review the GRID output line-by-line to understand any differences

[153] Staff/200, Kaufman/10; ICNU/100, Mullins/8.
[154] Staff/500, Kaufman/4.
[155] Staff/202, Kaufman/1.
[156] Staff/203, Kaufman/1; ICNU/100, Mullins/5.
[157] Staff/500, Kaufman/11; ICNU/100, Mullins/5.
[158] TR. 50-51, 54-55 (Wilding).
[159] TR. 50-51, 54-55 (Wilding).

between the model run and the actual NPC results from the historical period.[160] Because this is the same type of model validation analysis PacifiCorp recommends in the first place, it is difficult to justify a time-intensive backcast.[161]

PacifiCorp's concerns about the efficacy of backcasting are well supported. Indeed, in the 2013 TAM, Staff noted that "backcasting has not been tried and would be very time intensive."[162] Staff continued that there was "also the possibility that parties would spend considerable time and effort in backcasting, only to reach unclear or controversial results."[163] At hearing, Staff disavowed this prior argument and asserted that there is nothing controversial or unclear about a backcast.[164] Staff claimed that it "updated its opinion based on additional information that's available," but Staff never explained what that new information is, or why the new information would mean that a backcast would be uncontroversial and produce clear results.

Staff's position in the 2013 TAM is consistent with the U.S. Department of Commerce's "Validation and Assessment of Issues of Energy Models," which noted that "[b]ackcasting is no easier than forecasting" because of the required assumptions.[165] Thus, "it is clear that backcasting is not a useful approach to model validation."[166]

Staff's only academic support for backcasting comes from a textbook that does not address energy dispatch model validation, and never discusses the use of backcasting as a preferred approach to model validation.[167] On the contrary, the textbook describes model validation involving a comparison of "two sets of data, one generated by the simulation

[160] TR. 50-51, 54-55 (Wilding).
[161] TR. 50-51, 54-55 (Wilding).
[162] PAC/1102 at 4.
[163] PAC/1102 at 4.
[164] TR. 249 (Kaufman).
[165] PAC/800, Wilding/33-34.
[166] PAC/800, Wilding/33-34.
[167] TR. 240 (Kaufman).

model [*i.e.*, GRID] and the other already collected on the real system [*i.e.*, actual historical results]."[168] Validation is an "iterative process of comparing the model to actual system behavior, identifying the discrepancies, applying corrections and again comparing the performance."[169] The text generally describes PacifiCorp's proposed approach to model validation, not the backward-looking modeling recommended by Staff and ICNU.

3. The Commission should affirm the DA/RT adjustment while the model validation process is under review.

In the 2016 TAM, Staff asked the Commission to reject the DA/RT adjustment to allow additional time for the parties to propose alternatives.[170] The Commission ruled against Staff after finding that parties "had sufficient time and opportunity to review and assess" the adjustment in that case.[171] In the 2017 TAM, Staff again recommended rejection of the DA/RT adjustment so the parties could develop alternatives, and the Commission again approved the adjustment.[172] Now, Staff and ICNU argue that the Commission should require a backcast before affirming the DA/RT adjustment,—effectively reiterating the arguments made and rejected in the 2016 and 2017 TAMs. The Commission has never conditioned an NPC modeling change or adjustment on the results of a backcast. Neither Staff nor ICNU have presented any compelling argument why the Commission should change courses now and undo the DA/RT adjustment pending a backcast,

C. PacifiCorp's estimated inter-regional EIM benefits are reasonable.

PacifiCorp's initial filing included $27.5 million in total-company EIM benefits—$24.4 million in inter-regional benefits and greenhouse gas revenues and $3.1 million in

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[168] PAC/1105 at 12.
[169] PAC/1105 at 3.
[170] Order No. 15-394 at 3-4.
[171] *Id.* at 4.
[172] Order No. 16-482 at 13.

flexibility reserve savings.[173] This was 27 percent higher than the same benefits modeled in last year's TAM.[174] The company calculated EIM benefits consistent with the methodology approved by the Commission in the 2017 TAM, with one exception. As a result of the pre-filing workshops, the company adopted CUB's proposal to remove the transmission constraint the company modeled in previous cases.[175] Adopting CUB's proposal increased the EIM benefits.

In its reply update, PacifiCorp increased its forecasted inter-regional benefits and greenhouse gas revenues to [redacted].[176] PacifiCorp will update these benefits in the final update, consistent with prior TAMs. PacifiCorp's total EIM benefits for 2018 are [redacted] than the forecasted benefits in the 2017 TAM.

PacifiCorp acknowledges that past EIM forecasts of inter-regional benefits are understated, and this informed the company's decision to significantly increase its forecast of EIM benefits in this case. The company's past EIM benefit estimates were based on PacifiCorp's limited experience with the EIM,[177] and Staff generally supported the company's forecast of inter-regional EIM benefits using the most recent historical data without escalation.[178]

Staff is the only party to propose an EIM adjustment, and Staff's adjustment is limited to inter-regional benefits. Staff claims that the company's forecast does not account for the fact that inter-regional EIM benefits have historically increased.[179] Staff's claim, however, cannot be squared with the facts—PacifiCorp's inter-regional EIM benefit forecast

[173] PAC/100, Wilding/25.
[174] PAC/100, Wilding/25.
[175] PAC/100, Wilding/28-29.
[176] PAC/500, Brown/4.
[177] PAC/900, Brown/9; TR. 145-46, 149-51, 155-56 (Brown).
[178] PAC/900, Brown/9; Order No. 16-482 at 14; TR. 275-76 (Gibbens).
[179] Staff/400, Gibbens/9.

is substantially higher than past TAM forecasts and substantially higher than the most recent actual data. Moreover, Staff's methodology for increasing EIM benefits is arbitrary and effectively double-counts the impact of new market entrants.

1. PacifiCorp's EIM benefits rely on the most recent data and account for operational changes and expected market conditions in 2018.

PacifiCorp forecasts [redacted] in inter-regional EIM benefits for 2018.[180] The company's forecast is based on the most recent six months of validated EIM data to account for recent operational changes at PacifiCorp's coal plants that are expected to increase inter-regional benefits in 2018.[181] Although the use of only six months of data departs from previous forecasts that have relied on a full year of actual data, the most recent six months are more reflective of the expected 2018 market conditions. To account for growth in EIM benefits, PacifiCorp's forecast more heavily weights the most recent data, and includes an additional [redacted] in benefits resulting from the new market entrants (Portland General Electric Company. (PGE) and Idaho Power Company (Idaho Power)), and [redacted] for the impact of California's over-supply conditions.[182] PGE's and Idaho Power's E3 studies estimated incremental annual benefits for *all EIM participants* of only $3.38 million—meaning PacifiCorp's estimated benefits for itself are higher than E3's estimate for the entire market.[183]

2. PacifiCorp's forecasted EIM benefits reflect a robust growth rate over historical results.

The 2018 forecast is nearly three times higher than 2015 actual benefits and 73 percent higher than 2016 actual benefits.[184] Most importantly, PacifiCorp's forecast

[180] PAC/500, Brown/4.
[181] PAC/500, Brown/5, 8.
[182] PAC/900, Brown/3, 6-8.
[183] PAC/900, Brown/6-7.
[184] PAC/900, Brown/1-2.

methodology produced inter-regional benefits that are *45 percent higher than the most recent 12 months*.[185]

PacifiCorp presented evidence that the historical growth in EIM benefits is unsustainable, as the EIM becomes saturated with new participants and the opportunity to more efficiently dispatch PacifiCorp resources decreases.[186] Despite the expectation of diminishing returns, PacifiCorp's 2018 estimate includes a robust growth rate consistent with historical actual results.[187]

Staff claims that PacifiCorp's "methodology does not consider any growth rate or trend in EIM benefits," and, instead, simply takes the most recent data and copies it over the forecast horizon.[188] This is untrue—if PacifiCorp had simply used the most recent data, it would forecast EIM benefits of [redacted].[189] The fact PacifiCorp's forecast is 45 percent higher demonstrates that PacifiCorp did, in fact, consider trends in EIM benefits in its 2018 forecast.

Moreover, Staff testifies that PacifiCorp's lack of a growth rate constitutes a "glaring deficiency" in the company's methodology.[190] But the Commission approved PacifiCorp's past estimates without a separately applied growth rate, Staff's methodology last year did not include a growth rate, and Staff never raised this concern during the pre-filing workshops discussing EIM benefits.[191]

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[185] PAC/900, Brown/2.
[186] PAC/500, Brown/6-7, 13-16; TR. 149-51, 158-60 (Brown).
[187] PAC/900, Brown/2.
[188] Staff/400, Gibbens/9.
[189] PAC/900, Brown/8.
[190] TR. 280 (Gibbens).
[191] TR. 274-77 (Gibbens).

3. Staff's forecasted inter-regional EIM benefits are overstated.

Staff's opening testimony included estimated inter-regional EIM benefits of [redacted] for 2018.[192] In its reply testimony, PacifiCorp showed that Staff's estimate was overstated because it erroneously included greenhouse gas revenues.[193] In response to Staff's concern that the EIM benefits were too low, however, PacifiCorp increased its inter-regional benefits by [redacted].[194] After PacifiCorp increased its estimate to [redacted] (which, as described below, was effectively the same as Staff's corrected original estimate), Staff changed its methodology in rebuttal and increased its adjustment to offset its initial error.[195] Staff's original methodology affirms the reasonableness of PacifiCorp's estimate, while Staff's revised methodology significantly overstates EIM benefits by double-counting the benefits for new participants in the EIM.

a. PacifiCorp's forecast benefits are nearly equal to the benefits produced by Staff's original methodology.

Staff's original methodology applied a growth rate based on 50 percent of the "year/year growth rate in inter-regional benefits over the last 12 months of data which is currently available."[196] Calculating this 12-month growth rate using Staff's original workpapers[197] and applying it to only inter-regional benefits (not greenhouse gas revenues),[198] produces 2018 inter-regional benefits of [redacted] —only [redacted] than PacifiCorp's estimate.[199] At hearing, Staff changed its opening testimony to use a 16-

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[192] Staff/400, Gibbens/18.
[193] Staff/400, Gibbens/17.
[194] PAC/900, Brown/1-2.
[195] Staff/400, Gibbens/17-18 (noting the correction of errors but roughly the same adjustment).
[196] Staff/100, Gibbens/11.
[197] PAC/1107 at 1. The 12-month growth rate is calculated as 50 percent of the average of the growth rates in cells J18 to J29 and equals [redacted].
[198] Staff erroneously included [redacted] in greenhouse gas revenues in its adjustment. The greenhouse gas revenues are equal to the summation of cells O50 to Z50 on page 2 of PAC/1107.
[199] Subtracting [redacted] from [redacted] (PAC/1107 at 1, cell I50) produces [redacted]. Applying the [redacted] growth rate to [redacted] produces benefits of [redacted].

month growth rate, instead of 12, to increase its forecasted benefits.[200] But even using a 16-month growth rate produces forecasted benefits of [redacted], which is only [redacted] than PacifiCorp's forecast.[201]

If Staff's original growth rate is calculated using the same methodology as its rebuttal growth rate (*i.e.*, using an annual growth rate instead of the average of monthly growth rates[202]), then Staff's original methodology produces benefits of only [redacted], *which is less than PacifiCorp*.[203] Moreover, using the updated 12-month growth rate calculated by Staff in its rebuttal testimony (51 percent) in Staff's original framework produces benefits of [redacted], which is also less than PacifiCorp's forecast.[204]

The above comparisons demonstrate, in several different ways, that Staff's original methodology produced benefits that are nearly the same as PacifiCorp's current forecast, once greenhouse gas revenues are removed. Although Staff claims that both its methodologies are conceptually consistent with one another, the evidence is otherwise.[205]

b. Staff's revised methodology double counts the impact of new market entrants and is internally contradictory.

The most significant difference between Staff's original and revised methodologies involves the forecasted benefits for new market entrants. Staff's revised methodology includes [redacted] in additional benefits resulting from PGE's and Idaho Power's entry into the EIM, which effectively accounts for the difference between its original benefits

[200] TR. 272 (Gibbens).
[201] PAC/1107 at 1 (applying [redacted] growth rate to [redacted]).
[202] PAC/1107 at 1. The total benefits from the most recent 12 months included in Staff's workpapers is [redacted] (summation of cells G18 to G29) and the total benefits from the preceding 12 months is [redacted] (summation of cells G6 to G17). Fifty percent of the growth rate calculated by using these annual totals is [redacted]. PAC/500, Brown/10-11 describes the difference between this methodology and Staff's original methodology that used the average of monthly growth rates. Staff's revised methodology used annual growth rates. PAC/1106.
[203] Note this calculation uses Staff's original methodology that relies on 12-months of data. There is insufficient historical data to use this same approach using 16 months of historical data.
[204] PAC/1107 (applying a [redacted] growth rate to [redacted]).
[205] Staff/400, Gibbens/17-18.

estimate (as corrected) and its revised benefits estimate.[206] Staff's [redacted] estimate is substantially overstated.

To calculate [redacted] in new market entrant benefits, Staff applied its [redacted] growth rate to the company's estimated benefits of [redacted].[207] But Staff also applied a growth rate to the historical EIM benefits, partly to account for the same impact of new market entrants.[208] Thus, Staff (1) applied a [redacted] growth rate to historical EIM benefits intended to capture the benefits attributed to PGE and Idaho Power, (2) added PacifiCorp's incremental benefits for PGE and Idaho Power, and (3) applied its [redacted] adder to PacifiCorp's incremental benefits. Staff has effectively double, or even triple-counted the benefits resulting from PGE and Idaho Power, without ever explaining why the additional [redacted] adjustment is necessary when its [redacted] growth rate purportedly captures the same benefits.[209]

In fact, Staff never explains at all why its revised methodology relies on PacifiCorp's estimated benefits for new market entrants.[210] This is a particularly glaring omission because Staff argues that PacifiCorp's benefit for new market entrants is an inaccurate, uninformed, arbitrary "guess."[211] If this supposedly inaccurate estimate is removed from Staff's calculation, Staff's estimated EIM benefits are nearly the same as PacifiCorp's.[212]

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[206] PAC/900, Brown/6. Staff applied a [redacted] growth rate to the [redacted] benefits for PGE and Idaho Power, resulting in an overall increase of [redacted].

[207] Staff/400, Gibbens/17.

[208] Staff/100, Gibbens/8 (growth in EIM benefits is "most likely due to new entrants to the EIM").

[209] PAC/900, Brown/8.

[210] PAC/900, Brown/5-6.

[211] Staff/400/Gibbens/9 (PacifiCorp's calculation is "arbitrary in that [it is] not based on an informed study, but rather a 'best guess' to be added to the benefit calculation."); Staff/400, Gibbens/13 ("Staff also does not believe in the accuracy of the Company's new entrant adjustment.").

[212] Subtracting [redacted] from Staff's benefit estimate of [redacted], produces EIM benefits of [redacted].

Moreover, if the benefits from PGE and Idaho Power are calculated using an E3 study, which appears to be Staff's preferred approach, the results are also nearly the same as PacifiCorp's [redacted] estimate.[213] PacifiCorp's initial filing calculated the PGE and Idaho Power benefits using each utility's E3 study.[214] Replacing the [redacted] estimate PacifiCorp calculated with the $0.7 million estimate based on the E3 studies, and changing nothing else in Staff's revised methodology, produces inter-regional benefits of only [redacted].[215] Moreover, Staff's calculated benefit for PGE and Idaho Power is nearly [redacted] higher than the E3 studies Staff supports.[216]

c. The growth rate implied by Staff's estimate is excessive.

Staff defends its proposed methodology by claiming that a [redacted] growth rate is a reasonable "middle ground."[217] But Staff's estimated inter-regional benefits are [redacted] higher than the actual benefits received in the most recent 12-month period.[218] Indeed, applying a [redacted] growth rate to the most recent historical data produces benefits of [redacted], nearly the same as PacifiCorp's [redacted] estimate.[219] In this case, PacifiCorp's 45 percent growth rate represents the true "middle ground."

D. GRID reasonably models normalized coal plant dispatch, and there is no basis for Staff's uneconomic dispatch adjustment.

GRID models coal plants between their minimum and maximum capacities.[220] Thus, when a coal plant is uneconomic to dispatch, GRID will model the plant at its minimum capacity, which is consistent with how coal plants are normally dispatched in actual

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[213] Staff/400, Gibbens/8.
[214] *See* PAC/104; PAC/100, Wilding/26.
[215] This is calculated by applying Staff's [redacted] to the sum of [redacted] and $0.7 million.
[216] This is calculated as the ration of Staff's [redacted] benefit to the $0.7 million benefit included in PacifiCorp's initial filing.
[217] Staff/400, Gibbens/14.
[218] PAC/900, Brown/8 (most recent 12-month period had benefits of [redacted]).
[219] PAC/900, Brown/8.
[220] PAC/400, Wilding/32-33.

operations.[221] Staff recommends that PacifiCorp modify how GRID models coal plant dispatch to allow the model to include months-long economic shutdowns of coal plants.[222] Staff's recommendation ignores the limited circumstances in which PacifiCorp has economically shutdown coal plants and is narrowly focused on market prices, without consideration of non-economic operational issues that limit shutdowns. The adjustment also fails to consider that GRID already under-forecasts coal generation.[223] Thus, there is no basis to impute economic shutdowns that are unlikely to occur in 2018 given the normal conditions forecasted in the TAM.

1. PacifiCorp does not shutdown coal plants in normal operations.

PacifiCorp's coal plants have been subject to material economic shutdowns in 2016 and 2017 only, in response to unprecedented market conditions.[224] In 2016, historically low natural gas prices allowed PacifiCorp to displace coal with its natural gas resources. In 2017, historically high hydro generation allowed PacifiCorp to displace coal with hydro resources.[225] Neither of these anomalous market conditions are expected to occur in 2018.[226] Thus, a normalized forecast of coal plant dispatch in this case should not include prolonged economic shutdowns.

Staff misleadingly claims that PacifiCorp has performed economic shutdowns in every year Staff examined.[227] But economic shutdowns lasting a matter of hours, which are the predominant shutdowns that occurred before 2016, are not comparable to Staff's proposal

[221] TR. 110 (Wilding).
[222] Staff/200, Kaufman/21-24.
[223] PAC/800, Wilding/44.
[224] PAC/400, Wilding/30.
[225] PAC/400, Wilding/30.
[226] PAC/400, Wilding/33-34.
[227] Staff/500, Kaufman/35.

to idle two coal units for months.[228] In 2013, there were four economic shutdowns—three lasted for less than 10 hours and one lasted for a little over 24 hours.[229] In 2014, there were three shutdowns, none of which lasted more than six hours.[230] In 2015, three of the six shutdowns were less than 24 hours.[231] At hearing, Staff acknowledged that the three-year average for 2013 to 2015 was one-tenth of the 2,880 hours Staff proposed for shutdowns in 2018.[232] Moreover, in the historical scenarios where PacifiCorp extended an outage for several hours it incurs no additional start-up costs, unlike Staff's shutdown scenarios.[233]

2. Staff's ad hoc and purely price-driven analysis is too narrow.

Staff used an "intuitive" approach to select periods for economic shutdowns that relied exclusively on the GRID model, without considering the myriad of other factors that must be considered in actual operations.[234] For example, Staff's adjustment does not consider transmission congestion, voltage support, and other operational issues such as maintaining adequate system inertia, which all play a critical part in determining if a resource can be displaced.[235] At hearing, Staff was confronted with the 15 variables the company specifically identified during discovery that it considers before shutting down a coal plant.[236] Staff could identify only four variables it actually considered.[237]

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[228] PAC/800, Wilding/38-39; Staff/505 (data response showing the length of historical shutdowns).
[229] PAC/800, Wilding/38-39.
[230] PAC/800, Wilding/38-39.
[231] PAC/800, Wilding/38-39. The other three shutdowns occurred at the Cholla plant; the first was the 13-day economic shutdown, the second was the 66 hours between two forced outages, and the third was after a forced outage that completed the day before Thanksgiving and, due to low holiday loads, the unit was delayed coming back on until the next week.
[232] TR. 265-66 (Kaufman).
[233] PAC/800, Wilding/39.
[234] PAC/400, Wilding/32; s*ee also* Staff/501, Kaufman/3-4 (describing all the non-economic factors considered by PacifiCorp).
[235] PAC/800, Wilding/40; Staff/501, Kaufman/3-4; TR. 119 (Wilding).
[236] TR. 259-60 (Kaufman) (referring to Staff/501, Kaufman/4.
[237] TR. 259-60 (Kaufman).

Moreover, in Staff's scenarios, GRID replaced the idled coal plant output primarily with market transactions.[238] In reality, PacifiCorp would not shutdown coal plants to replace the output with market transactions—as evidenced by the economic shutdowns in 2016 and 2017, where natural gas and hydro resources displaced coal.[239]

Staff's shutdown scenarios also present reliability issues, which Staff did not consider.[240] Staff's shutdowns would have two Jim Bridger units offline at the same time, even though, for reliability purposes, PacifiCorp would not typically take two Jim Bridger units offline at the same time.[241] Staff claims that in an emergency, an economically shutdown unit could immediately return to service to minimize adverse reliability impacts.[242] But Staff correctly testified before that it can take 10 hours for a coal unit to start-up—meaning that in a reliability emergency, a shutdown unit would be of little use.[243]

Staff claims that its shutdowns would not pose a reliability issue because GRID models sufficient reserves.[244] In GRID, market transactions can be used to follow load because GRID does not experience intra-hour variability, but in actual operations, PacifiCorp must hold load-following reserves on a flexible resource. In GRID, market transactions provide similar flexibility to the system as coal units; this is not the case in actual operations.[245]

Staff's proposed Cholla shutdown also fails to account for PacifiCorp's contractual obligations with APS, which are typically served by the Cholla plant during the time period

[238] PAC/400, Wilding/30-31.
[239] PAC/400, Wilding/30.
[240] PAC/800, Wilding/40.
[241] PAC/400, Wilding/32; PAC/800, Wilding/45-46.
[242] Staff/500, Kaufman/44.
[243] PAC/800, Wilding/45-46.
[244] Staff/500, Kaufman/44.
[245] PAC/800, Wilding/41-42.

when Staff has modeled a shutdown.[246] If the company were to use a different resource to meet its contractual obligations, it would incur additional costs not considered by Staff.[247]

3. Staff's proposal is unlike PacifiCorp's gas screening process.

Staff likens its proposal to model economic shutdowns of coal plants to the company's natural gas plant screening process.[248] But Staff's comparison of the gas plant screening process is inapt because that process prevents GRID from dispatching gas units even when they are not the least-cost resource.[249] Thus, gas plant screening conforms GRID to actual operations.[250] Moreover, unlike natural gas plants, coal plants are subject to a supply curve.[251] Coal volumes are determined by GRID based on the economic dispatch of the coal plant between its minimum and maximum outputs. Coal plants cannot be screened like natural gas plants because the coal supply curve must be considered, including minimum take requirements.[252]

E. PacifiCorp's forecasted coal costs for the Cholla plant are reasonable.

1. PacifiCorp reasonably intends to reduce the Cholla plant stockpile in 2018 to target inventory levels.

PacifiCorp's coal stockpile at the Cholla plant grew in 2016 due to market conditions that significantly reduced Cholla's generation.[253] By increasing the stockpile levels in 2016, PacifiCorp prudently avoided higher liquidated damages in effect at that time.[254] PacifiCorp is now drawing down the stockpile to target levels at a lower liquidated damage rate.[255] To reduce the stockpile, PacifiCorp plans to purchase less coal than will be consumed in

[246] PAC/800, Wilding/44-45.
[247] PAC/800, Wilding/44-45; TR. 126-27 (Wilding).
[248] Staff/500, Kaufman/44-45.
[249] TR. 112 (Wilding).
[250] PAC/800, Wilding/46-47.
[251] PAC/800, Wilding/46.
[252] PAC/800, Wilding/46-47.
[253] PAC/1000, Ralston/5-6.
[254] PAC/1000, Ralston/3.
[255] PAC/1000, Ralston/3.

2018.[256] PacifiCorp's forecasted liquidated damages are calculated based on the coal that will be purchased, rather than consumed, under the terms of the coal supply agreement.[257] PacifiCorp's management of the plant stockpile is consistent with its coal inventory studies, and its forecasted coal purchases for 2018 are prudent.[258]

2. Staff's proposal to increase purchased coal would maintain an unreasonably high stockpile.

Staff recommends that PacifiCorp maintain the current stockpile level, even though it is nearly [redacted] higher than the maximum target level,[259] and purchase all the coal that will be consumed in 2018. Staff's adjustment unreasonably ignores the costs and risks associated with maintaining the current inventory levels. First, because the current inventory is above the level used to set rates in Oregon, PacifiCorp is incurring carrying costs associated with the excessive inventory.[260] Second, when the stockpile is effectively maxed out, it reduces the company's operational flexibility to respond to changing and unexpected market conditions.[261] Third, the Cholla plant is forecast to retire at the end of 2020 under PacifiCorp's 2017 Integrated Resource Plan, so if the stockpile is not drawn down in 2018, there is a risk that higher cost liquidated damages will be pushed into future years.[262]

Staff argues that maintaining the stockpile level in 2018 is consistent with historical average inventory levels.[263] But Staff makes the wrong comparison—the relevant metric is year-end inventory levels because the year-end level dictates the next year's coal purchases.

256 PAC/600, Ralston/7.
257 PAC/600, Ralston/7.
258 PAC/600, Ralston/8-9; PAC/1000, Ralston/3, 8-10.
259 Staff/500, Kaufman/48; PAC/600, Ralston/7; PAC/1000, Ralston/3.
260 PAC/1000, Ralston/7.
261 PAC/1000, Ralston/8.
262 PAC/1000, Ralston/8.
263 Staff/500, Kaufman/48-49.

The expected December 2017 inventory level is 18 percent higher than December 2013, 59 percent higher than December 2014, and 135 percent higher than December 2015.[264]

3. Staff's adjustment ignores the effective delivery limitations in PacifiCorp's coal supply agreement.

Staff's adjustment assumes that PacifiCorp can purchase more than [redacted] of coal in 2018.[265] This adjustment ignores the fact that [redacted].[266] Because PacifiCorp is [redacted], it could not reduce its liquidated damages to the level assumed in Staff's adjustment.

4. The costs associated with reducing current inventory levels are properly attributable to 2018.

Staff argues that the current inventory levels are the result of operational decisions in 2016, and therefore the costs of reducing those inventory levels should not be recovered in 2018.[267] This argument is contrary to established ratemaking principles. First, liquidated damages will be incurred in 2018 due to operational decisions made in 2018, not 2016.[268] While the stockpile grew above target levels in 2016, the decision to reduce the stockpile will be implemented in 2018.

Second, Staff's argument assumes that when rates were set for 2016 in the summer of 2015, parties should have anticipated the possibility of liquidated damages in 2018 and increased the 2016 coal costs accordingly.[269] Such speculation would be entirely unreasonable. Therefore, Staff's position would effectively preclude the recovery of

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[264] PAC/1000, Ralston/7.
[265] PAC/600, Ralston/9.
[266] PAC/600, Ralston/9; PAC/1000, Ralston/10.
[267] Staff/500, Kaufman/48.
[268] PAC/1000, Ralston/4.
[269] PAC/1000, Ralston/4.

liquidated damages even when they are prudently incurred because liquidated damages could always be attributable to a prior year.[270]

Third, Staff has previously supported, and the Commission has previously approved, coal price reductions resulting from decisions in prior periods. For example, in docket UE 207, PacifiCorp calculated coal costs that included lower-priced carryover tons from an earlier coal supply agreement.[271] Staff supported this approach in docket UE 207.[272] But Staff's rationale here would preclude customers from receiving the benefit of carryover tons because the operational decisions that created the benefit occurred in a prior period.[273] In addition, in 2008, the Commission approved a stipulation in a PGE case that specifically precluded future removal of coal inventory accruals from PGE's PCAM on the basis that they relate to a prior period.[274]

Third, in testimony filed in the 2017 TAM, which was filed in the summer of 2016, Staff explicitly argued that PacifiCorp should use its stockpiles to minimize liquidated damages.[275] Now, Staff claims that PacifiCorp should be precluded from recovering the costs resulting from operational decisions Staff supported.

F. PacifiCorp recommends a workshop to address the process used to evaluate new coal supply agreements and the inclusion of variable O&M in NPC dispatch.

PacifiCorp provided expert testimony from Seth Schwartz, the President of Energy Ventures Analysis, Inc., that the company must rely on multi-year coal supply agreements to

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[270] PAC/1000, Ralston/4.
[271] PAC/1000, Ralston/4-5.
[272] PAC/1000, Ralston/4-5.
[273] PAC/1000, Ralston/4-5.
[274] *In the Matter of Portland General Electric Company Application for Annual Adjustment to Schedule 126 under the Terms of the Annual Power Cost Variance Mechanism*, Docket No. UE 201, Order No. 08-553, Appendix A at 2 (Nov. 24, 2008).
[275] PAC/1000, Ralston/6.

have reliable and economic coal supplies to operate its plants.[276] The alternative to multi-year contracts—short-term or spot coal purchases—are frequently unavailable or not economic because of the costs associated with mining coal in the illiquid markets that serve PacifiCorp's plants.[277] Moreover, PacifiCorp coal suppliers have few customers and therefore the company must commit to substantial minimum purchase levels to support the economic operations of the coal supplier and to keep the pricing low.[278] Without a minimum-take requirement, the company would not have the same volume flexibility it has without paying higher prices.[279] PacifiCorp also could not contract for lower volume commitments and still expect to have coal available to operate its plants if it wanted to increase plant operations.[280] Mr. Schwartz concluded that PacifiCorp's general approach to negotiating multi-year coal supply agreements is prudent, reasonable, and consistent with industry standards.[281]

Both Sierra Club and Staff argue that PacifiCorp has not provided sufficient explanation for the process used to evaluate new coal supply agreements.[282] In response, PacifiCorp proposes that the parties convene a post-TAM workshop to more fully address this issue, similar to the process used before this case.[283] Sierra Club and PacifiCorp have agreed to a preliminary issues list for the proposed workshop, and Sierra Club agrees that this addresses its issues in this case.[284] Due to the complexities of the issues surrounding coal

[276] PAC/700, Schwartz/4.
[277] PAC/700, Schwartz/8.
[278] PAC/700, Schwartz/8-9.
[279] PAC/700, Schwartz/9-10.
[280] PAC/700, Schwartz/8-10.
[281] PAC/700, Schwartz/12.
[282] Sierra Club/100, Vitolo/18; Staff/400, Gibbens/23.
[283] PAC/1000, Ralston/12.
[284] PAC/1112.

supply agreements, the proposed workshop is a more effective way of addressing the parties' concerns than the written report proposed by Staff.[285]

Staff and Sierra Club also request that PacifiCorp model variable O&M costs in the TAM. PacifiCorp does not object to this proposal, provided that the variable O&M costs are also included in the TAM forecast and removed from base rates.[286] This modeling change will be complex, however, so PacifiCorp and Sierra Club have also included the issue in the scope of the proposed workshop.

G. PacifiCorp's proposed contract delay rate for new QFs is reasonable.

Based on an all-party stipulation in the 2015 TAM, PacifiCorp has included new QF contracts in the TAM if the company can attest that it reasonably expects the QF to reach commercial operation during the test period.[287] Staff and CUB criticize the attestation methodology, and recommend that PacifiCorp implement a CDR that would assume a new QF's commercial online date (COD) will be delayed based on the average QF COD delay over the last three years.[288]

To respond to CUB's and Staff's concerns, and to narrow the issues in dispute in this case, PacifiCorp agrees to implement a CDR.[289] PacifiCorp's proposed CDR would use the same three-year rolling average as CUB's and Staff's proposals, but would also weight the

[285] PAC/1000, Ralston/12.
[286] PAC/800, Wilding/47.
[287] *In the Matter of PacifiCorp d/b/a Pacific Power 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 at 5 (Oct. 1, 2014).
[288] CUB/100, Jenks/10.
[289] At hearing, CUB focused its cross-examination on the attestation method, implying that PacifiCorp failed to properly update its QF CODs prior to its 2017 TAM attestation. Because the merits of the attestation methodology are no longer in dispute, the cross-examination was irrelevant. TR. 136-37 (Wilding). Nevertheless, PacifiCorp explained that additional communications, other than the emails included in the record here, occurred and those additional communications informed the company's 2017 TAM attestation. TR. 77-78 (Wilding). The email exchanges explicitly acknowledge additional communications. Several emails refer to phone calls between PacifiCorp and the developers. *See, e.g.*, CUB/305 at 28. Several of the emails CUB pointed to as evidence that QFs were changing their CODs are inconsistent with later emails reflecting CODs aligned with PacifiCorp's attestation. *See* CUB/305 at 28

CDR based on the nameplate capacity of each QF, an approach supported by Staff.[290] By weighting the CDR, PacifiCorp's proposal recognizes that not every QF delay has the same impact.[291]

PacifiCorp also recommends the CDR be counted based on the number of days in the TAM year, so that a delay that does not affect rates is not considered when setting rates.[292] If the proposed COD is before the TAM year, however, then the delay rate will be applied beginning on January 1 of the TAM year.[293] For example, if a QF has a proposed COD of November 15, 2017, and comes online on January 15, 2018, the delay would be calculated as 15 days, not 61 days. But the 15-day delay would start at the beginning of the TAM year, so the QF would have a modeled COD of January 15, which corresponds to its actual COD.

H. The Commission should affirm PacifiCorp's proposed REC credit and consumer opt-out charge.

1. PacifiCorp's proposed REC credit conforms to the Commission's direction on valuation.

PacifiCorp has proposed a REC credit in the transition adjustment that calculates the benefits to remaining customers based on the future delay in PacifiCorp's Renewable Portfolio Standard (RPS) compliance obligation due to freed-up RECs.[294] This is the benefit the Commission identified in Order No. 16-482, where it concluded that, "[i]n the near term, we see little or no benefit from a reduction in RPS obligations due to the loss of load from direct access."[295] RECs that are freed-up by direct access "may" benefit "other customers by altering the point in time when PacifiCorp would need to take resource actions to comply

[290] PAC/800, Wilding/48; Staff/600, Anderson/11.
[291] PAC/800, Wilding/49.
[292] PAC/800, Wilding/48.
[293] PAC/800, Wilding/48.
[294] PAC/400, Wilding/51-52.
[295] Order No. 16-482 at 22.

with the RPS."[296] The Commission then noted that PacifiCorp does not need to take additional action to comply with its RPS obligation until the mid-2020s, and, therefore, the REC credit should be based on the "estimated benefits from that time period . . . discounted to today's dollars."[297] Providing a REC credit based on the Company's methodology ensures that remaining customers are unharmed—the credit paid to direct access customers matches the benefit received by remaining customers.

Calpine recommends a REC credit based on *current* REC values.[298] But, if a freed-up REC provides no current benefit to remaining customers, as the Commission found, then calculating the credit based on current REC prices results in impermissible cost-shifting.[299]

In the alternative, Calpine recommends that PacifiCorp transfer the freed-up REC to the Energy Service Supplier.[300] Transferring RECs, in lieu of a REC credit, may be a workable solution, but it will require the Commission and parties to develop an appropriate framework for the transfer.[301] Thus, PacifiCorp recommends that the Commission approve its proposed REC credit here and initiate workshops or another process to develop a framework to allow REC transfers in the future. Staff supports this approach.[302]

2. The evidence in this case confirms the reasonableness of the consumer opt-out charge.

In docket UE 267, the Commission found that PacifiCorp will experience transition costs for 10 years and approved the consumer opt-out charge to recover the company's fixed

[296] Order No. 16-482 at 22.
[297] Order No. 16-482 at 22.
[298] Calpine Solutions/100, Higgins/22-23.
[299] PAC/400, Wilding/52.
[300] Calpine Solutions/100, Higgins/22-23.
[301] PAC/800, Wilding/53.
[302] Staff/600, Anderson/8.

generation costs in years six through 10.[303] Consistent with the methodology approved in docket UE 267, the consumer opt-out charge here uses an inflation adjustment to forecast the fixed generation costs in years six through 10.[304] The Commission affirmed this methodology in the 2016 and 2017 TAMs.[305]

Calpine continues to argue that the fixed generation costs included in the consumer opt-out charge should decrease, rather than remain constant in real terms.[306] The only additional evidence in this case confirms that PacifiCorp's fixed generation costs do increase and that the consumer opt-out charge appropriately holds those costs constant in real terms.

PacifiCorp provided a historical time series of its fixed generation costs to confirm the reasonableness of the consumer opt-out charge.[307] PacifiCorp's data demonstrates that in the 10 years from 2006 and 2015, its fixed generation costs increased from $14.70 per MWh to $29.49 per MWh.[308] Moreover, the fixed generation costs increased by 40 percent from 2007 to 2015, 14 percent from 2008 to 2015, and 17 percent from 2009 to 2015.[309] By comparison, the consumer opt-out charge conservatively increases the fixed generation costs at the rate of inflation, which has been 2.5 percent in recent years.[310]

Calpine claims that when incremental generation investment is removed from the fixed generation costs, they decrease over time.[311] PacifiCorp disagrees that the consumer

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[303] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 6-7 (Feb. 24, 2016).
[304] PAC/400, Dickman/93.
[305] Order No. 15-060 at 6-7; *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-195 (June 16, 2015); Order No. 15-394 at 12; Order No. 16-482 at 23.
[306] Calpine Solutions/100, Higgins/32.
[307] Order No. 16-482 at 23; PAC/110.
[308] PAC/110.
[309] PAC/110.
[310] Calpine Solutions/100, Higgins/34.
[311] *See, e.g.*, Calpine Solutions/100, Higgins/35.

opt-out charge cannot account for incremental generation investments after year five.[312] But even if major capital additions are removed, Calpine's analysis shows that fixed generation costs still increase—by 64 percent from 2006 to 2015, 19 percent from 2007 to 2015, 2 percent from 2008 to 2015, and 16 percent 2009 to 2015.[313]

Moreover, Calpine's analysis confirms the reasonableness of the inflation escalator used to calculate the consumer opt-out charge. Without major capital additions, PacifiCorp's fixed generation costs increased by 5.65 percent per year from 2006 and 2015, 2.25 percent per year from 2007 and 2015, and 2.45 percent per year from 2009 to 2015.[314] Calpine assumes that these fixed generation costs should *decrease* by 2.36 percent per year.[315]

Calpine claims that from 2008 to 2015, the fixed generation costs decreased when all capital additions, even those less than $1 million are removed.[316] But PacifiCorp has never claimed that the consumer opt-out charge does not account for capital investments in existing plants in years six through 10. In Order No. 15-394, the Commission noted that PacifiCorp "explain[ed] that incremental generation is not added after year five"—meaning new generation plant, not investments in existing plants.[317] Moreover, in Order No. 16-482, the Commission explained that "there are many costs to operate and maintain existing generating assets that increase over time and offset the impact of accumulated depreciation, such as

[312] PAC/400, Wilding/58; PAC/800, Wilding/53-54.
[313] Calpine Solutions/105.
[314] Calpine Solutions/105. The compound annual growth rate was calculated by dividing the 2015 value by the earlier value and then raising that ratio to the power of 1 divided by the number of years and then subtracting one. Calpine argues that 2006 should be excluded because the data is two years removed from 2007 and is therefore not comparable to the other figures in the time series. Calpine Solutions/100, Higgins/35. To account for the vintage of the 2006 data by adding an additional year, the annual growth rate decreases to 5.07 percent—still more than twice the inflation adjustment used by PacifiCorp.
[315] Calpine Solutions/100, Higgins/32.
[316] Calpine Solutions/100, Higgins/35; Calpine Solutions/105.
[317] Order No. 15-394 at 12.

overhauls, *capital expenditures for maintenance*, and union labor contracts."[318] Thus, Calpine's analysis does not refute the Commission's previous findings that the consumer opt-out charge reasonably accounts for fixed generation costs in years six through 10.

III. CONCLUSION

PacifiCorp respectfully requests that the Commission approve the company's proposed 2018 TAM increase of approximately $7.9 million, or 0.6 percent. PacifiCorp's filing is fully aligned with the Commission's last two TAM orders. The only modeling changes reflect compromises by PacifiCorp to constructively address parties' issues, and these changes reduce NPC. Parties largely relitigate issues that the Commission comprehensively resolved in the last two TAMs, and no party presents compelling evidence supporting reconsideration of the Commission's previous decisions.

Consistent with the approach that worked well after the 2017 TAM, PacifiCorp again proposes workshops to allow collaboration among the parties on a number of issues raised in this case, including: (1) GRID model validation; (2) coal plant modeling and analysis of coal supply agreements; and (3) REC transfers related to direct access customers and RPS

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[318] Order No. 16-482 at 23 (emphasis added).

compliance obligations. All parties agreed that the pre-filing workshops in this case were useful, and PacifiCorp believes that continuing the collaborative process will streamline resolution of future TAM filings.

Respectfully submitted this 14th day of September, 2017.

Katherine A. McDowell
Adam Lowney
McDowell Rackner Gibson PC

Matthew McVee
Chief Regulatory Counsel
PacifiCorp d/b/a/ Pacific Power

Attorneys for PacifiCorp

CERTIFICATE OF SERVICE

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

Service List
UE 323

CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC PO BOX 7218 BOISE, ID 83702 greg@richardsonadams.com	GREG BASS CALPINE ENERGY SOLUTIONS, LLC 401 WEST A ST, STE 500 SAN DIEGO, CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY, UT 84111-2322 khiggins@energystrat.com	
ICNU UE 323	
JESSE E COWELL **(C)** DAVISON VAN CLEVE 333 SW TAYLOR ST., SUITE 400 PORTLAND, OR 97204 jec@dvclaw.com	BRADLEY MULLINS **(C)** MOUNTAIN WEST ANALYTICS 333 SW TAYLOR STE 400 PORTLAND, OR 97204 brmullins@mwanalytics.com
OREGON CITIZENS' UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	
PACIFICORP UE 323	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	KATHERINE A MCDOWELL **(C)** MCDOWELL RACKNER & GIBSON PC 419 SW 11TH AVE., SUITE 400 PORTLAND, OR 97205 katherine@mcd-law.com

MATTHEW MCVEE **(C)** PACIFICORP 825 NE MULTNOMAH PORTLAND, OR 97232 matthew.mcvee@pacificorp.com	
SIERRA CLUB	
TRAVIS RITCHIE **(C)** SIERRA CLUB ENVIRONMENTAL LAW PROGRAM 2101 WEBSTER STREET, SUITE 1300 OAKLAND, CA 94612 travis.ritchie@sierraclub.org	JOSHUA SMITH SIERRA CLUB 2101 WEBSTER STE STE 1300 OAKLAND, CA 94612 joshua.smith@sierraclub.org
ALEXA ZIMBALIST **(C)** SIERRA CLUB 2101 WEBSTER ST STE 1300 OAKLAND, CA 94612 alexa.zimbalist@sierraclub.org	
STAFF UE 323	
GEORGE COMPTON **(C)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM, OR 97308-1088 george.compton@state.or.us	SCOTT GIBBENS **(C)** PUBLIC UTILITY COMMISSION 201 HIGH ST SE SALEM, OR 97301 scott.gibbens@state.or.us
SOMMER MOSER **(C)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 sommer.moser@doj.state.or.us	

Dated this 14th day of September 2017.

Wendy McIndoo

Wendy McIndoo
Office Manager
McDowell Rackner Gibson, PC