ORDER NO. 12 409

ENTERED OCT 29 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 245

In the Matter of PACIFICORP dba PACIFIC POWER 2013 Transition Adjustment Mechanism	ORDER

DISPOSITION: NET POWER COSTS APPROVED SUBJECT TO ADJUSTMENTS

I. BACKGROUND

On February 29, 2012, PacifiCorp, dba Pacific Power (Pacific Power) filed revised tariff sheets for Schedule 201 (Advice No. 12-002), as well as testimony and exhibits regarding the company's 2013 Transition Adjustment Mechanism (TAM). The purpose of the TAM is to update Pacific Power's annual net power costs (NPC) and to set transition credits for the company's Oregon direct access customers. Pacific Power seeks an effective date of January 1, 2013, for the revised Schedule 200 tariff sheets. We docketed the filing as UM 245 for investigation.[1]

Pacific Power estimates its NPC based on projected data from the company's Generation and Regulation Initiative Decision (GRID) model, an hourly production cost model that the company has used in all its Oregon rate filings since 2002.[2] To initially forecast a NPC for the 2013 TAM filing, the company updated the following GRID inputs: system load, wholesale sales, purchase power expenses, wheeling expenses, market prices for natural gas and electricity, fuel expenses, and the characteristics and availability of generation facilities.[3] The company further updates its NPC forecast at various points throughout and after a TAM investigation.[4]

In its initial filing, Pacific Power forecasted normalized system-wide NPC of approximately $1.504 billion for the 12-month test period ending December 31, 2013. This equates to approximately $370.2 million on an Oregon basis—$3.5 million higher

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[1] Pacific Power made its 2013 TAM filing concurrently with a request for a general rate revision. That rate request, docketed as UE 246, is not addressed in this order.

[2] *In Re Pacific Power and Light: Request for General Rate Increase*, Docket No. UE 170, Order No. 05-1050, pp. 19-21.

[3] PAC/100, Duvall/12, ll 5-8.

[4] The scope and procedures of the TAM are governed by the Commission's TAM Guidelines, adopted in Order 09-274 (Appendix A at 9-19), as modified by Order No. 09-432 (Appendix A) and Order No. 10-363 (Appendix A).

than the NPC this Commission authorized in docket UE 227, Pacific Power's 2012 TAM. In addition, Pacific Power forecasted that it would under-collect $6.4 million due to a decrease in Oregon loads in the 2013 test period. Therefore, it sought an overall increase in rates of approximately $9.9 million, or approximately 0.8 percent.

Following the intervention by the Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and Noble Americas Energy Solutions LLC (Noble Solutions), and the filing of testimony by all three parties as well as the Commission Staff, Pacific Power filed a July 11, 2012 Update to its NPC. In its update, Pacific Power accepted two adjustments proposed by other parties: (1) Staff's $0.2 million Oregon NPC reduction related to dispatch modeling at the Chehalis generating facility; and (2) ICNU's $0.9 million Oregon NPC adjustment to remove the costs of integrating generation from the Rolling Hills wind farm. Those adjustments, combined with other GRID updates, reduced Pacific Power's Oregon-allocated NPC by approximately $6.5 million to $363.7 million. This resulted in a revised TAM proposed rate increase of $3.4 million, or approximately 0.3 percent.

On July 12, 2012, certain parties to the concurrent Pacific Power rate case proceeding, docket UE 246, filed a partial stipulation resolving cost of service and rate spread issues in that docket. Four of those parties—Pacific Power, CUB, INCU, and Staff—are parties to the instant proceeding. In the UE 246 partial stipulation, the parties agreed that Pacific Power would use generation allocation factors contained in that stipulation to determine the rate spread in this case.

A hearing in this docket was held on August 16, 2012. Staff and parties filed opening briefs on August 6, 2012, prehearing briefs on September 14, 2012, and closing briefs on September 21, 2012.

II. DISCUSSION

A. Scope of this Proceeding

1. Parties' Positions

ICNU and CUB allege that the TAM has functioned as a single issue rate case that harms—never benefits—ratepayers, while being inconsequential for direct access customers. Acknowledging that the Commission will have an opportunity in Pacific Power's general rate case to eliminate the TAM, ICNU and CUB ask the Commission to take some initial "steps toward dismantling the TAM by ordering a TAM-related rate decrease and directing Pacific Power to abandon the use of its flawed GRID model in all future rate proceedings."[5] Alternatively, argues ICNU, Pacific Power should be directed to use a power supply model created by a third party vendor rather than the proprietary GRID.

[5] ICNU-CUB's Joint Closing Brief, p. 2.

2. Resolution

This is not the appropriate forum to address the future of the TAM. We adopted parameters for the conduct of TAM proceedings in Order No. 09-274, as refined by the stipulation adopted by Order No. 07-446 (docket UE 191). In Order No. 09-274, we indicated that the purpose of a TAM is to "update [Pacific Power's] forecast net power costs to account for changes in market conditions," and set the transition adjustment for direct access customers. As part of this updating process, we expect parties to review the forecast NPC and propose adjustments. Larger concerns with the nature and process of a TAM are outside the scope of an individual TAM proceeding.

Proposed Adjustments to Pacific Power's 2013 TAM

The parties, including Staff, recommend certain adjustments to Pacific Power's proposed NPC calculation that the company opposes. The adjustments would collectively reduce Pacific Power's proposed NPC by approximately $7.2 million on an Oregon basis, decreasing rates by approximately $3.8 million.[6] Pacific Power characterizes all of the proposed adjustments as "technical in nature," challenging aspects of the company's GRID model, but not the core elements of the NPC or the company's management of the NPC. Five proposed adjustments remain contested, as discussed below.

1. Remove Market Caps

a. Parties' Positions

i. Pacific Power

Pacific Power states that GRID assumes unlimited market depth for short-term firm (STF) transactions, and does not take into account load requirements, all actual transmission constraints, market illiquidity, or static assumptions about market prices precluding sales at the forecast price.[7] To prevent GRID from overestimating sales revenue due to these modeling limits, Pacific Power uses market caps to limit sales based on a range of past market transactions. Pacific Power indicates that market caps have been used to model the Oregon NPC since GRID was first introduced in docket UE 134, in 2002.[8] Pacific Power observes that neither Staff nor ICNU points to historical problems with market caps or explains perceived current problems in the context of their historical use.

Pacific Power explains that before the 2012 TAM, the company capped sales, based on average spot prices, during graveyard hours at four major wholesale markets (Mid C, COB, Four Corners, and PV), while capping the Mona market in all hours.[9] Pacific Power indicates that ICNU challenged this methodology in the 2012 TAM, arguing that

[6] PAC/100, Duvall/11, ll 17-22; PAC/300, Duvall/11, ll 11-12.
[7] *Id.* at 18, ll 10-13.
[8] PAC/300, Duvall/11, ll 11-12.
[9] PAC/100, Duvall/19, line 10.

the caps should be based on all STF transactions during all hours.[10] Pacific Power asserts that it adopted ICNU's proposals, revising its cap methodology to apply caps, based on a four-year average of total short-term wholesale sales, to all hours. For six markets (the Mid C, COB, Four Corners, PV hubs, as well as the Mona and Mead hubs), the company specified market depth in all hours, segregated by heavy load hours (HLH) and light load hours (LLH), and based the cap on a four-year historical average of STF, balancing, and spot sales.[11] Pacific Power indicates that for the 2012 TAM filing, the new market caps methodology reduced the NPC by $10 million.[12]

Both Staff and ICNU raised concerns about the refined market caps methodology introduced in Pacific Power's 2012 TAM proceeding. Both objected to the change in methodology in a proceeding that did not provide sufficient opportunity to investigate the methodology. In Order No. 11-435 (docket UE 227), the Commission approved the company's market cap methodology on a non-precedential basis, but directed Staff to organize one or more workshops to further discuss the methodology with interested parties. The Commission also indicated that if no agreement was reached regarding revisions to the methodology, that Pacific Power would be expected "to provide clear and robust evidence justifying its modeling of market caps in the company's next TAM proceeding."[13] In such an event, the Commission also indicated that Staff would be expected to undertake its own technical analysis of the market cap methodology. Following a party workshop on January 11, 2012, the parties agreed it likely would not be possible to reach an agreement, and instead, that analyses and recommendations should be proffered in Pacific Power's 2013 TAM proceeding. In the 2013 TAM, Pacific Power re-introduced its refined market caps methodology that reduces the NPC by $4 million compared to the prior approach.[14]

Pacific Power characterizes the Commission's directive in the 2012 TAM as a request that the company demonstrate in the 2013 TAM that the use of market caps was "reasonably representative of the company's actual operations."[15] Pacific Power asserts that the testimony and exhibits presented in this case do just that. Pacific Power also observes that the Commission has rejected prior proposals to alter the company's modeling methodology when the results of the methodology were not demonstrated to be unreasonable.[16]

In this proceeding, Pacific Power revised GRID to cap modeled potential market sales every hour (for each trading hub, each month, differentiated by on- and off-peak) based on the company's actual average historical sales during the preceding four-year period.

[10] Pacific Power Prehearing Brief, p. 13 (Aug 6, 2012)
[11] PAC 100, Duvall/19, ll 18-21.
[12] PAC/300, Duvall/12, ll 5-6.
[13] Order No. 11-435 at 23.
[14] PAC/300, Duvall/12, ll 21-23.
[15] Order No. 11-435 at 23.
[16] Pacific Power's Prehearing Brief, pp. 9-10, citing Order No. 07-446 at 26. (Rejecting an ICNU proposal to change the company's approach to modeling the capacity of a plant, the Commission stated: " We defer to the company's judgment where it has been running the model using [this approach] for several years and ICNU has not shown that the results were unreasonable.")

Once the caps are triggered, even if GRID shows that Pacific Power has resources available to earn a margin at market prices, GRID will not assume that these resources may be dispatched. Pacific Power asserts that market caps are an important input to GRID because they reflect constraints in the actual wholesale power market, restricting GRID's default assumption of unlimited market depth for STF sales. Pacific Power indicates the methodology is appropriate as the Commission has recognized for other NPC elements that past performance based upon a four-year rolling average is an appropriate predictor of future performance. Pacific Power also observes that market caps moderate, but do not eliminate, GRID's "undisputed" overestimation of actual physical sales.[17]

Pacific Power asserts that removing market caps from GRID would result in a 23 percent increase in the number of short-term sales modeled.[18] Pacific Power disputes ICNU's contention that sales will not significantly increase, arguing that ICNU compares "apples and oranges" by comparing a historical average inclusive of bookouts against a GRID model result exclusive of a bookout.[19] Coupled with the fact that GRID already overestimates actual sales, Pacific Power argues that this increase will further distort the company's modeling and unreasonably reduce the forecast NPC. Basing market caps on hourly sales levels instead of monthly heavy load and light load averages, as Staff and ICNU suggest, would also result in GRID significantly overestimating total actual wholesale sales volume.[20] Pacific Power also argues that market caps are needed because without the caps, "GRID shifts sales from liquid hubs, with their generally lower market prices, to illiquid hubs, with their generally higher market prices."[21]

ii. Staff

Staff believes that Pacific Power's revised market cap methodology that sets, as a cap, the same average historical sales level in every hour in GRID, is "inconsistent with both actual historical and uncapped GRID sales figures, both of which show great variation across hours."[22] Staff asserts that this approach cuts off potential sales with positive margins, resulting in a $15.5 million overstatement of expected NPC on a total company basis, and approximately $3.9 million on an Oregon-allocated basis.[23] Staff asks the Commission to direct Pacific Power to either subtract these amounts, or to re-run GRID without market caps.[24]

Staff rebuts Pacific Power's claim that the removal of market caps would not dramatically increase the number of sales. Staff estimates that there would be an increase in sales of approximately 2,500 GWh in context of the company's system-wide load of

[17] *Id.* at 10-11, citing PAC/100, Duvall/20, Table 5; PAC/300, Duvall/18, Figures 1 and 2; 19, ll 1-4.
[18] PAC/300, Duvall/16.
[19] *Id.* at 15 ("Bookouts are financial transactions that are offsetting at the same market hub.")
[20] ICN/100, Deen/8.
[21] Pacific Power's Opening Brief at 19.
[22] Staff's Prehearing Brief, p. 1.
[23] Staff/100; Schue/5, ll 5-6.
[24] *Id.* at ll 6-8.

approximately 60,000 MWh. Staff also accuses the company of exaggerating its claims by graphing data based on actual data for a 12-month period ending June 2011, rather than the 48-month period ending June 2011 used to derive the market caps.[25] Staff asserts that the graphs "incorrectly show GRID capped sales being greater than actuals, which would be impossible if the relevant 48-month actual data were used."[26]
Should the Commission determine that arguments by Staff and Pacific Power both have merits, and that market caps should be revised but not eliminated, Staff recommends an alternative market caps methodology that would change how the caps are calculated.[27] Staff analyzed two alternative approaches, ultimately recommending an approach based upon a concept first suggested by ICNU at the January 11, 2012 party workshop.[28] The alternative approach would base the market cap for a particular on- or off-peak month at a particular trading hub on the highest of the four most recently available relevant sales averages, rather than on the average of the four averages. Staff indicates that its alternative approach "would effectively 'split the difference' between the Company's approach and Staff's recommended no cap approach."[29] Applying Staff's alternative approach would reduce the system NPC forecast by $7.7 million, resulting in a 2013 NPC forecast approximately half way between the results advocated by Staff and Pacific Power.[30]

iii. ICNU

ICNU calls market caps an artificial limit devised by Pacific Power that causes inaccurate estimates of the company's actual sales activities.[31] ICNU explains that utilities, including Pacific Power, offset total NPC by engaging in short-term sales at each interconnected market hub, but unlike other utilities, Pacific Power caps these potential sales in its power cost model. ICNU recommends the market caps be removed because there are many hours in which actual sales exceed the historic sales averages used as caps, resulting in an inflated estimate of forecast NPC in this case. ICNU complains that Pacific Power "limits only the amount of profitable market sales that it can make, but does not impose any limitations or caps on the amount of its costly market purchases that can be made in GRID."[32] ICNU also asserts that other mechanisms within GRID prevent the model from assuming that Pacific Power will make unlimited short-term sales.

ICNU disputes the notion that removing the market caps will dramatically increase short-term sales, asserting that the new levels will still be below historic averages.

ICNU argues that Pacific Power's assertion that removing market caps in GRID will distort actual market transactions is not supported by evidence, pointing out that the

[25] PAC/300, p. 18, figures 1 and 2; PAC/100, p. 21, table 6; Staff's Prehearing Brief, p. 2.
[26] Staff's Posthearing Brief, p. 7.
[27] Staff/100, Schue/16-18.
[28] *Id.* at 16.
[29] *Id.* at 18.
[30] Staff/100, Schue/16-17.
[31] ICNU's Prehearing Brief, p. 3.
[32] ICNU-CUB's Joint Posthearing Brief, p. 9.

company first raised the argument in briefing.[33] ICNU agrees that removing the market caps will increase modeled sales at the smaller hubs, but claims that Pacific Power does not show that the modeled sales levels at the individual hubs (including the smaller hubs), without market caps, will be outside of a reasonable range.

ICNU claims that Pacific Power's argument that market caps are necessary to address market illiquidity distorts ICNU's testimony and briefing in this and other cases, and is not based on evidence presented by the company in this case. ICNU also points out that Pacific Power's assertion that other utilities use dynamic pricing to account for liquidity supports moving away from GRID entirely. ICNU states, "[a]t a minimum, not making the model worse, with one-sided restrictions that harm customers and reduce the accuracy of its forecast of market sales, would be an improvement."[34]

b. *Resolution*

The parties raise two fundamental questions: (1) Does Pacific Power's GRID model need market caps to produce realistic estimates of sales; and, if so (2) What is the nature of the market caps that should be adopted?

Pacific Power's request to further revise market caps shows that the company has continuing problems with GRID accurately forecasting sales and the dispatch of generation. Pacific Power argues that, without the caps, GRID makes incorrect assumptions about market depth for STF transactions, and fails to take into account critical inputs such as load requirements, transmission constraints, and market illiquidity. Even with market caps, Pacific Power argues that GRID overestimates market sales. We note, however, that even though Staff and ICNU recommend that market caps be removed, neither assert that GRID will function perfectly without them.

Because GRID is a forecasting model that is only as good as its constructs and inputs, the real question presented is not whether market caps should be used as a patch to address certain limitations of the GRID model, but whether the GRID model itself should be fixed. As we have already indicated, that question is not one that we can fully address in this proceeding. Pacific Power should understand, however, that as the company and others continue to raise questions about the accuracy and reasonableness of GRID forecasts, we will expect Pacific Power to refine its modeling to produce the best possible estimates of all components of net power costs.

As Pacific Power observes, market caps have always been part of GRID and neither Staff nor ICNU persuasively argue that GRID, as it is currently exists, no longer needs market caps. Based upon the evidence presented in this proceeding, we conclude that some form of market caps continue to be needed in GRID as it is now constructed. For this reason, we reject the recommendations of Staff and ICNU to eliminate market caps.
Staff and ICNU effectively argue, however, that an alternative market cap methodology is superior to Pacific Power's revised market cap methodology. We adopt the alternative

[33] ICNU-CUB's Joint Closing Brief, p. 9.
[34] *Id.* at 11.

approach suggested by Staff and direct Pacific Power to revise GRID to base market caps on the highest of the four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours.

2. Arbitrage and Trading Revenue Credit

a. Parties' Positions

In Pacific Power's 2008 TAM, the Commission directed the company to adjust the NPC calculation to impute an incremental revenue credit into its NPC to reflect a profit margin on certain STF transactions that were not being modeled in GRID.[35] The decision was based on two findings: (1) GRID systematically understates wholesale sales volumes as compared to historical actual volumes; and (2) there was no evidence that the company's arbitrage transactions were accounted for in GRID.

For the 2013 TAM, Pacific Power proposes to eliminate the arbitrage and trading and revenue credit on the basis that the conditions justifying an arbitrage adjustment no longer exist. Since the 2008 TAM, the company indicates it has added both STF transmission and non-firm transmission to GRID's topology. Pacific Power asserts that GRID no longer underestimates wholesale sales volumes, and in fact overestimates these sales volumes. The company observes that the transactions covered by this adjustment have been steadily declining, along with the associated revenue credit, suggesting that this revenue credit will soon become *de minimus*. Pacific Power argues that continuing to include the arbitrage and trading revenue credit would result in the over-forecasting of sales activity, largely based on transactions dating back to 2007, and the lowering of system NPC by approximately $2.5 million.[36]

ICNU and CUB oppose this proposal. ICNU argues that the company's rationale for removing the adjustment is undermined by evidence showing that GRID is not over-forecasting sales activity relative to the company's historical levels.[37] ICNU further argues that the trading and arbitrage adjustment does not double count revenues associated with such transactions, but instead imputes revenues that GRID does not count. Pacific Power's power cost model only accounts for a small portion of hourly system balancing sales, ICNU argues, and the trading and arbitrage adjustment ensures that the company's modeling more realistically accounts for all the company's sales. Pacific Power responds that ICNU's opposition is based on an erroneous calculation of actual sales volumes.[38] The company points out that when ICNU argues that GRID does not model arbitrage sales, ICNU fails to account for system balancing sales and purchases modeled in GRID, transactions that serve as proxies for STFs.[39]

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[35] Order No. 07-446 at 10-11.
[36] PAC/300, Duvall/22, ll 16-17.
[37] ICNU/100, Deen/4-5.
[38] Pacific Power's Prehearing Brief, p. 19, citing ICNU/100, Deen/5.
[39] *Id.* at 20.

CUB acknowledges that GRID now currently "greatly overestimates" wholesale sales volumes compared to actual sales volumes—as opposed to underestimating them in the 2008 TAM.[40] CUB argues, however, that the arbitrage and trading revenue credit "is a safeguard that would protect customers in the event that the company is able to take advantage of arbitrage opportunities in a way that is not otherwise included in the TAM estimate of net power costs."[41] Pacific Power retorts that GRID's overestimation of sales already provides a safeguard for customers.[42]

Staff takes the view that the arbitrage and trading revenue credit together with market caps are adjustments to GRID that introduce too much volatility to the modeling of NPC.[43] Staff supports Pacific Power's proposal to discontinue the arbitrage and revenue credit if the market cap structure is also discontinued.

b. Resolution

In Pacific Power's 2008 TAM, we identified two specific modeling flaws with GRID and directed Pacific Power to make the appropriate adjustments to compensate for these flaws. The company complied in subsequent TAM proceedings by instituting the arbitrage and trading revenue credit. Now, Pacific Power asserts that the company has fundamentally addressed the basis for the modeling flaws, rendering the revenue credit unnecessary and counter-productive to accurately estimating the company's NPC.

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. When the model flaw itself is addressed, the adjustment should be reduced or eliminated. We are persuaded that Pacific Power has revised GRID's topology to address the identified flaws and approve elimination of an adjustment that we directed the company to institute to compensate for the flaws.

3. Inclusion of Third-Party Wind Integration Costs

a. Parties' Positions

Pacific Power's proposed NPC includes approximately $3.87/MWh in NPC costs for integrating wind generation in the company's balancing authority areas, broken down between inter-hour costs of wind integration for system balancing, and intra-hour costs for increasing operating reserves in certain hours. Pacific Power asserts that all of the third-party integration costs are incurred due to the company's status as a balancing area

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[40] CUB/100, Jenks-Feighner/2.
[41] *Id.*
[42] Pacific Power's Prehearing Brief, p. 20.
[43] Staff/100, Schue/19 ("In the 2012 NPC calculations, market caps increased NPC by $5.5 million and the arbitrage and trading adjustment decreased NPC by $3.0 million, for a net effect of $2.5 million increase in NPC. In the Company's initial 2013 filing, market caps increase NPC by $15.5 million, and there is no arbitrage and trading adjustment, resulting simply in a $15.5 million increase in NPC. This is too much volatility from controversial adjustments.").

authority, which provides generalized benefits to all customers.[44] ICNU, joined by CUB, challenges the inclusion of costs associated with the integration of third-party generator transmission customers, recommending a $0.8 million downward adjustment for the Oregon-allocated NPC.[45]

ICNU analyzed the wind-integration costs to determine whether they are associated with generation that provides benefit to Oregon customers, or whether the costs are caused by the company's wholesale transmission customers.[46] ICNU argues a cost-causation theory that Oregon ratepayers should pay only for the integration of generation facilities that directly provide benefits to Oregon customers, and not for the integration of third-party generation that are transmission customers of Pacific Power.[47] Accordingly, ICNU argues that the company should remove integration costs associated with wind generation facilities owned by third-parties.[48] Pacific Power challenges this cost-causation theory, arguing that ICNU does not challenge "the corresponding revenues in Docket UE 246 for third-party storage and integration" that "fully offset third-party wind integration costs, producing a net benefit for customers."[49]

ICNU asserts that Pacific Power should obtain compensation from the wind generators that impose integration costs on the company.[50] They observe that the Washington Utilities and Transportation Commission (WUTC) agrees, stating: "These costs should be borne by the third-parties who create these costs, not by Washington ratepayers who do not receive the power generated at these faculties."[51] Moreover, they indicate that the Idaho Public Utilities Commission (IPUC) rejected the company's request to impose both the variable and fixed costs of integrating third-party wind generators.[52]

Pacific Power responds that ICNU and CUB fail to acknowledge the existence of favorable precedent from the Utah Commission allowing third-party wind integration charges in rates.[53]

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[44] PAC/300, Duvall/29.
[45] ICNU-CUB's Joint Posthearing Brief, pp. 25-26, citing PAC/300, Duvall/31 (The adjustment was revised from $1.6 million to $0.8 million to remove adjustment for costs for third-party wind integration for which Pacific Power receives revenue credits.).
[46] ICNU/100, Deen/15-16.
[47] ICNU-CUB's Joint Posthearing Brief, p. 22, citing Docket No. UE 245, PAC/300, Duvall/9-10. (ICNU asserts that Pacific Power agrees with this cost-causation position, having previously removed all integration costs associated with the company's Rolling Hills facility on the basis that Oregon ratepayers should not pay for integration costs for generation facilities not in Oregon rate base.)
[48] ICNU/100, Deen/15-16.
[49] Pacific Power's Opening Brief, p. 23, citing PAC/300, Duvall/31.
[50] *Id.*
[51] WUTC Docket UE-100749; Order No. 06 ¶126.
[52] ICNU-CUB's Joint Posthearing Brief, p. 25, citing *Re Rocky Mountain Power 2010 General Rate Case,* IPUC Case No. PAC-E-10-07, Order No. 32196 at 30 (Feb 28, 2011); Docket No. UE-100749, Order No. 6 at ¶ 125.
[53] Pacific Power's Prehearing Brief, p. 22, citing FERC Docket No. 09-035-23, Report and Order on Revenue Requirement, Cost of Service, and Spread of Rates at 27 (Feb 18, 2010).

Pacific Power also indicates that since the WUTC and IPUC decisions, the company has filed an open access transmission tariff (OATT) that seeks recovery of certain third-party wind integration costs in a pending rate case before FERC (docket no. ER11-3643-000). The company also indicates that a partial stipulation was filed in the company's 2012 GRC that requires Pacific Power to file an application for deferred accounting for the Oregon-allocated share of the incremental revenues associated with the pending rate case, beginning January 1, 2013, and continuing until the revenues are included in rates. Under the partial stipulation, customers will be credited for incremental revenues from ancillary services charges approved by FERC, including the fixed costs associated with third-party wind integration. Pacific Power asserts that the terms of its filed OATT related to recovery of wind integration costs are as broad as allowed under FERC Order No. 764[54], absent the operational system enhancements that the company has not yet made.[55] Pacific Power argues that the Supremacy Clause and the filed rate doctrine would prevent approval of ICNU's proposed adjustment to a FERC-approved rate.[56]

ICNU and CUB criticize Pacific Power's OATT filing as being too limited, arguing the company wrongly elected to seek recovery of only the fixed costs of third-party wind integration, and not the variable costs.[57] The two parties disagree with Pacific Power's characterization of FERC's position that the variable costs of wind integration may be recovered in a utility's OATT only if the utility makes certain operational changes, such as fifteen minute scheduling. CUB and ICNU state that FERC concluded the opposite, finding that transmission provides could include variable costs of wind integration in OATTs without first making certain mandated operational changes.

> FERC actually concluded the opposite, finding that it will allow transmission providers to include variable costs of wind integration in OATTs. Integration of Variable Energy Resources, 139 FERC ¶ 61,246, Order No. 764 at 315-335 (Jun 22, 2012). FERC did not condition recovery upon transmission providers making certain operational changes, but instead simply mandated that all transmission providers make operational changes, including providing the option of 15-minute, intra-hour scheduling. 139 FERC ¶ 61,246 at 91-92.[58]

ICNU and CUB observe that Pacific Power has already indicated that it intends to comply with FERC's requirement to adopt 15 minute scheduling.[59] The two parties also point out that Bonneville Power Administration (BPA) and at least one other transmission provider have been allowed by FERC to recover these costs.[60] They argue that Pacific

[54] Docket No. RM10-11-000 (Jun 22, 2012).
[55] PAC/300, Duvall/31-32.
[56] Pacific Power's Prehearing Brief, p. 23.
[57] *See* ICNU/100, Deen/15-16.
[58] ICNU-CUB Joint Posthearing Brief, p. 24, citing Integration of Variable Energy Resources, 139 FERC ¶ 61,246, Order No. 764 at 91-92, 315-335. (Jun 22, 2012).
[59] *Id* at 24, citing UE 245, ICNU/206; ICNU/205.
[60] *Id* at 25, citing Westar, 130 FERC ¶ 61,215 at 35 (Mar 18, 2010); BPA Administrator's Record of Decision, 2012 Wholesale Power and Transmission Rate Adjustment Proceeding at 189 (Jul 2011).

Power should have at least asked FERC whether the variable costs of wind integration could be recovered in the OATT.

b. Resolution

We take official notice of Pacific Power's FERC OATT filing, recognizing that Pacific Power filed the OATT after the decisions cited by ICNU were published by the Washington and Idaho Commissions. We also take official notice of the partial stipulation filed in docket UE 246. In so doing, we acknowledge that should we approve the stipulation in that docket, Oregon customers will be credited for any incremental revenues for fixed costs associated with third-party wind integration that FERC approves by authorizing the pertinent ancillary charges in the company's OATT. Absent compelling legal argument to the contrary, we defer to Pacific Power's interpretation of FERC Order No. 764, that the company may not pursue recovery of the variable costs of third-party wind integration absent the operational system enhancements that the company has not yet made.[61] We decline to adjust the NPC to remove third-party wind integration costs, but we encourage Pacific Power to make the necessary operational system enhancements and to subsequently pursue recovery at FERC of the variable costs of wind integration.

4. Hydro Modeling Adjustment

a. Parties' Positions

Pacific Power's NPC study, in this TAM proceeding, models planned and forced outages at the company's hydro facilities using historical data from a 48-month period ending June 2011.[62] Staff and ICNU object to Pacific Power's modeling of hydro outages for differing reasons.

Staff challenged Pacific Power's modeling of both forced and planned outages. Staff originally took the position that certain "outlier" outage events—identified as extended, isolated plant outages—should be removed from data used by GRID to model forced hydro outages. Staff expressed concern that Pacific Power's modeling of forced outages was overly influenced by a small number of outlier outages, and argued that these outages should be excluded consistent with the methodology recently adopted by the Commission to model forced outages for thermal plants.[63] Staff subsequently withdrew a proposed disallowance based on this argument following clarification that "the main drivers behind Staff's recommended hydro forced outage rate adjustment, although included in the work papers, are not, in fact, incorporated into GRID."[64]

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[61] PAC/300, Duvall/31-32.

[62] Pacific Power explains that, although the company agreed in Docket No. UM 1335 to not model hydro forced outages in the 2010 TAM (docket UE 207), it reserved the right to model hydro forced outages in future TAM proceedings.

[63] *See* Order No. 10-414.

[64] Staff's Prehearing Brief, p. 3.

Staff made two arguments with regard to planned outages. First, Staff indicated that the same identified "outlier" events noted above inflated Pacific Power's calculation of planned outages by $2.60 million.[65] Second, Staff raised a fundamental concern with Pacific Power's approach to forecasting planned outages in general. Staff argued that planned outages should be modeled based on the utility's actual outage plan for the test period rather that estimated based on historical data.[66] Recognizing the procedural impracticalities of asking the company to use a new methodology to recalculate planned hydro outages, Staff recommended the company change its methodology for planned outages in its modeling for the company's 2014 TAM and beyond. Following additional information provided by Pacific Power, Staff withdrew its recommended disallowance of $2.6 million related to planned hydro plant outages for 2013, but still recommended the Commission direct the company to use planned test year outages for all plants for 2014 and beyond.[67] Staff now accepts Pacific Power's suggestion to defer the Commission's consideration of how planned hydro outages should be modeled until the Commission addresses the creation of a power cost adjustment mechanism for the company in its pending rate case, docket UE 246.

Although ICNU concurs with Staff's original position regarding Pacific Power's failure to exclude outliers, ICNU primarily criticizes another aspect of the company's modeling of hydro forced outages. ICNU argues that the company's model fails to take into account any opportunity the company may have to re-optimize the system to avoid lost generation after a forced outage occurs. According to ICNU, this ignores significant potential storage potentially and system flexibility that could reduce the impact of forced outages on hydro generation.[68] ICNU recommends the Commission reject the company's modeling of forced hydro outages, reducing the overall NPC by 2.1 million.[69]

Pacific Power denies it has the flexibility alleged by ICNU to reshape hydro around forced outages.[70] Pacific Power asserts that ICNU's recommendation is unreasonable, because it simply removes any recognition of hydro forced outages. According to Pacific Power, such a recommendation erroneously assumes that there will be no forced outages or that the company can perfectly work around any outages. Pacific Power contends that recalculating ICNU's proposed adjustment to account only for the impact of additional generation purported to result from re-optimization reduces the adjustment to $1.3 million, but adds that even this figure incorrectly assumes there is never any lost generation due to hydro forced outages.

b. Resolution

Given Staff's withdraw of its proposed 2013 TAM adjustments for modeling forced and planned hydro outages, we are asked to consider only ICNU's recommendation that we

[65] Staff/100, Schue/25.
[66] *Id.* at 24.
[67] *Id.* at 5.
[68] ICNU/100, Deen/14.
[69] *Id.* at Deen/13, ll 8-11; Deen/15, ll 2-3.
[70] *Id.*

adjust the company's proposed NPC to exclude modeling of hydro forced outages. Based on the evidence in the record, we support no adjustment based on the exclusion of modeling hydro forced outages. At the same time, we urge Pacific Power, with parties, to review the modeling of forced hydro outages and make any necessary changes, if warranted.

For the 2014 TAM proceeding and beyond, in anticipation of a PCAM being authorized for Pacific Power in the company's general rate case proceeding (docket UE 246), Staff recommends that we direct the company to use planned test year outages for modeling purposes for all plants including hydro plants. Staff accepted Pacific Power's suggestion to defer consideration of this issue until after we fully address PCAM issues for the company. We agree and defer this issue.

5. Schedules 294 and 295 Transition Credit Calculation Adjustment

As part of Oregon's direct access program allowing a non-residential retail customer to purchase electricity from a certified electricity service supplier (ESS), the Commission sets Pacific Power's Schedule 294 and 295 transition credit (or charge) in the annual TAM proceeding.[71] The purpose of the transition adjustment is to credit or charge 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 made available when a customer chooses direct access. The approved methodology to calculate the transition adjustment is based on the assumption that 25 MW of Pacific Power load will opt out of the company's cost-of-service tariff and enroll in direct access.[72] Pacific Power makes two GRID runs for each rate schedule, one assuming a full Oregon load and another assuming a 25 MW load reduction due to direct access participants.[73] Theoretically, these two GRID runs calculate the weighted market value of the energy used to serve direct access customers. In the TAM, this weighted market value is compared to the cost-of-service rate (Schedule 201) to determine the Schedule 294 or Schedule 295 credit (or charge). In each of the last four Pacific Power TAM proceedings, refinements to this calculation were agreed to in stipulations approved by the Commission, the last adopted in Order No. 11-435 (docket UE 227).

Noble Solutions proposes, in this proceeding, three adjustments related to the calculation of the Schedule 294 and Schedule 295 transition credits. We address each below.

[71] Schedule 294 provides a one-year direct access option, while Schedule 295 provides a three-year option.
[72] *See In Re Investigation into Direct Access Issues*, Docket No. UM 1081, Order No. 04-516, p. 10.
[73] *Id.* at 19, 21.

a. Relaxation of Market Caps for Calculation of Schedules 294 and 295

i. Parties' Positions

Noble Solutions asserts that the company's market caps unreasonably reduce Schedules 294 and 295's transition adjustment credits to direct access customers. The company's GRID runs incorrectly assume, Noble Solutions argues, that the generation freed up by 25 MW of direct access load (as assumed in calculating the transition adjustment) is unable to be sold in market hubs once the market caps are reached.[74] Noble Solutions indicates this problem can be readily resolved (as it has been in the last four Pacific Power TAM cases) by making a corresponding adjustment to market liquidity in the amount of the assumed 25 MW of direct access load when calculating the transition adjustment in Schedules 294 and 295.[75] Noble Solutions further explains that in the company's 2009 TAM (docket UE 199), the Commission approved a stipulation that required the company to "relax" the market cap limitations in the GRID model when calculating the Schedules 294 and 295's transition adjustment.[76] Thus, GRID would assume that although Pacific Power would not sell all the energy freed up by direct access, the company would back down lower-priced thermal units. Noble Solutions indicates that substituting the lower-priced thermal generation for market prices resulted in a reduction in the calculated value of the weighted market value of freed-up energy, thereby reducing the Schedule 294 and 295 credits paid to direct access customers. Noble Solutions contends that Pacific Power failed to make this necessary corresponding adjustment in this case, without explanation, thereby understating the credits to direct access customers.

Noble Solutions recommends that the Commission require Pacific Power to continue to apply the relaxation of the market cap limitations in the GRID model by 15 MW at Mid-Columbia and 10 MW at COB in the calculation of the Schedule 294 and 295 transition credits. Additionally, Noble Solutions asks that to the extent that the Commission approves Pacific Power's proposal to expand use of the market cap limitations to all hours, the Commission should require a corresponding relaxation of the market caps for all hours when calculating the transition adjustment.

Pacific Power continues to assert that market caps are necessary to accurately forecast NPC in GRID, and further argues that relaxing the market caps to calculate Schedules 294 and 295 would provide a subsidy to direct access customers. The company claims that Noble Solutions' argument is based on a faulty premise that the wholesale market will increase with retail customers' participation in direct access. Pacific Power retorts as already argued—GRID currently overstates wholesale volumes. In any case, Pacific Power notes, the market size will not increase by the assumed 25 MW because such a level is greater than the company's load electing direct access.[77]

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[74] Noble Solutions/100, Higgins/14-15.
[75] *Id.* at 15-16.
[76] *Id.* at 14.
[77] PAC/300, Duvall/36.

ii. Resolution

Although market cap limitations have been relaxed in prior years for purposes of calculating transition adjustments, such action was taken pursuant to approved stipulations without precedential value. We must decide whether and how to apply market caps to the calculation of transition adjustments based upon the evidence presented in this proceeding. Noble Solutions' argument that market caps in GRID unreasonably limit assumptions about how much of the generation freed up by 25 MW of direct access load will be sold is effectively the same in nature as the more general arguments made by ICNU and Staff about the limitations of market caps. We are not persuaded that there is any reason to depart from our decision to retain but revise the market caps in GRID. We direct Pacific Power to apply the alternative market caps recommended by Staff to the calculation of transition adjustments for direct access customers.

b. BPA Transmission Credit

i. Parties' Positions

Noble Solutions indicates that Pacific Power owns 636 MW of long-term point-to-point (PTP) BPA transmission rights from the Mid-Columbia.[78] Noble Solutions asserts that Pacific Power can resell the BPA PTP transmission rights to another entity.[79] Consequently, when a customer chooses direct access, the company can either resell the any freed up BPA PTP transmission to the ESS serving that direct access customer, or use it another manner, perhaps avoiding the purchase of new BPA transmission rights. For this reason, Noble Solutions asserts that calculation of the transition adjustment should reflect a BPA transmission credit to reflect the potential value associated with reselling BPA PTP wheeling rights freed up by customers choosing direct access.[80]

Noble Solutions states that a BPA transmission credit has been included in the calculation of transition adjustments for Portland General Electric Company's service territory for several years and that the Commission has recently authorized small BPA credits for Pacific Power's Schedule 747 and 748 (direct access) customers.[81] Noble Solutions explains that pursuant to a stipulation approved in docket UE 216 in Order No. 10-363, a small BPA transmission credit of $0.50/MWH was authorized for Schedule 747 and 748 customers to reflect the potential value associated with reselling BPA PTP wheeling rights freed up due to the customers choosing direct access.[82] The stipulation adopted in Order No. 11-435, the most recent TAM proceeding, increased the BPA transmission credit to $0.75/MWH. Pacific Power proposes in this proceeding, however, to eliminate the BPA transmission credit without justification.[83] Noble Solutions observes that this

[78] Noble Solutions/100, Higgins/10.
[79] *Id.* at 9.
[80] *Id.* at 7.
[81] *Id.* at 9.
[82] *Id.*
[83] *Id* at 9-10.

increased credit still only represented 33 to 42 percent of the true value of the transmission rights.[84] Noble Solutions recommends that the Schedule 294 and 295 transition adjustment calculations be modified to include a credit for the resale of BPA transmission of $1.422/MWH to more accurately reflect the value of the transmission, calling this valuation still conservative.[85] In the alternative, Noble Solutions asks the Commission to continue the credit approved in docket UE 227.[86]

Pacific Power responds that the BPA transmission credits instituted pursuant to stipulation are non-precedential.[87] Pacific Power also observes that the Commission previously rejected a BPA transmission credit in docket UM 1081 for the reason that the company was contractually precluded from reselling its BPA transmission rights.[88] Pacific Power asserts that there are still constraints on its ability to resell transmission rights.[89] The company asserts that it cannot resell network rights at all and can sell PTP rights only when they are actually freed up.[90] Pacific Power explains that because direct access customers may return to cost of service rates, the company must continue to plan for these customers, and therefore retain the transmission rights to serve these customers.[91] Pacific Power asks the Commission to reject Noble Solution's request to institute a BPA transmission credit for transition adjustments in this proceeding.

ii. Resolution

As we observed above, any ratemaking actions taken pursuant to approved stipulations do not have any precedential value. We must decide whether to apply a BPA transmission rights credit to the calculation of transition adjustments based upon the evidence presented in this proceeding. We find that compelling evidence was not presented that Pacific Power is able to resell BPA transmission rights due to direct access.

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[84] *See* Noble Solutions/100, Higgins/10 ("At a 100 percent load factor, [the BPA PTP transmission rate] is equivalent to $1.778/MWH. In addition, Pacific Power has a network integration transmission agreement with BPA for 497 MW that allows for delivery to various load pockets on BPA's system * * * At a 100 percent load factor, this rate is equivalent to $2.28/MWH.").

[85] Noble Solutions/100, Higgins/10-11.

[86] *Id.* at11.

[87] PAC/300, Duvall/36.

[88] Pacific Power's Prehearing Brief, p. 28, citing *Investigation into Direct Access Issues for Industrial and Commercial Customers under SB 1149*, Docket No. UM 1081, Order No. 04-516.

[89] PAC/300, Duvall/35.

[90] *Id.*

[91] *Id.*

III. ORDER

IT IS ORDERED that:

1. Advice No. 12-002, 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 2013, filing tariffs to be effective January 1, 2013.

Made, entered, and effective OCT 29 2012.

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

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.