ENTERED DEC 11 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of PACIFICORP, dba PACIFIC POWER, 2016 Transition Adjustment Mechanism	FINAL ORDER

DISPOSITION: APPLICATION GRANTED

I. INTRODUCTION

In Order No. 15-353, we granted PacifiCorp, dba Pacific Power's 2016 Transition Adjustment Mechanism (TAM) application in a preliminary order. In this order we describe more fully the parties' positions and the rationale for our decisions.

PacifiCorp's final update for its 2016 net power costs (NPC) shows Oregon-allocated power costs of $373.4 million. This results in an overall annual rate increase of approximately $9.4 million or 0.7 percent. This is approximately $3.0 million less than the forecast described in Order No. 15-353.

II. BACKGROUND

Order No. 15-353 describes the background of this filing, which we only briefly summarize here. PacifiCorp's TAM is an annual filing with the objective to forecast the actual NPC the company expects to incur during the test year (12 months ending December 2016) to account for changes in market conditions. It also identifies the proper amount for the transition adjustment for customers wishing to move to direct access service.[1]

The Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and Noble Americas Energy Solutions LLC (Noble Solutions) intervened in this proceeding. All parties filed two rounds of testimony, prehearing memoranda, and two rounds of briefs. A hearing was held on August 25, 2015.

[1] Under OAR 860-038-0275, each electric company must announce by November 15 the prices to be charged for electricity services in the next calendar year. For a more thorough discussion of the TAM, *see e.g.*, Order No. 09-274 (adopting the TAM guidelines) (Jul 16, 2009); Order No. 09-432 (refining TAM guidelines) (Oct 30, 2009); Order No. 14-331 (2015 TAM update) (Oct 29, 2014).

III. DISCUSSION

A. Background

PacifiCorp's 2016 TAM increases NPC by $9.4 million or 0.7 percent, for $373.4 million in Oregon-allocated NPC. PacifiCorp states that its NPC increase is due to several changes in GRID[2] modeling, a decrease in wholesale power sales revenue driven by its system balancing modeling change and lower electricity prices in the forward market, and an increase in purchased power expense due to its system balancing modeling change and new qualifying facilities (QFs).

In Order No. 15-353, we concluded that PacifiCorp met its burden to establish that its 2016 TAM filing will result in rates that are fair, just and reasonable. We found that the company had justified the need for the modeling changes it proposed with evidence in the record that was not adequately rebutted by the parties. We accepted no adjustments suggested by intervenors or the three changes requested by Noble Solutions. We imposed a one-year moratorium on PacifiCorp changing the GRID model to allow parties adequate time to understand, review, and evaluate recent changes to the model.

We provide below additional discussion of the parties' arguments and the reasoning to support our decisions below.

B. GRID Modeling Changes

1. System Balancing Modeling Change

a. Parties' Positions

PacifiCorp's system balancing transactions occur when PacifiCorp buys hourly and daily power when it needs additional resources to balance demand and supply and sells hourly and daily power when it has excess power resources. PacifiCorp made two changes to its modeling of system balancing transactions. First, it included separate, adjusted prices for short-term purchases and sales in its forward price curves.[3] Second, it added additional balancing volumes.[4] The impact of these modeling changes is $8 million.

PacifiCorp explains that it made these changes because its analysis of short-term transactions at multiple trading hubs from July 2011 through June 2014 showed that "at every trading hub, and for both on and off peak purchases and sales, in nearly every month for 36 months, it has been the case that purchases tend to cost more per MWh than

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[2] GRID stands for Generation and Regulation Initiative Decision Tool. GRID is PacifiCorp's hourly production cost model that the company has used in its Oregon rate filings since 2002.
[3] *See* PAC/500, Dickman/21-22 (a step-by-step explanation of the calculation).
[4] PAC/100, Dickman/20 (PacifiCorp increased system balancing transaction volume by 28 percent to reflect incremental balancing volumes associated with using 25 MW block monthly and daily products, and closing its position with real-time hourly products).

average spot prices and sales tend to have occurred below the average monthly spot price* * *."[5] PacifiCorp adds that the systematic difference in prices occurs because short-term resource needs are largely determined by loads and wind generation, which are correlated with market prices. Purchases tend to occur during higher-priced periods and sales tend to occur during lower-priced periods.[6]

Staff, CUB, and ICNU oppose this modeling change. ICNU and CUB assert that the power cost forecast should use a forward price curve that represents an unbiased, median estimate for future spot prices. ICNU and CUB characterize the system balancing modeling change as extraneous GRID adders, or out of model adjustments. CUB states the purpose of the TAM is to forecast power costs on a weather-normalized basis, with weather-related variations addressed in the Power Cost Adjustment Mechanism (PCAM), and also accounted for in the company's return on equity. CUB also states that PacifiCorp's proposal will allow one bad hydro year (or other weather event) to lead to over-forecasting of system balancing purchases, and that historical averages are not appropriate for variables that are highly influenced by weather and hydro conditions. PacifiCorp responds that its multi-year rolling average is a common normalizing tool.

ICNU also believes PacifiCorp is including a bid-ask spread by proposing to model a higher price for purchases than for sales in the same market at the same time. ICNU requests we adopt an alternative spread between purchases and sales of $0.50/MWh, which would reduce NPC by $1.7 million, and also remove the market caps. PacifiCorp answers that its proposal is similar to past adjustments made by Idaho Power Company and Portland General Electric (PGE) to use separate purchase and sale pricing.[7] CUB distinguishes these cases, stating that Idaho Power is more hydro dependent than most utilities, and Idaho Power's adjustment used normalized prices for purchases and sales, not actual historical (non-normalized data). CUB states that PGE's proposal for super-peak pricing was reduced in the second partial stipulation, in response to parties' concerns that it was inconsistent with normalized forecasting.

ICNU also opposes the additional volumes that PacifiCorp seeks to add. ICNU believes a better way to address any finding that transactional volume is too low in GRID modeling would be to eliminate the market cap mechanism which presently constrains transactional volume in GRID. PacifiCorp replies that the issue of market caps was fully litigated in the 2013 TAM and approved because market caps prevent the GRID model from artificially increasing sales to illiquid market hubs. PacifiCorp asserts that removal of the market caps would overstate the company's short-term market sales.

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[5] PAC/200, Graves/8.

[6] PAC/507, Dickman/1 (showing that PacifiCorp's system balancing purchases were, on volume weighted average, $3.47/MWh over the market average price, and system balancing sales were $5.42 below the average market price).

[7] *In the Matter of Idaho Power Co. Request for General Rate Revision*, Docket No. UE 167, Order No. 05-871 at 17-18 (Jul 28, 2005) (allowing Idaho Power to use on-peak prices for purchases and off-peak prices for sales). We grant PacifiCorp's request to take official notice of the Idaho Power testimony in UE 167, Idaho Power/300, Peseau/17-19, pursuant to OAR 860-001-0460(1)(d). *In the Matter of Portland General Electric Co. 2015 Annual Power Cost Update Tariff*, Docket No. UE 208, Order No. 09-433 at 3 (Oct 30, 2009).

Staff recommends the Commission open an investigation to allow the parties more time to explore the company's proposed changes. Staff fundamentally agrees with PacifiCorp's goal of improving GRID's modeling of balancing transactions, but Staff could not understand and verify the price and volume adders proposed, due to their complexity and the time constraints of this docket.

b. Resolution

Based on the evidence in the record, we are persuaded that short-term power purchase prices systematically exceed short-term power sales prices.[8] We are also persuaded that PacifiCorp has offered a reasonable adjustment to its forward price curve to account for these expected price differences that will result in a more accurate estimate of net power costs.[9]

We concur with PacifiCorp that its historic GRID modeling understated volumes of transactions because it assumed the volumes of purchases and sales matched exact needs. PacifiCorp's proposal increases balancing transaction volumes to reflect that. Based on the evidence in the record, we accept PacifiCorp's adjustment to increase balancing transaction volumes to reflect that the company balances its system with hourly products and 25 megawatt (MW) block monthly and daily products.

We are not persuaded by the intervenors' arguments to reject or modify PacifiCorp's modeling changes. First, with regard to CUB's concern that this adjustment should be rejected because it is not normalized, we note that PacifiCorp's use of three years of data is sufficient to smooth out variations to generate a reasonable estimate of expected spot price differentials. Second, with regard to ICNU's proposal to remove market caps, we addressed that issue in a prior order and adhere to that reasoning to keep market caps in GRID.[10] Third, we reject ICNU's recommendation to adopt an alternative bid-ask spread adjustment, because we agree with PacifiCorp that the difference in prices for short-term purchases and sales is not a bid-ask spread.

Finally, we reject Staff's request to open an investigation to examine GRID changes. Parties have had sufficient time and opportunity to review and assess the proposal. At the same time, we encourage parties to examine this modeling change in more detail in the next TAM cycle. Again we reiterate that we impose a moratorium on GRID modeling changes in the 2017 cycle to provide time for Staff, parties, and the Commissioners to get a better understanding of the GRID modeling changes that have been made over the past few years.

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[8] For the 36 months ended June 2014, PacifiCorp's short-term firm transactions with deliveries spanning less than one week increased NPC by an average of $7.1 million compared to the historical average market prices. PAC/100, Dickman/26.

[9] *In the Matter of PacifiCorp, dba Pacific Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 9 (Oct 29, 2012) ("Our goal is to appropriately value Pacific Power's resources and we support adjustments to the valuation model only when there is evidence of a flaw in the model.").

[10] Order No. 12-409 at 7-8 (concluding that some form of market caps continue to be needed in GRID).

2. *Regulating Reserves*

a. *Parties' Positions*

PacifiCorp proposes to reflect regulation reserve requirements for its balancing authority areas (BAAs) on an hourly basis instead of flat monthly amounts. PacifiCorp uses the results from its 2014 Wind Integration Study to set hourly regulation reserves based on the hourly wind and load forecast. The company estimated reserves using a 99.7 percent confidence interval level and assumed compliance with its current North American Electric Reliability Corporation (NERC) reliability standard (RBC/BAAL). This change increases NPC by $0.5 million, due to more hours when the reserves are higher than the monthly average.

ICNU argues that PacifiCorp's reserve estimate is unduly conservative and proposes a reduction in regulation reserves based on the company's past (CPS2) performance. ICNU states that the company averaged 65 percent confidence with the prior reliability standard, and expects PacifiCorp to operate at a lower interval in the future due to EIM participation. ICNU suggest a 90 percent predictive confidence interval as a compromise that would reduce NPC by $2.8 million. PacifiCorp states that ICNU's adjustment would slash the company's regulation reserves by one-third.

b. *Resolution*

Based on the evidence in the record, we accept PacifiCorp's regulation reserves estimate and reject ICNU's proposed adjustments. We find that the CPS2 score is not relevant for calculating the regulation reserves needed to comply with the RBC/BAAL standard.[11] PacifiCorp provided unrebutted evidence that ICNU's proposed reduction would result in insufficient regulation reserves at certain times that could force PacifiCorp to curtail load or violate the standard, depending on the deviation for the entire interconnection.[12] Further, the 99.7 percent confidence interval is consistent with the confidence intervals derived by Bonneville Power Administration (BPA) and BC Hydro in similar studies, and PacifiCorp's 2014 Technical Review Committee expressed no concern with the company's use of a 99.7 percent confidence interval to determine reserve levels.[13]

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[11] PAC/500, Dickman/47-49 (CPS2 measured the number of violations, not the magnitude of the violation, and the new RBC/BAAL standard measures deviations relative to the impact on the interconnection as a whole). At hearing, ICNU explained that it disagrees with the wind integration study being structured around this standard, but we do not have enough evidence in this record to disregard the wind integration study. Tr. at 18 (Aug 25, 2015).

[12] PAC/500, Dickman/52 (ICNU's proposal would result in insufficient regulation resources in 10 percent of each month).

[13] *See In the Matter of PacifiCorp, dba Pacific Power's 2015 Integrated Resource Plan,* Docket No. LC 62 at Appendix H (Mar 31, 2015) (the independent committee commented favorably on PacifiCorp's discussion and justification for its 99.7 percent exceedance level, noting that it reflected the company's policy of 100 percent reserve compliance).

Finally, we also note that PacifiCorp's reliability analyses suggest that "the company may need to consider more regulation reserves, not less, to maintain compliance with the RBC/BAAL standard in the future."[14]

3. Forced Outage Modeling Adjustment

a. Parties' Positions

PacifiCorp proposes to model forced outages and de-rates for individual plants rather than apply a uniform de-rate factor to all plants for all operating hours. PacifiCorp's revised method does not require adjustments for heat rates or minimum operating levels.

ICNU and Staff ask that PacifiCorp continue to use its current methodology and that we move this issue to a generic docket. ICNU states that PacifiCorp's proposal will result in a pattern of frequent, short outages not representative of normalized operations. PacifiCorp replies that, in Order No. 10-414 we found that the methodology was imperfect and encouraged future refinements.

b. Resolution

Consistent with the method we set forth in our Order No. 10-414, PacifiCorp still uses a four-year average of actual outage events to forecast plant outage duration and adjusts the average for lengthy individual plant outages.[15] Based on the unrebutted evidence, we find PacifiCorp's revised method results in projected plant availability distribution that better aligns with historic plant operations.[16]

We encourage parties to explore the modeling adjustment in the next TAM proceedings.

4. Wind Modeling: Avian Compliance and PPA Modeling

a. Parties' Positions

PacifiCorp made two changes to its forecasts of generation output at its wind plants. First, it reduced the projected generation output at the Glenrock and Seven Mile Hill wind sites to reflect expected energy lost to comply with a court order to reduce the risk to eagles. Second, PacifiCorp forecasted output from its wind power purchase agreements (PPAs) based on 48 months of actual generation results (or a combination of actual results and generator forecasts if forty-eight months of information is not available).

ICNU counters that the company should use the same generation output assumptions for ratemaking that were originally used to justify the wind facilities and the PPAs. For the

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[14] PAC/500, Dickman/52.

[15] *In the Matter of Public Utility Commission of Oregon Investigation into Forecasting Forced Outage Rates for Electric Generating Units,* Docket No. UM 1355, Order No. 10-414 at 7 (Oct 22, 2010).

[16] *See* PAC/100, Dickman/35, Figure 2.

avian protection, ICNU states that the Wyoming wind projects were controversial at the time they were built. For the PPAs, ICNU states that the pricing negotiated for these contracts was based upon an assumed level of generation.

b. Resolution

We agree with PacifiCorp that its proposed adjustments will yield more accurate wind generation forecasts. We reject ICNU's proposals on two grounds. First, PacifiCorp must comply with the court order for avian protection. Second, actual wind generation at the wind PPA sites has been lower than forecasted. Forty-eight months of actual operation is sufficient for deriving a reasonable forecast of expected wind generation at a site that is superior to the long-range forecasts provided by the project owners.

5. EIM Benefits

a. Parties' Positions

PacifiCorp proposes $1.3 million in EIM costs and approximately $3 million in EIM benefits on an Oregon-allocated basis.[17] PacifiCorp increased the EIM benefits to address intervenors' arguments over lack of summer data, new EIM participants in 2016, and reduced flexibility reserves due to the new participants.

PacifiCorp explains that the majority of the EIM benefits are due to the company exporting to the California Independent System Operator (CAISO), and are reflected in the NPC report as wholesale sales revenue ($7.5 million company-wide). EIM imports from CAISO are a reduction to purchased power expense ($1 million company-wide). The remaining benefits are due to reduced flexibility reserves because of the diversity of the combined load in a larger footprint ($1.54 million company-wide).

Staff and intervenors raise numerous objections to PacifiCorp's forecast of EIM benefits and propose adjustments. First, Staff and ICNU contend that PacifiCorp has under-forecasted EIM benefits. Staff argues that PacifiCorp should impute an additional $1.07 million in EIM dispatch benefits from the Idaho Power asset exchange, which increased the dynamic transfer capability between PacifiCorp's west and east BAAs from 200 MW to 400 MW. Staff explains that the company's marginal resources are located in the east balancing area and must be dynamically transferred to the west BAA before being exported to CAISO. PacifiCorp disagrees, stating that it will use the additional dynamic transfer capability for the balancing of its own resource (intra-regional transfers), which are already modeled in GRID. PacifiCorp also questions whether its coal-fired east-side resource will be dispatched in the EIM when its natural gas units have a similar marginal energy cost and when CAISO imports incur a greenhouse gas charge.

[17] PacifiCorp Prehearing Memorandum at 2 and 19 (Aug 17, 2015) states approximately $3 million in EIM benefits on an Oregon-allocated basis. This value is not used in testimony or exhibits. *See infra* n. 18.

ICNU asserts that PacifiCorp should have reduced reserves due to the increased dynamic transfer capability from the Idaho Power asset exchange. PacifiCorp disagrees, stating that there is no mechanism for sharing flexibility reserves under the EIM. PacifiCorp clarifies that it can transfer contingency reserves from one BAA to another, but the transfers must be scheduled in advance, and then the dynamic transfer capability is no longer available to the EIM.

Second, several parties raise concerns about the limited data PacifiCorp used to forecast the benefits. PacifiCorp responded with additional historical results, a proposal for EIM results through September 2015 via its final update, and provided greater weight to the June 2015 results to address seasonality concerns. Staff supports PacifiCorp's revised proposal. CUB recommends that we accept PacifiCorp's forecast and defer the difference between that forecast and the actual results for later ratemaking treatment. CUB explains that a deferral is appropriate with less than one year of data upon which to base a forecast. ICNU states that seven months of data requires some type of proxy be used to model EIM benefits and address seasonality, and recommends PacifiCorp model EIM benefits based on the market spreads between two trading hubs, which would reduce NPC by $0.4 million.

Finally, ICNU raised concerns about the benefits that might be provided by new EIM participants – NV Energy, Puget Sound Energy (PSE), and Arizona Public Service (APS). Although PacifiCorp included additional $0.4 million on an Oregon-allocated basis to account not only for NV Energy's full year of participation, but also for three months of PSE and APS participating, ICNU continues to assert that NPC should be reduced by an additional $0.8 million to account for the new entrants joining the EIM.

b. Resolution

We accept PacifiCorp's forecast of EIM benefits in the test period of $2.7 million on an Oregon-allocated basis, and reject the adjustments proposed by Staff and ICNU.[18] We find that, PacifiCorp's 2016 EIM benefits, net of EIM costs, are $1.41 million on an Oregon-allocated basis.

We reject Staff's recommendation to increase interregional EIM benefits based on the increased dynamic transfer capability between PacifiCorp's BAAs because there is insufficient evidence to support that adjustment. PacifiCorp has explained that interregional EIM exports are limited by several factors depending on timing, including available California Oregon Intertie (COI) capacity;[19] COI congestion in California;[20] and

[18] EIM benefits are incorporated into the NPC report and not specifically listed in testimony, so we have applied Oregon's 25.464 percent allocation factor to the total-company figures in PAC/506, Dickman/1 ($9,104,990 in EIM exports and imports), PAC/100, Dickman/9 ($1.0 million in initial flexibility reserves savings), PAC/500, Dickman/13 and Dickman/43 ($213,000 in additional reserve savings for PSE and APS joining in October 2016 and $323,000 in additional reserve savings for NV Energy interconnecting with PacifiCorp's east balancing area) = $2.71 million in Oregon-allocated benefits. EIM costs are reported in PAC/505, Dickman/1 as $1.3 million on an Oregon-allocated basis.
[19] PAC/500, Dickman/56 ("The export benefit is also tied to the transmission capacity available for EIM transactions in each month of the forecast period.").

the economics of generating resources.[21] PacifiCorp has also explained that some of the increased dynamic transfer capability will go for intraregional transfers which are already modeled in GRID. Further, Staff's analysis fails to account for the greenhouse gas adders that would change what resources are economic to meet imbalance energy needs. Thus, we cannot conclude that additional transfer capability between PacifiCorp's BAAs will necessarily increase EIM benefits.

We reject ICNU's proposed adjustment to increase flexibility reserve savings due to the increased dynamic transfer capability between PacifiCorp's BAAs. PacifiCorp has explained that increased dynamic transfer capability will be used for intraregional EIM transfers and for contingency reserve transfers occurring outside of the EIM. PacifiCorp states, without rebuttal, that it cannot dynamically transfer flexibility reserves between BAAs.

We also reject ICNU's proposed seasonality adjustment to forecast interregional EIM benefits for the test period. We agree with PacifiCorp's assessment of the flaws in the proposed modeling adjustment. Based on the evidence in the record, we agree with PacifiCorp that the spread between market prices in Oregon and California is not representative of the benefits that will be achieved and that the assumption of identical export volumes is unwarranted.

We accept PacifiCorp's approach to incorporate benefit results through September 2015 and its methodology for generating estimates for the test year period months. We concur that this approach will yield reasonable estimates of interregional benefits.

We concur with PacifiCorp that ICNU's estimates of the incremental interregional EIM benefits due to NV Energy, PSE, and APS are unjustifiably and unreasonably high. The estimates are considerably higher than estimates generated in the separate studies prepared by the Energy and Environmental Economics used by PacifiCorp. Further, we agree that ICNU fails to account for diminishing returns from increased transfer capability and overstates the transmission capacity available to support transfers between PacifiCorp's east BAA and NV Energy's BAA.

C. Generation Portfolio: Hermiston PPA and Hermiston Transmission Contract

1. Parties' Positions

ICNU challenges PacifiCorp's decision not to renew the Hermiston PPA, as well as the company's earlier decision to renew the transmission contract associated with the PPA. This PPA is for the output of the 50 percent share of the plant that is not owned by the

[20] PAC/100, Dickman/13 ("During periods of transmission congestion on the COI, even if the company has economic resources and transmission available to the California-Oregon Border (COB), the CAISO may not be able to import EIM volumes.").
[21] PAC/100, Dickman/17 ("In other periods, the Company may not have sufficient resources that are economic at the CAISO market price to fill the entire available path.").

company. ICNU argues that PacifiCorp was imprudent in only considering its summer peaking needs in making the decision not to renew the PPA, noting that PacifiCorp's 2015 Integrated Resource Plan (IRP) stated that a winter peaking resource may be needed in the near-term. ICNU also contends that PacifiCorp was imprudent in renewing the PPA transmission agreement before analyzing whether it would extend the underlying PPA.

2. Resolution

We reject the recommendations by ICNU to find termination of the Hermiston PPA imprudent and disallow the costs of the point-to-point transmission that had served the plant. With regard to the decision to not renew the PPA, we find that PacifiCorp adequately evaluated its system peak needs and the resources needed to meet its peak needs in its IRP. Based on its evaluation, PacifiCorp concluded the Hermiston PPA was an expensive source of capacity and was not needed. In addition, the inclusion of the PPA will pose immediate costs to customers by increasing NPC by $3 million.

With regard to the transmission contract, PacifiCorp was contractually required to terminate or renew the transmission contract nine months before the renewal deadline for the Hermiston PPA. Further, PacifiCorp provides unrebutted evidence that the line will be used during the forecast period, and that contract renewal is worthwhile to maintain its rollover transmission rights. Accordingly, we find no basis to disallow costs.

D. Direct Access Adjustments

PacifiCorp's TAM is used to establish transition adjustment charges or credits that direct access customers must pay. The charge is the difference between net power costs in Schedule 201, and the estimated market value of the electricity that is freed up when a customer chooses direct access.[22]

1. Parties' Positions

Noble Solutions asks for three changes related to the direct access charge. First, Noble Solutions states that the transition credit for freed-up generation should include the value of Renewable Portfolio Standard (RPS) compliance, asserting that PacifiCorp's RPS compliance obligation is reduced for direct access departing load, thus freeing up renewable energy credits (RECs) that were previously acquired by PacifiCorp to serve that load. Noble Solutions states that, without a REC credit, direct access customers pay for RPS compliance twice, once from PacifiCorp and once from their Electricity Service Supplier (ESS). Because there is not a market index for the value of the RECs, Noble Solutions proposes using the average sales price of PacifiCorp's unstructured (or unbundled) RECs as a reasonable proxy price.

[22] *See* Order No. 13-387 at 10 (Oct 28, 2013); Order 12-409 at 14 (Oct 29, 2012).

PacifiCorp responds that the Commission requires the company to bank all RECs that are compliant with the RPS.[23] PacifiCorp states that it may not be able to sell RECs freed-up by departing direct access load, and that if a benefit did occur it is unnecessary to include that revenue as a transition credit because the revenue would be passed back to all customers through the property sales balancing account.[24]

Second, Noble Solutions challenges the escalation of the Schedule 200 opt-out charge in PacifiCorp's five-year opt-out program. Noble Solutions explains that the opt-out charge should be limited to the generation investment incurred prior to the sixth year. Noble Solutions states that once that portfolio is frozen, the revenue the company earns will decline each year as a portion of those assets is depreciated and amortized. Noble Solutions asks that the Schedule 200 entry decline 2.36 percent per year from years 6 through 10.

PacifiCorp responds that the consumer opt-out charge properly escalates the company's fixed generation costs at the average rate of inflation—so the fixed generation costs are held constant through year 10. PacifiCorp states that the Commission has already denied Noble Solutions' request to decrease the consumer opt-out charge in years 6 through 10 in docket UE 267,[25] and that Noble Solutions has not presented any new evidence or arguments.

Third, Noble Solutions seeks a change in the five-year opt-out program enrollment deadline. Currently, if a customer opts out, but does not submit its Direct Access Service Request (DASR) by the cutoff date, then the customer's opt-out election reverts to the one-year program. Noble Solutions states that this approach is different than the one and three year program policies and is unjustified. Noble Solutions states that the customer with the late DASR should have the option to enter the five-year program late by paying PacifiCorp all applicable five-year opt-out charges that would have applied to the customer with a timely DASR. PacifiCorp states that the company's five-year opt-out program is treated differently than the one-year and three-year program because customers pay transition adjustments for the five-year program and are then no longer subject to transition adjustments, and a late DASR would pay less than the full five years of transition adjustments.

Regarding the deadline to submit a DASR, PacifiCorp had stated that, if the Commission does allow leeway with the deadline, then the customer should pay the difference between the one-year and three-year programs and the five-year program; that service from the ESS begin no later than February 1; and that the company receives the completed DASR from the ESS no later than 13 days before the commencement of service from the ESS. Noble Solutions agreed to this proposal, but PacifiCorp maintained that its deadline policy should not be changed.

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[23] PacifiCorp Prehearing Memorandum at 31 (citing *In the Matter of PacifiCorp, dba Pacific Power, Application for Sale of Renewable Energy Credits,* Docket No. UP 266, Order No. 11-512 (Dec 20, 2011)).
[24] PacifiCorp Prehearing Memorandum at 31 (citing PAC/500, Dickman/84).
[25] PacifiCorp Prehearing Memorandum at 32 (citing *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out,* Docket No. UE 267, Order No. 15-195 at 2 (Jun 16, 2015)).

2. *Resolution*

We reject all of Noble Solutions' proposed changes. Noble Solutions' formula for valuing freed-up RECs assumes PacifiCorp will sell its RECs. As PacifiCorp points out, today and for the foreseeable future, PacifiCorp will be banking RECs. Further, PacifiCorp states if the RECs are sold in the future, departing direct access customers will receive a share of the revenues from sales. At best, the net present value of the value of any freed-up RECs is *de minimis.*

We have previously addressed the claim that the customer opt-out charge should be reduced to reflect a more accurate estimate of fixed generation costs. Noble Solutions has produced no new evidence or argument to persuade us to change our positon. PacifiCorp explains that incremental generation is not added after year five.[26] PacifiCorp also explains that, in real (inflation-adjusted) terms, the fixed generation costs are held constant through year 10. As we did in previous orders, we find it reasonable to assume that fixed generation costs will increase at the rate of inflation after year five.

Finally, the four-week time period allowed is ample time for the ESSs to file direct access requests.[27] We find no compelling reason to allow for late requests, and the record does not show customers struggling to submit DASRs in the December time period under the current one-year and three-year programs.[28]

IV. ORDER

IT IS ORDERED THAT:

1. Advice No. 15-005 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 2016, filing tariffs to be effective January 1, 2016.

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[26] Noble Solutions/100, Higgins/23.
[27] PAC/800, Ridenour/4.
[28] Noble Solutions/105, Higgins/5. In the last six years, there have been three DASRs that did not allow the ESS to begin service on January 1, and these three DASRs were submitted in the months of March and May, for the one-year program (under the one-year and three-year opt-out program the consumer is moved to one-year direct access service 13 business days after the DASR is received due to the ongoing nature of the transition adjustments under the program).

3. PacifiCorp, dba Pacific Power, will make no changes to its GRID modeling for its 2017 TAM, and is directed to work with parties and the Commission to allow thorough review and evaluation of recent GRID model changes.

Made, entered, and effective DEC 11 2015.

Susan K. Ackerman
Chair

John Savage
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

Commissioner Bloom concurring:

I support today's order but write separately to set forth my concern that this TAM proceeding, with PacifiCorp's numerous proposed changes to GRID, left the parties and this Commission little time to evaluate and verify the assertions made by PacifiCorp. The complexity of PacifiCorp's TAM filings and GRID adjustments has been a recurring theme—one raised by both the parties and the Commission.[29] I acknowledge PacifiCorp's attempts to explain the workings of GRID to parties at various workshops. Despite these efforts, however, many stakeholders appear to be lacking the necessary understanding of the model that would allow them to sufficiently comprehend proposed modeling changes and respond to them as necessary in a compressed TAM proceeding.

The difficulty of understanding GRID is exacerbated by PacifiCorp's continual adjustments to it. For example, the system balancing change adopted in this order adds another layer of complexity to the company's forward price curve and hourly scalars that we adopted not long ago in the 2012 TAM. Similarly, the forced outage modeling change adds more detail and cost to the previous "haircut" method that PacifiCorp adopted following our directives in docket UM 1355. I signed the order today because I believe that the company has shown that these refinements and new adjustments will produce a more accurate GRID forecast. However, I remain concerned that the parties had little time to catch-up and understand recent GRID adjustments before PacifiCorp proposed a new layer of adjustments here. Moreover, although these significant changes deserved close scrutiny, they needed to compete for attention as the parties focused on other NPC items and a disputed EIM benefit forecast.

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[29] *See e.g., In the Matter of PacifiCorp, dba Pacific Power, 2012 Transition Adjustment Mechanism,* Docket No. UE 227, Order No. 11-435 at 21 ("We initially observe, as a general matter, that a stand-alone TAM is intended to be a streamlined proceeding. Review and verification of the company's complex modeling presents a serious challenge, particularly in the context of a stand-alone TAM proceeding, when the Commission is presented with limited information and a short timeframe for decision.").

To give the parties additional time to understand GRID and the various adjustments adopted in this and prior proceedings, we have imposed a one year moratorium on PacifiCorp making further changes to the model. During this moratorium, I ask PacifiCorp to renew and increase its efforts to explain GRID to the parties with the hope of resolving some of the recurring GRID questions, such as short-term transactions and outage modeling. I would also request a Commissioner workshop once the parties have had time to work together.

Stephen M. Bloom
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.