

**PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: November 19, 2010**

REGULAR X **CONSENT** _____ **EFFECTIVE DATE** _____ **Upon
Commission
Acknowledgement**

DATE: November 12, 2010

TO: Public Utility Commission

FROM: Maury Galbraith and Lisa Gorsuch

THROUGH: Lee Sparling

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. LC 48) Acknowledgment of 2009 Integrated Resource Plan.

STAFF RECOMMENDATION:

Staff recommends that the Commission acknowledge Portland General Electric's (PGE or Company) 2009 Integrated Resource Plan (IRP or the Plan) with the requirements listed below.

Discussion

On October 15, 2010, Staff filed a Draft Proposed Order and Staff Comments regarding PGE's 2009 IRP (Docket No.LC 48). Several parties filed comments regarding these documents, some supporting Staff's recommendations and others opposing them.

Boardman

PGE. PGE's Reply Comments include a description of an accord reached by PGE, the Citizen's Utility Board (CUB), NW Energy Coalition (NWEC), Angus Duncan, Oregon Environmental Council (OEC), and Renewable Northwest Project (RNP) regarding a "reasonable" plan to end the use of coal at Boardman no later than December 31, 2020, and PGE's commitment to work with stakeholders in the next IRP to evaluate and consider carbon-reduction options for replacement power.¹ PGE has asked the Department of Environmental Quality (DEQ) to allow PGE to modify its BART III proposal to include the refinements PGE and the other stakeholders have agreed to, which consist of (1) an SO₂ requirement than is lower than what is currently in BART III

¹ PGE Reply Comments 2-3.

that will commence July 2018, so long as the requirement does not cause Boardman to exceed PM_{2.5} or PM₁₀ ambient standards, prevent Boardman from meeting mercury reduction goals, or cause significant operational issues, and (2) advocating for the repeal of the existing BART I option once BART III is finally approved by EPA and is binding on Boardman.²

PGE asserts that the BART III refinements have no material impact on PGE's IRP analysis and do not represent a material change in the cost or risk of PGE's recommended Action Plan for Boardman. PGE states that no additional analysis or updates should be necessary if the Environmental Quality Commission (EQC) approves a rule substantially consistent with the refinements. PGE urges the Commission to acknowledge its IRP in such a way that the Company can proceed with a 2020 plan so long as the EQC adopts a rule that is substantially similar to BART III and consistent with the provisions outlined in PGE's letter to the DEQ.

PGE disagrees with Staff's recommendation that the Commission not acknowledge an alternative to BART III in this IRP process, and asks the Commission to acknowledge BART I (Closure in 2040) as the best backstop alternative.³

The Group. The Citizen's Utility Board (CUB), Renewable Northwest Project (RNP), Angus Duncan, Oregon Environmental Council, and NW Energy Coalition (NVEC) (collectively "the Group"), support BART III with the refinements described above, or would support a plan substantially similar to BART III that is allowed by the DEQ.⁴ The Group explains that its support of BART III is predicated in part on PGE's commitment to develop a limited number of carbon reduction candidate resource portfolio options for replacing Boardman upon cessation of its coal-fired operations, and meeting the anticipated resource requirements of the Company's customers.⁵

The Group does not support Staff's recommendation that the Commission specifically acknowledge BART III because the EQC is currently evaluating alternative rules that may improve upon both PGE's BART III and DEQ's 2018 option. The Group states that the Commission's acknowledgment should be sufficiently flexible to accommodate certain refinements to BART III. The Group recommends the Commission incorporate into its acknowledgment of PGE's IRP a requirement similar to the following:

If EQC approves BART III or a plan that is substantially similar to BART III and acceptable to PGE, PGE must lead a collaborative effort in its next IRP process to develop CO2 reduction portfolios in consultation with

² PGE Reply Comments 2-3.

³ PGE Reply Comments 3.

⁴ Group Comments on Staff's Proposed Order 1-2.

⁵ Group Comments on Staff's Proposed Order at 2.

*stakeholders to replace Boardman's generation and meet the utility's resource needs.*⁶

CUB. CUB agrees with Staff that of the options presented in the IRP, BART III is the best performer from a least cost/least risk basis.⁷ CUB asserts that the date Boardman ceases to operate will depend on a variety of factors that are not yet known, and that is not possible to select an option with a concrete closure date, although it is possible to select a time frame that will result in closure not later than 2020. To allow flexibility, CUB recommends that the Commission not limit its acknowledgment to BART III, but instead acknowledge actions that are substantially similar to BART III.⁸ CUB also recommends that the Commission require that PGE work with stakeholders to develop low-carbon portfolios for the next IRP.⁹

NWEC. NWEC also recommends that the Commission broaden the scope of its acknowledgment regarding Boardman to allow PGE to proceed with its proposed refinements to BART III, should the EQC and EPA allow it. NWEC also repeats its recommendation that the Commission require PGE to issue an RFI and "do whatever due diligence is needed in time for [PGE's] IRP update to establish the facts regarding the market's ability to provide replacement power."

Sierra Club, et al. The Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, and the Northwest Environmental Defense Center (Sierra Club, et al.) disagree with Staff's recommendation that the Commission acknowledge BART III and with Staff's consideration of alternatives other than closure by 2015/early 2016. The Sierra Club, et al., states that contrary to Staff's assertion there is ample replacement power to transition from Boardman coal to other sources by the end of 2015/early 2016.

Other parties. Associated Oregon Industries, the Oregon Forest Industries Council, the Morrow County Commission, West Side Economic Alliance, Salem Area Chamber of Commerce, the Association of Oregon Counties, the Portland Business Alliance, SEDCOR, Wilsonville Chamber of Commerce, Clackamas County Business Association, and the Columbia Corridor Association, support Staff's recommendation that the Commission acknowledge BART III as the preferred plan for Boardman. These parties also agree with Staff's conclusion that the DEQ's proposed 2015/2016 closure option does not allow sufficient time to find and acquire reliable replacement resources and argues that the DEQ option creates unacceptable risks to the state's economy. With the exception of the Portland Business Alliance, which does not comment on the 2040 backstop, these parties oppose Staff's recommendation that the Commission not

⁶ Group Comments on Staff's Proposed Order 2.

⁷ CUB's Comments on Staff's Draft Order 3.

⁸ CUB's Comments on Staff's Draft Order 3-4.

⁹ CUB's Comments on Staff's Draft Order 4-5.

acknowledge the 2040 backstop and urge the Commission to formally and explicitly acknowledge this alternative.

IBEW also supports Staff's recommendation that the Commission acknowledge BART III, but urges the Commission to acknowledge the 2040 alternative.

Staff Response:

PGE's refinement of its BART III option raises two issues. The first is whether the Commission should proceed with its acknowledgment decision without requiring additional analysis at this time. The second is whether the Commission should acknowledge all options that are substantially similar to PGE's BART III and thereby provide the company the flexibility to act without coming back to the Commission for further acknowledgment.

Staff agrees with PGE's position that the refined BART III option is substantially similar to the original BART III and no further analysis or IRP modeling is needed to proceed with acknowledgment. The most significant change to the original BART III proposal is the lower SO₂ standard beginning in July 2018. PGE estimates that the incremental net present value (NPV) cost of achieving this standard is \$8 to \$10 million. This incremental cost is associated with additional capital investment and operations and maintenance expense for the proposed Dry Sorbent Injection (DSI) system. The cost increase is not enough to alter Staff's conclusion that BART III is the option with the best combination of cost and risk for ratepayers. Staff conservatively estimates the NPV of the dispatch benefits from continued operation of the Boardman plant over the period July 2018 through December 2020 to be \$40 million. In comparison, Staff does not find the \$10 million change in the NPV cost of BART III to be material.

Staff does not agree with the various recommendations for the Commission to acknowledge other refinements deemed to be substantially similar to BART III. Staff doubts that there is a common understanding of the meaning of "substantially similar" between the various stakeholders. It is also uncertain how future Commissions would interpret the meaning of "substantially similar". The proposed broadening of the acknowledgment of BART III would lessen the value to PGE, stakeholders, and future Commissions of this Commission's acknowledgement decision. Staff recommends that the Commission handle any further near-term refinements to the BART III option by allowing PGE to seek acknowledgement of a Boardman-only IRP Update. Staff also continues to support using the IRP Update process as the means to address any backstop options that may be necessary if the EQC rejects the BART III option.

Cascade Crossing

PGE With respect to Cascade Crossing, PGE re-asserts its request that the Commission acknowledge Action Plan Item 16, subject to the requirement that PGE include certain additional information in its IRP Update. PGE also asks the Commission to clarify that once Cascade Crossing is acknowledged, stakeholders are not free to advocate for non-acknowledgement of PGE's 2009 IRP in future proceedings.¹⁰

Willard Rural Association The Willard Rural Association (WRA) asserts that PGE's least cost analysis "appears to be based on the overriding assumption that all of its transmission costs currently paid by BPA will increase in the future, but the future cumulative cost increase to PGE customers can be made less if PGE self-builds its own power line."¹¹ WRA argues that assuming the amount of money that PGE pays to BPA increase by 10% a year, the costs will still not exceed PGE's costs to capitalize Cascade Crossing.¹²

WRA also asserts that neither Staff nor PGE addressed the fact that BPA intends to build a "major new east-west transmission line" and continues to question PGE's assertions regarding the cost to build a new line from Salem to Oregon City or how Cascade Crossing can improve system reliability if the majority of PGE's customers are in Portland and Cascade Crossing will terminate near Salem. WRA also questions how it is in the public interest to have privately-owned utilities own and operate pieces of a larger transmission system.¹³

RNP RNP states that it supports "Staff's recommendation that the Commission acknowledge PGE's proposal to move forward with permitting for its Cascade Crossing transmission project, subject to the requirement that PGE provide additional economic analysis in its next IRP Update and future IRPs."¹⁴ RNP states that it is sensible to allow the relatively inexpensive, multi-year permitting process to move forward while preserving the ability of regulators and stakeholders to evaluate updated economic analysis of large transmission projects in future IRPs.¹⁵

¹⁰ PGE Reply Comments 3.

¹¹ WRA's Comments on Proposed Order 1.

¹² WRA's Comments on Proposed Order 1.

¹³ WRA's Comments on Proposed Order 2.

¹⁴ RNP's Comments on Staff's Proposed Order 3.

¹⁵ RNP's Comments on Staff's Proposed Order 3

Staff Response:

While the section on Cascade Crossing in Staff's proposed Commission order has undergone substantial revision, Staff's position on the Cascade Crossing project remains unchanged. Staff's position, as stated in the revised proposed order, is that PGE's benefit-cost analysis is sufficiently robust, and shows sufficient net benefits under certain scenarios, to warrant acknowledgment of Cascade Crossing at this time. However, the Company should provide a thorough update of the Cascade Crossing benefit-cost analysis in its next IRP; with the understanding that acknowledgment of the next IRP will depend on the outcome of that updated analysis.

Staff appreciates the comments provided by various parties with regard to PGE's proposed Cascade Crossing project. While Staff understands the concerns raised by each of these parties, Staff ultimately recommends the following requirement:

PGE shall include an updated benefit-cost analysis of the Cascade Crossing transmission project in its next IRP. For the updated analysis, PGE shall update its assumptions about project configuration, capital cost, path rating, wheeling revenues, and equity participation and conduct sensitivity analyses that address any uncertainty about capital cost, path rating, levels of equity participation, and levels of wheeling revenues.

Demand Response

In response to Staff's criticism that PGE did not evaluate Demand Response (DR) on par with other resources, PGE notes that it did not materially change the manner in which it analyzed DR from its last IRP in which the Commission concluded that PGE's DR approach met Guideline requirements.¹⁶ In response to Staff's criticism that PGE did not evaluate DR on par with other resources because it did not include projected capacity contributions and cost by year and DR class, PGE notes that such information is not required by the IRP Guideline. PGE states that its analysis comports in substance with Staff's recommendations because PGE relied on third-party estimates from the Brattle Group for DR availability.

CUB also agrees with Staff that PGE did not adequately analyze DR, but recommends a different requirement for DR than what is proposed in Staff's draft proposed order issued on October 15, 2010. CUB recommends that the Commission require that PGE report in its next IRP update the specific steps PGE will take to evaluate DR in the next IRP.¹⁷

¹⁶ PGE Reply Comments 7.

¹⁷ CUB's Comments on Staff's Draft Order 5-7.

In support of this recommendation, CUB notes that PGE promised certain demand response programs and significant annual savings in connection with its request in to install advanced meter infrastructure in UE 189. CUB notes that notwithstanding these promises, PGE has not made much progress toward significant demand response. CUB wants to ensure that the analysis of potential demand response is complete prior to PGE's next IRP so PGE can effectively analyze demand response as a resource in its next IRP.¹⁸

Staff Response:

For the reasons discussed in its previous comments, Staff does not believe that PGE evaluated DR on par with other resources and recommends that the Commission impose a requirement so that PGE will do so in the future.¹⁹ Staff agrees with CUB's observations regarding PGE's implementation of DR to date. Staff also recommends requirements that will require PGE to provide the Commission and stakeholders with information regarding PGE's acquisition of DR:

In its next IRP update, PGE must provide the following:

- a. Its estimated cost per MW of capacity savings by DR type (i.e., firm vs. non-firm resources), and projected MW acquisitions by DR type for the next 5 years,*
- b. A discussion of the steps it is and will be taking to evaluate DR in the next IRP, and*
- c. An updated action plan for assessing (e.g., plans for pilot programs) and acquiring DR for the next 3 years.*

¹⁸ CUB's Comments on Staff's Draft Order 6-7.

¹⁹ Staff has modified its recommended requirement regarding Demand Response.

Conservation Voltage Reduction

PGE's response to Staff's recommendation that PGE be required to evaluate conservation voltage reduction is similar to its response regarding DR. PGE notes that its treatment of conservation voltage reduction (CVR) has not changed from its last IRP and that analysis of conservation voltage reduction is not required by the IRP Guidelines. PGE also notes that it does not consider CVR to be a long-term planning issue, but an "operational efficiency," and in any event, CVR is not material to PGE's IRP and Action Plan.²⁰

Staff Response:

To the extent that PGE is arguing that it need not consider CVR as a resource under Guideline 6, Staff disagrees. Further, Staff is not persuaded that it is not necessary to analyze CVR as a potential resource in the IRP because the amount of available CVR is not material. Staff recommends that the Commission impose the following requirement regarding CVR:

In its next IRP, PGE should consider CVR for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings.

Wind Integration Study

PGE states that it agrees to Staff's recommendation that it include a wind integration study that has been vetted by regional stakeholders in its IRP Update, but disagrees with Staff's conclusion that the wind integration study relied on in the 2009 IRP was not properly vetted. In support of the conclusion that the study was properly vetted by regional stakeholders, PGE relies on the fact that an independent examiner (IE) PGE hired in late 2008 to "vet" the study for another docket (Docket No. UM 1345) concluded the study was a "thorough integration study."²¹

CUB. CUB agrees with Staff that PGE's wind integration study was not vetted by regional stakeholders and supports the requirement in the draft order regarding wind integration.²²

RNP. RNP supports Staff's recommendation that the Commission direct PGE to produce a wind integration study that is vetted by regional stakeholders in PGE's IRP Update. RNP recommends that the Commission also impose more specific

²⁰ PGE Reply Comments 8-9.

²¹ PGE Reply Comments 11.

²² CUB's Comments on Staff's Draft Order 7-8.

requirements on PGE, *i.e.*, that PGE must use a technical review committee of national or regional wind integration experts or use an independent facilitator, to avoid repeated non-compliance and promote constructive dialogue between PGE and stakeholders.²³

RNP notes that Staff rejected RNP's recommendation that the Commission require PGE to use Bonneville's wind integration rate until PGE provides an adequate wind integration study. RNP states that it cannot follow Staff's recommendation to RNP to address what appear to be overstated wind integration costs used by PGE in its IRP by evaluating the effect a lower wind integration cost would have on the selection of least cost/least risk portfolios. RNP states that it does not have this modeling capability. RNP notes that its preference is for PGE to complete an acceptable wind integration study before it begins its IRP development to avoid producing an IRP whose results and analysis are difficult to disentangle from its integration study.²⁴

Staff Response:

The opportunities that PGE gave to *stakeholders* to review its proposed methodology do not substitute for the opportunity to study the actual methodology and its results. Also, Staff expects that in the vetting process, stakeholders would have opportunity to provide comments and recommendations to PGE. Staff also expects that PGE will respond to stakeholder comments and that to the extent PGE does not accept a recommendation, PGE will explain why.

Furthermore, Staff recommends that PGE produce a vetted wind integration study by the next IRP Update and next IRP planning cycle, which is consistent with RNP's preference that PGE complete an acceptable wind integration study before it begins its IRP development.

Staff recommends that the Commission impose the following requirement:

In its next IRP Update and in the next IRP planning cycle, PGE must include a wind integration study that has been vetted by regional stakeholders.

²³ RNP's Comments on Staff's Proposed Order 1-2.

²⁴ RNP's Comments on Staff's Proposed Order 3.

Renewable Portfolio Standard/Renewable Energy Credits

PGE disagrees with Staff's recommendation that PGE should project future prices and availability for unbundled Renewable Energy Credits (RECs) to assess the potential for acquiring unbundled RECs to meet Oregon's RPS. PGE states "[w]e believe that, given the lack of liquidity and transparency in the REC markets, it would not be prudent to rely on such projections."²⁵

Staff Response:

Staff believes that PGE's response underscores the need to include analysis of unbundled RECs in the IRP. If PGE omits any suggestion that it analyzed using unbundled RECs to meet Oregon's RPS from the IRP, the Commission and stakeholders are left to wonder whether PGE simply forgot about this option. PGE should include its analysis of unbundled RECs in the IRP to allow the Commission and stakeholders to understand the basis of all its resource decisions. Further, as discussed in earlier comments, Staff does not necessarily agree with some of PGE's assumptions regarding unbundled RECs.

Staff recommends that the Commission impose the following requirements:

In its next IRP Update and in the next planning cycle, PGE must evaluate the use of unbundled RECs in its strategy to meet RPS Requirements for the entire planning period.

In its next IRP Update and in the next planning cycle, PGE must evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.

²⁵ PGE Reply Comments at 10.

PROPOSED COMMISSION MOTION:

PGE's 2009 Integrated Resource Plan be acknowledged with the following requirements by adoption of the attached proposed order

1. *PGE shall include an updated benefit-cost analysis of the Cascade Crossing transmission project in its next IRP. For the updated analysis, PGE shall update its assumptions about project configuration, capital cost, path rating, wheeling revenues, and equity participation and conduct sensitivity analyses that address any uncertainty about capital cost, path rating, levels of equity participation, and levels of wheeling revenues.*
2. *In its next IRP update, PGE must provide the following:*
 - a. *Its estimated cost per MW of capacity savings by DR type (i.e., firm vs. non-firm resources), and projected MW acquisitions by DR type for the next 5 years,*
 - b. *A discussion of the steps it is and will be taking to evaluate DR in the next IRP, and*
 - c. *An updated action plan for assessing (e.g., plans for pilot programs) and acquiring DR for the next 3 years.*
3. *In its next IRP, PGE should consider CVR for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings.*
4. *In its next IRP Update and in the next IRP planning cycle, PGE must include a wind integration study that has been vetted by regional stakeholders.*
5. *In its next IRP Update and in the next planning cycle, PGE must evaluate the use of unbundled RECs in its strategy to meet RPS Requirements for the entire planning period.*
6. *In its next IRP Update and in the next planning cycle, PGE must evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.*

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
LC 48**

In the Matter of
PORTLAND GENERAL ELECTRIC
2009 Integrated Resource Plan.

PROPOSED ORDER

DISPOSITION: PLAN ACKNOWLEDGED

I. INTRODUCTION

Portland General Electric Company (PGE) seeks acknowledgment of its 2009 Integrated Resources Plan (IRP) and 2010 Addendum. We acknowledge the plan subject to certain requirements that are discussed below.

A. IRP Guidelines

We require regulated energy utilities to engage in integrated resource planning and to file an IRP every two years. We review the filed plans to determine whether they adhere to our IRP guidelines and either “acknowledge” them, or return to the utility with comments. Acknowledgement does not guarantee favorable ratemaking treatment, but means that the plan seems reasonable at the time of Commission review.

The Commission has set forth thirteen IRP guidelines. The first guideline includes substantive requirements under which the utility must (1) evaluate all resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) have as its primary goal the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) draft a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.¹ The remaining twelve guidelines set forth procedural and other requirements that provide direction on how to prepare and update the plan and regarding specific resources such as transmission and conservation.

B. Procedural history.

Portland General Electric Co., (PGE) filed its 2009 Integrated Resource Plan (IRP) on November 5, 2009. Following a prehearing conference on December 1, 2009, the administrative law judge (ALJ) issued a procedural schedule calling for a PGE presentation to the Commission on January 19, 2010, intervenor comments in February 2010, PGE reply comments and Staff recommendations and proposed order in March 2010, and Commission consideration at a May 25, 2010 public meeting.

¹ OPUC Order No. 07-002.

On January 14, 2010, PGE asked the Commission to defer consideration of PGE's plan to invest over \$500 million to retrofit its Boardman coal-fired plant to meet requirements of the Oregon Environmental Quality Commission's (EQC) Regional Haze Plan and asked the Commission to postpone PGE's presentation to the Commission scheduled for January 19, 2010. PGE explained that it intended to meet with stakeholders to assess whether PGE could devise alternatives to its proposal to invest over \$500 million to retrofit Boardman and operate the plant until 2040 that would be acceptable to the EQC and other stakeholders. On January 15, 2010, the Commission stayed all proceedings in Docket No. LC 48.

On April 9, 2010, PGE filed an addendum to its IRP outlining revisions to its IRP regarding Boardman. Subsequently, the ALJ adopted a procedural schedule that called for a PGE presentation to the Commission in April 2010, intervenor comments on May 19, 2010, PGE reply comments on June 11, 2010, Staff comments and proposed order as well as PGE and intervenor reply comments in July 2010, and Commission consideration at a public meeting in August 2010.

Prior to the time PGE filed its comments replying to May 19, 2010 intervenor comments, Staff asked the ALJ to abate the procedural schedule to allow opportunity for PGE, intervenors, and Staff to consider whether certain EQC and Department of Environmental Quality (DEQ) actions impact their recommendations to the Commission regarding PGE's IRP. Staff pointed out that on June 17, 2010, the EQC would consider (1) PGE's request to modify the EQC's 2009 Regional Haze Plan in a manner that would allow PGE to pursue its revised operating plan for Boardman, and (2) DEQ's recommendation that the EQC direct DEQ to base analysis regarding potential revisions to the Regional Haze Plan on a range of operating options for Boardman, rather than on the single operating plan underlying PGE's proposed rule change. The Commission granted Staff's motion and scheduled a pre-hearing conference for July 1, 2010, for the purpose of setting a new procedural schedule.

The ALJ adopted a procedural schedule at the July 1, 2010 prehearing conference requiring PGE to file reply comments analyzing three DEQ-proposed alternatives for Boardman retrofits and operation and responding to the May 19, 2010 intervenor comments. The procedural schedule gave intervenors opportunity to respond to PGE's supplemental comments, PGE opportunity to file reply comments on September 27, 2010, and directed staff to file recommendations and a proposed order on October 11, 2010, with Commission consideration at the November 9, 2010 public meeting.

On September 21, 2010, the Commission issued a bench request directing PGE to file additional analysis regarding the three DEQ retrofit and operation scenarios and allowing intervenors the opportunity to reply to PGE's response to the bench request. On October 7, 2010, the ALJ granted Staff's request to postpone the due date for Staff

recommendations and proposed order, as well as the due date for reply comments by intervenors and PGE, and to schedule a special public meeting on November 12, 2010, to consider Docket No. LC 48. On November 1, 2010, the ALJ issued an order *sua sponte* postponing the special public meeting to November 19, 2010.

In sum, the procedural schedule in this docket allowed three rounds of intervenors' comments and an opportunity for PGE to file an addendum to its IRP as well as the opportunity to file three rounds of reply comments and respond directly to the Commission's bench request. In addition, the procedural schedule included two technical workshops attended by the Commission, one addressing PGE's proposal for a new transmission line and the other addressing Boardman; three other opportunities for PGE to present to the Commission at public meetings, two opportunities for intervenors to present to the Commission at public meetings, and two public comment hearings, one in Portland and one in Boardman, at which the Commission did not allow PGE to comment.

C. Parties.

The following entities intervened in this proceeding: Northwest and Intermountain Power Producers Coalition, Citizens' Utility Board of Oregon, NW Energy Coalition, Ecumenical Ministries of Oregon, Oregon Environmental Council, PacifiCorp, Iberdrola Renewables, Inc., Oregon Department of Energy, Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, Northwest Environmental Defense Center, Renewable Northwest Project, Physicians for Social Responsibility, Northwest Pipeline GP, City of Portland, Industrial Customers of Northwest Utilities, Turlock Irrigation District, International Brotherhood of Electrical Workers Local 125, Northwest Food Processors Association, Portland Metropolitan Building Owners and Managers Association, Oregon Forest Industries Council, Oregon Cattlemen's Association, Willard Rural Association, Power Resources Cooperative, Salem Area Chamber of Commerce, Strategic Economic Development Corporation, Clackamas County Business Alliance, Columbia Corridor Association, Associated Oregon Industries, Westside Economic Alliance, Portland Business Alliance, Association of Oregon Counties, Wilsonville Chamber of Commerce, Morrow County, Oregonians for Food and Shelter, Oregon Farm Bureau, Community Action Partnership of Oregon, and Pareto Energy, LTD.

In addition, well over one thousand people filed written public comments with the Commission. Many of the comments are form letters that the Commission received at the public comment hearings held in Boardman and Portland. More than 800 form letters support closure of Boardman by 2014. More than 250 form letters support operating Boardman through 2040, or at the minimum, through 2020.

II. Discussion.

Load Forecast and Resource Need:

Parties Positions:

The Sierra Club, National Environmental Defense Center (NEDC), Friends of the Columbia Gorge, and Columbia Riverkeeper (hereinafter the “Coalition”), NW Energy Coalition (NWECC), Willard Rural Association (WRA), and Ecumenical Ministries of Oregon (EMO) argue that PGE has overstated its reference case load forecasts and, therefore, its future energy and capacity needs. Many of these parties argue that this has a direct bearing on the options for shutdown of the Boardman coal plant.

The Coalition, NWECC, and EMO all argue that PGE’s load forecasts are inconsistent with recent historical load growth in PGE’s service territory. The Coalition emphasizes that since 2000 the yearly growth in sales has exceeded PGE’s March 2009 projected growth rate of 1.9 percent per year for 2010 through 2030 only once.² NWECC points to analysis by WRA that shows PGE’s load growth has been essentially flat over the past ten years and questions why the next ten years should be projected to be any different.³

The Coalition urges the Commission to consider the differences between the Company’s March 2009 load forecasts used in the IRP and its more recent December 2009 load forecasts.⁴ The Coalition provides the year-by-year reductions in peak load and annual average energy and argues that the forecast reductions are significant and material. For example, the December 2009 forecasts show reductions of 157 MW in peak load and 152 average MW in annual energy during 2015.

NWECC, the Coalition, and EMO all argue that PGE’s load forecasts are inconsistent with those of independent forecasters. NWECC takes issue with PGE’s comparison of its projected load growth of 1.72 percent for the period 2010–2015, assuming a continuation of historic levels of embedded energy efficiency, to the Northwest Power and Conservation Council’s (NPCC or Council) Draft Sixth Plan projected load growth for Oregon of 1.96 percent. NWECC argues that the appropriate comparison is to an adjusted load growth forecast for Oregon of 0.47 percent per year. NWECC calculated this adjusted growth rate after subtracting the Council’s forecast of future energy efficiency from its medium load forecast.⁵

On September 27, 2010, PGE responded to these criticisms of its load forecasts. PGE argues that its forecasts appropriately incorporate data from both the recent and distant historical past. To counter the Coalition’s point that recent load growth exceeded the

² Schlissel Technical Consulting, September 1, 2010 Comments at 17-18.

³ NWECC, May 14, 2010 Comments at 5.

⁴ Schlissel Technical Consulting, September 1, 2010 Comments at 16-17.

⁵ NWECC, May 14, 2010 Comments at 5.

forecasted average rate of 1.9% only once since 2000, PGE indicated that historic annual growth exceeded 1.9 percent during sixteen of the last twenty-eight years.⁶

PGE also responds to the Coalition's comparison of its March 2009 and December 2009 load forecasts. PGE indicates that the differences between the two forecasts can be explained in part by different accounting treatment of Senate Bill 838 energy efficiency and by recession-driven reductions in a very limited set large industrial customer loads. PGE emphasizes that the load reduction of 152 average MW in 2015 needs to be put into the context of PGE's overall forecasted resource need of 873 average MW in 2015.⁷

Staff argues that PGE's reference case forecast is too high because it does not adequately account for the continued effect of the 2007–2009 recession.⁸ Staff argues that the NPPC's Final Sixth Plan projected annual load growth of 1.4 percent for 2010–2015 is more reasonable than PGE's projected 1.7 percent. Staff indicates that this level of growth is consistent with PGE's low case forecasts. Staff also attempts to put this adjustment into the context of PGE's overall resource need. Staff indicates that under PGE's reference case load forecast, with Boardman operating, PGE is short 952 annual average megawatts (MWa) of energy in 2016. Staff notes that shutting down Boardman in late 2015 would push that deficit to 1,266 MWa in 2016. Updating PGE's model to include its low load scenario, with Boardman shutdown in 2015, the resource deficit would be 1,158 MWa in 2016. Under this low load scenario, the winter and summer capacity deficits are 1,979 MW and 1,788 MW, respectively in 2016. Staff asserts that these resource gaps under the low load forecasts are still significant and would be challenging to fill if Boardman were shut down in 2016.

Resolution:

We agree that PGE's reference case load forecast for the 2010-2015 period is likely too high because it fails to account for the lingering effect of the 2007-2009 recession. We also agree with PGE and Staff that we must consider this within the context of PGE's overall resource need. Even under the low load scenarios and even if Boardman keeps operating, PGE has significant resource needs. PGE's future resource needs are driven not just by growing demand, but also by the expiration of key power purchase contracts.

In the IRPs, we require utilities to evaluate alternative resource portfolios across a wide range of potential futures, including those with low, medium, and high demand for electricity. PGE's range of load forecasts appears reasonable. PGE evaluated its resource portfolios across this range of load forecasts. Our finding that PGE's reference case load forecasts is likely overstated does not change our decision regarding Boardman and the best resource options for ratepayers, as discussed in the next sections.

We do not agree with NWECA that PGE's projected average annual growth in load is significantly higher than that projected by the Northwest Power and Conservation

⁶ PGE, September 27, 2010 Comments at 14.

⁷ PGE, September 27, 2010 Comments at 13.

⁸ Staff, October 15, 2010 Comments at 9.

Council. PGE correctly compares its forecasts with embedded energy efficiency to the Council's "frozen efficiency" forecasts. This apples-to-apples comparison is consistent with the IRP objective of measuring resource need prior to the addition of any demand- or supply-side resource actions. More fundamentally, we agree with PGE that this comparison is founded on the faulty premise that the Pacific Northwest is one large homogeneous region economically and demographically. As PGE points out, for example, its service territory is more urban and has more high-technology customers than the rest of the region. There are many good reasons why load growth rates will differ by area within a state and within the region.

Boardman.

Parties' Positions:

PGE

PGE requests that the Commission acknowledge continued coal-fired operations at Boardman with compliance actions to meet Oregon Regional Haze Plan and Oregon Utility Mercury Rule standards. The proposed compliance actions at the Boardman plant include:

1. Installation of low-nitrogen oxide (NOx) burners with a modified overfire air control system in July 2011;
2. Installation of mercury controls in July 2012;
3. Installation of selective non-catalytic reduction (SNCR) in July 2014;
4. Operation using reduced sulfur coal beginning in July 2014;
5. Installation and pilot testing of a Dry Sorbent Injection (DSI) system in July 2014; and
6. Cessation of coal-fired operations at the end of 2020.⁹

These compliance actions comprise PGE's BART III proposal submitted to the DEQ on July 30, 2010. Contingent on the results of the DSI pilot testing, PGE would commit to meeting a 0.4 lb. sulfur dioxide (SO₂) per million British thermal unit (MMBtu) emission limit through 2020 using DSI. If the pilot testing demonstrated that operating the plant with DSI technology is incapable of achieving this level of SO₂ emissions without triggering an increase in emissions of particulate matter, then PGE proposes to meet an alternative SO₂ limit established by DEQ procedure based on the DSI testing. It is unclear whether the EQC will adopt PGE's BART III proposal.

In comments filed in this docket on August 10, 2010 and September 27, 2010, PGE argues that its BART III compliance actions, when combined with its energy efficiency, renewable energy, and other resource actions, comprise a portfolio of resources that provide the best combination of cost and associated risk for ratepayers over the IRP planning period.

⁹ PGE's August 10, 2010 Comments at 8-9.

PGE analyzed its BART III proposal, as well as three alternative DEQ options, using its IRP portfolio modeling. DEQ Option 3 calls for installation of a low-NOx burner system in 2011 and mercury controls in 2012; but would require the shutdown of the Boardman plant by late 2015 or early 2016. DEQ Option 2 is similar to PGE's BART III proposal, but would result in cessation of coal-fired operations in 2018. DEQ Option I includes the low-NOx burner system in 2011, the mercury controls in 2012, adds installation of semi-dry flue gas desulfurization (dry scrubbers) in 2014 to control SO₂ emissions, and would cease coal-fired operations at Boardman in 2020. Based on its IRP modeling, PGE concludes that its BART III resource portfolio is both less costly and less risky than the three DEQ options.¹⁰

PGE observes that among the early closure options, those that keep Boardman open longer perform better. PGE suggests that DEQ Option 1 is unacceptable because the dry scrubbers are a very costly additional layer of control. PGE questions the regulatory implementation of DEQ Option 2, which does not include pilot testing of the DSI technology, and therefore fails to account for the possibility that achieving the SO₂ emission limit may simultaneously trigger a violation of particulate matter limits. Finally, PGE argues that DEQ Option 3, which would shutdown Boardman in late 2015 or early 2016, offers an extremely poor outcome for ratepayers in terms of cost and risk.

PGE urges the Commission to acknowledge the compliance actions in its BART III proposal as being the least cost and least risk option for ratepayers. PGE believes these actions define a reasonable transition to non-coal fuel resources and would set national precedent.¹¹

PGE concedes that its BART III proposal does not guarantee that future regulation of hazardous air pollutants or the resolution of pending litigation in United States District Court will not require PGE to install additional controls at Boardman prior to 2020. However, PGE no longer makes its acknowledgment request contingent upon obtaining a reasonable assurance by March 31, 2011 that it will be able to operate Boardman through 2020 without installing additional emission control technologies. PGE asks the Commission to acknowledge its BART III compliance actions despite these risks.¹²

PGE does, however, make its acknowledgement request contingent on EQC approval of its BART III proposal by March 31, 2011. In the event that the EQC fails to approve BART III, PGE requests acknowledgement of a backstop proposal. PGE's backstop is full implementation of BART I controls and continued operation of the Boardman plant through a least 2040. Based on incremental rate impact analysis, PGE concludes that the BART I emission controls, as modeled in the Diversified Thermal with Green portfolio, outperform the three DEQ early shutdown options and is the second best option for ratepayers.¹³

¹⁰ PGE's August 10, 2010 Comments at 11-13.

¹¹ PGE's August 10, 2010 Comments at 52.

¹² PGE's August 10, 2010 Comments at 16.

¹³ PGE's August 10, 2010 Comments at 15.

PGE argues that backstop acknowledgment is necessary because any delay in ordering the equipment needed to implement BART I will subject ratepayers to increased costs and risks associated with a compressed Engineering, Procurement and Construction (EPC) schedule and with a potential temporary shut-down of the Boardman plant in 2014 as a result of failure to install the dry scrubbers by the BART I deadline.¹⁴ PGE has continuously emphasized throughout this proceeding that failure to comply with the Oregon Regional Haze Plan is not an option. The Boardman plant must meet the emissions requirements by either installing the required controls or by ceasing coal-fired operations.

In its comments on Staff's proposed draft order, PGE states that it asked DEQ to reopen the record in the ongoing DEQ rulemaking proceeding to allow PGE to make a refinement to the BART III plan. PGE noted that the Citizen's Utility Board (CUB), RNP, Angus Duncan, Oregon Environmental Council (OEC), and NWECA, support the refined BART III plan. PGE also informed the Commission that PGE has committed to work with stakeholders in the next IRP to evaluate and consider carbon-reduction options for replacement power.¹⁵

The following parties submitted opening comments that largely support PGE's BART III proposal without qualification: Morrow County Commission, Portland Business Alliance, Oregon Forest Industries Council, Associated Oregon Industries, Oregon Cattlemen's Association, Community Action Partnership of Oregon, Strategic Economic Development Corporation, Association of Oregon Counties, Salem Chamber of Commerce, Wilsonville Chamber of Commerce, Clackamas County Business Association, Columbia Corridor Association, Oregon Farm Bureau and Oregonians for Food and Shelter. In reply comments Associated Oregon Industries, Salem Area Chamber of Commerce, West Side Economic Alliance, Oregon Forest Industries Council, Association of Oregon Counties, Columbia Corridor Association, and Morrow County Commission urge the Commission to acknowledge PGE's 2040 option as a backstop alternative.

IBEW Local 125 urges the Commission to acknowledge operation of the Boardman plant until 2040 and beyond, with nothing less than 2020 as a backstop.

The Physicians for Social Responsibility urge the Commission to consider the serious health concerns and costs associated with continued operation of the Boardman Coal Plant beyond 2014.

Other parties submitted comments that challenge PGE's analysis of the Boardman compliance options and contained alternative recommendations for the Commission. We summarize these parties' positions below.

¹⁴ PGE's August 10, 2010 Comments at 5 and IRP Addendum at 124.

¹⁵ PGE's October 29, 2010 Reply Comments at 3.

The Coalition

The Sierra Club, National Environmental Defense Center (NEDC), Friends of the Columbia Gorge, and Columbia Riverkeeper (the Coalition) characterize PGE's proposed compliance actions as a plan to transition off coal in 2020 or never.¹⁶ The Coalition argues that PGE's proposed BART III is virtually identical to its BART II proposal that was already rejected by the EQC. The Coalition recommends that the Commission order PGE to start over and develop a balanced and reasonable outcome for Boardman that is consistent with clean air laws and Oregon's greenhouse gas emissions reduction goals.

The Coalition argues that PGE's own modeling shows that compared to PGE's BART I backstop both DEQ Option 2, with early shutdown in 2018, and DEQ Option 3, with early shutdown in late 2015, are lower cost alternatives.¹⁷

The Coalition argues that PGE uses unreasonably high natural gas prices in its IRP modeling and biases the results in favor of continued operation of the Boardman plant and against the early shutdown scenarios.¹⁸ The Coalition concedes that it did not prepare its own natural gas prices forecasts, but instead relied upon the forecasts provided in the record of this proceeding by other parties. However, the Coalition argues that it is critically important that planning analyses and decisions be based on current information. The Coalition recommends that the Commission require PGE to update its reference case natural gas price forecast before accepting the modeling results.

The Coalition also claims that PGE has overstated its energy and capacity needs.¹⁹ Again emphasizing the importance of current information, the Coalition argues that PGE should use its December 2009 peak and average energy load forecasts in its IRP modeling. The Coalition argues that the differences between the December 2009 forecasts and the March 2009 forecasts used in PGE's IRP modeling are significant and material to the development of PGE's IRP Action Plan.

The Coalition opines that contrary to PGE's assertions, a natural gas-fired combined-cycle combustion turbine (CCCT) can be built in two to two-and-a-half years.²⁰ Given actual construction times, the Coalition believes that a CCCT could be built and ready to replace Boardman by 2016.

The Coalition states that PGE has completely failed to evaluate the economic cost and benefits of replacing some or all of Boardman's output with a mid-term power purchase agreement (PPA).²¹ According to the Coalition a mid-term PPA strategy could be used to implement DEQ Options 2 & 3.

¹⁶ Coalition's September 1, 2010 Comments at 1-2.

¹⁷ Schlissel Technical Consulting September 1, 2010 Comments at 2-6.

¹⁸ Schlissel Technical Consulting September 1, 2010 Comments at 7-16.

¹⁹ Schlissel Technical Consulting September 1, 2010 Comments at 16-18.

²⁰ Schlissel Technical Consulting September 1, 2010 Comments at 18.

²¹ Schlissel Technical Consulting September 1, 2010 Comments at 19.

The Coalition points to PGE's IRP modeling which shows Boardman operating as an intermediate-load resource in the future and questions the prudence of investing in emissions controls at the plant if it would no longer operate as a baseload resource.²²

The Joint Parties

The Citizens' Utility Board (CUB), Renewable Northwest Project (RNP), NW Energy Coalition (NWEC), Oregon Environmental Council (OEC), Angus Duncan, Ecumenical Ministries of Oregon (EMO), Sierra Club, and NEDC, (collectively, "the Joint Parties"), have one simple recommendation for the Commission, do not acknowledge the BART I emission controls, as modeled in the Diversified Thermal with Green portfolio or any other portfolio, even as a backstop plan.²³ Installing these emissions controls and hoping to run the plant through 2040 is viewed as the most objectionable option before the Commission.

The Joint Parties support closing the Boardman plant as early as possible, yet indicate that they would prefer a broadly supported plan, even if the plan closed the plant at a somewhat later date. Therefore, PGE and DEQ are urged to use DEQ's Option 2 and PGE's BART III proposals as the basis for achieving convergence on a broadly supported plan. The Commission is urged to only acknowledge the pollution controls that are immediately necessary and to leave the door open for further amendments to this IRP. According to the Joint Parties these actions will allow room for PGE, DEQ, and other stakeholders to agree on a comprehensive plan to achieve the responsible closure of Boardman.

The Joint Parties argue that the replacement of Boardman should be significantly cleaner and more flexible than replacement with only a baseload natural gas plant.²⁴ The Joint Parties are confident that PGE could replace Boardman in the 2015/2016 timeframe with a diverse mix of resources. However, they concede that early closure risks replacement with a natural gas resource and its associated carbon emissions. Again, the Joint Parties urge the Commission to create space for stakeholders to develop a clean and diverse replacement strategy.

In summary, the Joint Parties seek early closure of the Boardman plant, a replacement strategy with a clean and diverse mix of resources, and broad consensus among stakeholders; while simultaneously protecting ratepayers and keeping the cost of closure and replacement power under control.

The NW Energy Coalition

NWEC joins the Joint Parties in recommending shutdown of the Boardman plant by no later than 2020. Like the Joint Parties, NWEC prefers an agreement between PGE, DEQ, and stakeholders on an acceptable plan. As a result, NWEC recommends that the

²² Schlissel Technical Consulting September 1, 2010 Comments at 20-21.

²³ Joint Parties September 1, 2010 Comments at 1.

²⁴ Joint Parties September 1, 2010 Comments at 2.

Commission only indicate the boundaries of an acceptable closure plan. According to NWEAC, formal acknowledgement should only occur after an actual agreement to close Boardman is achieved.²⁵

NWEAC opines that not enough effort has been put into developing a resource strategy to replace Boardman.²⁶ NWEAC urges the Commission to consider the state's carbon reduction goals and in the next IRP cycle to begin working on a comprehensive plan to achieve significant reductions in emissions. NWEAC has repeatedly argued that the risk metrics used by PGE in its IRP portfolio analysis assign no weight to the risk of carbon regulation because they average scenarios with high and low carbon costs. NWEAC recommends that the Commission require future IRPs to include a risk metric that directly measures carbon dioxide emissions.

NWEAC is most forceful in its objection to PGE's request for backstop acknowledgment of the BART I compliance actions.²⁷ NWEAC argues the DEQ Option 3 with closure of Boardman in late 2015 or early 2016 is the better backstop. According to NWEAC a comparison of the modeling results of PGE's BART I backstop to DEQ Option 3 shows no significant difference on a cost basis. NWEAC argues that the lower carbon dioxide emissions of DEQ Option 3 should be used to break this tie. NWEAC suggests that the advantage in emissions could be even larger if Boardman is replaced with power sources cleaner than a natural gas-fired CCCT. NWEAC scolds PGE for introducing new factors, such as near-term rate impacts, inadequate time to develop replacement resources, and insufficient transition time for its employees and the Boardman community, as tie-breaking criteria.

Although NWEAC joins the Coalition in questioning PGE's timeline for construction of a CCCT, it more fundamentally questions the need for immediate and full replacement of Boardman's capacity and energy output.²⁸ NWEAC has repeatedly argued that the load forecast used by PGE in its IRP modeling is higher than the Northwest Power and Conservation Council's Oregon (NPCC) forecast. NWEAC also asserts that PGE has overstated its resource need by deciding to lower its exposure to the wholesale power market. NWEAC criticizes PGE for not analyzing its level of market exposure in this IRP. NWEAC concludes that there is little need for quick and full replacement of Boardman by 2015.

Finally, NWEAC concedes that over reliance on the wholesale power market can be risky and detrimental to ratepayers. It then points to a healthy surplus of generating capacity in the Northwest and the area covered by the Western Electricity Coordinating Council and concludes this risk is worth taking to close Boardman in late 2015 or early 2016. NWEAC argues that reliance on the market can provide the space needed in time to acquire a clean mix of replacement resources.

²⁵ NWEAC September 1, 2010 Comments at 1.

²⁶ NWEAC September 1, 2010 Comments at 1-2.

²⁷ NWEAC September 1, 2010 Comments at 2-6.

²⁸ NWEAC September 1, 2010 Comments at 4.

NIPPC

The Northwest and Intermountain Power Producer's Coalition (NIPPC) offers no opinion regarding the cessation of coal-fired operations at the Boardman plant.²⁹ NIPPC emphasizes, however, that the shutdown risks being debated in this proceeding are largely ratepayer risks and opines that diversifying ownership of generation resources is in the best interest of ratepayers. NIPPC says it is well established that power purchase agreements (PPAs) lower a utility's business risk. Contrasting PGE's Boardman ownership with PGE's PPA with TransAlta for a portion of the output of the coal-fired Centralia plant, NIPPC concludes that power secured through a PPA with an independent power producer is far less risky for ratepayers.³⁰

NIPPC offers more detailed criticism of PGE's analysis of the potential replacement resources for Boardman. NIPPC argues that PGE has not adequately evaluated the costs and risks, including the reliability risks, of entering into power purchase agreements with independent power producers. NIPPC's criticism is not limited to the evaluation of PPAs for long-term replacement of Boardman, but also covers the evaluation of short-term PPAs that could temporarily bridge the capacity and energy need until a permanent replacement is built or purchased. According to NIPPC, PGE's repeated assertions that this type of analysis is more appropriate in a competitive procurement proceeding are misplaced. Commission IRP Guideline 1 requires utilities to evaluate all resources on a consistent and comparable basis.³¹ NIPPC argues that postponement of the evaluation of PPAs to the competitive bidding process makes PGE's IRP noncompliant with IRP Guideline 1.

NIPPC has specific recommendations to remedy PGE's lack of analysis of the PPA option. NIPPC asks the Commission to require PGE to issue a Request for Information (RFI) to potential suppliers of replacement power.³² This streamlined information gathering process would allow PGE to adequately consider the PPA resource and to re-evaluate its replacement options. NIPPC states that PGE should be required to file an IRP addendum explaining the results of the RFI and to allow parties to fully vet the merits of the PPA replacement option.

NIPPC also has recommendations for improving PGE's upcoming Request for Proposal (RFP) process.³³ Concerned that PGE intends to favor its own self-built benchmark resources, NIPPC recommends the Commission encourage PGE to identify the actual amount of nameplate megawatts that it intends to acquire through unit contingent PPAs linked to resources that PGE does not intend to build or subsequently acquire. NIPPC also recommends that the Commission strongly encourage PGE to solicit bids that include build-to-own replacement options at PGE's sites, long-term PPAs linked to

²⁹ NIPPC September 1, 2010 Comments at 2.

³⁰ NIPPC September 1, 2010 Comments at 7.

³¹ OPUC Order 07-002 at 3.

³² NIPPC September 1, 2010 Comments at 5.

³³ NIPPC September 1, 2010 Comments at 8-9.

replacement resources located at non-PGE sites, as well as sales of existing assets from independent power producers.

Staff

Staff recommends that the Commission acknowledge PGE's BART III proposal. Staff recommends that the Commission not acknowledge PGE's BART I backstop proposal, but instead require PGE to include a backstop proposal and supporting analysis in its next IRP Update if EQC denies its request to revise the Regional Haze Program to facilitate PGE's BART III proposal.

Staff primarily focused its analysis of PGE's portfolio modeling on three metrics, expected cost, the average of the four worst deterministic futures, and the stochastic TailVar90 risk metric. Staff also reviewed the analysis and comments of the other parties in this case. Based on this analysis, Staff agrees with PGE that its BART III proposal represents the portfolio with the best combination of cost and risk for ratepayers. The BART I portfolios, including Diversified Thermal with Green, would impose too great of a risk on ratepayers from future federal and state regulation of carbon emissions. Staff also agrees with PGE that the execution risks associated with implementing the earlier shutdown scenarios are also significant.

While Staff agrees with NIPPC and NWECA that power purchases from independent power producers or the wholesale power market could be used to bridge the early energy and capacity deficits associated with these scenarios, Staff concludes that the risk associated with this type of strategy is not in the best interest of ratepayers. For these reasons, Staff recommends that the Commission acknowledge PGE's BART III proposal.

Staff agrees with comments of other parties that there is evidence that PGE's reference case load forecast may overstate future demand. However, Staff's analysis indicates that PGE's energy and capacity need remains significant even under a lower load scenario. Under PGE's reference case load forecast, with Boardman operating, PGE is short 952 annual average megawatts (MWA) of energy in 2016. Staff notes that shutting down Boardman in late 2015 would push that deficit to 1,266 MWA in 2016. Updating PGE's model to include its low load scenario, with Boardman shutdown in 2015, the resource deficit would be 1,158 MWA in 2016. The winter and summer capacity deficits under this low load scenario without Boardman are 1,979 MW and 1,788 MW, respectively. Staff asserts that these resource gaps are significant and would be challenging to fill if Boardman were shut down in 2016.

Staff agrees also with the Coalition and NWECA that PGE's reference case natural gas price is slightly overstated. However, Staff concludes that PGE's response to the Commission's bench request, which tested a combined low natural gas price, low load forecast scenario, continues to show very little difference between the shutdown scenarios on an expected cost basis. Staff prefers PGE's BART III proposal because it allows adequate time to implement a lower-risk replacement resource strategy.

CUB

In its Reply Comments, CUB agrees with Staff that of the options presented in the IRP, BART III is the best performer from a least cost/least risk basis. Nonetheless, CUB believes that the Commission should not specifically acknowledge BART III in the event the EQC adopts a rule that is substantially similar to BART III, but with a different off-ramp for the DSI technology. CUB recommends the Commission use the following language:

If the EQC adopts the BART III compliance actions or compliance actions that are substantially similar to BART III, then this combination of pollution control investments and commitment to cease operation at Boardman no later than 2020 provides the best combination of expected costs and risks for customers. We acknowledge compliance actions that are substantially similar to BART III for the Boardman plant.³⁴

NWEC also recommends that the Commission should broaden the scope of its acknowledgment regarding Boardman to allow PGE to proceed with its proposed refinements to BART III, should the EQC and Environmental Protection Agency allow it.³⁵

CUB, NWEC, RNP, Angus Duncan and the OEC also filed joint comments urging the Commission to issue an acknowledgment order “flexible enough to accommodate the refinements that PGE have worked to make possible.” These parties also urge the Commission impose a requirement on PGE that tracks with the commitment PGE has made to certain parties to develop low-carbon portfolios for evaluation in PGE’s next IRP.³⁶

Commission resolution:

There are six Boardman options currently under consideration:

- The BART I option with shutdown targeted for 2040
- The Boardman through 2014 option
- PGE’s proposed BART III option with shutdown targeted for 2020
- DEQ’s Option 1 with shutdown targeted for 2020
- DEQ’s Option 2 with shutdown targeted for 2018; and
- DEQ’s Option 3 with shutdown targeted for 2015/2016

Of these options PGE’s proposed BART III option offers the best combination of cost and risk for ratepayers. We consider PGE’s BART III to be the superior option because it is a low-cost option for ratepayers; it mitigates the risk of future carbon regulation by

³⁴ CUB’s Comments on Staff Order at 3-4.

³⁵ NWEC Final Comments at 2.

³⁶ Group Comments on Staff’s Proposed Order at 2.

closing the plant at the end of 2020; it mitigates the risk of acquiring replacement resources by providing the time needed to evaluate and implement a reasonable replacement strategy; and it provides the flexibility needed to test the effectiveness of DSI technology and to adapt the plant's operation to control both SO₂ and PM emissions prior to the plant's closure.

The BART I option which requires a \$510 million investment in pollution control equipment in order to operate the plant through 2040 is too costly and too risky. The risk of future carbon regulation, whether it takes the form of cap-and-trade regulation, carbon taxation, or the mandated closure of specific coal plants, makes this an inferior option for ratepayers. Under a worst-case scenario, PGE's ratepayers could potentially pay the cost of replacing Boardman with low carbon emission resources while continuing to pay for pollution control equipment at a plant that no longer operates.

DEQ Option 3 which calls for shutdown of the Boardman plant in late 2015 or early 2016 does not allow enough time for PGE and interested parties to develop and implement a reasonable resource replacement strategy. PGE has argued that any replacement for Boardman needs to be a baseload resource and has modeled replacement with a natural gas CCCT. The Joint Parties and others have indicated a strong preference for replacing Boardman with a mix of renewable resources. The choice of the best replacement resources is a complex decision that should be considered in PGE's IRP process. Closing Boardman in late 2015 or early 2016 does not allow enough time to fully consider and develop alternative replacement options and could result in ratepayers bearing higher costs in the long-run. The same logic and conclusion applies to the Boardman through 2014 option.

DEQ Option 1 which requires a \$343 million investment in pollution control equipment and closes the Boardman plant in 2020 is simply too costly for ratepayers. In PGE's IRP modeling, this option and the BART I option are consistently the highest cost options over a wide range of potential futures, including both PGE's reference case scenario and our bench request scenario.

DEQ Option 2 lacks the flexibility needed to test the effectiveness of DSI technology and to adapt the plant's operation to control both SO₂ and PM emissions prior to shutdown in 2018. This lack of flexibility makes operating the plant to 2018 a more risky endeavor. If DSI technology is incapable of controlling SO₂ emissions without simultaneously violating PM emission standards, then PGE and its ratepayers would be confronted with the choice of making an expensive investment in additional pollution control equipment or closing the plant prior to the 2018 target. The increased risk of shutdown prior to 2018 raises the issue of having enough time fully develop and implement a reasonable resource replacement strategy. For these reasons, we find PGE's BART III option to be superior to DEQ Option 2.

On October 22, 2010, PGE requested that DEQ re-open its BART rulemaking to consider a refinement to PGE's BART III option. The refinement consists of a lower SO₂ emissions requirement beginning July 2018 and a request to repeal the existing BART I

option if PGE's BART III option is ultimately approved by the EQC and the EPA. With this refinement, and a PGE commitment to work with stakeholders to develop low-carbon resource portfolios for consideration in its next IRP, BART III now has the support of CUB, NWECC, OEC, and RNP.

PGE proposes to reach the lower SO₂ emissions standard with increased use of DSI beginning in July 2018. This change increases the total expected net present value cost of the BART III option by \$10 million. This change in cost is not significant enough to alter our finding that BART III is the best option for ratepayers. We acknowledge both PGE's original and refined BART III options.

We decline, however, to adopt CUB's recommendation to acknowledge other compliance actions that are "substantially similar" to BART III for the Boardman plant. Although we share CUB's preference to not be involved in an IRP Update proceeding that is comparing small differences in BART compliance actions, the evaluation of differences in resource portfolios is complex and the determination that two options are equivalent is not amenable to allowing parties to interpret the phrase "substantially similar."

We also decline to acknowledge BART I as a backstop option. The acknowledgement of a backstop option would require us to predict or prejudge which compliance options might remain if the EQC denies PGE's BART III proposal. If the EQC denies PGE's BART III proposal, then PGE has the ability to present its next preferred option, and ask for Commission acknowledgment, in an IRP Update. There is no limit on the frequency of IRP Updates, if needed PGE can expeditiously file a Boardman-Only Update and also file a general IRP Update a year from now.

We also decline to not acknowledge BART I. We will wait for the EQC to make its decision on BART III before we consider any backstop option. Our decisions do not address the question of the prudence of pursuing the BART I compliance actions, they simply mean that we refuse to prejudge the EQC's actions. Our acknowledgement of PGE's BART III, conditional on EQC approval, does signal our intention to address the replacement strategy for Boardman in PGE's next IRP.

Cascade Crossing

The Cascade Crossing Transmission Project (Cascade Crossing) is a proposed 500 kV transmission line connecting its Boardman and Coyote Springs plants to the southern portion of its service territory. The proposed project would begin at PGE's Coyote Springs substation, go to the Boardman plant and terminate at PGE's Bethel substation. The project would parallel existing utility lines for the first 106 miles from the Boardman substation toward Bethel, and parallel PGE's existing Bethel-to-Round Butte 230 kV line over the Cascades for the last 77 miles. The project will require the construction of a 500/230 kV substation, 500/230 kV transformer, and 500/230 kV transformer bank and improvements to two existing substations.³⁷

³⁷ PGE IRP at 187.

PGE asserts that Cascade Crossing will (1) directly connect west-side load to existing and new resources on the east side of the Cascade; (2) add transfer capacity to the Cross-Cascades South and West of Slatt cutplanes; (3) reduce stress on the I-5 cutplanes by providing another path to its system from the south; (4) provide firm transmission service as an alternate to BPA service for existing generation; and (5) improve reliability by providing additional transmission and reducing load on transfer paths parallel to Cascade Crossing, reducing the severity of currently limiting contingencies.³⁸

PGE seeks acknowledgment to build Cascade Crossing as a double-circuit 500 kV and alternatively, as a single-circuit 500 kV facility. PGE states that whether it proceeds with Cascade Crossing, as either a double-circuit or single-circuit, will depend on future economic analysis incorporating refined cost estimates, updated information regarding path rating, the level of equity participation from third parties, transmission service requests received by PGE, and updated information regarding PGE's generation facilities that would utilize the project.

Parties' positions: RNP believes Cascade Crossing will directly facilitate wind interconnections and will provide links between eastern Oregon wind, solar, and geothermal resources with western load centers. RNP supports acknowledgment of Cascade Crossing so long as it can be responsibly sited and developed within parameters of a sensible and timely cost-benefit analysis. RNP recommends that the Commission require PGE to update its analysis regarding Cascade Crossing in a future IRP or IRP update.³⁹

CUB has the following questions and concerns regarding PGE's proposed Cascade Crossing Transmission Project, but does not go so far as to recommend against acknowledging the project: (1) Why does the expected closure of Boardman not affect PGE's plan for Cascade Crossing; (2) Why aren't BPA transmission services sufficient to serve PGE's needs; (3) Does PGE have sufficient experience to manage construction of Cascade Crossing without incurring significant cost overruns; (4) Should new transmission be a top priority for PGE?

Willard Rural Association (WRA) recommends that the Commission not acknowledge Cascade Crossing asserting that PGE overstates its load forecast, understates the amount of transmission BPA will have in the future and overstates the cost of that transmission, underestimates the cost to acquire right of way for Cascade Crossing and understates the risk associated with an \$823 million investment.

³⁸ PGE IRP at 189-90.

³⁹ RNP Sept 1, 2010 Reply Comments at 3.

Staff recommends that the Commission acknowledge Cascade Crossing in the double-circuit configuration, subject to the requirement that PGE provide the Commission certain information and updated analysis in its next IRP Update.

Staff asserts that PGE's proposal to acquire a transmission resource is supported by analysis under Guideline 8. Staff agrees with PGE's conclusions that adding transmission to PGE's system will allow additional purchases and sales, access to less costly resources in remote locations, access to renewable resources developed on the east side of the state, and will improve reliability.

Staff also asserts that PGE's financial and qualitative analysis (some done in response to a Staff data request) supports PGE's proposal to build Cascade Crossing, as opposed to acquiring transmission in another manner.

Commission Resolution:

PGE conducted a benefit-cost analysis of the Cascade Crossing transmission project to determine whether it should include Cascade Crossing in its IRP Action Plan and continue to invest in the project. The choice analyzed was whether it is preferable for PGE's ratepayers to continue to purchase transmission capacity from the Bonneville Power Administration (BPA) or to obtain transmission capacity by building Cascade Crossing. PGE's analysis consisted of five case studies with different assumptions regarding third party equity participation in Cascade Crossing and different assumptions regarding the growth of BPA's transmission rates after 2025.

PGE analyzed both a single-circuit and double-circuit configuration of the Cascade Crossing project. For the single-circuit configuration PGE estimated total project costs to be \$613 million and assumed a path rating of 1,500 MW of transfer capability. For the double-circuit configuration PGE estimated total costs of \$823 million and assumed a transfer capability of 2,200 MW. Under Case 3, its mid-point case study, PGE further assumed that it would partner with a third party to share the costs of the 17-mile segment of transmission line from the Coyote Springs plants to the Boardman plant and for the expansion of the Coyote Springs substation.

PGE estimated the cost of continued service from BPA by assuming that BPA's current transmission rates experience a one-time increase of 10 percent in 2015 and grow at an average nominal rate of 4.0 percent from 2011 to 2025. Under its mid-point case study, PGE further assumed that BPA transmission rates grow at a rate of 3.2 percent from 2025 to 2082. In all five of the case studies, PGE included approximately \$65.5 million for new transmission substations and radial lines needed to connect PGE's planned resources to the BPA transmission system.

PGE, through its case studies, considered higher and lower levels of equity participation and higher and lower growth of BPA's transmission rates after 2025. For example, in Case 1, PGE assumed no equity participation in the 17-mile line segment from the

Coyote Springs plants to the Boardman plant and a growth rate of 2.5% in BPA's transmission rates after 2025. In Case 5, PGE assumed an additional third party equity share equivalent to 209 MW of transfer capability under the single-circuit configuration (or 300 MW under the double-circuit configuration) and a growth rate of 3.5% in BPA's transmission rates after 2025.

The primary benefit of Cascade Crossing is that PGE can avoid future increases in BPA's transmission rates. Cascade Crossing can achieve these savings by connecting PGE's existing Boardman and Coyote Springs plants, and any new generation located in eastern Oregon, directly to PGE's load. PGE's analysis shows that the single-circuit configuration of Cascade Crossing provides net benefits to ratepayer under the mid-point and high equity participation cases. The double-circuit configuration only shows net benefits under the high equity participation cases.

PGE did not attempt to quantify all of the potential benefits of Cascade Crossing in its benefit-cost analysis. For example, in all cases PGE assumed zero revenues from transmission sales or use in the west-to-east direction. PGE also did not estimate the potential reliability benefits or the savings in energy losses that would accrue to PGE ratepayers from building Cascade Crossing.

Further, under both the single- and double-circuit configurations, Cascade Crossing would provide other load serving entities the opportunity to access new renewable resources located east of the Cascade Mountains. PacifiCorp recently signed a Memorandum of Understanding with PGE to explore obtaining an equity share in the line equivalent to 600 MW of bi-directional transfer capability.

PGE's benefit-cost analysis is sufficiently robust, and shows sufficient net benefits under certain scenarios, to allow us to acknowledge Cascade Crossing at this time. However, when developing an IRP, we always expect utilities to update their assessments of previously acknowledged projects that are still in the planning or development stages. We make this updating requirement explicit for the Cascade Crossing project because of the current uncertainty regarding equity participation and other key factors. We expect the Company to provide a thorough update of the Cascade Crossing benefit-cost analysis in its next IRP; with the understanding that Commission acknowledgment of the next IRP will depend on the outcome of that updated analysis. Therefore, we acknowledge Cascade Crossing with the following requirement:

PGE shall include an updated benefit-cost analysis of the Cascade Crossing transmission project in its next IRP. For the updated analysis, PGE shall update its assumptions about project configuration, capital cost, path rating, wheeling revenues, and equity participation and conduct sensitivity analyses that address any uncertainty about capital cost, path rating, levels of equity participation, and levels of wheeling revenues.

Finally, we reiterate that at the time of ratemaking any utility is required to show that its investment was a prudent decision. At that time, the Company will be expected to address any significant changes in construction cost, path rating, equity partnership, or

third-party subscription and how these changes influenced the Company's decision to continue with the project.

Natural gas price forecast method

Parties Positions: The Coalition argues that PGE uses unreasonably high natural gas prices in its IRP modeling and biases the results in favor of continued operation of the Boardman plant and against the early shutdown scenarios. The Coalition compares PGE's reference case natural gas prices forecasts to those of the NPCC, the OPUC Staff, and the U.S. Energy Information Administration (EIA).⁴⁰ The Coalition argues that it is critically important that planning analyses and decisions be based on current information. The Coalition recommends that the Commission require PGE to update its reference case natural gas price forecast before accepting the modeling results.⁴¹

Staff agrees also with the Coalition that PGE's reference case natural gas price is slightly overstated. Staff argues that PGE's forecasting methodology is flawed because the Company only relies on a single source, PIRA Energy Group, for its long-term natural gas price forecast. Staff also argues that PGE's short-term price forecast is flawed because it only relies on NYMEX futures prices, and does not include fundamentals based price forecast. Staff recommends that the Commission require PGE to obtain natural gas prices forecast from multiple third party sources.

In response to Staff's analysis and recommendations, PGE states that it is unaware of any bias in PIRA's forecasts. PGE also notes that it appears that Staff compared the IRP's August 2009 PIRA forecast to the 2010 forecasts of EIA and Wood MacKenzie Research and Consulting (Wood Mackenzie). PGE notes that comparing PIRA's 2009 forecast to these 2010 forecasts is misleading because most forecasters reflected a downturn in prices for 2010.⁴² With respect to Staff's observations regarding PGE's use of NYMEX future prices for near-term forecasting, PGE maintains that using prices from actual trades reflects the most current and accurate information that is available in the market.⁴³

Commission Resolution: We agree that PGE's reference case natural gas price forecast is likely overstated because of the lingering effect of the 2007-2009 recession and recent developments related to shale gas production. In the IRPs, we require utilities to evaluate alternative resource portfolios across a wide range of potential futures, including those with low, medium, and high prices for natural gas. PGE's range of natural gas prices appears reasonable. PGE's natural gas forecasts satisfy IRP Guidelines 1b and 4g. Our finding that PGE's reference case natural gas prices are likely overstated does not change our decision regarding Boardman. We decline to require PGE to use multiple forecasting sources in future IRPs. We expect PGE to continue to update its natural gas price forecasts in future IRPs and IRP Updates.

⁴⁰ Schlissel Technical Consulting, May 19, 2010 Comments at 4-10.

⁴¹ Schlissel Technical Consulting, September 1, 2010 Comments at 12.

⁴² PGE, November 1, 2010 Comments, at 13-14.

⁴³ PGE, November 1, 2010 Comments, at 13-14.

Parties' positions: Staff takes issue with PGE's reliance on single sources for fundamental long-term natural gas price forecasts and short-term price indicators. Staff notes that by relying on only the PIRA Energy Group for long-term gas price forecasts, PGE has failed to ameliorate any bias that PIRA has. The same is true of PGE's reliance on only one source, New York Mercantile Exchange (NYMEX), for short-term price indicators. However, Staff's concern regarding NYMEX is also based on the fact NYMEX is not a forecasting service.

Demand response

Parties' positions: Staff concludes that PGE did not comply with IRP Guideline 7 regarding demand response (DR) because the company failed to evaluate DR "on par" with other options for meeting energy, capacity, and transmission needs. Staff notes that PGE included 60 MW of firm DR in its portfolios in 2012 through 2016 (50 MW from an RFP and 10 MW from a curtailment tariff option for large industrial customers) but that the company did not explain why those were the only DR resources projected in that time period. Staff recommends that the Commission direct PGE to meet Guideline 7 and provide certain information on projected amounts and costs of DR in its next IRP update.⁴⁴

PGE responded to Staff's analysis asserting that it did comply with the guideline, pointing out in particular that it evaluated DR on par with other resource options by assessing and selecting DR using a benefit/cost ratio based on an alternative capacity resource (a simple cycle combustion turbine or SCCT).⁴⁵

In comments responding to the draft proposed order, CUB notes that PGE has not made much progress towards acquiring significant DR since the Commission approved the company's Advanced Metering Infrastructure (AMI) proposal in 2008. CUB agrees with Staff that PGE did not adequately analyze DR in the IRP and recommends that Commission require the company to report in the next IRP update what steps it will be taking to evaluate DR programs in the next full IRP.⁴⁶

Commission resolution: We share the concerns expressed by Staff and CUB. PGE evaluated DR against an SCCT but did not provide DR cost information in the IRP. The company included 10 MW from a critical peak pricing (CPP) program as a capacity resource in its last (2007) IRP but did not do so in this IRP, without explaining the change (other than to say now that it primarily assumes acquisition of firm DR resources). And PGE has not made the progress we expected on acquisition of DR, e.g.,

⁴⁴ Staff Final Comments and Recommendations at 9-10.

⁴⁵ PGE Reply Comments at 7-8.

⁴⁶ CUB's Comments on Staff's Draft Order at 5-7. CUB expressed concern about waiting two years to address DR, apparently because it understood Staff to be proposing a condition for the next IRP. But Staff, like CUB, recommends that PGE report on DR in the next IRP update (which should be filed a year after this order is issued).

it has delayed its CPP pilot for a year, and its RFP for direct load control resources was unsuccessful.

We believe that DR can be a significant resource but realize that there is still much to learn about the potential for and reliability of different types of DR (mainly through pilot programs by PGE and other utilities). We adopt a combination of the proposals made by Staff and CUB and will require PGE to provide information and show the steps it is taking, and intends to take, to assess and acquire DR. Also, we agree with the timing of these requirements recommended by CUB and Staff and direct PGE to comply with these directives at the time of its IRP update.

In its next IRP update, PGE must provide the following:

- a. Its estimated cost per MW of capacity savings by DR type (i.e., firm vs. non-firm resources), and projected MW acquisitions by DR type for the next 5 years,*
- b. A discussion of the steps it is and will be taking to evaluate DR in the next IRP, and*
- c. An updated action plan for assessing (e.g., plans for pilot programs) and acquiring DR for the next 3 years.*

Energy Efficiency

Parties' positions: Staff concludes that PGE met the IRP guideline for conservation (Guideline 6) except that the company did not treat conservation voltage reduction (CVR) as a resource and consider whether to include it in the action plan. Staff notes that the Energy Trust identified technical potential for 19 MWa of savings from CVR in the company's service territory.⁴⁷

PGE replies that it views CVR as an operational efficiency, not a long-term resource planning issue. The Commission found that PGE complied with Guideline 6 (except with respect to the planning horizon) in the company's last IRP, even though its treatment of CVR was the same as in the current IRP. PGE also points out that potential CVR savings are small and would not have a material impact on its resource requirements or action plan.⁴⁸

Commission resolution: We agree that PGE should consider CVR in its resource planning and adopt the following requirement:

In its next IRP, PGE should consider CVR for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings.

RPS Requirements

Parties' positions: PGE proposes to acquire 122 MWa of renewable wind generation by the end of 2012 to achieve physical compliance with the (RPS) Requirement for 2015.

⁴⁷ Staff Final Comments and Recommendations, 10-11.

⁴⁸ PGE Reply Comments, 8-9.

PGE asserts that banking renewable energy credits (RECs) from early renewable resource actions provides a significant cushion for “meeting RPS compliance.”⁴⁹

Staff is concerned that PGE did not model the use of unbundled RECs to comply with the RPS Requirements for the entire planning period. Staff notes that PGE’s analysis is predicated on an assumption that PGE would comply with the RPS Requirement with physical resources, rather than unbundled RECs. Staff recommends that the Commission require to PGE “relax” the assumption that PGE must be in physical compliance with the 2015 RPS Requirement. In other words, Staff recommends that PGE’s analysis include the possibility that PGE will use unbundled RECs to comply with the 2015 RPS Requirement.

In support of this recommendation, Staff notes that several factors could result in a situation in which it is more cost effective to acquire physical resources later, rather than sooner, *e.g.*, due to emerging technology. Staff also notes that PGE’s concerns regarding penalties for non-compliance appear to be overstated.

The Oregon Department of Energy (ODOE) notes that PGE’s plan for physical RPS compliance overbuilds in the near term. ODOE finds the plan appropriate where short-term REC sales provide value to current utility customers at the same time prudent banking reduces RPS compliance risk beyond 2020. ODOE notes, however, that PGE should address the substantial REC output to be made available in 2011 due to the passage of HB 3674 (2010). ODOE reports that the bill makes a number of pre-1995 biomass facilities eligible for the RPS with the condition that REC output from those facilities cannot be used until 2026. ODOE notes that these facilities are expected to produce over 7 million RECs.⁵⁰

ODOE also notes that PGE’s IRP contains an incorrect conclusion regarding the penalty risk associated with failure to meet the RPS Requirement. ODOE notes that the Alternative Compliance Payment is not a direct penalty as the RPS allows a variety of paths for a utility to invest those payments toward future project development.⁵¹

PGE disagrees with Staff’s recommendation that PGE should project future prices and availability for unbundled RECs to assess the potential for acquiring unbundled RECs to meet Oregon’s RPS. PGE states, “[w]e believe that, given the lack of liquidity and transparency in the REC markets, it would not be prudent to rely on such projections.”⁵²

⁴⁹ PGE IRP at 114.

⁵⁰ ODOE May 14, 2010 Comments at 3.

⁵¹ ODOE May 14, 2010 Comments at 4.

⁵² PGE Reply Comments at 10.

Commission resolution: We see no reason that PGE’s analysis of the least cost and least risk method to comply with RPS Requirements should exclude the possibility of using unbundled RECs to meet RPS Requirements at any point in the planning period, including the early years. Both Staff and ODOE identify circumstances that could lead to the conclusion that relying on unbundled RECs in early years of the planning period could be least cost and least risk.

In its next IRP Update and in the next planning cycle, PGE must evaluate the use of unbundled RECs in its strategy to meet RPS Requirements for the entire planning period.

In its next IRP Update and in the next planning cycle, PGE must evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.

Wind integration study

Parties’ positions: RNP recommends that the Commission not acknowledge PGE’s wind integration study on which PGE based its analysis of the cost to operate and acquire wind generation. RNP asserts that PGE’s wind integration costs include an unusually cost of reserves and that that stakeholders and the Commission cannot evaluate the reasonableness of PGE’s costs because PGE based them on an analysis that has not been unveiled.⁵³ RNP recommends that the Commission order PGE to continue to use the BPA wind integration rate to model new wind resources until such time as PGE is prepared to fully engage with stakeholders in review of its methodology and results.

Staff also asserts that PGE did not comply with the Commission’s order stemming from PGE’s last IRP to “include in the [next IRP] analysis a wind integration study that has been vetted by regional stakeholders.”⁵⁴ Staff echoes RNP’s statements that PGE has not produced a study whose detailed methodology and results have been made available for review.

PGE disputes RNP’s and Staff’s characterization of the wind integration study process. PGE states that it engaged a Technical Review Committee consisting of several stakeholders to evaluate its study approach, inputs and findings, and on September 19, 2009, conducted a three-hour workshop to present the details of its wind integration study. In its comments on the draft proposed order, PGE notes that although it believes it has already complied with the requirement to produce a vetted wind integration study, it agrees to Staff’s recommendation to include in its next IRP Update a wind integration

⁵³ RNP Sept 1, 2010 Reply Comments 1-3.

⁵⁴ OPUC Order No. 08-246 at 10.

study that has been vetted by regional stakeholders.⁵⁵ PGE also notes that in addition to the input it received from stakeholders that has already been described in comments, PGE hired an independent examiner (IE) in late 2008 to “vet” the study for another docket (Docket No. UM 1345), and that the IE concluded the study was a “thorough integration study.”⁵⁶

PGE also disputes RNP’s assertion that the wind integration costs underlying PGE’s IRP analysis are unreasonably high. PGE notes that RNP’s assertions are largely based on comparisons to other utilities’ costs and to BPA’s Balancing Authority within-hour integration tariff. PGE notes that these comparisons are inappropriate because each utility’s costs depend on the unique characteristics of the utility’s system and PGE’s wind integration costs is comprised of several components, only of which is comparable to the within-hour integration tariff.⁵⁷

Commission resolution: We agree with RNP that it is important that “vetting” by regional stakeholders of a wind integration study include opportunity for regional stakeholders to examine, in detail, the methodology of the study and the results. We also believe that when vetting PGE’s wind integration study, stakeholders should have the opportunity to comment on the methodology and make recommendations. Also, it is incumbent on PGE to respond to any such comments and to the extent it does not adopt recommendations of stakeholders, explain why.

As PGE itself acknowledges, the *stakeholder* “vetting” consisted of preliminary input from a technical group and a workshop attended by PGE and interested parties. PGE’s presentation at the workshop, a hard copy of which PGE attached to its comments, reflects that PGE informed stakeholders how it intended to go about the study. As RNP and Staff note, such a presentation is not a substitute for an opportunity for regional stakeholders to evaluate the methodology that PGE actually used and the results obtained from the methodology. Accordingly, we will once again impose a requirement that PGE prepare a wind integration study and allow stakeholders an opportunity to vet it, and that PGE do so prior to its next IRP Update:

In its next IRP Update and in the next IRP planning cycle, PGE must include a wind integration study that has been vetted by regional stakeholders.

⁵⁵ PGE Reply Comments at 11.

⁵⁶ PGE Reply Comments 11.

⁵⁷ PGE Sept 27, 2010 Reply to Intervenor Response Comments at 18.

Risk metrics

Parties' positions: Staff cautions the Commission regarding the interpretation of two of PGE's risk metrics. The "Average of Worst Four Futures Less the Reference Case Cost"⁵⁸ and "TailVar90 Less the Mean" risk metrics are calculated by subtracting a resource portfolio's reference case or mean cost from the average of its worst case or highest cost outcomes. According to Staff, these calculations can produce counter-intuitive and misleading results. The problem is that the risk metrics may assign a lower risk to a portfolio that has both a higher expected (or reference case) cost and a higher extreme (or worst case) cost. Staff recommends that the Commission rely on PGE's "Average of Worst Four Futures" and "TailVar90" risk metrics which do not subtract the reference case or mean value from the high cost outcomes.

RNP and NWEAC take issue with these two risk metrics, as well. NWEAC asserts that these risk metrics are measures of spread or variability, not measures of risk of bad outcomes. NWEAC argues that "any metrics such as these that subtracts out the mean, in cases where the mean can be very different across tested portfolios, is faulty, since high variability in itself is not a bad outcome."⁵⁹ RNP asserts the metrics do not measure relevant risks.⁶⁰ RNP and NWEAC also take issue with PGE's "Year-to-Year Variation" risk measure.⁶¹

RNP recommends that the Commission require PGE to revise its methodology in future IRPs to appropriately reflect relevant risk factors, dropping duplicative or irrelevant metrics and adding a risk metric proportional to emissions of pollutants, including carbon dioxide.⁶² NWEAC urges the Commission to direct PGE to improve future IRPs to correct the flaws in its risk analysis and portfolio scoring.⁶³ NWEAC argues that the risk metrics used by PGE assign no weight to the risk of future carbon regulation because they average scenarios with high and low carbon costs. NWEAC recommends that the Commission require future IRPs to include a risk metric that directly measures carbon dioxide emissions.

In response to NWEAC's and RNP's criticisms, PGE, asserts that the disputed risk metrics are required by IRP Guideline 1c, which require two measures of risk; one that measures the variability of costs and one that measures the severity of bad outcomes.⁶⁴ According to PGE, the disputed risk metrics satisfy the requirement to have a measure of the variability of costs. The "Average of Worst Four Futures" and "TailVar90" risk metrics

⁵⁸ PGE also refers to this metric as the "Deterministic Portfolio Risk Variability vs. Reference Case." See PGE IRP at 249.

⁵⁹ NWEAC May 14 Comments at 13.

⁶⁰ RNP May 20 Comments at 3.

⁶¹ RNP May 20 Comments at 3.

⁶² RNP May 20 Comments at 3.

⁶³ NWEAC May 14 Comments at 14.

⁶⁴ PGE Aug 10 Reply Comments at 46.

satisfy the requirement to have a measure of the severity of bad outcomes. Finally, according to PGE, the “Year-to-Year Variance Metric,” is necessary because rate stability is important to customers.⁶⁵ PGE also rebuts the NWEAC assertion its risk metrics assign no weight to future carbon regulation by indicating that the “Average of Worst Four Futures” and “TailVar90” metrics do not combine or average high and low CO₂ price futures.

Staff agrees that the “Year-to-Year Variance Metric” is an important measure of the variability in costs.⁶⁶ According to Staff this last metric obviates the need for the disputed metrics that it finds can be misleading.

Commission resolution: In its 2009 IRP, PGE models the risk and uncertainty associated with load requirements, natural gas prices, electricity prices, plant forced outages, and the cost of compliance with the future regulation of greenhouse gas emissions. Although we share concerns about some of the specific measures used by PGE, PGE’s 2009 IRP includes risk metrics that measure both the variability of costs and the severity of bad outcomes for each of the candidate resource portfolios considered in the plan. PGE’s risk analysis is robust and satisfies the requirements of IRP Guidelines 1b, 1c, 4i, 4j and 8a.

We decline to adopt NWEAC’s and RNP’s recommendations to require PGE to drop the disputed risk metrics as long as they continue to provide measures that comply with the IRP risk guidelines. We also decline to require PGE to add an additional metric that measures a portfolio’s carbon dioxide emissions in its next IRP. PGE provided carbon dioxide emissions analysis, including total emissions in short tons and emissions in short tons per megawatt-hour, for each of the portfolios under consideration in its 2009 IRP. We encourage Staff and other parties to continue to identify risk metrics and results that require careful interpretation and to make resource recommendations based on the metrics and results they find to be most relevant.

Reliability

Parties’ positions: NWEAC comments that PGE’s expected unserved energy (EUE) reliability metric measures a resource portfolio’s exposure to the wholesale power market and is independent of the portfolio’s mix of resources. NWEAC notes that because the EUE metric is a measure of market exposure it is possible to improve a portfolio’s performance simply by adding additional resources. NWEAC asserts that the EUE metric should not be used to judge the reliability of PGE’s resource portfolios.⁶⁷

⁶⁵ PGE Aug 10 Reply Comments at 47.

⁶⁶ PGE IRP at 267 and 285.

⁶⁷ NWEAC Sept 1 Reply Comments at 6-8.

Staff also takes issue with PGE's reliability analysis. Staff notes Guideline 11 requires the utility to determine by year for top-performing portfolios: (1) the loss of load probability (LOLP), (2) the expected planning reserve margin, and (3) the expected and worst-case unserved energy. Staff asserts that PGE included neither the LOLP metric nor conventional metrics for EUE and Worst-Case Unserved Energy (WCUE) in scoring of its resource portfolios.

Staff notes that instead of calculating a conventional EUE metric, PGE calculated a conditional EUE (CEUE) metric. CEUE is defined as the average amount of unserved energy that occurs *given* the occurrence of an unserved energy event. Staff echoes NWECC's concern with this metric. Staff notes that a portfolio can get a low CEUE score even if it has a high frequency of unserved energy events. In other words, a particular portfolio may suffer from frequent exposure to the wholesale power market, but due to a low purchase amounts during these events receive an overall favorable CEUE score.

Staff recommends that the Commission require PGE to perform the analyses required by Guideline 11 in PGE's next IRP Update.

PGE denies NWECC's assertion that PGE's EUE metric is independent of the resource mix of IRP portfolios. PGE asserts that this metric "addresses the relative reliability of the portfolios based on the particular resources in them, with their assumed associated forced outage rates and mean times to repair."⁶⁸

Commission resolution: IRP Guideline 11 specifically requires electric utilities to provide measures of expected and worst-case unserved energy for the top-performing resource portfolios. PGE's EUE and CEUE metrics measure a portfolio's overall exposure to the wholesale power market, not annual unserved energy. PGE correctly points out that its metrics also reflect the forced outage rates and mean times to repair of the resources included in the portfolios. However, we cannot tell whether differences in outage rates and repair times impact the likelihood and amount of unserved energy. It is important to be able clearly distinguish between a portfolio's market exposure and its level of expected unserved energy.

This gap in the metrics used by PGE does not impact on our decisions in this IRP. In its 2009 IRP, PGE constructed its resource portfolios to meet specific energy and capacity targets. With a few noted exceptions, all of PGE's resource portfolios reflect similar levels of wholesale market exposure. Since all the portfolios have roughly the same market exposure, differences in the EUE metric largely reflect difference in the portfolios' overall generation outage rate.

⁶⁸ PGE Reply to Intervenor Comments at 34, *citing* PGE IRP at 245-47.

We direct PGE to work with Staff, NWECC, and other parties in its next IRP cycle to develop reliability metrics that measure unserved energy. We recognize that this may require parties to estimate the depth of the wholesale power market over the IRP planning period.

III. CONCLUSION

PGE's 2009 IRP reasonably adheres to the principles of resource planning established in Order No. 07-002 and is acknowledged with the following requirements:

PGE shall include an updated benefit-cost analysis of the Cascade Crossing transmission project in its next IRP. For the updated analysis, PGE shall update its assumptions about project configuration, capital cost, path rating, wheeling revenues, and equity participation and conduct sensitivity analyses that address any uncertainty about capital cost, path rating, levels of equity participation, and levels of wheeling revenues.

In its next IRP update, PGE must provide the following:

- a. Its estimated cost per MW of capacity savings by DR type (i.e., firm vs. non-firm resources), and projected MW acquisitions by DR type for the next 5 years,*
- b. A discussion of the steps it is and will be taking to evaluate DR in the next IRP, and*
- c. An updated action plan for assessing (e.g., plans for pilot programs) and acquiring DR for the next 3 years.*

In its next IRP, PGE should consider CVR for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings.

In its next IRP Update and in the next IRP planning cycle, PGE must include a wind integration study that has been vetted by regional stakeholders.

In its next IRP Update and in the next planning cycle, PGE must evaluate the use of unbundled RECs in its strategy to meet RPS Requirements for the entire planning period.

In its next IRP Update and in the next planning cycle, PGE must evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.

Effect of acknowledgement on Future Rate-making Actions

Order No. 89-507 set forth the Commission's role in reviewing and acknowledging a utility's least-cost plan as follows:

The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission[.]

Acknowledgement of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan.⁶⁹

⁶⁹ Order No. 89-507 at 6 and 11.