ORDER NO. 13 387

ENTERED: OCT 28 2013

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 264

In the Matter of PACIFICORP, dba PACIFIC POWER, 2014 Transition Adjustment Mechanism.	ORDER

DISPOSITION: NET POWER COSTS APPROVED SUBJECT TO ADJUSTMENTS

I. INTRODUCTION

PacifiCorp, dba Pacific Power, submitted its Transition Adjustment Mechanism (TAM) filing on March 1, 2013, to update net power costs (NPC) for 2014 and set transition credits for Oregon customers who choose direct access in the November open enrollment window. The company filed several corrections to its initial filing on May 14, 2013.

In its initial filing, Pacific Power requested an overall decrease of $15.5 million in NPC for calendar year 2014 over what is currently collected in rates, from $1.473 billion to $1.457 billion. This translated to a $0.4 million increase in Oregon-allocated NPC, from $362.7 million in 2014 to $363.1 million in 2014. The company identified major cost drivers for the 2014 NPC as a decrease in overall system load of 0.85 percent and a decrease of purchased power expense of $69 million, off-set by an increase in coal expenses of $41 million, an increase in natural gas fuel expense of $6 million, an increase in wheeling, hydro, and other expenses of $10 million, and a decrease in wholesale sales revenue of $4 million.

In its Reply Update, filed on September 6, 2013, Pacific Power reported updated system NPC as $1.461 billion, an increase of approximately $3.5 million from its initial filing. On an Oregon-allocated basis, updated NPC were $364.1 million, a $0.9 million increase from the initial filing. The revised TAM decrease requested by the company is $48,371.[1] On an Oregon-allocated basis, the company proposes a TAM rate decrease of approximately $0.5 million.

Pacific Power states that it modeled NPC in accordance with the Commission's final order in the company's 2013 TAM, Order No. 12-409, with updates for market caps, arbitrage and trading revenue credit, third-party wind integration, and hydro-forced outages. The filing also reflects changes in the company's system operations since the

[1] The company will reduce system NPC by an additional $1.9 million, before any additional final NPC updates, to reflect the rates adopted in the Final Record of Decision (ROD) in the Bonneville Power Administration's (BPA) recent transmission rate case, which was issued after the company's Reply Update.

2013 TAM, including the company's new 637 MW natural gas-fired generating plant (Lake Side 2), which is scheduled to come online during the test period, and the transfer of three generating facilities (Chehalis, Leaning Juniper, and Goodnoe Hills) from the BPA balancing authority area to Pacific Power's west balancing authority area.

In this order, we adopt proposed changes to the data used to model wind generation, to captive coal mine costs, and to the Jim Bridger heat rate. We reject other changes proposed by the parties.

II. PROCEDURAL HISTORY

The Staff of the Public Utility Commission; Wal-Mart Stores, Inc. (Walmart); the Citizens' Utility Board of Oregon (CUB); Industrial Customers of Northwest Utilities (ICNU); and Noble Americas Energy Solutions LLC (Noble Solutions) filed opening testimony on June 4, 2013, and Pacific Power filed reply testimony on July 15, 2013. All parties filed pre-hearing memoranda in August, followed by post-hearing briefs in September.

III. DISCUSSION

The parties propose six adjustments to Pacific Power's NPC calculation. In addition to the adjustments addressed more thoroughly below, Staff and CUB initially contested Pacific Power's proposed modeling of its interruptible contracts with three large industrial customers (Monsanto, Nucor, and US Magnesium). Pacific Power accepted the parties' objections, and agreed to forego further updates to the contracts at issue. Staff also initially claimed Pacific Power's hydro modeling did not reflect normalized conditions, but later withdrew its argument.

A. Wind Shaping

Wind generation is currently included in Pacific Power's Generation and Regulation Initiative Decision (GRID) model, the hourly production cost model that the company has used in all its Oregon rate filings since 2002. Wind generation is included in GRID based on a "P50" forecast, which projects generation at a level that is expected to have an equal probability of over or under forecasting wind output in a given year. Historically, Pacific Power has input wind generation into GRID using the P50 forecast, divided into six four-hour blocks per day. Generation was flat over the four-hour block, and each period was the same for every day during a month.

In this case, Pacific Power has continued to use the P50 forecast approach for determining total wind generation, but used actual 2011 energy output data from its owned and purchased wind facilities to shape hourly wind generation profiles. Pacific Power scaled actual generation levels up or down so that, when the output within the traditional four-hour blocks is averaged over the course of a month, it is the same as in the P50 forecast. In other words, the total energy output of the wind facilities is the same as the P50 forecast used in previous cases, but the shape of the generation varies on an hourly basis consistent with actual output during 2011. Removing this change reduces Oregon-allocated NPC by $1.1 million.

1. Parties' Positions

a. Pacific Power

Pacific Power argues that its modeling changes to shape hourly wind generation profiles are consistent with ORS 469A.120(1), which mandates recovery of costs to comply with Oregon's renewable portfolio standard, including costs to integrate, firm, or shape renewable generation. Pacific Power states that, because the design of the PCAM adopted in the company's 2012 general rate case effectively precludes recovery of wind shaping costs unless they are included in baseline NPC, it would be inconsistent with the cost recovery mandate in ORS 469A.120(1) to indefinitely eliminate wind shaping costs from the TAM.

Pacific Power further explains that the use of a single year of data permitted it to create a pattern of wind generation that reflects the actual operations of the company's wind resources, while maintaining correlations between the various projects in the company's fleet. Pacific Power states that 2011 was the first year all of the company's owned wind resources were online for a full year.

b. Staff

Staff takes no issue with continued use of the P50 method for forecasting probability of generation, and recognizes that the P50 method does not accurately reflect the intra-day variability inherent in wind generation. Although Staff believes some method to capture this variability would be an improvement, Staff does not believe it is proper to do so in this proceeding. Staff states the purpose of the TAM is to present a normalized projection of test year power cost and, as such, it is not intended to be a forecast.

In addition, Staff states that it is not persuaded that the use of one year's data is sufficient to present a normalized wind profile, given wind generation's high volatility. Staff proposes that the Commission engage in workshops with all interested parties, to develop needed improvements to the current model. With regard to Pacific Power's PCAM argument, Staff states that Pacific Power has not shown continuing to use the current methodology will result in a failure of cost recovery to the extent it would violate ORS 469A.120(1).

c. CUB

CUB states wind modeling for determining power costs is still in a state of development, and it would not be prudent to make any changes to the current method of modeling wind until further cooperative study which includes all parties to the wind issues. CUB shares Staff's concerns about Pacific Power's use on one year of data, as we do not know whether 2011 is a typical year or an outlier. CUB proposes a minimum of three years of data as a reasonable threshold for analysis. CUB requests that the company's proposed methodology be denied until more evidence can be gathered to demonstrate that 2011 has reasonable predictive value, or until the company has gathered a larger data set.

d. ICNU

ICNU states Pacific Power fails to support its proposal to reshape the hourly output of wind resources in GRID based on one year of historical data. ICNU argues Pacific Power has a history of dramatically overestimating its costs of wind integration, and that the company has not demonstrated that its current approach does not fully account for the costs of dealing with the variable output of wind resources.

In addition, ICNU notes Pacific Power did not supply the information supporting its change until its rebuttal testimony, depriving parties of the opportunity to properly examine it. ICNU adds that many of the parties that typically review the company's wind generation and wind integration cost estimates are not intervenors in this proceeding.

2. Resolution

We adopt Pacific Power's proposed change. While it may be preferable to have multiple actual years of data for use in modeling wind generation profiles, Pacific Power's proposed change nevertheless represents an improvement over the company's current modeling methodology. Pacific Power currently inputs wind generation into GRID using six four-hour blocks per day, with generation flat within each block and across each four-hour period in any given month. Pacific Power proposes to leave total energy output of its wind facilities the same as that in previous P50 forecasts, but to use actual 2011 energy output data from its owned and purchased wind facilities to shape hourly wind generation profiles. We agree with Pacific Power that improving the granularity of its modeling by including actual hourly variation will represent a superior forecasting of the dispatch value of wind output than the flat blocks the company has used in previous TAM dockets.[2]

We acknowledge the concerns raised by Staff, CUB, and ICNU that one year of data may not properly represent future years, and that use of 2011 data may skew Pacific Power's modeling as it moves forward. The parties will be permitted to introduce evidence in Pacific Power's next TAM proceeding considering additional years of data as they become available. We will consider the data at that time.

[2] As demonstrated in PAC/100, Duvall/20, figure 3, the figure presented by Pacific Power in its direct testimony, while use of 2011 data results in the same total wind generation volume as the current P50 forecast, the wind profiles resulting from 2011 data better represent the volatility of wind generation. As Pacific Power notes, this captures more of the cost impacts associated with intermittent wind generation.

B. Bridger Coal Expense

Pacific Power supplies two-thirds of its fuel needs for the Bridger plant from affiliated Bridger Coal Company (BCC) facilities, with the remaining amounts supplied from third-party Black Butte coal contracts. The third-party fuel prices for Black Butte coal are less than the affiliate fuel prices for BCC coal.

1. Parties' Positions

a. ICNU

ICNU proposes that, under OAR 860-027-0048, BCC coal should be re-priced at the current contract price for Black Butte coal. ICNU relies on OAR 860-027-0048(4)(e), which governs affiliated transactions, stating:

> When services or supplies (except for generation) are sold to an energy utility by an affiliate, sales shall be recorded in the energy utility's accounts at the approved rate if an applicable rate is on file with the Commission or with FERC. If services or supplies (except for generation) are not sold pursuant to an approved rate, sales shall be recorded in the energy utility's accounts at the affiliate's cost or the market rate, whichever is lower.

The rule defines "market rate" as the "lowest price that is available from nonaffiliated suppliers for comparable services or supplies."[3] ICNU also criticizes Pacific Power for failing to capitalize on storage opportunities, and argues the Commission should adjust the amount the company is allowed to collect for what it claims are excessive and unwarranted BCC purchases. At a minimum, ICNU advocates that the Commission should expect Pacific Power to have minimized costs by filling Bridger capacity with the lowest price coal available; as a result, the Black Butte coal market rate should apply at least to the available excess capacity at the Black Butte mine and the full storage capacity at the Bridger plant.

b. Pacific Power

Pacific Power states that OAR 860-027-0048 is an accounting rule, and that in practice, the Commission has always applied a cost-based standard to coal sales from affiliate mines, and has never adjusted the transfer price of coal from an affiliate mine in a ratemaking proceeding under the lower of cost or market standard (sometimes called the "LCM" standard).[4] Pacific Power adds that the Commission adopted OAR 860-027-0048 specifically to prevent cross-subsidization between utilities and their affiliates, and that in the case of BCC coal, there is no possibility of cross subsidization: if BCC earns a margin over Pacific Power's authorized rate of return, BCC must credit this margin back to the company through a reduced transfer price.

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[3] OAR 860-027-0048(1)(i).

[4] *See* Pacific Power Reply Brief at 9, fn. 34.

Pacific Power argues the Commission's standard for cost recovery for BCC-supplied fuel to Bridger has always been whether the cost is objectively reasonable. Pacific Power notes the Commission has expressly approved the supply agreement between BCC and Bridger as "fair, reasonable and not contrary to the public interest."[5] Even if the lower of cost or market standard applies, Pacific Power states there is no lower price coal available from a non-affiliate in this case, because the Black Butte mine does not have sufficient excess capacity to supply the Bridger plant. Therefore, coal from the Black Butte mine is not available to replace BCC coal as required by the lower of cost or market rule.

2. Resolution

We find that Pacific Power met its burden to show that its approach to coal supply for the Jim Bridger plant is "fair, just and reasonable."[6] Pacific Power presented evidence that it supplies the Bridger plant with a blend of coal from its affiliate mine, BCC, and a third-party contract with the Black Butte mine. 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."[7] The company presented testimony regarding the scarce availability of lower cost market alternatives to BCC coal for 2014, and the complexity of determining how to assess and price those alternatives.[8] Pacific Power also presented testimony and briefs supporting the argument that this Commission 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.[9] Pacific Power made a sufficient showing that its method for providing coal to the Bridger plant is fair, just and reasonable.

We now turn to ICNU's proposed adjustment to re-price BCC coal used to fuel the Bridger plant in 2014 at the 2014 contract cost of Black Butte coal. On the record presented in this docket, ICNU fails to persuade us to adopt its proposed adjustment.[10] ICNU argues that, under the LCM rule, Pacific Power "must record all of its BCC

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[5] *See* Pacific Power Opening Brief at 16, *citing In the Matter of PacifiCorp,* Docket No. UI 189, Order No. 01-472 at 2 (Jun 12, 2001).

[6] *See* ORS 757.210; *see also In the Matter of Portland General Electric Company 2012 Annual Power Cost Update Tariff (Schedule 125),* Docket No. UE 228, Order No. 11-432 at 3 (Nov. 2, 2011), *citing In re PGE Application to Amortize the Boardman Deferral,* Docket No. UE 196, Order No. 09-046 at 7-8 (Feb 5, 2009) ("Once a utility has met the initial burden of presenting evidence to support its request, 'the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement.'").

[7] Pacific Power Opening Brief at 12; *see also* PAC/600, Crane/10.

[8] *See Id.* at 18-19, noting (1) the Black Butte mine lacks sufficient excess capacity to supply the Bridger plant; (2) BCC's costs compare favorably to the costs of coal supply from other mines in Wyoming, and (3) additional coal supply from Black Butte for 2014 would be priced higher than under the current contract price. *Id.*, citing PAC/600, Crane/10-13.

[9] *See* Pacific Power Opening Brief at 17, fn. 84-86.

[10] We note that ICNU waived the opportunity to cross-examine Pacific Power's witnesses, an opportunity that would have cured any perceived "ambush" by Pacific Power in its reply testimony. *See* ICNU Post-Hearing Response Brief at 3 ("the Company has essentially ambushed the parties by withholding substantive testimony").

purchases at the market rate, if BCC pricing exceeds the market rate."[11] In order for ICNU to prevail on this argument, it must articulate a persuasive market rate to be substituted for BCC pricing. However, Pacific Power raises a number of issues with ICNU's use of Black Butte coal as the comparable market price for BCC coal, arguing primarily that the LCM rule defines "market rate" as the lowest price *available* from non-affiliated suppliers, and that in this case, no lower-cost, comparable market supplier exists for the 2014 rate period.[12] Pacific Power also contests ICNU's calculation, arguing that even if the company could obtain sufficient additional coal supply from Black Butte, the price would be higher than the current contract price, which is now several years old.[13] In response, ICNU cites in its brief to the testimony of a Pacific Power witness in Utah, stating that Pacific Power intends to replace significant amounts of BCC supply with Black Butte coal in 2015-2017.[14] ICNU argues this strengthens its claim that Black Butte has sufficient capacity to supply Bridger with coal at prices below BCC's. Pacific Power counters that ICNU selectively quotes from and misrepresents the company's Utah testimony. We find ICNU's use of the 2014 contract cost of Black Butte coal as a substitute for BCC coal under the LCM rule to be unpersuasive in this docket. We reject the proposed adjustment.

However, we adopt the 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.

C. Adjustments to Captive Coal Mine Costs

1. Parties' Positions

a. Staff

Staff proposes what it calls a "rate-case type adjustment" to certain itemized operations and maintenance costs related to the Bridger and Deer Creek affiliated captive coal mines. Staff proposes to disallow 100 percent of the costs for management overtime, and 50 percent of the costs for management bonuses. Staff's proposal results in an Oregon-allocated decrease of approximately $460,000.

Staff states that its proposed adjustments are consistent with prior Commission policy. Staff argues the activities Pacific Power describes that generated the overtime costs at issue are typical costs, and there is no reason to depart from prior Commission precedent for their disallowance. With regard to bonuses, Staff followed Commission precedent to share the costs between ratepayers and shareholders. To the extent the company's Annual Incentive Plan (AIP) results in management employees receiving more than base

[11] ICNU Prehearing Memorandum at 7.
[12] *See* Pacific Power Reply Brief at 10, citing PAC/600, Crane/11.
[13] *See* Pacific Power Opening Brief at 18-19.
[14] *See* ICNU Post-Hearing Response Brief at 10-11.

salary based upon good performance, Staff views them as bonuses and they should be treated accordingly.

b. Pacific Power

Pacific Power argues Staff's citation to precedent is not on point, because Staff does not identify any cases where the Commission authorized the adjustments proposed here for affiliated mines. Pacific Power notes that the overtime expenses at issue here were required to ensure, as a safety measure, the presence of front-line supervisors during additional weekend shifts, as well as coverage for vacation or absenteeism. Pacific Power argues Staff's "bonus" adjustment should likewise be rejected, because the company's AIP is not a bonus plan, but rather an integral part of employee compensation.

2. Resolution

At the outset, we clarify that Staff's proposal seeks an adjustment to coal supply costs through the reduction of O&M costs at the Bridger and Deer Creek mines. We also acknowledge that the orders cited by Staff generally address adjustments to O&M costs in general rate case proceedings.

Nonetheless, we agree with Staff that our precedent, particularly Order No. 10-022, in which we reaffirmed the proposal "that 100 percent of officer bonuses and 50 percent of annual incentive plan bonuses be removed from rates," should be applied here to reduce the costs of coal supplied by these mines.[15] As noted in its reply testimony, Pacific Power itself requires supervision of represented employees during all shifts, and the management personnel at its affiliate mines are eligible for the same AIP as that offered to the rest of the company. We are not persuaded that employees of an affiliate who are eligible for the same employee incentive plans offered to the rest of the employees of Pacific Power, and who are subject to supervision requirements imposed by Pacific Power, should nonetheless be treated differently with respect to sharing of bonuses and overtime expense.

D. Jim Bridger Heat Rate Improvement

1. Parties' Positions

a. ICNU

ICNU seeks an adjustment to Pacific Power's power costs modeling to reflect an efficiency improvement to one of its generating facilities.[16] ICNU explains that, in the company's pending general rate case, docket UE 263, Pacific Power seeks cost recovery for an estimated $31 million for an efficiency upgrade to its Jim Bridger 2 facility.

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[15] *See In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 210, Order No. 10-022 at 11 (Jan 26, 2010).

[16] ICNU also argued in its testimony that Pacific Power's use of a full 48 months to develop an adjustment to the heat rate for Bridger 1 improperly diluted the improved efficiency from a May 2010 upgrade. However, as we discuss further below, ICNU abandoned that argument in its pre-hearing brief.

ICNU states that that the primary benefit of the project is an increase in generating capacity, with no additional fuel requirement to maintain maximum output.

ICNU argues Pacific Power improperly excluded these efficiency improvements to Bridger 2 from its power cost modeling in this case. In order to correct that error, ICNU proposes to impute, for Bridger 2, the average heat rate for Bridger 1 since the Bridger 1's turbine was upgraded in May 2010. Based on the company's testimony in docket UE 263 and responses to data requests in this docket, ICNU states that Pacific Power anticipates the Bridger 2 upgrade to produce similar heat rate improvements as those obtained at Bridger 1.

ICNU notes that Pacific Power traditionally estimates heat rates in its GRID model based on the most recent 48-month period. Using that method here, however, the efficiency improvements to Bridger 2 would not be fully reflected until 2015, although customers would already have been paying for the capital improvements. To remedy this, ICNU argues Bridger 1's known, measurable, post-upgrade average heat rate should be used to model power cost costs for Bridger 2 for 2014.

b. Pacific Power

Pacific Power contends that ICNU's proposed adjustment is contrary the company's traditional practice, to the parties' stipulation in the company's 2011 TAM, docket UE 216, and ICNU's arguments in that docket. Pacific Power also contends the adjustment is speculative.

Pacific Power explains that 48 months of historical data is used because it aligns with the historical period used to normalize other thermal attributes in the company's filing, specifically forced and planned outage rates, which typically cycle every four years. Pacific Power states using only the period immediately following an outage would understate the normalized heat rate.

Pacific Power notes that in docket UE 216, the company proposed incremental increases to heat rates for three units, to reflect the addition of emissions control systems. ICNU objected to that adjustment, arguing it would open a "can of worms" to make ad hoc adjustments to address the expected or assumed reliability benefits of a new investment.[17] For that and other reasons, the stipulation subsequently adopted in that docket specifically requires the use of a 48-month average for derivation of heat rates in the company's TAM filings. As part of a stipulated settlement in docket UE 216, the company agreed that, absent a change in facts or circumstances identified by the company, it would rely on the traditional analysis of four years of actual data to derive heat rate inputs. Pacific Power notes that it has abided by this agreement despite additional reductions in net generation related to capital improvements at its plants. Finally, Pacific Power states that ICNU's adjustment is speculative, because Bridger Units 1 and 2 did not undergo the same type of turbine upgrade.

[17] PAC/100, Duvall/22, *citing* Docket No. UE 216, ICNU/100, Falkenberg/54.

2. *Resolution*

We find that ICNU's proposed adjustment results in a more accurate assessment of the heat rate at Bridger 2, and we adopt the proposed adjustment. Pacific Power has accurately described the order we issued in docket UE 216, adopting the parties' stipulation that the company would rely on a four-year analysis to derive heat rate inputs *absent a change in facts or circumstances.*[18] In this case, however, ICNU has presented us with a change in circumstances, namely, the efficiency improvements resulting from the Bridger 2 turbine upgrade. We agree with ICNU that accurate net power cost modeling should include timely integration of these benefits, and direct Pacific Power to use the average heat rate for Bridger Unit 1 since that unit's turbine upgrade for power cost modeling purposes for Bridger Unit 2 for 2014.

ICNU presented testimony in this docket proposing a similar heat rate adjustment should be made for Bridger 1, explaining that Pacific Power's use of a full 48 months of data improperly diluted the improved efficiency at that plant resulting from a May 2010 upgrade. ICNU, however, abandoned that argument in its pre-hearing brief. Although ICNU's reasoning that we adopted for the upgrade at Bridger 2 applies equally to the upgrade at Bridger 1, we will not adopt an adjustment when a utility had no opportunity to respond to legal arguments in favor of that adjustment. Parties must clearly present all proposed adjustments in their briefs. As a result, we decline to adopt any purported adjustment proposed in ICNU's testimony regarding net power cost modeling for Bridger 1.

E. Calculation Methodology

Pacific Power's transition adjustment charges or credits direct access customers the difference between Pacific Power's net power cost, as reflected in Schedule 201, and the estimated market value of the electricity that is freed up when a customer chooses direct access service. The transition adjustment is calculated using the GRID model. The estimated market value of the electricity that is freed up when a customer chooses direct access service is determined by running two system simulations: one with Pacific Power serving direct access load, and one with the company not serving direct access load. These simulations are run assuming direct access occurs in 25 MW decrements, which are shaped using the load shape of the rate schedule being analyzed for purposes of determining its Schedule 294 or Schedule 295 credit or charge. The difference between the two scenarios is used to calculate the impact on Pacific Power's total system, which is then used to determine the weighted market value of the energy freed up due to direct access. The weighted market value of the energy is then compared to the customer's price under Schedule 201 to determine the credit or charge.

[18] *See In the Matter of PacifiCorp, dba Pacific Power, 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363, Appx A at 3-4 (Sept 16, 2010) (adopting stipulation providing that, "absent a change in facts or circumstances identified by the Company," Pacific Power "* * * will not implement adjustments for scrubbers or other capital projects, but instead will rely on the traditional analysis of four years of actual data to derive the heat rate inputs").

1. Parties' Positions

a. Noble Solutions

Noble Solutions argues Pacific Power's use of the GRID model, which produces a valuation of energy freed up by direct access that is based on a blend of market prices and thermal generation costs, violates our rules and results in an artificially under-market energy valuation that drives customers away from the company's direct access program. Noble Solutions states that because the incremental cost of thermal generation is typically less than market prices, blending market prices and thermal costs produces a lower valuation of freed-up energy. To remedy this, Noble Solutions argues Pacific Power should calculate transition adjustments using the value of energy freed up by direct access, as measured directly from the company's projection of market prices at the California-Oregon Border and Mid-Columbia trading hubs.

Noble Solutions notes our rules require Pacific Power to measure the value of freed-up power at the projected cost of market power, because the rules assume that Pacific Power should be able to dispose of the energy freed-up by direct access through market transactions, thus warranting the use of projected market prices to value freed up energy.[19] Noble Solutions notes that Portland General Electric Company calculates its transition adjustment by a simple comparison to projected market prices, and also includes a credit for BPA transmission freed up by direct access customers, resulting in a much higher customer participation rate than Pacific Power's.

Noble Solutions maintains this is a new argument, resulting from the Commission's decision in the 2013 TAM to permit Pacific Power to stop relaxing market caps by 25 MW for the purpose of determining the transition adjustment. Noble Solutions states the market cap relaxation is directly tied to the logic of the transition adjustment exercise that assumes a 25 MW incremental market demand for direct access power has been created. Noble Solutions states that failing to relax market caps in this assumed situation rigs the result in advance, to the detriment of direct access customers, and warrants our reconsideration on this issue.

b. Walmart

Walmart supports Noble Solutions' argument that GRID underestimates the market value of freed-up energy resulting from direct access load leaving Pacific Power's system, resulting in transition charges that present an economic barrier to customers seeking direct access service.

[19] *See* Noble Solutions Response Brief at 2-3, *citing* OAR 860-038-0005(42) ("'Ongoing valuation' means the process of determining transitions costs or benefits for a generation asset by comparing the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period"); OAR 860-038-0140 (stating that an electric company will "use an ongoing valuation method to determine the transitions costs or transition credits applicable to Oregon cost-of-service consumers until otherwise directed by the Commission").

c. *Pacific Power*

Pacific Power states that it has relied on GRID to calculate the transition adjustment in every TAM filing from 2005 to the present. Pacific Power states relying exclusively on market prices would result in an inflated transition adjustment and illegal cost shifting to non-participating customers. In the 2013 TAM, the Commission approved Pacific Power's proposal to eliminate the relaxation of GRID's market caps when calculating the transition adjustment, concluding that GRID's market caps are designed to approximate liquidity restraints that exist in the markets in which Pacific Power transacts, and that relaxing market caps would result in an overestimation of the value of freed-up energy. Noble Solutions' complaints about a GRID-based approach are also inaccurate. Pacific Power notes that using the Commission-approved method demonstrates that the modified GRID run used to calculate the transition adjustment is based almost entirely on market prices (99 percent for heavy load hours and 92 percent overall). It is only during light load hours that 16 percent of the transition adjustment is based on the costs of thermal generation.

2. *Resolution*

We agree with Pacific Power that we have addressed the use of GRID to calculate the transition adjustment in previous dockets, and we decline to adopt Noble Solutions' proposed change in this docket. As Pacific Power notes, we considered, and rejected, a market price approach in favor of using differential GRID runs to value the loss of direct access load in docket UM 1081.[20] In a subsequent Pacific Power rate case, docket UE 179, we noted our previously stated goal that a transition adjustment "will value utility resources impacted by direct access based on actual, appropriate operational responses." At the time we decided docket UE 179, we had adopted an interim TAM for Pacific Power, and we directed the parties to "work toward developing a TAM that values resources affected by direct access using actual, appropriate operational responses." ICNU then advocated for a "market-plus" approach, and objected to the use of GRID because it "does not capture the value" of freed-up resources. We rejected ICNU's position, and adopted the GRID-based TAM proposed by Pacific Power. As we noted at the time, the "purpose of the TAM is not to promote direct access," but rather "to capture costs associated with direct access, and prevent unwarranted cost shifting."[21]

In the case of Pacific Power, we agree that relying solely on a forecast of prices in a major, formally constituted electricity market may not accurately reflect an actual estimate of direct access costs, because Pacific Power's utility operations "are complex and multidimensional. As demonstrated by GRID modeling, [Pacific Power] operates an integrated, multi-state utility that has numerous and geographically diverse energy and

[20] *In the Matter of Public Utility Commission of Oregon Investigation into Direct Access Issues for Industrial and Commercial Customers Under SB 1149*, Docket No. UM 1081, Order No. 04-516 (Sept 14, 2004).

[21] *In the Matter of Pacific Power & Light Company Request for a General Rate Increase in the Company's Oregon Annual Revenues*, Docket No. UE 170, Order No. 05-1050 at 20-21 (Sept 29, 2005).

transmission resources."[22] Our elimination of the relaxation of market caps in the 2013 TAM was intended to improve the accuracy of GRID calculations, not to trigger a new review of the merits of GRID. We decline to adopt Noble Solution's proposed change.

F. BPA Transmission Credit

1. *Parties' Positions*

a. *Noble Solutions*

Because Pacific Power owns 636 MW of long-term, point-to-point BPA transmission from Mid-Columbia (Mid-C) to serve cost-of-service customers, Noble Solutions argues the Schedules 294 and 295 transition adjustment calculations should be modified to include a credit of $1.422 per MWH. Noble Solutions finds it unreasonable for Pacific Power to take the position that the company would be unable to use any freed-up transmission assets for any economic purpose if eligible customers were to choose direct access. Noble Solutions states Pacific Power may now sell its BPA PTP rights, and it is reasonable to assume that Pacific Power should do so. Noble Solutions states inclusion of a transmission credit in the transition adjustment calculation is an assumption that has been a part of PGE's calculation for years, because it is reasonable to assume that when customers choose direct access some amount of transmission formerly used to serve them is freed-up for other economic uses. Noble Solutions argues the Commission should expect Pacific Power to put freed-up transmission to an economic use and appropriately credit direct access customers for that freed up economic utility investment.

b. *Pacific Power*

Pacific Power states that in the 2013 TAM order, Order No. 12-409, the Commission considered and rejected the proposal that the transition adjustment should include an adder for freed-up transmission costs as a result of the direct access customers. The Commission found no compelling evidence was presented that Pacific Power is able to resell BPA transmission rights due to direct access. Pacific Power argues nothing has changed since that decision that warrants reconsideration. Pacific Power states the Commission's conclusion was consistent with Commission precedent; the Commission has previously rejected "market plus" proposals, reasoning that the purpose of the TAM is not to promote direct access.

2. *Resolution*

As with our decision on calculation methodology, our decision here rests on the complexity of Pacific Power's system and the difficulty in looking at one part of its system in isolation. For example, as Pacific Power noted in its testimony in this docket, the company uses Mid-C transmission rights "to help serve a much larger quantity of

[22] Order No. 04-516 at 9-10 *See also* PAC/500, Duvall/30 ("the [c]ompany's generation resources previously used to serve departing direct access customer load are primarily located at some distance from major markets").

Oregon customers and optimize the dispatch of its system to the benefit of all retail customers."[23] Since the expenses associated with Mid-C transmission "are paid for by all retail customers, not just those in Oregon," Pacific Power argues "assigning a 100 percent share to a departing direct access customer would be inappropriate."[24] Depending on the location of the lost load, Pacific Power may also need to acquire additional transmission to deliver the freed-up generation to market. Comparisons to PGE's system do not address these differences.

We find no compelling reason to depart from our precedent. We rejected a proposal to recognize a BPA transmission credit in Order 12-409 in docket UE 245, and affirmed the ruling on reconsideration in Order No. 13-008. We affirm our previous ruling on this issue.

[23] *See* PAC/500, Duvall/33.
[24] *Id.*

III. ORDER

IT IS ORDERED THAT:

1. Advice No. 13-005 is permanently suspended.

2. PacifiCorp, dba Pacific Power, shall update its net power costs (NPC) to reflect the changes adopted in this order to establish its Transition Adjustment Mechanism NPC for the calendar year 2014, filing tariffs to be effective January 1, 2014.

Made, entered, and effective OCT 28 2013.

Susan K. Ackerman
Chair

Stephen M. Bloom
Commissioner

<u>Commissioner Savage Concurring on the Bridger Coal Expense</u>:

I agree with the majority's decision on the recovery of Bridger coal expense. Pacific Power's testimony in a previous docket strengthens the argument that Bridger coal costs must be assessed over a period of years, and not yearly as proposed by ICNU, because of the nature of the mining operation. The full costs of surface mine stripping are included in the costs of Bridger coal in the year it is uncovered, even if the stripping results in inventory that is extracted in future years. Because coal "may or may not be extracted in the same year stripping costs have been incurred," Bridger coal costs should be examined on a multi-year basis. Single year costs may be inappropriately skewed for accounting reasons only and may not be a reasonable assessment of Bridger coal costs.[25]

John Savage
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

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[25] *See In the Matter of PacifiCorp, dba Pacific Power 2010 Transition Adjustment Mechanism*, Docket UE 207, PPL/201, Lasich/1-2.