MCDOWELL RACKNER GIBSON PC

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

September 14, 2016

VIA ELECTRONIC FILING

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

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

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic copy of PacifiCorp's Redacted Opening Brief. The confidential pages will follow via Federal Express to qualified persons.

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 2017 Transition Adjustment Mechanism	**UE 307**

PACIFICORP'S OPENING BRIEF

REDACTED

September 14, 2016

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

CASES

PUBLIC UTILITY COMMISSIO OF OREGON ORDERS

Oregon Revised Statutes

Oregon Administrative Rules

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) respectfully submits this opening brief to the Public Utility Commission of Oregon (Commission), in support of the Company's proposed 2017 Transition Adjustment Mechanism (TAM) increase of approximately $16.2 million, or 1.3 percent overall.[1] The increase reflects decreased wholesale sales revenue, increased coal fuel expense, and a modest increase in purchased power expense (related primarily to new Qualifying Facility (QF) contracts),[2] offset by reductions in natural gas fuel and wheeling expenses.[3]

The Company's modeling in the 2017 TAM reflects the methodologies and adjustments the Commission approved in Order No. 15-394 in the 2016 TAM, including the system balancing transactions adjustment and the Company's approach to calculating the benefits of participating in the Energy Imbalance Market (EIM).[4] The Commission approved these items to create a "more accurate estimate of net power costs."[5] The evidence through June 2016 confirms the efficacy of Order No. 15-394—for the first six months of 2016, the Company's forecast and actual net power costs (NPC) have been within one percent, resulting in the most accurate NPC forecast since at least 2008.[6]

Despite the relatively modest 2017 TAM increase and the similarity of the 2016 and 2017 TAM filings, parties have vigorously contested this filing, proposing adjustments totaling over $42 million.[7] The largest adjustment in this case is Staff's Jim Bridger plant

---

[1] PAC/400, Dickman/7. Unless otherwise stated, all values are stated on an Oregon-allocated basis.
[2] PAC/100, Dickman/9-10.
[3] PAC/100, Dickman/9.
[4] PAC/100, Dickman/4, 6-7.
[5] *In the Matter of PacifiCorp d/b/a Pacific Power's 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec. 11, 2015).
[6] PAC/400, Dickman/6; PAC/800, Dickman/7.
[7] PAC/801 (surrebuttal exhibit listing Staff and intervenor adjustments).

coal supply adjustment, which reduces NPC by nearly $25 million. As most recently reframed in its rebuttal testimony, Staff argues that, in 2013, the Company unreasonably failed to begin an irrevocable, expedited switch to obtaining its coal supply from the Powder River Basin (PRB). Staff's adjustment ignores the large associated costs and risks of such a decision and the fact that in 2013, the Commission approved the Company's current coal supply strategy as fair, just and reasonable.[8]

The remaining adjustments are a mix of recommendations that the Commission rejected last year and proposals for new modeling changes, even though Order No. 15-394 imposed a moratorium on modeling changes in this case:[9]

- Staff, the Citizens' Utility Board of Oregon (CUB), and the Industrial Customers of Northwest Utilities (ICNU) again challenge the system balancing transactions adjustment, based largely on the same arguments as last year.
- Staff and CUB propose new methodologies for modeling EIM benefits, without considering the overall effect of their recommendations.
- Staff and CUB recommend an adjustment to the modeling of coal plant dispatch that the Company has used, without objection, since 2005.
- Staff and CUB recommend new methodologies for modeling QF contracts, although neither actually quantifies their adjustment or addresses why the TAM Guideline that already addresses this issue is insufficient.
- Staff adopts an adjustment proposed last year by ICNU and rejected by the Commission related to avian curtailment of the Company's wind generation.
- Staff initially proposed an adjustment to the modeling of forced outages approved in the 2016 TAM.[10] Staff did not pursue this adjustment after the Company's reply testimony made clear that it would increase NPC.[11]
- In response to the Company's initial proposal under Section 18(b) of Senate Bill (SB) 1547 to track production tax credit (PTC) variances, Staff proposed an

[8] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 6-7 (October 28, 2013).
[9] Order No. 15-394 at 2. ICNU proposed a one-year extension of this moratorium, to which the Company objects. PAC/400, Dickman/17.
[10] Staff/200, Kaufman/15.
[11] Executive Session Transcript (ES TR.) 59 (Kaufman).

alternative approach.[12] Under Staff's approach, PTCs are reset to zero in base rates and the full PTC forecast is included in the TAM, subject to true-up in the Power Cost Adjustment Mechanism. The Company agreed to this approach in its reply testimony.[13]

- Noble Americas Energy Solutions LLC (Noble Solutions) proposes direct access adjustments that are identical to those rejected in the 2016 TAM and rely on substantively identical evidence and arguments.

Taken together, the parties' adjustments would produce a TAM forecast for 2017 of $333 million—a result that is facially unreasonable given that NPC has not been that low since 2011.[14] This result is even more unreasonable in light of the Company's persistent under-recovery of NPC since at least 2008.[15]

II. ARGUMENT

A. The costs of the Company's fuel supply to the Jim Bridger plant in 2017 are reasonable.

1. Background

In 1974, the Bridger Coal Company (BCC) began providing "mine mouth" coal supply to the Jim Bridger plant, which was constructed to take advantage of the location of BCC coal reserves.[16] As Staff testified in docket UE 264, BCC is a "captive coal mine," which "refers to a coal mine that satisfies the needs of a mine owner rather than for open market sale."[17] BCC coal is delivered to the Jim Bridger plant by conveyor belt, which reduces operational supply and price risk associated with rail transportation.[18] BCC has

---

[12] Staff/100, Crider/20.
[13] PAC/600, Dalley/22-23.
[14] PAC/800, Dickman/5.
[15] PAC/400, Dickman/6.
[16] PAC/500, Ralston/7-8. PacifiCorp (through its wholly owned subsidiary Pacific Minerals, Inc.) owns a two-thirds interest in BCC, and Idaho Power Company (through its wholly owned subsidiary Idaho Energy Resources Co.) owns a one-third interest. PacifiCorp and Idaho Power Company have the same ownership percentages in the Jim Bridger plant. *Id.* at 7.
[17] PAC/1209 at 8 n.1.
[18] PAC/500, Ralston/8.

never operated as an independent mine selling coal to the market, and it has no rail load-out facilities to enable such sales.[19]

Shortly after BCC began supplying coal to the Jim Bridger plant, the Commission recognized that PacifiCorp "treats Bridger Coal as an integral part of its own utility operation and never intended that Bridger Coal stand independent of the company."[20] The Commission adopted a "general policy" of consolidating PacifiCorp and its affiliate mines for reporting and regulatory purposes.[21] BCC's records and accounts are subject to regulatory review in rate cases, its operations are summarized in PacifiCorp's results of operations, and its results are consolidated with PacifiCorp's for income tax and state ratemaking purposes.[22]

Since the 1970s, the Company has included its share of BCC in rate base and its share of mining costs—including depreciation, depletion, and reclamation costs—in NPC. While PacifiCorp has a coal supply agreement with BCC, approved as reasonable in Order No. 01-472, the contract price is not used in setting the Company's rates.[23] Rather, the Commission approved a cost-based approach, allowing recovery of BCC's actual, prudent costs of production, plus a return on the mine at PacifiCorp's authorized rate of return (ROR).[24]

---

[19] PAC/500, Ralston/26-27; PAC/1000, Ralston/23.

[20] *In the Matter of Pacific Power & Light Company*, Docket No. UF 3508, Order No. 79-754 at 18 (Oct. 29, 1979).

[21] *In the Matter of Pacific Power and Light Co.*, Docket No. UE 21, Order No. 84-898 (Nov. 14, 1984). The rationale is that "no asset used in providing utility service may earn a rate of return greater than that authorized for Pacific, whether owned by the company or its affiliate." *In the Matter of Pacific Power and Light Co.*, Docket No. UF 3779, Order No. 82-606 (Aug. 18, 1982).

[22] PAC/600, Dalley/7-8. The Commission has approved ratemaking adjustments to the costs of coal supplied by BCC. *See* Order No. 13-387 (reducing PacifiCorp's net power costs by $0.5 million of labor adjustments for management overtime and bonuses). This same adjustment is reflected in BCC's fuel costs in this case.

[23] *In the Matter of PacifiCorp*, Docket No. UI 189, Order No. 01-472 at 2 (June 12, 2001); PAC/600, Dalley/18.

[24] *See, e.g.,* Order No. 79-754 (noting that "staff's ideal coal price would be one permitting Bridger Coal to recover expenses and earn a fair and reasonable rate of return," and reducing transfer price of BCC coal accordingly); Order No. 82-606 (same).

Under this approach, if BCC earns a margin over PacifiCorp's ROR, it must credit the margin back to customers through a reduced transfer price.[25]

PacifiCorp uses a diversified fuel supply strategy for the Jim Bridger plant, which it regularly reviews and refines.[26] At least once a year, the Company develops a BCC mine plan using a 10-year planning horizon to develop a strategy for least-cost, least-risk fueling of the Jim Bridger plant.[27] The Company also develops more comprehensive fueling plans based on the life-of-plant approximately every two years, for use in the Company's integrated resource plan (IRP).[28]

The only readily available market source of fuel supply to the Jim Bridger plant is the Black Butte mine, located 20 miles from the Jim Bridger plant.[29] For many years, PacifiCorp has acquired roughly two-thirds of Jim Bridger plant's fuel from BCC and one-third from the Black Butte mine.[30] BCC has provided significant price leverage on coal supplied from the Black Butte mine, and coal from the two mines has generally been priced comparably.[31] In the last seven TAMs, Black Butte mine costs have increased at a similar rate as BCC's, and have at times exceeded BCC's unit costs.[32]

The current Black Butte contract resulted from a competitive bidding process in 2014.[33] The coal request for proposals (RFP) was issued to all potential market suppliers to the Jim Bridger plant, including mines in southwest Wyoming and the PRB, and Black Butte proved the most economic. The contract was executed at the end of 2014 and has a three-

---

[25] PAC/600, Dalley/5.
[26] PAC/1000, Ralston/2-4, 8-9. In 2017, market supplies will account for approximately 85.1 percent of total fuel supply and affiliate mines will account for approximately 14.9 percent. PAC/200, Ralston/2.
[27] PAC/1000, Ralston/8.
[28] PAC/1000, Ralston/8.
[29] Staff/215, Kaufman/6.
[30] Staff/215, Kaufman/5.
[31] PAC/500, Ralston/8; PAC/600, Dalley/11-16.
[32] PAC/600, Dalley/11-16.
[33] PAC/1000, Ralston/3.

year term (2015-2017). The 2016 TAM included coal priced using the current contract, and no party objected to the prudence of the contract or the reasonableness of the coal costs.[34]

While the Company has relied on coal from BCC and Black Butte for the Jim Bridger plant, it has also regularly considered how to secure an alternative source of supply from the PRB, which is the next logical supplier.[35] But the transportation costs and risks associated with delivery from PRB mines that are 400 to 600 miles away from the plant, combined with major retrofits the plant needs to receive and burn PRB coal, have rendered PRB coal an uneconomic and infeasible option in the past:[36]

- In 2003, before developing the BCC underground mine, the Company assessed the alternative of supplying the Jim Bridger plant with coal from the PRB, Uinta Basin (Utah and Colorado), and the Hannah Basin (Wyoming). The underground mine proved to be the least-cost, least-risk option, and the Commission approved a stipulation allow recovery of the capital costs in 2005.[37]

- In 2009, Staff prepared an audit report concluding that BCC's unit costs were comparable to regional coal market prices and the coal costs for the Company's only other plant supplied by coal from southwest Wyoming.[38] Staff's report also indicated that the "next logical supply of coal for Bridger" was PRB coal, but that transportation costs "could possibly make this option economically infeasible."[39] Staff further noted that "soaring demand" was expected to cause PRB prices to "spike."[40] As a result, Staff determined that "having captive mines may result in an increasing benefit to PacifiCorp's customers."[41]

- In the 2010 TAM, the Company testified that it periodically evaluated PRB coal as an alternative to BCC, but that the cost of PRB coal, including transportation, was more than $[redacted] per ton higher than BCC coal.[42] The Company also explained that the Jim Bridger plant "lacks the physical capacity to accept significant new volumes of rail delivered coal."[43] Therefore, using PRB coal would require

[34] *In the Matter of PacifiCorp*, Dockets Nos. UM 995, UE 121, & UC 578, Order No. 02-469 at 7 (July 18, 2002) (if neither the parties nor the Commission challenge a particular item, "then the item is adopted when the Commission issues its final order, even if not specifically addressed in the order.").
[35] PAC/601, Dalley/8.
[36] PAC/500, Ralston/3, 10, 12; Staff/215, Kaufman/8-9.
[37] PAC/1000, Ralston/9-10.
[38] PAC/601, Dalley/5, 7.
[39] PAC/601, Dalley/8.
[40] PAC/601, Dalley/5.
[41] PAC/601, Dalley/6.
[42] PAC/600, Dalley/11.
[43] PAC/600, Dalley/11 (quoting Docket No. UE 207, PAC/400, Morgan/14).

"significant new infrastructure investments to its receiving facilities," which were not justified based on BCC coal prices at that time.[44]

- In the 2011 TAM, PacifiCorp provided evidence that PRB coal was $[redacted] per ton higher than BCC, without considering the costs of capital modifications.[45]
- In the 2012 TAM, PacifiCorp affirmed that PRB coal remained higher cost than BCC and was therefore not a least-cost option for the Jim Bridger plant.[46]
- In 2013, the Company retained Black and Veatch to "estimate the maximum achievable load [of PRB coal] while incorporating the minimum capital modifications necessary to safely fire PRB coal and coal blends in the Jim Bridger units."[47] Black and Veatch estimated that the "minimum capital modifications necessary" would cost $[redacted] (PacifiCorp share).[48]
- As explained above, in 2014, the Company issued an RFP for coal to serve the Jim Bridger plant and sent the RFP to PRB suppliers.[49] The RFP resulted in the execution of the current Black Butte contract, which proved lower cost than available alternatives from the PRB. The Company executed a new rail agreement for shipment of both Black Butte coal and the volume of PRB coal the Jim Bridger plant could use without retrofits or potential operational concerns.[50]
- In April 2015, the Company issued an RFP to PRB suppliers related to the Dave Johnston plant. Based on that RFP, the Company concluded that PRB remained an uneconomic coal supply at that time for the Jim Bridger plant.[51]

In July 2014, the Company completed a new long-term fuel plan for its 2015 IRP that reflected the closure of the BCC underground mine in 2024 and the use of PRB coal as a long-term fuel supply source for the Jim Bridger plant.[52] In the first half of 2015, the Company conducted a test burn of PRB coal at the Jim Bridger plant and determined that the plant could burn PRB coal without deration.[53] Through its follow-up analysis, the Company was able to reduce the projected capital investment to receive and burn PRB coal to $[redacted]

---

[44] PAC/600, Dalley/11 (quoting Docket No. UE 207, PAC/400, Morgan/14).
[45] PAC/1208 at 5.
[46] PAC/600, Dalley/12-13.
[47] PAC/1000, Ralston/11; PAC/1002, Ralston/1.
[48] PAC/1002, Ralston/6.
[49] PAC/1000, Ralston/3.
[50] PAC/1000, Ralston/3.
[51] PAC/500, Ralston/21.
[52] PAC/1000, Ralston/3.
[53] ES TR. 17 (Ralston).

[redacted] (PacifiCorp share).[54] This led to the Long-Term Fuel Plan filed with the Commission in 2015, which includes the capital investments necessary at the Jim Bridger plant to switch to PRB coal by 2023.[55]

On an expedited basis, the permitting and construction of the new, PRB-related facilities at the Jim Bridger plant could be completed in four years, although it may take up to six years.[56] The Company's Long-Term Fuel Plan targets a transition to PRB coal in mid-2023 to permit orderly completion of these facilities and to allow the Company to wind down BCC's underground operation once its reserves are fully depleted in 2023.[57] PRB volumes will increase beginning in 2024 while the BCC surface mine provides the remainder of the coal supply. During the transition to PRB coal, the Jim Bridger plant will continue to rely on BCC coal while [redacted]. No party commented on the Company's Long-Term Fuel Plan or objected in any way to the strategy included in that plan. Seven months later, Staff filed testimony in this case, arguing that the Company's 2017 Jim Bridger fuel supply costs were imprudent because they were more expensive than coal from PRB.

2. Legal standards for prudence review of Jim Bridger fuel supply in 2017.

The Commission's prudence standard examines the "objective reasonableness of a decision at the time the decision was made."[58] As the Commission explained, "if the record demonstrates that a challenged business decision was objectively reasonable, taking into account established historical facts and circumstances, the utility's decision must be upheld

[54] PAC/1000, Ralston/29.
[55] Staff/215 (2015 Long-Term Fuel Plan).
[56] PAC/500, Ralston/16.
[57] PAC/500, Ralston/10.
[58] Order No. 02-469 at 4-5.

as prudent[.]"[59] Reasonableness does not require perfection, and the Commission's standard does not preclude the possibility that more than one decision could be reasonable.[60] Importantly, the analysis cannot rely on the benefit of hindsight.[61]

In Order No. 13-387, issued on October 28, 2013, the Commission reviewed and approved the Company's approach to Jim Bridger fuel supply in the 2014 TAM, docket UE 264. Specifically, the Commission found that the Company's "approach to coal supply for the Jim Bridger plant," which relied on BCC and Black Butte coal, was "fair, just and reasonable."[62] The Commission continued, "BCC and Black Butte mine prices have both fluctuated over the years, but viewed over the long term, have provided 'a reasonably priced, stable supply of coal for the Bridger plant.'"[63] The Commission observed that it "has historically approached the company's affiliate transactions with a cost-based approach, and that in the case of BCC coal, there is no possibility of utility-affiliate cross-subsidization."[64]

The Commission rejected ICNU's adjustment to BCC coal prices under the "lower of cost or market standard" and approved a "proposal, endorsed by Staff, CUB, and Pacific Power, for the company to prepare a periodic fuel supply plan that compares affiliate mine fuel supply to other alternative fuel supply options, including market alternatives, to facilitate implementing prudence and affiliate transaction standards in future rate proceedings."[65]

In a concurring opinion, Commissioner Savage explained that BCC costs "must be assessed over a period of years, and not yearly as proposed by ICNU, because of the nature

---

[59] *Id.*
[60] *In the Matter of Portland General Electric Co.*, Docket No. UE 196, Order No. 10-051 at 10 (Feb. 11, 2010).
[61] *In the Matter of PacifiCorp d/b/a Pacific Power Request for General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 25 (Dec. 20, 2012).
[62] Order No. 13-387 at 6.
[63] *Id.*
[64] *Id.*
[65] *Id.* at 7.

of the mining operation."[66] According to Commissioner Savage: "Single year costs may be inappropriately skewed for accounting reasons only and may not be a reasonable assessment of Bridger coal costs."[67]

3. The Company's fuel strategy for the Jim Bridger plant remains fair, just and reasonable in 2017.

In 2017, the Company projects the Jim Bridger plant will be fueled with 65 percent BCC coal, 30 percent Black Butte coal, and 5 percent PRB coal.[68] The fuel mix reflects the supply strategy approved as fair, just and reasonable in the 2014 TAM, with primary reliance on coal from both BCC and the Black Butte mine. The fuel mix also demonstrates the beginning of a transition to greater reliance on PRB coal, consistent with the direction set in the Company's Long-Term Fuel Plan.[69] While BCC unit costs in this case have increased relative to last year's TAM, the Company's diversified approach moderates the impact on total Jim Bridger fuel supply costs in 2017. The reply update fueling costs for the Jim Bridger plant are $[redacted] per ton, compared to $[redacted] per ton 2016 TAM.[70]

The underlying operating costs at BCC have not changed materially in the 2017 TAM.[71] Instead, the BCC unit cost increase is driven primarily by dramatic market changes that occurred in the first half of 2016.[72] Significantly lower natural gas and electricity prices reduced the forecast dispatch of the Jim Bridger plant in 2017.[73] This lower dispatch decreases the volume of BCC coal burned, which increases the unit cost of BCC coal as the

---

[66] *Id.* at 15.
[67] *Id.*
[68] PAC/500, Ralston/7, 26.
[69] PAC/500, Ralston/10-11.
[70] PAC/500, Ralston/26 (consisting of BCC costs of $[redacted] per ton and Black Butte costs of $[redacted] per ton).
[71] PAC/200, Ralston/16.
[72] PAC/200, Ralston/13-18.
[73] PAC/200, Ralston/13-18.

mine's fixed costs are distributed over fewer tons.[74] As market conditions returned to a more normal state in the reply update, forecast BCC unit costs decreased as the expected plant dispatch increased.[75] The Company's reply update reflects a BCC unit cost decrease of [redacted] percent (or $[redacted] per ton), relative to the initial filing.[76]

As recognized by the Commission in Order No. 13-387, the reasonableness of the Company's approach to Jim Bridger fuel supply should be reviewed on a multi-year basis.[77] Market conditions and mining operations will cause coal unit costs to fluctuate year-to-year, as demonstrated in this case. There are costs, risks, and lengthy transition periods associated with a major change in coal suppliers, and it is unreasonable to base such decisions on potentially short-term unit cost swings.

This is particularly true when considering a decision as monumental as moving the Jim Bridger plant from mine-mouth coal supply to coal supply located hundreds of miles away. Staff advocates an immediate and complete replacement of BCC and Black Butte coal with PRB coal, which would result in closure of both of these mining operations.[78] Along with the required plant retrofits, this makes the decision to switch to PRB coal irrevocable. PacifiCorp has continued to rely on its historical fuel supply while conducting a multiple-year planning process to evaluate and transition to PRB coal supply based on the operational realities of running the Jim Bridger plant.[79] PacifiCorp's approach is reasonable and prudent, even though BCC prices increase *in the test period*, while PRB unit costs decrease.

---

[74] PAC/200, Ralston/13-18.
[75] PAC/500, Ralston/6-7.
[76] PAC/200, Ralston/13; PAC/500, Ralston/26.
[77] Order No. 13-387 at 7, 15.
[78] PAC/500, Ralston/26-27; PAC/1000, Ralston/23.
[79] PAC/1000, Ralston/2-4.

It is undisputed that the Company would have had to decide in 2013, at the latest, to switch to PRB coal at Jim Bridger plant for this change to be in effect by 2017.[80] The information available in 2013 confirms the Company's reasonableness in not rushing to change coal suppliers.[81] In late 2013, the Commission had just reviewed and approved the Company's strategy of relying on BCC and Black Butte to fuel the Jim Bridger plant.[82] At the time, coal from the PRB was not an economic or viable alternative to replace the long-term fuel supply for the Jim Bridger plant. The 2013 Black and Veatch study advised that the Jim Bridger plant retrofit would cost $[redacted] (100 percent share), or $[redacted] in 2017 after adjusting for inflation.[83] Due to this prohibitively large capital investment and uncertainty about how the Jim Bridger plant would operate using PRB coal, the Company maintained its historical fueling strategy. The Company then issued its 2014 RFP for the Jim Bridger plant, which confirmed the cost-effectiveness of Black Butte as compared to PRB and other market suppliers.[84]

The Company demonstrated that the Jim Bridger plant's 2017 fuel costs compare favorably to PRB coal supply, after accounting for the required capital investments in the Jim Bridger plant and BCC mine closure costs.[85] This is true from both a 2013 perspective[86] and a 2016 perspective.[87]

Staff's recommended disallowance has resource planning implications that go beyond forecasting NPC for a single year. PacifiCorp supported the use of a long-term fuel plan in the 2014 TAM with the hope of engaging parties in a collaborative planning process, moving

[80] PAC/500, Ralston/15.
[81] PAC/1003 Revised.
[82] Order No. 13-387 at 6-7.
[83] PAC/1000, Ralston/28; PAC/1002.
[84] PAC/1000, Ralston/3.
[85] PAC/500, Ralston/2-3.
[86] PAC/500, Ralston/20 (Figure 2); PAC/1000, Ralston/30 (Figure 1).
[87] PAC/500, Ralston/26 (Figure 4).

away from litigating Jim Bridger coal supply issues on a year-by-year basis as costs fluctuate in annual NPC filings. Given the complexity of long-term fueling issues at the Jim Bridger plant, the Company continues to believe that a collaborative process is a better path to producing a least-cost, least-risk fuel plan for the Jim Bridger plant than the current litigation process. For this reason, the Company recommends that the Commission reject Staff's adjustment and open an expedited planning docket as soon as practicable to review these important issues outside the context of a litigated TAM filing.[88] The Company is preparing a comprehensive update to the previous Long-Term Fuel Plan to file before the end of the year to facilitate this review.[89] In this filing, the Company will add a broader range of scenarios and analysis to respond to Staff's positions in this case.

4. Staff's prudence disallowance is based on unsupported allegations, flawed analysis, and improper hindsight review.

Staff argues that the Company is imprudent because it is not exclusively using PRB coal to fuel the Jim Bridger plant in 2017. In its opening testimony, Staff relied on data from 2015 and 2016 and argued that the Company should have replaced all BCC coal with PRB because PRB coal is less expensive than coal from BCC in 2017.[90] Staff initially recommended a disallowance based on the 2017 price difference between BCC and PRB coal—not taking into account the full costs of switching fuel supply.[91] Although Staff claims that this recommendation was based on a long-term present value revenue requirement differential (PVRR(d)) analysis, Staff's opening testimony includes only one sentence mentioning this analysis, and it was not attached as an exhibit.[92] Staff's initial adjustment

[88] PAC/1100, Dalley/5.
[89] PAC/1100, Dalley/5.
[90] Staff/200, Kaufman/66.
[91] Staff/200, Kaufman/66-67.
[92] ES TR. 36-37 (Kaufman); Staff/200, Kaufman/66; Staff/400, Kaufman/6.

decreases NPC by $40.9 million on a total-company basis, or $10.43 million on an Oregon-allocated basis.[93]

The Company rebutted Staff's initial adjustment in its reply testimony, demonstrating that it would be physically impossible for the Company to replace BCC with PRB coal in 2017, unless the Company had made the decision no later than 2013.[94] Staff did not challenge this testimony in rebuttal and instead presented a new adjustment using different data and analysis. Staff's rebuttal adjustment purports to rely on data from 2013 and disallows *all* Jim Bridger plant fuel costs (Black Butte and BCC), based on a new long-term PVRR(d) analysis.[95] In total, Staff's rebuttal adjustment increases its proposed disallowance by 130 percent, from $40.9 million to $95.2 million on a total-company basis.[96]

Staff's approach is strictly numerical and ignores the broader factual, operational, and regulatory context of its proposed disallowance.[97] Staff's analysis also includes numerous errors and unreasonable assumptions. When corrected, the analysis demonstrates that PacifiCorp acted reasonably in not beginning an expedited transition to PRB coal in 2013.

a. BCC unit costs did not escalate rapidly before 2016.

Staff supports its adjustment through the inaccurate claim that BCC unit costs rapidly escalated over the last decade and the Company was on notice that continued reliance on BCC was unreasonable.[98] Staff supports this argument by misleadingly citing monthly BCC unit costs for March, April, and May 2016.[99] Staff's supporting exhibit, however, indicates that: (1) the unit costs in those three months were approximately double the average monthly

---

[93] Staff/200, Kaufman/67.
[94] PAC/500, Ralston/16-20.
[95] Staff/400, Kaufman/4 n. 8.
[96] Staff/400, Kaufman/31.
[97] PAC/1207 at 4; Staff/200, Kaufman/24.
[98] Staff/200, Kaufman/58, 66; Staff/400, Kaufman/3.
[99] Staff/200, Kaufman/52, 66.

unit cost for the preceding 12 months (March 2015 to February 2016); (2) the average monthly BCC unit cost for March 2015 to February 2016 was nearly the same as the unit cost in January 2010; and (3) the monthly unit costs Staff cites are approximately double the BCC unit costs included in the 2016 TAM and nearly double the BCC unit costs included in the 2017 TAM.[100]

At hearing, Staff acknowledged that it relied on monthly prices that were considerably higher than any monthly price going back to 2010.[101] Staff's own graphical representation of BCC monthly unit costs going back to 2010 indicates that BCC unit costs have been fairly consistent and the unit cost increases in the first part of 2016 are a spike that is not indicative of any historical trend of rapidly escalating prices.[102] Staff's reliance on atypical monthly prices to support its prudence disallowance is contrary to its position that Jim Bridger fuel supply should be judged on a long-term basis.[103]

Staff also testifies that "PacifiCorp has been repeatedly notified that Jim Bridger coal unit costs are unacceptably higher than market over an extended period of time."[104] But in TAM testimony filed annually between 2010 and 2015, Staff either specifically analyzed BCC unit costs and found them reasonable, or did not challenge the reasonableness of BCC unit costs.[105] Notably, in 2013—the very year Staff claims that the Company was unreasonable for not transitioning to PRB coal—Staff did not challenge the Company's

[100] Staff/213, Kaufman/1-2.
[101] ES TR. 29 (Kaufman).
[102] Staff/200, Kaufman/30.
[103] Staff/400, Kaufman/8.
[104] Staff/200, Kaufman/66.
[105] PAC/600, Dalley/11-16; PAC/1100, Dalley/8. Staff has identified only one instance, in 2009, when Staff claimed that BCC coal unit costs were higher than market. Staff/200, Kaufman/58. In that case, the Company rebutted Staff's analysis and the case was ultimately resolved by settlement without any Commission finding that BCC unit costs were unreasonable.

fueling strategy, and the Commission found that reliance on BCC and Black Butte was reasonable.[106]

Staff acknowledges in testimony that the increase in BCC unit costs in the 2017 TAM results from lower dispatch of the Jim Bridger plant.[107] Staff's testimony also describes at length the relationship between BCC volumes and costs, including a description of Staff's statistical analysis verifying that BCC volume and costs are inversely proportional.[108]

b. Contrary to Staff's claims, the Company regularly analyzed long-term fuel costs for the Jim Bridger plant, including PRB.

Staff also states unequivocally that the Company had *never* performed any multi-year cost analysis of market alternatives to BCC, including PRB coal, until ordered to do so by the Commission in the 2014 TAM.[109] This is demonstratively false. As outlined above, the Company has regularly evaluated market alternatives, including PRB coal.[110] The December 2015 Long-Term Fuel Plan relied on the Company's extensive, pre-existing planning processes.[111] In discovery, the Company produced numerous plans and studies of Jim Bridger long-term fuel costs, several of which included PRB data.[112] In fact, much of Staff's own analysis in this case relies on these very studies.

---

[106] Order No. 13-387 at 6; PAC/600, Dalley/14-15.
[107] Staff/200, Kaufman/27-28, 30.
[108] Staff/200, Kaufman/31, 35-36. At hearing, when confronted with the fact that market conditions that had caused the significant increase in BCC unit costs appeared to be subsiding, Staff claimed that low production volumes caused by less plant dispatch were not necessarily the cause of increased BCC unit costs. ES TR. 32 (Kaufman). This testimony is difficult to reconcile with Staff's opening testimony on the same issue, and with the Commission's recent order in Idaho Power Company's annual power cost filing. *See In the Matter of Idaho Power Company 2015 Annual Power Cost Update*, Docket No. UE 301, Order No. 16-206 at 2 (May 31, 2016) (increase in per unit coal costs related to higher operating costs spread over lower production volumes).
[109] Staff/400, Kaufman/2, 3, 7-8.
[110] PAC/500, Ralston/29; PAC/600, Dalley/11-13; PAC/1000, Ralston/3, 8-11; PAC/1002, PAC/1208 at 5.
[111] PAC/1000, Ralston/8-9.
[112] PAC/1000, Ralston/8.

c. Staff's long-term analysis does not demonstrate that the Company unreasonably continued to rely on BCC and Black Butte coal.

Staff's rebuttal adjustment is based on a long-term PVRR(d) analysis that purports to rely on information known to the Company in 2013.[113] Staff's analysis compares two scenarios—a base case (where the Company transitions to PRB coal in 2024) and a PRB case (where the Company transitions to PRB coal in 2017).[114] In its surrebuttal testimony, the Company corrected Staff's analysis and showed that continuing to rely on BCC and Black Butte was favorable by nearly $[redacted].[115]

(1) Staff's base case uses 2015 data, overstates capital costs in the PRB case, and constitutes improper hindsight review.

The base case used by Staff is similar to the base case from the Company's 2015 Long-Term Fuel Plan, which assumes that the Company would transition to PRB coal in 2024, following the depletion of BCC's underground reserves.[116] In other words, Staff's PVRR(d) analysis compared two PRB transition scenarios—one where the transition happens in 2017 (PRB case) and one where the transition happens in 2024 (base case). But, as Staff itself argues in proposing its coal adjustment, the Company did *not* contemplate switching to PRB coal in 2013.[117] In 2013, the Company assumed the underground operation would be replaced with increased coal from the BCC surface and Black Butte mines.[118]

Staff's incorrect and overstated base case includes the costs of the PRB retrofits at the Jim Bridger plant, even though the base case, by definition, should reflect no PRB coal related costs or benefits.[119] Simply removing these costs from Staff's base case decreases

---

[113] Staff/400, Kaufman/4.
[114] Staff/400, Kaufman/403, Kaufman/1.
[115] PAC/1003, Ralston/1; PAC/1210.
[116] Staff/403, Kaufman/1; Staff/215, Kaufman/8-9.
[117] Staff/200, Kaufman/2-3; Staff/400, Kaufman/20 (2013 IRP did not include switch to PRB coal).
[118] PAC/1000, Ralston/32.
[119] ES TR. 48 (Kaufman).

Staff's calculated PRB benefits by $[redacted] percent.[120] Moreover, because Staff's base case included PRB coal and had a different combination of BCC and Black Butte coal, the forward prices were substantially different from the Company's 2013 mine plan, which relied exclusively on BCC and Black Butte.[121] Inserting the correct forward coal prices into Staff's analysis to reflect the 2013 mine plan, decreases the PRB benefits by $[redacted] percent.[122] Using the correct base case eliminates almost 90 percent of Staff's calculated PRB benefits and nearly swings the PVRR(d) in favor of continued reliance on BCC and Black Butte.

(2) Staff's PRB case understates capital costs.

Staff's PVRR(d) analysis also unreasonably disregards the capital cost estimate from the 2013 Black and Veatch study and instead relies on the capital estimate developed by the Company in 2015, which is included in the Long-Term Fuel Plan.[123] At hearing, Staff testified that the Black and Veatch study "represents a *maximum* capital expenditure," a claim that is expressly contradicted by the study's first paragraph.[124] Staff also testified that the study's call for follow-up analysis means that it was unreasonable for the Company to rely on the estimated capital costs.[125] But Staff provided no evidence that the Company could have conducted all the additional studies and test burns in 2013 that ultimately resulted in the downward revision to the Black and Veatch estimate.[126] In fact, the Company did conduct the additional analysis, including PRB test burns, over the next two years, and that

---

[120] PAC/1210.
[121] PAC/1003 Revised; Staff/403; PAC/1210.
[122] PAC/1210.
[123] Staff/400, Kaufman/20.
[124] ES TR. 40 (Kaufman) (emphasis added); PAC/1002, Ralston/1.
[125] ES TR. 40 (Kaufman).
[126] ES TR. 51 (Kaufman).

additional analysis resulted ultimately in the downward revision of capital costs included in the 2015 Long-Term Fuel Plan.[127]

Had the Company acted in accordance with Staff's recommendation and rushed the transition to PRB coal in 2013, it may well have resulted in substantially higher capital investments at the Jim Bridger plant than were ultimately necessary. At hearing, Staff acknowledged that the work PacifiCorp conducted in 2014 and 2015 resulted in a significant reduction in the estimated costs of transitioning to PRB coal.[128] Staff also acknowledged that it would be risky to rush a project of this magnitude.[129] The Company's deliberate and comprehensive analysis of the transition to PRB coal, including additional studies and test burns, ultimately benefited customers by reducing the capital costs by $[redacted].

Staff also claims that it was unreasonable to rely on the Black and Veatch study because its estimated costs were higher than the costs for similar facilities at the Company's other plants.[130] Staff admitted at hearing, however, that it had reviewed no engineering study or analysis justifying its conclusion that the cost for Jim Bridger plant should be comparable to the costs of similar facilities at other plants.[131] In contrast, the Company testified that Staff's comparison is inapt because it ignores the specific characteristics and vintage of the facilities at each plant.[132]

Staff's PVRR(d) analysis also amortized the capital costs over 20 years, from 2017 through 2036, based on the Company's most recent depreciation study.[133] But this treatment is inconsistent with the Commission's 2025 depreciable life for the Jim Bridger plant—which

[127] PAC/1000, Ralston/29; ES TR. 17 (Ralston).
[128] ES TR. 51 (Kaufman).
[129] ES TR. 51-52 (Kaufman).
[130] Staff/400, Kaufman/20.
[131] ES TR. 43 (Kaufman).
[132] PAC/1000, Ralston/28,
[133] Staff/400, Kaufman/20.

the Commission affirmed in the Company's 2013 depreciation docket.[134] There is no basis to assume the Commission would adopt a depreciable life for the new rail and handling investments that is 11 years longer than the rest of the plant. At hearing, Staff defended its amortization period, claiming that its analysis was not intended to reflect actual ratemaking treatment of the capital investment.[135] But Staff's analysis purports to compare the *revenue requirement* of each scenario, which necessarily means that it must model the ratemaking treatment of each cost element. Correcting Staff's treatment of the capital investments in the PRB case decreases Staff's PVRR(d) by $[redacted] percent.[136]

(3) Staff's analysis understates the size of the regulatory asset resulting from the closure of BCC and includes an unreasonable amortization period.

The Company presented substantial evidence that the BCC mine would close if the Jim Bridger plant replaced BCC coal with PRB coal.[137] If the public interest is served by BCC's closure (which is presumed in Staff's analysis), customers would be responsible for the undepreciated investment at the mine and the closure and remediation costs.[138] This regulatory treatment is consistent with the Commission's approach to closure of the Company's Deer Creek mine, another affiliated, captive mine.[139]

Ignoring evidence to the contrary, Staff assumes there would be a market for BCC coal, and therefore disputes that BCC would close if it could no longer sell coal to the Jim

[134] PAC/1000, Ralston/29; *PacifiCorp Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1647, Order No. 13-347 (Sept. 25, 2013).
[135] ES TR. 47 (Kaufman).
[136] PAC/1210.
[137] PAC/500, Ralston/26-27; PAC/1000, Ralston/23.
[138] PAC/600, Dalley/19-20.
[139] *In the Matter of PacifiCorp Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 at 7-8 (May 27, 2015); *see also In the Matter of PacifiCorp Application for an Accounting Order Regarding Deferral of Trail Mountain Mine Unrecovered Costs*, Docket No. UM 1047, Order No. 02-343 at 4 (May 20, 2002); PAC/600, Dalley/18-20.

Bridger plant.[140] Staff also disputes that customers would be responsible for closure costs if the mine were to close, without acknowledging the Commission precedent to the contrary.[141] Despite these two claims, Staff includes a regulatory asset reflecting undepreciated investment and mine closure costs in its PRB case.[142] Staff's analysis, however, assumes significantly understated costs resulting from the closure of the mine and then amortizes those costs over 20 years, beginning when the mine closes in 2017. Both assumptions are unreasonable.

First, Staff understates the unrecovered investment portion of the regulatory asset that would be created upon mine closure by 46 percent.[143] Staff determined the unrecovered investment using the 2015 Long-Term Fuel Plan and removed all capital expenditures between 2014 and 2016, incorrectly assuming that the Company could run the mine without those expenditures for the remaining three years of its life.[144] This calculation effectively models closure of BCC's underground operations in 2013 because it removes all of the capital investments required for the underground mine to continue through 2016, as assumed in Staff's analysis.[145] Staff also ignores removal costs, based on the unsupported assumption that the costs are already included in the mine's depreciation and net salvage rates.[146]

Second, Staff's amortization period for the regulatory asset is much too long.[147] As discussed above, there is no basis to assume that the Commission would approve an amortization period for the BCC mine regulatory asset that is 11 years longer than the depreciable life of the Jim Bridger plant. The Company's analysis assumes a four-year

---

[140] Staff/200, Kaufman/67.
[141] Staff/200, Kaufman/56, 63-64.
[142] Staff/400, Kaufman/15.
[143] PAC/1000, Ralston/25.
[144] PAC/1000, Ralston/26.
[145] PAC/1000, Ralston/26-27; ES TR. 23-24 (Ralston).
[146] PAC/1000, Ralston/27.
[147] PAC/1000, Ralston/23-25.

amortization period, which is similar to the amortization period approved by the Commission in previous mine closure cases and for the BCC underground investments in 2005.[148]

Third, Staff applied an interest rate of 3.43 percent to the unamortized balance because Staff assumes a 20-year amortization period that *begins after the mine is closed and no longer used and useful*.[149] In reality, if in 2013 the Company determined that it would close the mine in 2017, it would seek to amortize the mine closure costs and undepreciated investment *before closure in 2017*.[150] This approach would be consistent with the treatment of the Carbon plant, where the Commission approved accelerated depreciation once the Company determined that the plant would be retired before the end of its depreciable life.[151] Thus, the regulatory asset would earn a return at the Company's weighted average cost of capital because it would be recovered while the mine was still used and useful. Correcting Staff's calculation and amortization of the regulatory asset associated with BCC's closure reduces Staff's PRB benefits by $[redacted] percent.[152]

(4) Staff's transportation price is facially unreasonable.

Transportation from the PRB to the Jim Bridger plant is the largest cost element of PRB coal.[153] Based on what was known in 2013, the Company's PVRR(d) analysis includes a transportation rate of $[redacted] per ton for 2017.[154] This amount uses a model developed by the U.S. Department of Transportation Surface Transportation Board's Uniform Rail Costing

---

[148] PAC/1000, Ralston/24-25.
[149] Staff/400, Kaufman/17.
[150] PAC/1100, Dalley/10.
[151] Order No. 12-493 at 3. *See also In the Matter of Idaho Power Company Application for Authority to Implement a Boardman Operating Life Adjustment Tariff for Electric Service to Customers in the State of Oregon*, Docket No. UE 239. Order No. 12-235 (June 26, 2012) (allowing accelerated depreciation to respond to early retirement of Boardman plant).
[152] PAC/1210.
[153] Staff/400, Kaufman/9.
[154] PAC/1000, Ralston/17.

System, which is a recognized and reasonable methodology for estimating rail rates in the industry.[155]

The reasonableness of the Company's estimate is confirmed by its actual rail contract price for delivery of PRB coal to the Jim Bridger plant as of June 2016.[156] The Company's rail contract was negotiated at arms-length between PacifiCorp and the Union Pacific Railroad Company.[157] The actual contract price of $[redacted] in 2017 is [redacted] than the 2013 estimate.[158]

Staff dismisses the contract's real world evidence of rail costs with little more than a paragraph of testimony.[159] Staff claims that Company's actual contract price is too high because it is not a high-volume contract.[160] On the contrary, the contract had minimum volumes of [redacted], which by any reasonable measure is a high-volume contract.[161] Staff also argues the Company had no incentive to negotiate a reasonable rail price and therefore its actual contract price is not a reliable estimate of an actual contract price.[162] To meet its obligations to its customers and business partner Idaho Power Company, however, the Company had a clear incentive to negotiate least-cost contract terms.[163] Moreover, Staff never challenged the price in the contract when it was included in the 2016 TAM, nor has it objected to its inclusion in rates in this case.[164]

---

[155] PAC/1000, Ralston/17.
[156] PAC/1000, Ralston/18; ES TR. 16 (Ralston).
[157] PAC/1000, Ralston/20.
[158] PAC/1000, Ralston/18.
[159] Staff/400, Kaufman/13.
[160] Staff/400, Kaufman/13.
[161] Highly Confidential Transcript (HC TR.) 13 (Ralston).
[162] Staff/400, Kaufman/13.
[163] PAC/1000, Ralston/20-21.
[164] PAC/1000, Ralston/20.

Staff's PVRR(d) analysis includes estimated transportation costs of $[redacted] per ton for 2016.[165] Staff's methodology for determining its transportation costs, however, is too simplistic and has no relation to how actual transportation costs are developed.[166] Staff simply examined PacifiCorp's other rail contracts and concluded that transportation costs are a function of distance.[167] Based on the distance from the PRB to the Jim Bridger plant, Staff calculated a transportation price. This analysis ignores the numerous other factors that impact transportation costs, such as rail line traffic and congestion, the size of the train required, and the market alternatives available, among many others.[168] The data set Staff relies on is also far too limited—Staff relies almost exclusively on just two contracts, both of which are with a different railroad for plants located far from the Jim Bridger plant.[169]

Staff relies on generic data relating to PRB transportation costs to verify its calculations.[170] But Staff never acknowledges that its own evidence indicates that the vast majority of PRB coal is transported south and east, not in the direction of the Jim Bridger plant.[171] Staff provided no basis to support its assumption that the cost to transport PRB coal east and south is comparable to the cost to transport west, given the vastly different transportation markets.

In the 2011 TAM, the Company testified that the delivered price of PRB coal to the Jim Bridger plant for 2011 would be over $[redacted] per ton, an estimate that Staff verified in its testimony in that case.[172] Staff's testimony in this case indicates that PRB coal was roughly

---

[165] Staff/400, Kaufman/12.
[166] PAC/1000, Ralston/18-19.
[167] Staff/400, Kaufman/11-12.
[168] PAC/1000, Ralston/19.
[169] PAC/1000, Ralston/22.
[170] Staff/400, Kaufman/11, 14.
[171] Staff/400, Kaufman/11; Staff/252, Kaufman/72.
[172] PAC/1208 at 5.

$14 per ton in 2011.[173] Thus, the transportation and handling costs would have been approximately $[redacted] per ton in 2011—an amount that is nearly double Staff's estimated transportation costs of $[redacted] per ton in 2013.[174] Moreover, the Company's 2011 TAM estimate of $[redacted] per ton delivered costs is nearly the same as the Company's calculated PRB price in this case of $[redacted] per ton in 2013.[175] The fact Staff reviewed and accepted the Company's $[redacted] per ton estimate in the 2011 TAM undermines its claim here that the Company's 2013 estimated price is overstated. Correcting Staff's analysis to include a reasonable transportation cost, decreases its PRB benefits by $[redacted] percent.[176]

(5) Staff's analysis fails to account for the risk of relying exclusively on PRB coal.

Staff incorrectly claims that its analysis demonstrates that a 2013 transition to PRB coal is both least cost and *least risk*.[177] Staff's adjustment does not consider the risk associated with exclusive reliance on the PRB market and rail transportation, a risk Staff expressly flagged in its August 2013 comments in the Company's 2013 IRP. Staff's comments warned of increasing rail transportation prices and coal market volatility, claiming that both developments have "introduced more risk into coal procurement than has been typical in the past."[178] Staff also included PacifiCorp's 2010 coal inventory study as an exhibit to its testimony. This study underlines the transportation risk related to PRB coal, stating that the "risks associated with rail transportation out of the PRB and unloading of coal are currently greater than the supply risk."[179] The study continued: "Following the

---

[173] Staff/200, Kaufman/65.
[174] Staff/402, Kaufman/1.
[175] PAC/1000, Ralston/30.
[176] PAC/1210.
[177] Staff/400, Kaufman/4.
[178] PAC/1207 at 4.
[179] Staff/212, Kaufman/16; *see also* PAC/1000, Ralston/10.

disruptions on the joint line in 2005, it became readily apparent that most utilities severely underestimated the transportation risk associated with PRB coal." [180]

At hearing, Staff testified that the Company could mitigate these risks through long-term coal supply and transportation contracts.[181] But this testimony contradicts Staff's pre-filed testimony in this case, which indicates that new long-term coal contracts may be imprudent "given the current regulatory and economic uncertainty regarding coal generation."[182] In effect, Staff now argues that the Company should have mitigated the risk of shifting entirely to PRB coal through long-term contracts, at the same time it is claiming that such contracts may be imprudent. Staff defended this stance by claiming that its PVRR(d) analysis relies on pricing based on annual one-year contracts, not long-term commitments.[183] But if the Company engaged in annual short-term contracts, it would be exposed to considerable price risk.[184] And even long-term contracts cannot mitigate the risks of rail disruptions, which could completely cut-off fuel supply to the Jim Bridger plant.

5. The Commission should again reject ICNU's lower of cost or market adjustment.

ICNU claims that PRB coal is cheaper in 2017, so the Company should have replaced BCC coal with PRB coal in 2017. ICNU's recommendation is framed as a lower of cost or market adjustment under OAR 860-027-0048.[185] ICNU's adjustment decreases NPC by $6 million on an Oregon-allocated basis.[186]

As outlined above, the Commission has always applied cost-based pricing to sales from affiliate mines, not the lower-of-cost-or-market standard. Most recently, in Order

[180] Staff/212, Kaufman/16.
[181] ES TR. 53 (Kaufman).
[182] Staff/200, Kaufman/24.
[183] ES TR. 54-55 (Kaufman).
[184] ES TR. 53 (Kaufman).
[185] ICNU/100, Mullins/9.
[186] ICNU/200, Mullins/10.

No. 13-387, the Commission specifically declined to apply the lower-of-cost-or-market standard to BCC coal, after concluding that the Company's fueling strategy for the Jim Bridger plant was "fair, just, and reasonable."[187]

ICNU has not presented evidence that PRB coal is an available alternative for 2017. The lower-of-cost-or-market rule states that transactions between utilities and affiliates "shall be recorded in the energy utility's accounts at the affiliate's cost or the market rate, whichever is lower."[188] The rule defines "market rate" as "the lowest price that is *available* from nonaffiliated suppliers for comparable services or supplies."[189] In the 2014 TAM, ICNU recommended that the Commission re-price BCC coal using a Black Butte contract price. The Company demonstrated, however, that Black Butte did not have sufficient volumes available in the 2014 test period to actually replace BCC coal.[190] The Commission rejected ICNU's adjustment.[191]

Here, the Company has presented unrebutted evidence that the Jim Bridger plant lacks the physical infrastructure to accept and burn sufficient volumes of PRB coal to replace BCC in 2017.[192] The Company further testified that it could not have the infrastructure in place for at least four years.[193] Thus, PRB coal is not physically available in 2017 to replace BCC.[194] ICNU has not disputed the Company's testimony on this point.[195]

Even if the Company could physically accept PRB coal in 2017, the all-in cost of that coal is higher than the Company's Jim Bridger plant fueling costs. ICNU's pricing of PRB

---

[187] Order No. 13-387 at 6.
[188] OAR 860-027-0048(4)(e).
[189] OAR 860-027-0048(1)(i) (emphasis added).
[190] Order No. 13-387 at 7.
[191] *Id.*
[192] PAC/500, Ralston/14-17.
[193] PAC/500, Ralston/16.
[194] PAC/500, Ralston/32.
[195] PAC/1000, Ralston/34.

coal ignored fuel surcharges, anti-freeze dust-suppression costs, handling costs, and, most notably, the amortization of the regulatory asset that would be created if BCC closed.[196] When properly adjusted, ICNU's own calculations result in 2017 PRB costs of $[redacted] per ton, compared to BCC costs of $[redacted] per ton, which includes a BCC return on rate base.[197]

In rebuttal, ICNU largely conceded that the Company's all-in calculations were correct, recommending only two meritless changes.[198] First, ICNU extended the amortization period for the regulatory asset for 13 years, so that it corresponded with the removal of coal assets from customer rates in 2029.[199] As discussed above, the Company's four-year amortization is reasonable and consistent with relevant Commission precedent.[200] Second, ICNU recommends a lower return on the unamortized regulatory asset.[201] ICNU's recommendation is unreasonable for the reasons discussed above regarding Staff's similar position.[202] ICNU's analysis also fails to adjust the PRB coal volumes modeled for heat content and analyzed BCC in isolation, instead of analyzing total plant-fueling costs.[203]

B. The Company reasonably relies on minimum-take provisions in coal contracts.

The Company presented unrebutted evidence that minimum-take provisions are a component of virtually all cost-effective long- and short-term coal supply agreements.[204] Under these provisions, the Company is required to accept a specified volume annually or

[196] PAC/500, Ralston/26, 32.
[197] PAC/1000, Ralston/5.
[198] ICNU/200, Mullins/8.
[199] PAC/1000, Ralston/35.
[200] PAC/1000, Ralston/35.
[201] PAC/1000, Ralston/35.
[202] PAC/1100, Dalley/10.
[203] PAC/1000, Ralston/36.
[204] PAC/500, Ralston/34-35.

pay a penalty. These provisions provide a steady revenue stream for the coal supplier, allowing continued investment in the resources necessary to supply coal.[205]

The Company demonstrated that its long-term coal contracts ensure access to fuel at predictable and stable prices, terms, and conditions.[206] Without minimum-take provisions, the Company would be required to rely on the spot market for its coal supply, a high-risk strategy both in terms of supply and price.[207]

1. CUB's allegation of imprudence lacks any evidentiary support.

CUB argues that the minimum-take provisions in three of the Company's coal supply agreements executed since 2015 are imprudent and recommends that all "costs and impacts" of these contracts be disallowed.[208] CUB's only basis for this disallowance is the conclusory claim that after the 2013 IRP, "an expensive and binding commitment to coal in the current environmental, federal, and regulatory atmosphere is imprudent."[209] Contrary to CUB's implication, however, the challenged contracts are not all long-term agreements. Two of the three contracts expire in 2017 and 2018.[210] The only contract extending beyond 2018 is the contract for the Huntington plant that CUB previously stipulated was prudent, even though it contains a minimum-take provision.[211] In addition, because wholesale market prices increased in the reply update, the minimum-take provisions in the challenged contracts are not currently implicated in the Company's NPC modeling.[212]

---

205 PAC/500, Ralston/34.
206 PAC/500, Ralston/34-35.
207 PAC/1000, Ralston/37.
208 CUB/100, McGovern/9.
209 CUB/100, McGovern/7.
210 PAC/500, Ralston/34.
211 PAC/500, Ralston/35-36.
212 PAC/500, Ralston/33-34.

2. The Company's stockpiles cannot be used to mitigate minimum-take provisions.

Staff does not directly challenge the prudence of the Company's minimum-take provisions.[213] Instead, Staff criticizes the Company for failing to use its coal plant inventory stockpiles to mitigate the impact of minimum-take provisions. Staff claims that the Company's coal-hedging policy relies on coal-plant stockpiles to manage minimum-take provisions and faults the Company for failing to conduct analysis on the relationship between inventory capacity and minimum-take requirements.[214] Contrary to Staff's testimony, the Company has never stated that its hedging policy relies on plant stockpiles to manage minimum-take provisions.[215] The Company has been clear that under its coal-inventory policy, stockpiles are used to manage normal fluctuations in coal supply and demand, and they have insufficient capacity to mitigate the impact of minimum-take provisions.[216]

C. The Company's coal plant dispatch modeling is consistent with prior TAMs.

GRID's modeling of coal plant dispatch relies on a single, annual incremental cost of coal that is used in every hour of the forecast test period to determine whether to dispatch a particular coal plant.[217] Because GRID does not model minimum-take provisions and uses a single incremental cost, the Company manually adjusts the incremental cost of coal to achieve the overall least-cost dispatch of the entire coal fleet, while meeting the minimum-take obligations for each plant.[218] The Company's approach to modeling minimum-take provisions through a manual adjustment to the incremental cost of coal is consistent with past

---

[213] PAC/502, Ralston/1.
[214] Staff/400, Kaufman/42.
[215] Staff/400, Kaufman/40 (acknowledging stockpiles cannot be used to mitigate minimum-take provisions).
[216] PAC/500, Ralston/36. Staff attached the Company's coal inventory policy as exhibit Staff/212.
[217] PAC/400, Dickman/41.
[218] PAC/400, Dickman/41-42.

TAMs and has been a part of the GRID model since 2005.[219] In the Company's initial filing in this case, the impact of minimum-take provisions was more pronounced than in the past due to the unprecedented market conditions that decreased coal-plant dispatch.[220] The impact was mitigated in the reply update, based on increasing forward wholesale electricity market prices and coal-plant dispatch.[221]

Staff objects to the Company's modeling, claiming that it is a modeling change prohibited by the 2017 TAM modeling moratorium adopted in Order No. 15-394.[222] Although Staff recognizes that minimum-take provisions have real world impacts on forecast NPC,[223] Staff recommends that the Commission ignore these impacts in this case. Staff is incorrect that the Company's treatment of minimum-take provisions is new; similar adjustments were made in past TAMs.[224] Staff's position that the Commission should intentionally ignore the Company's actual costs is also inconsistent with the Commission's (and Staff's) position that the purpose of the TAM is to produce the most accurate NPC forecast.[225]

Staff also recommends that before modifying the dispatch in GRID, the Company should max out its coal-plant inventory levels.[226] As described above, this recommendation is inconsistent with the Company's coal-inventory policy, which relies on the operational flexibility provided by coal stockpiles to respond to normal changes in supply and demand.[227]

---

[219] PAC/400, Dickman/48-49; PAC/800, Dickman/37.
[220] PAC/400, Dickman/49.
[221] PAC/400, Dickman/47.
[222] Staff/200, Kaufman/22-23.
[223] Staff/200, Kaufman/25.
[224] PAC/400, Dickman/48-49.
[225] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7 (Oct. 29, 2012); PAC/400, Dickman/51; PAC/800, Dickman/6 n. 5.
[226] Staff/400, Kaufman/42.
[227] PAC/1000, Ralston/39.

D. The Company's modeling of EIM benefits is reasonable.

1. The Company's filing reflects the EIM modeling approved in the 2016 TAM.

The Company's forecast of EIM benefits relies on the same methodology the Commission found reasonable in Order No. 15-394 in the 2016 TAM.[228] The Company incorporates annualizing adjustments to account for the impact of Nevada Energy's (NVE) participation and to capture the expected seasonal variation in EIM benefits.[229] The forecast also accounts for the added participation of Puget Sound Energy, Arizona Public Service, and Portland General Electric in the EIM.[230] The Company's forecast includes benefits associated with inter-regional dispatch, which result from transactions between PacifiCorp and the California Independent System Operator Corporation (CAISO), and flexibility reserve benefits, which result from a reduced regulating reserve requirement modeled in GRID.[231] These benefits are in addition to the optimized dispatch of the Company's generation within its balancing authority areas (BAAs) (*i.e.*, intra-regional dispatch), which has always been reflected in the GRID model.[232]

The Company's filing includes $23.79 million (on a total-company basis) in EIM benefits in addition to the benefits of optimized dispatch already reflected in the GRID model results.[233] In addition, to respond to specific suggestions from the parties, the Company does not object to Staff's auditing its EIM results and or to a generic investigation on the modeling of EIM benefits.[234]

---

[228] Order No. 15-394 at 8.
[229] PAC/400, Dickman/53-54.
[230] PAC/100, Dickman/30-31.
[231] PAC/100, Dickman/25-27.
[232] PAC/100, Dickman/27.
[233] PAC/400, Dickman/55.
[234] PAC/400, Dickman/57.

2. The Company's EIM benefits align with reasonable expectations.

The Company's forecast EIM benefits of nearly $24 million are well within the range of benefits forecasted by the Energy and Environmental Economics, Inc. (E3) study that was prepared in 2013.[235] Staff claims that the Company's EIM benefits are "significantly lower in value" than the estimates included in the E3 study and faults the Company for failing to describe the discrepancy between its own estimates and E3's.[236] CUB claims that customers were misled because the expected benefits have yet to materialize and the benefits that do exist are "trivial."[237] These accusations cannot be squared with the facts.

First, Staff's allegation is based on a comparison of PacifiCorp's benefits in this case to E3's total benefits for PacifiCorp *and CAISO*.[238] A fair comparison would look at E3's estimated benefits for just PacifiCorp; that comparison demonstrates that the Company's estimated benefits are much higher than E3's:

- E3 estimated inter-regional benefits of $5.5 to $7 million; PacifiCorp estimates inter-regional benefits of $19.2 million, over three times higher than E3's midpoint;
- E3 estimated flexibility reserve benefits of $1.2 to $6.1 million; PacifiCorp estimates benefits of $4.5 million, nearly 25 percent higher than the midpoint of E3's range;
- E3 estimated total benefits ranging from $10.5 million to $34.5 million, including intra-regional benefits; PacifiCorp estimates benefits of $23.7 million, *without accounting for intra-regional benefits already accounted for in GRID*, a level above E3's midpoint.[239]

At hearing, Staff acknowledged that it made an erroneous comparison and agreed that PacifiCorp's benefits were, in fact, equal to or greater than E3's.[240]

---

[235] Staff/106, Crider/35.
[236] Staff/100, Crider/7, 12; Staff/300, Crider/2-3.
[237] CUB/100, McGovern/19-20.
[238] Staff/100, Crider/6; Staff/106, Crider/35.
[239] Staff/106, Crider/35; PAC/400, Dickman/56.
[240] TR 106-108, 110-111 (Crider).

Second, by Staff's own measure, its calculated benefits are facially unreasonable. Based on 2015 data, Staff calculated total benefits (including intra-regional benefits) of $46.1 million, which is more than double the midpoint of E3's range.[241] Staff's inter-regional benefits of $31.5 million are more than five times the midpoint of E3's range.[242] Staff's calculation of 2015 benefits is also nearly twice CAISO's calculation of benefits over the same time period.[243]

3. Intra-regional benefits are inherent in the GRID forecast and imputing additional benefits is double-counting.

EIM's intra-regional benefits result from the use of CAISO's security constrained economic dispatch to optimize the Company's system, which creates a more efficient dispatch than the Company could previously achieve when its sub-hourly dispatch was purely manual.[244] Because GRID is already perfectly optimized, in every hour the lowest cost resources will be dispatched, subject to transmission constraints, and the intra-regional benefits manifest as a decrease in the Company's *actual*, not modeled, NPC.[245] The intra-regional benefits are real, but they are already built into the Company's overall NPC forecast. Imputing an incremental intra-regional benefit outside of GRID is therefore unreasonable.

Staff claims that intra-regional benefits are not captured in the GRID model and proposes to separately impute intra-regional benefits relying on CAISO's overall benefits calculation.[246] In this calculation, CAISO compares the actual EIM dispatch results to a counterfactual scenario that estimates the cost of serving load imbalance as if the EIM did

[241] Staff/300, Crider/15; Staff/106, Crider/35.
[242] Staff/300, Crider/15; Staff/106, Crider/35.
[243] Staff/300, Crider/15; Staff/100, Crider/6.
[244] PAC/400, Dickman/57-58; TR. 43-46 (Dickman).
[245] PAC/400, Dickman/57-58; TR. 50-51 (Dickman).
[246] Staff/100, Crider/11, 17-18.

not exist.[247] Staff claims that the counterfactual scenario is "an optimized production cost model, identical to the modeling used for the EIM solution except that EIM transfers are not allowed" and it is therefore "not a comparison of the manual operational solution to a more efficient automated system."[248] Staff concludes that the counterfactual scenario and GRID are both perfectly optimized dispatch solutions and the difference in the EIM benefits calculated by CAISO and PacifiCorp reflect incremental intra-regional benefits.[249] The only basis for Staff's imputation of intra-regional benefits is its claim that GRID and CAISO's counterfactual are identical.[250] This claim is untrue.

Based on CAISO's statements, the counterfactual is not the same as GRID because the counterfactual is intended to mimic the pre-EIM manual dispatch used by the Company and is therefore not a perfectly efficient dispatch solution.[251] At hearing, Staff agreed its pre-filed testimony was incorrect and acknowledged that the counterfactual does, in fact, mimic manual dispatch.[252] Staff has also admitted that GRID does not model manual dispatch.[253] Because the counterfactual is not perfectly optimized, it is not equivalent to GRID.[254]

NVE's participation in the EIM provides additional evidence that intra-regional benefits are fully captured in GRID. CAISO has indicated that NVE receives limited intra-regional benefits because NVE submits "optimized base schedules" to the EIM—meaning that NVE uses a computerized model to dispatch its resources in actual operations, instead of

[247] PAC/400, Dickman/59-60.
[248] Staff/100, Crider/10.
[249] Staff/100, Crider/11.
[250] TR. 114 (Crider).
[251] PAC/900, Brown/13-17; PAC/400, Dickman/60-61; PAC/1201 at 7 ("The counterfactual dispatch for PacifiCorp mimics PacifiCorp's pre-EIM manual dispatch[.]"); *id.* at 8.
[252] TR. 117 (Crider); *see also* PAC/1203 at 2.
[253] PAC/1203 at 2.
[254] PAC/400, Dickman/60. Staff further testifies that CAISO uses the same model in both its EIM case and counterfactual. Staff/300, Crider/5; PAC/1203 at 3. Staff's testimony is at odds with CAISO's own statement that the counterfactual does not, in fact, use the same model as the EIM case. PAC/1201 at 7.

manual dispatch.[255] CAISO's statement confirms that intra-regional benefits result from the transition from manual to computerized dispatch. Because GRID does not model manual dispatch, it already captures these benefits.

Similarly, E3 calculated PacifiCorp's EIM benefits using an economic dispatch model that "assumes perfect, security-constrained, least-cost dispatch."[256] According to E3, the intra-regional benefits resulting from the EIM were already captured in the model.[257] The same is true for GRID—because it assumes perfect, least-cost dispatch, the benefits resulting from the EIM's more perfect real-world dispatch are already included in the GRID results.[258]

Staff also argues that because the EIM provides for five-minute dispatch, it provides efficiencies over-and-above the efficiencies modeled using GRID's hourly dispatch.[259] This argument, however, fails to account for the fact that GRID's modeling does not include within-hour costs.[260] Because there are no within-hour costs, it is unreasonable to impute within-hour benefits.[261] Moreover, even if GRID was modeled using a five-minute dispatch, like the EIM, it would still be perfectly efficient.[262]

Staff recommends that the Commission impute intra-regional benefits calculated as the difference between CAISO's 2015 benefit calculation and the Company's calculated EIM benefits.[263] Based on this methodology, Staff recommends the imputation of $12.3 million of

---

[255] PAC/400, Dickman/62; PAC/900, Brown/15-17. This is confirmed by the fact that CAISO's counterfactual for NVE does not mimic manual dispatch. Staff/108, Crider/3-4 (NVE's counterfactual does not rely on limited resource pool intended to mimic manual dispatch).
[256] Staff/106, Crider/49.
[257] Staff/106, Crider/49. This is why E3 had to quantify the intra-regional benefits outside of the model.
[258] PAC/400, Dickman/59-60.
[259] Staff/100, Crider/11.
[260] PAC/400, Dickman/63.
[261] PAC/400, Dickman/63.
[262] PAC/400, Dickman/63; TR. 47, 49-50 (Dickman).
[263] Staff/300, Crider/6 (*i.e.*, the Company's calculation of inter-regional and flexibility reserve benefits).

intra-regional benefits.[264] Staff acknowledges that its calculated benefits are only correct if the Company correctly calculated the inter-regional benefits.[265] But Staff claims that the Company's benefits are dramatically understated.[266] If the Company's inter-regional benefits are wrong, as Staff claims, then Staff's intra-regional benefits are wrong too. More importantly, if the Company's inter-regional benefits are understated, then Staff's calculated intra-regional benefits are overstated. Using Staff's calculated inter-regional benefits results in intra-regional benefits of *negative* $7.6 million—a patently unreasonable result.[267]

4. The Company's calculation of inter-regional benefits is sound.

In the 2017 TAM, the Company refined the calculation of inter-regional dispatch benefits to identify the cost of specific incremental resources that could have facilitated transfers in each interval of the historical period.[268] Generally, the benefit of EIM exports is equal to the revenue received less the production cost of generation assumed to supply the transfer.[269] The benefit of EIM imports is equal to the import expense less the avoided expense of the generation that would have otherwise been dispatched.[270] The refined calculation more accurately identifies the dispatched resource supporting the EIM transfer, and therefore results in a more accurate calculation of inter-regional benefits.[271]

The production cost used in the Company's calculation of EIM benefits is the marginal cost to produce an additional megawatt-hour (MWh) at a given resource.[272] The

264 Staff/300, Crider/6-7.
265 Staff/300, Crider/7.
266 Staff/300, Crider/15.
267 Staff/300, Crider/6-7, 15 (subtracting Staff's calculated inter-regional benefits from CAISO's 2015 benefit calculation).
268 PAC/400, Dickman/52.
269 PAC/400, Dickman/66.
270 PAC/400, Dickman/66.
271 PAC/400, Dickman/53.
272 PAC/900, Brown/5.

Company's production costs are equal to the resource bids submitted to the EIM.[273] Staff and CUB argue that the Company's bid costs do not reflect the actual marginal cost of production. Instead, they claim that the Company's EIM bid is the same as its default energy bid (DEB), which includes certain adders to the marginal costs of production.[274] In fact, the DEB establishes the *maximum* bid, but the Company does not actually use the DEB to establish its EIM bids.[275] Rather, the Company's bids are based on the actual marginal production costs for each unit.[276] The only adder applied is a small percentage adjustment to the bid to account for the possible change in natural gas prices or other costs typically incurred over time, such as pipeline charges.[277]

Contrary to Staff's and CUB's implication that the Company inflates its bids, the Company has a strong incentive to bid as accurately as possible to its actual marginal cost of production.[278] Inflated bids create the very likely possibility that CAISO would displace a PacifiCorp resource with a cheaper resource, potentially forcing PacifiCorp to import energy from CAISO at a price higher than the Company's own costs of generation. Similarly, a deflated bid may result in the PacifiCorp resource being dispatched to support an export at less than its production cost. The fundamental premise of the EIM is to optimize the diverse pool of participating resources to generate the least-cost dispatch. Attempting to extract additional market value from resources participating in the EIM could have the opposite effect.[279]

---

[273] PAC/900, Brown/5.
[274] Staff/300, Crider/9-10; CUB/200, McGovern/6.
[275] PAC/900, Brown/6.
[276] PAC/900, Brown/5.
[277] PAC/900, Brown/7.
[278] PAC/900, Brown/8.
[279] PAC/900, Brown/8.

Instead of using bids reflecting the marginal cost of production, Staff recommends that the Company use its annual average cost of production in the calculation of inter-regional benefits.[280] By relying on average, rather than marginal costs, Staff's recommendation produces a less accurate forecast because it does not reflect the actual costs to generate the energy transferred to the EIM.[281]

5. Staff's inter-regional benefits are based on demonstrative errors.

Staff's proposed inter-regional EIM benefits uses data from 2015 to establish benefits of $31 million.[282] Staff's analysis, however, contains multiple errors:

- Staff's analysis relies on 13 months of data, instead of 12. Removing the additional month reduces the benefits by [redacted].[283]

- Staff's calculated production costs are wrong. Staff calculated production costs using 15 months of export volumes reported to CAISO for greenhouse gas compliance purposes.[284] In addition to including three additional months of data, the data does not reflect actual energy transferred to the EIM, which is necessary to calculate the inter-regional benefits.

- Staff's analysis contains a mismatch between the volumes used to calculate the export revenue and the volumes used to calculate the production costs.[285] Staff includes [redacted] MWh of exports, but calculates the production costs using only [redacted] MWh. Thus, Staff assumes that [redacted] MWh (or [redacted] of the export volumes) have zero production cost. Correcting this error by using Staff's own calculated production costs applied to the missing [redacted] MWh decreases Staff's benefit calculation by [redacted].

- Staff's calculation of the import volumes fails to account for the avoided cost of generation. Staff agrees that the import revenues are equal to the costs paid for the import volumes less the avoided cost that PacifiCorp would have incurred but for the import energy.[286] But Staff's calculation did not account for the avoided cost and therefore overstated the EIM benefits by [redacted].

---

[280] Staff/300, Crider/13.
[281] PAC/900, Brown/11-12.
[282] Staff/300, Crider/13.
[283] PAC/800, Dickman/20.
[284] PAC/800, Dickman/20-21.
[285] PAC/800, Dickman/21.
[286] Staff/300, Crider/7.

In total, correcting just Staff's mathematical errors reduces Staff's inter-regional benefit calculation by nearly 50 percent, to [redacted]—an amount that is less than PacifiCorp's calculated inter-regional benefits.[287]

6. Staff's and CUB's "simplified" approach to calculate EIM benefits does not produce reasonable estimates and is no less complex.

Both Staff and CUB recommend that the Commission approve a less rigorous methodology for determining EIM benefits because they claim that the Company's methodology is too complex and lacks transparency. The Commission has previously accepted modeling refinements to the NPC forecast over objections that the refinement was too complex or relied on voluminous data.[288] In these cases, the Commission recognized that the purpose of the TAM is to produce an accurate NPC forecast, which may require complex analysis of voluminous data.

Staff recommends a so-called "top down" approach that would determine intra-regional and flexibility reserve benefits directly from the CAISO reports and calculate the inter-regional benefits using average system costs.[289] In addition to the flaws discussed above, Staff's preferred methodology would still require the Company to analyze every single five-minute interval to determine which resource dispatched into the EIM so that the average annual production cost could be assigned to that resource.[290] The only simplification in Staff's approach is the use of the average system cost, instead of the marginal cost at the time of the transfer.

---

[287] PAC/800, Dickman/21.
[288] *See, e.g.,* Order No. 15-394 at 4; Order No. 13-387 at 3-4; PAC/800, Dickman/12.
[289] Staff/300, Crider/12-13.
[290] PAC/800, Dickman/13; Staff/300, Crider/13.

CUB recommends that the Commission simply adopt CAISO's benefit calculation.[291] There are two problems with this approach. First, as discussed above, CAISO's calculation includes intra-regional benefits that are already built into the Company's NPC forecast. So simply adopting CAISO's estimate double counts these benefits. Second, adopting CAISO's calculations does nothing to remedy concerns over complexity and transparency.[292] CAISO's calculations are just as complex as PacifiCorp's, but, unlike PacifiCorp, the parties have no ability to audit CAISO.

7. The Company's calculations appropriately account for transmission necessary to support inter-regional transactions.

The Company's ability to export energy to CAISO across the California-Oregon Intertie (COI) is limited by the transmission lines' path rating, which is frequently derated, and by the volume of transactions forecast at the California-Oregon Border (COB).[293] Both COB transactions and EIM exports use the same transmission capacity, so if NPC includes forecasted transactions at COB, there will be less transmission available for EIM exports.[294] To apply the historical export benefits to the 2017 TAM forecast, the actual historical benefits are divided by the total transmission that was available for the EIM during the historical period and expressed in dollars per megawatt-hour of available transmission.[295] This margin is then applied to the transmission in the 2017 TAM that is available for EIM.[296] This approach ensures the transmission constraints are recognized and that the same transmission capacity is not improperly used for both sales to the COB market and EIM.

---

[291] CUB/200, McGovern/33.
[292] PAC/800, Dickman/13.
[293] PAC/400, Dickman/77.
[294] PAC/400, Dickman/77.
[295] PAC/400, Dickman/77.
[296] PAC/400, Dickman/77.

CUB argues that the Company's methodology underestimates EIM benefits by limiting EIM transfers based on the available transmission in the forecast test period.[297] But CUB acknowledges that EIM transfers and sales at COB rely on the same transmission and that the forecast cannot assume use of the same transmission capacity for both EIM transfers and sales at COB.[298]

CUB also argues that the Company forecasts EIM benefits by multiplying the historical margin per megawatt-hour of available transmission by the forecasted EIM exports.[299] This is wrong—the historical margin is multiplied by the forecast available transmission.[300] CUB's own testimony demonstrates that the Company's actual calculations correctly multiply the margin per megawatt-hour of transmission by the available transmission, not by the forecast export megawatt-hours.[301]

CUB also claims that the Company's calculation unfairly applies to only CAISO exports.[302] But this is because the Company's actual experience with NVE indicates that there are no comparable transmission constraints.[303] Therefore, there is no reason to model exports to NVE based on available transmission.

Staff supports CUB's recommendation, testifying that because the Company cannot perfectly forecast the transmission that will be available for EIM transfers, it should simply assume there are no limits.[304] This testimony ignores the fact that the Company already forecasts available transmission because it is a function of COB transactions.[305]

---

[297] CUB/100, McGovern/15.
[298] CUB/100, McGovern/16.
[299] CUB/200, McGovern/15-16.
[300] PAC/800, Dickman/22-24.
[301] PAC/800, Dickman/23-25.
[302] CUB/200, McGovern/18.
[303] PAC/800, Dickman/26.
[304] Staff/300, Crider/14.
[305] PAC/800, Dickman/26-27.

8. The Company does not include an offset for opportunity costs.

The Company's calculation of inter-regional benefits is based on the difference between the revenue received for an EIM transfer and the marginal cost of production that supported the energy transfer. The Company's calculations do not account for the opportunity cost, *i.e.*, the revenue that the Company could have potentially earned if it had not transferred the energy through the EIM and instead sold the energy in a bilateral transaction at COB.[306]

CUB claims that the Company improperly offsets EIM benefits by the opportunity cost.[307] But CUB has been unable to actually verify this claim or identify where the offset occurs.[308] The Company has been clear that there is no offset and therefore no basis for CUB's criticism.[309]

Staff appears to agree with the Company that there is no offset for opportunity costs for thermal resources.[310] But Staff claims that the Company does discount hydro exports based on opportunity costs in determining the production cost of hydro resources.[311] Staff is referring to the fact that for hydro resources the Company determines the production cost based on the cost of replacement power. This approach is reasonable because, unlike other renewable resources with zero variable costs, hydro resources have a limited supply of water with which to generate electricity.[312] If hydro generation is used to support an EIM transfer,

---

[306] PAC/400, Dickman/73-74.
[307] CUB/100, McGovern/17.
[308] PAC/413, Dickman/1.
[309] PAC/400, Dickman/74-75.
[310] Staff/300, Crider/14.
[311] Staff/300, Crider/14.
[312] TR. 86-87 (Brown).

then that hydro generation is no longer available to serve customers and the Company will be required to replace that generation when needed.[313]

E. The Commission should approve continued application of the system balancing transactions adjustment.

1. The Company's modeling is materially unchanged from the 2016 TAM.

In the 2016 TAM, the Commission approved a modeling refinement to more accurately reflect the costs of system balancing transactions in the Company's NPC forecast.[314] The Company's modeling in this case applies the adjustment as approved last year, except that the Company now uses four years of historical data, instead of three.[315] No party objects to this change, which increases the accuracy of the adjustment and decreases the NPC impact.[316]

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.[317] To address this deficiency, the adjustment has two components. First, to better reflect the market prices available to the Company when it transacts in the real-time market, the Company includes in GRID separate prices for forecasted system balancing sales and purchases.[318] These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market prices.[319] Second, the Company also reflects additional volumes to account for the use of monthly, daily, and hourly products.[320]

---

313 TR. 87 (Brown).
314 Order No. 15-394 at 4.
315 PAC/400, Dickman/18.
316 PAC/400, Dickman/34. CUB is the only party that recommended the Company use only three years of data. CUB/100, McGovern/25-26. CUB's position changed, however, after the Company testified that the use of three years' of data increased the adjustment. In rebuttal, CUB takes no position on the historical period used to calculate the adjustment. CUB/200, McGovern/27.
317 PAC/100, Dickman/18.
318 PAC/100, Dickman/18-19.
319 PAC/100, Dickman/18-19.
320 PAC/100, Dickman/19-20.

2. The Commission's findings in the 2016 TAM remain correct.

When approving the system balancing transactions adjustment, the Commission made three key findings. First, the Commission found that "short-term power purchase prices systematically exceed short-term power sales prices."[321] This is still true and no party disputes it.[322]

Second, the Commission found that the system balancing transactions adjustment is a "reasonable adjustment to [PacifiCorp's] forward price curve to account for these expected price differences that will result in a more accurate estimate of net power costs."[323] Modeling different purchase and sale prices in GRID better reflects the reality of the Company's system balancing transactions. The change has improved the accuracy of PacifiCorp's NPC forecast.[324]

Third, the Commission found that GRID understates the volumes of transactions "because it assumed the volumes of purchases and sales matched exact needs."[325] GRID still underestimates transaction volumes due to its perfectly efficient system balancing and no party contends that GRID overstates volumes.[326]

3. The parties have not raised substantive new arguments.

In Order No. 15-394, the Commission concluded that parties "have had sufficient time and opportunity to review and assess" the system balancing transactions adjustment.[327] The parties have now had an additional year to review and assess the adjustment, explore refinements, and submit two rounds of testimony in this case. The parties have not presented

---

321 Order No. 15-394 at 4.
322 PAC/100, Dickman/18; Staff/200, Kaufman/3-4; CUB/100, McGovern/28-29; PAC/400, Dickman/19.
323 Order No. 15-394 at 4.
324 PAC/100, Dickman/15-21; PAC/400, Dickman/21-23.
325 Order No. 15-394 at 4.
326 PAC/100, Dickman/20-21.
327 Order No. 15-394 at 4.

any new or compelling evidence or arguments justifying a reversal or modification of the decision in the 2016 TAM.

a. The Company's testimony fully explains the adjustment.

Staff claims that the Company did not fully explain the system balancing transactions adjustment.[328] The Company devoted 38 pages of its testimony to this issue. In docket UE 296, the Company filed another 60 pages of testimony on the adjustment, including extensive testimony from expert witness Frank Graves, detailing both the rationale behind the adjustment and the mechanics of the adjustment. There is no basis for Staff to claim that nearly 100 pages of testimony this year and last (and numerous data request responses) is insufficient to explain the adjustment.[329]

b. The adjustment is not unrealistic because it models simultaneous purchase and sale prices.

Just like last year, Staff claims that the system balancing transactions adjustment is unrealistic because it models a separate purchase and sale price for each hour, a claim that ignores how the adjustment actually works.[330] In each hour, GRID is either buying or selling and therefore in each hour there is only one price applicable in GRID.[331] As noted above, there is no dispute that PacifiCorp typically buys when prices are high and sells when prices are low, and this modeling refinement captures that reality. Modeling two price streams better represents the actual operations and is reasonable given the difficulty of forecasting a single market price for every hour of every day of the year.[332]

---

[328] Staff/200, Kaufman/6.
[329] PAC/400, Dickman/21.
[330] Staff/200, Kaufman/5.
[331] PAC/400, Dickman/26; TR. 77 (Dickman).
[332] PAC/400, Dickman/25-26.

c. The forward price curve's existing price differentiation does not obviate the need for the system balancing transactions adjustment.

Staff argues that "GRID already differentiates market price into periods of higher and lower prices," implying that the system balancing transactions adjustment is therefore unnecessary.[333] While GRID does model different forward prices based on high and low load hours, those prices still do not reflect the actual costs incurred by the Company to balance its system.[334] Further refinement is warranted, and that is what is accomplished by the Company's adjustment.

Staff's argument is also internally inconsistent. Staff claims that the system balancing adjustment is unnecessary because forward prices are already differentiated based on high and low load hours.[335] But Staff also argues that the Company should be modeling more variation in forward prices, not less.[336]

d. The system balancing transactions adjustment properly *includes* arbitrage transactions and *excludes* hedging transactions.

Staff criticizes the adjustment for including both arbitrage and hedging transactions.[337] First, Staff is correct that the adjustment includes arbitrage transactions because those transactions reduce the cost of system balancing and inclusion of these transactions creates a more realistic model.[338] Second, Staff is wrong that the adjustment includes hedging transactions, just as ICNU was wrong when it made the same argument last year.[339] In fact, the only transactions included in the adjustment are those with delivery times

[333] Staff/200, Kaufman/3.
[334] PAC/400, Dickman/27.
[335] Staff/200, Kaufman/3.
[336] Staff/200, Kaufman/7-8.
[337] Staff/200, Kaufman/12.
[338] PAC/400, Dickman/32.
[339] PAC/400, Dickman/31.

of less than one week, which therefore do not include a hedging component.[340] Staff attempts to identify transactions it claims were hedges, but of the 3,140 transactions analyzed by Staff, it found only nine that were done more than five days in advance and which were included in the calculation of the system balancing transactions adjustment.[341] The inclusion of these nine transactions is immaterial.

e. The use of historical data produces a normalized adjustment.

CUB again argues that the use of historical data to calculate the adjustment results in a non-normalized NPC forecast.[342] The Commission specifically rejected this argument last year, finding that the use of three years of historical data is sufficient to smooth out variations and produce a reasonable, normalized forecast.[343]

f. The Company's participation in the EIM does not affect the need for the system balancing transactions adjustment.

CUB argues that the use of pre-EIM historical data to calculate the adjustment is improper because historical pre-EIM transactional patterns do not represent future patterns.[344] Actual historical results indicate that the participation in the EIM has not decreased the Company's system balancing costs, a result that is unsurprising given that the EIM primarily affects sub-hourly transactions, and not the monthly, daily, and hourly transactions upon which the Company's adjustment is based.[345] The scheduling requirements of the EIM also potentially result in higher system balancing costs, although any increase in those costs is offset by EIM benefits within the hour.[346]

---

340 PAC/400, Dickman/31.
341 PAC/400, Dickman/32.
342 CUB/100, McGovern/28.
343 Order No. 15-394 at 4.
344 CUB/100, McGovern/26-27.
345 PAC/400, Dickman/35-36, 65; PAC/800, Dickman/28.
346 PAC/400, Dickman/35-36; PAC/800, Dickman/28-29.

g. The Company does transact in the monthly market.

Staff also argues that the Company does not, in fact, perform monthly balancing transactions.[347] To support this claim, Staff purports to analyze over a thousand balancing transaction categories and concludes that the Company performed monthly transactions in only 30 percent of them.[348] Staff's conclusion, however, misunderstands both the data it relies on and the calculation of the system balancing transactions adjustment. Staff's analysis includes transactions at illiquid points of delivery, in addition to major market hubs.[349] The only transactions that are included in the system balancing transactions adjustment are transactions at major market hubs.[350] Examining the hubs included in the system balancing transactions adjustment demonstrates that the Company has made monthly transactions in a major hub in each month of the historical period.[351]

h. The system balancing transactions adjustment does not double count day-ahead integration costs.

The Company's NPC forecast includes day-ahead, or inter-hour, integration costs that are based on the system balancing costs resulting from the difference between day-ahead unit commitment and the actual dispatch in response to changing loads and variable generation.[352] ICNU argues that because day-ahead integration costs account for system balancing, these costs are double counted by the system balancing transactions adjustment.[353] ICNU's argument, however, relies on the incorrect assumption that the system balancing costs included in the day-ahead integration calculation are market transactions.[354] In fact, the day-

---

[347] Staff/400, Kaufman/35.
[348] Staff/400, Kaufman/35.
[349] PAC/800, Dickman/34.
[350] TR. 66-67, 69 (Dickman).
[351] Staff/606.
[352] PAC/400, Dickman/39-40.
[353] ICNU/100, Mullins/3-5.
[354] PAC/400, Dickman/39-40; PAC/800, Dickman/30-31.

ahead integration costs primarily measure the NPC impact of changes in gas plant commitment, not the impact of market transactions to balance the system.[355]

i. The fact that system balancing affects fuel costs is no basis to reject the adjustment.

Staff claims that the system balancing transactions adjustment should be rejected because it does not take into account other changes to the Company's NPC resulting from system balancing transactions. Specifically, Staff claims that if real-world market transactions differ from those modeled in GRID, fuel use will also differ.[356] But this is no basis to reject the adjustment. To the extent that actual market prices are higher or lower than the prices in GRID, the impact will be to increase NPC. If actual prices are higher than GRID, the Company will dispatch higher-cost resources.[357] If actual prices are lower than GRID, the Company will back down lower-cost resources.[358] Under either scenario, the actual NPC will be greater than the NPC modeled in GRID.[359] Thus, the fact that fuel use is not adjusted in tandem with the system balancing adjustment understates overall NPC.

4. The system balancing transactions adjustment is not arbitrary.

Staff argues that the adjustment is arbitrary and irrational. The Commission did not agree when it carefully reviewed and approved the modeling change last year. The adjustment is similar to other established methodologies used to forecast NPC based on historical data, and it produces results that are rational and reflective of the Company's actual, real world operations.

---

[355] TR. 10-11 (Dickman).
[356] Staff/200, Kaufman/12.
[357] PAC/400, Dickman/28.
[358] PAC/400, Dickman/28.
[359] PAC/400, Dickman/28.

a. The reliance on historical data is not arbitrary.

Staff argues that the volume component of the adjustment is arbitrary because the price applied to the additional volumes is intended to result in overall system balancing costs that match the historical average.[360] There is nothing arbitrary about refining the NPC forecast based on normalized historical results.[361] The Commission has frequently relied on historical averages to forecast NPC, and all the parties to this case have at some point supported the use of historical data in discrete NPC adjustments.[362] The Commission has never concluded that relying on historical data is arbitrary.

b. The adjustment produces reasonable results.

Staff argues that the adjustment is irrational because it does not model fewer monthly and daily transactions when there are less real-time transactions.[363] In reality, the volume of real-time transactions does not impact the volume of monthly and daily transactions that preceded them.[364] In fact, this outcome is physically impossible—an hourly transaction today cannot allow the Company to forego a monthly transaction 30 days ago.

---

[360] Staff/200, Kaufman/11

[361] PAC/800, Dickman/32.

[362] *See e.g. In the Matter of PacifiCorp d/b/a Pacific Power 2008 Transition Adjustment Mechanism*, Docket No. Docket No. UE 191, Order No. 07-446 at 10-11 (Oct. 17, 2007) (approved an adjustment to reflect the Company's arbitrage and trading activity that relied on historical data); *In the Matter of PacifiCorp d/b/a Pacific Power 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 18-20 (Nov. 4, 2011) (approved the use of hourly scalars derived from historical data to improve the accuracy of the NPC forecast); Order No. 12-409 at 7-8 (affirmed the use of market caps to model market liquidity and the market caps were calculated using historical data); Order No. 13-387 at 2-4 (approved the shaping of hourly wind profiles based on historical data); *In the Matter of Avista*, Docket No. UG 246, Order No. 14-015 (Jan. 21, 2014) (approving stipulation using three-year historical averages to forecast uncollectible expense and rate); *In the Matter of PacifiCorp Request for General Rate Revision*, Docket No. UE 217, Order No. 10-473 (Dec. 14, 2010) (using historical averages to forecast insurance expense); *Investigation into Forced Outage Rates*, Docket No. UM 1355, Order No. 10-414 (Oct. 22, 2010) (using historical average to forecast outage rates); *In the Matter of Portland Gen. Elec. Co.*, Docket No. UE 197, Order No. 09-020 (Jan. 22, 2009) (using historical average to forecast employee levels); *In the Matter of Portland Gen. Elec. Co.*, Docket No. UE 266, Order No. 13-280 (Aug. 5, 2013) (approving stipulation using historical average to forecast wind generation).

[363] Staff/200, Kaufman/11.

[364] PAC/400, Dickman/30.

Staff claims that the use of monthly prices in the adjustment, instead of some other time period, is also arbitrary.[365] But the use of monthly prices corresponds to the Company's traditional use of a monthly forward price curve, which no party has challenged.[366]

Staff also testifies that the Company's reply update includes 46 percent fewer market transactions, while the system balancing transactions adjustment decreased by only one percent, which is a "clear sign" the adjustment is arbitrary.[367] But Staff conceded that its calculations had major errors that, when corrected, show that the reply update had only five percent fewer transactions.[368]

c. The adjustment does not double count costs.

Staff claims that GRID understates system balancing transactions because it limits market purchases.[369] According to Staff, because market purchases are limited, GRID cannot go to market for system balancing and instead will dispatch higher cost resources. Thus, Staff reasons that the understatement of system balancing transactions actually results in higher NPC, not lower. Based on this claim, Staff argues that the adjustment is arbitrary because it double counts certain costs.[370] But GRID does not limit market purchases and therefore the adjustment does not double count costs.[371]

5. The Company is willing to explore further refinements to its modeling, while the adjustment remains in place.

Staff and CUB recommend that the Commission reject the Company's system balancing transactions adjustment, while simultaneously recommending that the Company refine its forward price curve to include greater variation to more accurately reflect actual

---

365 Staff/200, Kaufman/4-5.
366 PAC/400, Kaufman/27-28.
367 Staff/400, Kaufman/32-33.
368 PAC/800, Dickman/33.
369 Staff/400, Kaufman/34.
370 Staff/400, Kaufman/34.
371 PAC/800, Dickman/33-34. GRID does limit market sales, in some circumstances, but not purchases.

market prices.[372] There is no dispute that the Company's adjustment results in greater variation in monthly prices, an outcome Staff and CUB support in concept.[373]

Moreover, no party has proposed a meaningful methodology that could be used in addition to or in place of the Company's system balancing transactions adjustment.[374] While the Company is willing to explore further refinements to its modeling, there is no basis in the record to reject the system balancing transactions adjustment in the meantime.[375]

F. There is no basis for adopting CUB's and Staff's proposed QF adjustments.

The Company's modeling of QF contracts follows the TAM Guidelines, as amended by stipulation in the 2015 TAM. The Company includes 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.[376] Once a QF contract is included in the forecast, the Company models it as it is expected to operate during the test year (*i.e.*, if the QF is operational for one month, then only one month of generation is included in the forecast).[377] On average, the Company's final TAM forecasts have understated both the total count of QFs that are generating energy and the volume of energy generated.[378]

CUB recommends a change in how the Company models new QF contracts, based on its claim that the Company consistently models greater QF generation from new resources than actually occurs. CUB proposes that the Company include all QFs that are operational or have a signed contract in the TAM, but apply a discount factor to new QF contracts based on

---

372 Staff/400, Kaufman/36; CUB/200, McGovern/27.
373 PAC/400, Dickman/26-27;
374 PAC/400, Dickman/19-20.
375 PAC/400, Dickman/20.
376 PAC/400, Dickman/83-84; *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).
377 PAC/400, Dickman/86-87.
378 PAC/800, Dickman/42.

the historical difference between forecasted and actual energy generation from new QFs.[379] While Staff agrees the Company's current methodology works, it nevertheless recommends that the Company apply a "historical success factor" to new QFs with executed contracts that are not operational by January 1 of the test period.[380]

CUB and Staff have not quantified their proposals, but they are both designed to systematically reduce QF generation in the TAM. Given that the Company already under-forecasts QF generation in the TAM, there is no basis to further reduce the forecast. This is especially true because neither CUB nor Staff have demonstrated the insufficiency of the current TAM Guidelines for modeling new QF contracts.

G. Staff has not demonstrated imprudence to support its avian curtailment adjustment.

The Company reduced generation output at two wind sites to reflect expected energy lost from implementing avian protection curtailments to comply with a court order.[381] This curtailment was litigated in the 2016 TAM, where ICNU proposed a similar adjustment. In that case, the Commission rejected the adjustment, concluding that "PacifiCorp must comply with the court order for avian protection."[382]

Staff argues that the Company was imprudent for siting its wind facilities in avian-sensitive areas and seeks to disallow all costs associated with avian curtailment.[383] The Company established that the wind projects are prudent even with the curtailment, as demonstrated by their high capacity factor.[384] Moreover, the fact that the wind projects were sited in avian sensitive areas was disclosed to the parties in docket UE 200 when the

379 CUB/200, McGovern/31.
380 Staff/300, Crider/17, 19.
381 PAC/400, Dickman/78.
382 Order No. 15-394 at 7.
383 Staff/200, Kaufman/17-19.
384 PAC/400, Dickman/80.

Company sought to include these projects in rates.[385] No party to docket UE 200 challenged the prudence of the projects based on avian curtailment risk and the Commission found both projects prudent. There is no basis for the Commission to revisit its previous rejection of this adjustment.

H. The Commission should again reject Noble Solutions' direct access adjustments.

In the 2016 TAM, Noble Solutions presented two proposals related to direct access. First, Noble Solutions recommended that the transition adjustment account for the value of renewable energy certificates (RECs) freed up by the departing direct access customer. Second, Noble Solutions recommended that the consumer opt-out charge in the five-year program be reduced to account for the impact of accumulated depreciation. The Commission rejected both these recommendations.[386] Noble Solutions proposes the same two adjustments in this case, relying on virtually the same evidence and arguments.

1. Noble Solutions' REC adjustment remains deficient.

Noble Solutions recommends that the Schedule 294, 295 and 296 transition adjustments be adjusted to reflect the value of freed-up RECs resulting from the departure of the direct access load.[387] In Order No. 15-394, the Commission rejected this adjustment for three reasons. First, the adjustment incorrectly assumes that PacifiCorp will sell its RECs and can therefore monetize the value of the freed-up REC.[388] The underlying facts remain unchanged. The Company again testified that it does not intend to sell any Oregon-allocated RECs and is instead banking them all for future compliance obligations.[389]

---

[385] PAC/800, Dickman/30.
[386] Order No. 15-394 at 12.
[387] Noble Solutions/100, Higgins/18-22.
[388] Order No. 15-394 at 12.
[389] PAC/400, Dickman/90.

Although Noble Solutions contends that its adjustment does not assume that PacifiCorp will sell the RECs, the adjustment necessarily requires the Commission to determine a reasonable value associated with the freed-up RECs.[390] The Company testified that there is no reliable basis to value the freed-up RECs because the REC market is volatile and illiquid and that attaching a hypothetical sales price creates a significant risk of cost shifting if the REC value is over- or under-valued.[391] At hearing, Noble Solutions argued that the Company's recent RFP results provide a reasonable estimated value.[392] The purchases that may result from the RFP are quantitatively and qualitatively different from the sale of a small quantity of RECs at some undisclosed future time when a direct access customer departs.[393] Nothing has changed in the last year that would allow the Commission to now reliably estimate the value of a freed-up REC.

Second, the Commission found that direct access customers receive the benefits whenever RECs are sold.[394] This is still true and the record is no different on this point than it was in the 2016 TAM.[395] Third, the Commission concluded that the net present value of any freed-up RECs is *de minimus*.[396] This is also still true.[397]

In addition, the Company presented evidence in the 2016 TAM that the adoption of Noble Solutions' proposal would create an undue administrative burden. If a REC is hypothetically sold and the value provided to the departing customer, that hypothetically sold REC would need to be separately tracked to ensure that it is used exclusively to the benefit of remaining cost of service customers and not for the benefit of the departing customer if that

---

390 TR. 28-29 (Dickman).
391 PAC/400, Dickman/91; PAC/800, Dickman/44-45; TR. 34-35 (Dickman).
392 TR. 36 (Dickman).
393 TR. 34 (Dickman).
394 Order No. 15-394 at 12.
395 PAC/400, Dickman/90.
396 Order No. 15-394 at 12.
397 PAC/400, Dickman/90; TR. 39 (Dickman).

customer chooses to return.[398] Noble Solutions' proposal here creates the same administrative burden.[399]

Noble Solutions claims that that passage of SB 1547 and the increased renewable portfolio standards (RPS) obligation is a changed circumstance that supports its proposal.[400] On the contrary, an increased RPS obligation has provided additional reasons to reject Noble Solutions' adjustment. The increased obligation makes it more likely that the Company will continue to bank its Oregon eligible RECs indefinitely.[401] The fact that the Company's REC bank is now more administratively burdensome due to the different types of RECs created by the legislation argues against further complicating the bank by implementing Noble Solutions' proposal.[402] In addition, because RECs now have different lives, the valuation problem becomes more intractable because different RECs have different values and there is no reasonable basis to assume which RECs were freed-up by the departing customer.[403]

2. Noble Solutions presented no additional evidence or argument to support its proposed reduction in the consumer opt-out charge.

Consistent with the Commission's decisions in dockets UE 267 and UE 296, the Company's proposed consumer opt-out charge in this case uses an inflation adjustment to forecast the Company's fixed generation costs in years six through 10 and then reduce those costs to a present value to calculate the charge.[404] The Commission affirmed this

---

398 PAC/800, Dickman/45-47.
399 PAC/400, Dickman/90-91.
400 Noble Solutions/100, Higgins/19.
401 TR. 24 (Dickman).
402 TR. 24-25, 41-42 (Dickman).
403 TR. 41-42 (Dickman).
404 PAC/400, Dickman/93.

methodology three times, and Noble Solutions has presented no new arguments or evidence that would justify a different result here.[405]

The Commission has discretion under the direct access statutes and its general ratemaking authority to adopt transition charges, like the consumer opt-out charge, that account for generation costs incurred after the direct access customer departs.[406] Noble Solutions does not object to the departing customer paying Schedule 200 charges in years one through five and does not object to using inflation to forecast the Schedule 200 charges up to year five.[407] If the Commission can legally require direct access customers to pay these costs, as Noble Solutions concedes, there is no legal barrier to its use of an inflation adjustment to forecast Schedule 200 costs in years six through 10.

The crux of Noble Solutions' recommendation is the claim that after year five, the fixed generation assets are "frozen" and therefore should decrease due to accumulated depreciation.[408] But the Commission specifically found that PacifiCorp will experience transition costs through year 10 and therefore approved the consumer opt-out charge to recover the Company's fixed generation costs in years six through 10.[409] Nowhere has the Commission concluded that the generation assets are "frozen" in year five.[410] Instead, the Commission has repeatedly found that the prohibition on cost shifting requires that the Company forecast its fixed generation costs for a full ten years and recover those costs

---

[405] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 (Feb. 24, 2016); *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.

[406] *See e.g.* ORS 757.659 (directing Commission to adopt rules implementing direct access); ORS 757.607 (granting Commission discretion to determine transition charges); *Springfield Educ. Ass'n. v. Springfield School Dist.*, 290 Or 217, 230 (1980) (use of delegative terms regarding transition charges in ORS 757.607 means the Commission is "empowered to . . . make delegated policy choices of a legislative nature within the broadly stated legislative policy."); *Gearhart v. Publ. Util. Comm'n of Oregon*, 365 Or at 216, 221 (2014) (setting rates "is a unique enterprise that is governed by statute but largely left to the PUC's discretion.").

[407] Noble Solutions/100, Higgins/26; PAC/400, Dickman/93.

[408] Noble Solutions/100, Higgins/27.

[409] Order No. 15-060 at 6-7.

[410] PAC/800, Dickman/51-52.

through Schedule 200 (reflecting actual fixed generation costs in years one through five) and through the consumer opt-out charge (reflecting forecast fixed generation costs in years six through 10).[411]

The use of an inflation adjustment results in a conservative forecast that holds Schedule 200 costs constant in real terms over the entire 10-year period used to calculate the consumer opt-out charge.[412] This treatment is reasonable because there are many aspects of fixed generation costs that increase over time and offset the impact of accumulated depreciation.[413] Noble Solutions argues that Schedule 200 costs do not actually increase at the rate of inflation, relying on the Company's preliminary estimates of Schedule 200 rates from docket UE 296 and this case.[414] In reality, however, Noble Solutions' testimony simply demonstrates that the Company has not filed a new rate case since docket UE 296 to adjust Schedule 200 rates.

III. CONCLUSION

The Company respectfully requests that the Commission approve PacifiCorp's proposed 2017 TAM increase of approximately $16.2 million, or 1.3 percent. The Company's filing adheres to the modeling moratorium in place in this TAM and reflects only previously filed or approved methodologies.

Staff's largest proposed adjustment improperly re-prices all fuel costs to the Jim Bridger plant. The record shows that the Company has worked diligently to secure a diversified and least-cost fuel supply to the Jim Bridger plant, recently including transitioning to greater supply from PRB coal. The increases in BCC unit costs in 2017 are a

[411] *See* Order No. 15-060; Order No. 15-195; Order No. 15-394.
[412] PAC/400, Dickman/92.
[413] PAC/400, Dickman/94.
[414] Noble Solutions/200, Higgins/15.

function of wholesale market changes and decreasing generation dispatch, not any imprudent action or omission by PacifiCorp. Staff's adjustment relies on an inaccurate narrative regarding BCC cost escalation, downplays the economic and feasibility challenges of switching to PRB coal, and fails to acknowledge the Company's regular review of market options for Jim Bridger fuel supply.

The parties' other major adjustments in the case relitigate adjustments and issues decided in the 2016 TAM, including the calculation of EIM benefits and the system balancing transactions adjustment. The parties have not demonstrated that the modeling changes the Commission approved last year are unreasonable, nor have they proposed alternatives to improve NPC forecast accuracy. In short, there is no basis for reconsidering these issues.

The Company proposes to move forward from this TAM to a collaborative planning process with the parties regarding future coal supply to the Jim Bridger plant. The Company is also willing to participate in a generic Commission investigation on how best to model EIM benefits. It is the Company's hope that the results of these dockets will reduce controversy in the 2018 TAM and beyond.

Respectfully submitted this 14th day of September, 2016.

Katherine A. McDowell
Adam Lowney
McDowell Rackner & Gibson PC

Matthew McVee
Assistant General Counsel
PacifiCorp d/b/a/ Pacific Power

Attorneys for PacifiCorp