BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 48

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

DISPOSITION: PLAN ACKNOWLEDGED WITH REQUIREMENTS

I. INTRODUCTION

Portland General Electric Company (PGE or the Company) seeks acknowledgment of its 2009 Integrated Resources Plan (IRP) and 2010 Addendum. In this order 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 adopted 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 include procedural requirements that provide direction on how to prepare and update the plan, and other provisions that address specific resources such as transmission and conservation.

[1] Docket UM 1056, Order No. 07-002 (Jan 8, 2007).

B. Effect of Acknowledgement of an IRP on Future Ratemaking Actions

The Commission's role in reviewing an IRP is to determine whether the IRP meets the substantive and procedural guidelines in Order Nos. 89-507 and 07-002. The Commission generally does not address the need for specific resources, but rather determines whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk.[2] Commission acknowledgement of an IRP means only that the Commission finds that the utility's preferred portfolio is reasonable at the time of acknowledgement.[3]

In Order No. 89-507, the Commission described its role in reviewing and acknowledging a utility's least-cost plan:

> 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.
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> Acknowledgment 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.[4]

This order does not constitute a determination on the ratemaking treatment of any resource acquisitions or other utility expenditures. As a legal matter, the Commission must reserve judgment on all ratemaking issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the ratemaking process. In ratemaking proceedings, in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged plans. A utility is expected to explain actions they take that are inconsistent with Commission-acknowledged plans.

C. Procedural History

PGE filed its 2009 Integrated Resource Plan on November 5, 2009. In that filing, PGE proposed to invest over $500 million to retrofit its Boardman coal-fired plant

[2] *See* Order No. 07-002 at 25.
[3] *See Id.* at 16.
[4] *See* Order No. 89-507 at 6, 11 (Docket UM 180). The Commission affirmed these principles in Docket UM 1056. *See* Order No. 07-002 at 24.

(Boardman) to meet requirements of the Oregon Environmental Quality Commission's (EQC) Regional Haze Plan and operate the plant until 2040. Following a prehearing conference on December 1, 2009, an administrative law judge issued a procedural schedule that included a presentation to the Commission on January 19, 2010.

On January 14, 2010, PGE 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 retrofit the Boardman plant and operate it until 2040 in a manner that would be acceptable to the EQC and other stakeholders. On January 15, 2010, the Commission stayed all proceedings in this docket.

On April 9, 2010, PGE filed an addendum to its IRP that included a revised operating plan for Boardman. Following the adoption of a new procedural schedule, however, we delayed proceedings to allow PGE, intervenors, and Commission Staff (Staff) the opportunity to consider whether certain EQC and Department of Environmental Quality (DEQ) actions might impact PGE's revised IRP. Staff noted that EQC would soon 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.

A final procedural schedule was subsequently adopted that required PGE to file reply comments analyzing three DEQ-proposed alternatives for Boardman retrofits and operation and responding to earlier filed comments. The procedural schedule gave intervenors the opportunity to respond to PGE's supplemental comments, PGE the opportunity to file reply comments on September 27, 2010, and directed Staff to file recommendations and a proposed order. 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.

In sum, the procedural schedule in this docket included multiple opportunities for the parties to address PGE's IRP. This included three rounds of written comments; three public meetings; two technical workshops (to address Cascade Crossing and Boardman); and public comment hearings in Portland and Boardman, Oregon.

D. Parties and Comments

The following entities intervened in this proceeding: the Northwest and Intermountain Power Producers Coalition; the Citizens' Utility Board of Oregon (CUB); NW Energy Coalition (NWEC); Ecumenical Ministries of Oregon (EMO); Oregon Environmental Council, PacifiCorp, dba Pacific Power; Iberdrola Renewables, Inc.; Oregon Department of Energy (ODOE); the Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, and the Northwest Environmental Defense Center; Renewable Northwest Project (RNP); Physicians for Social Responsibility; Northwest Pipeline GP; the City of

Portland; Industrial Customers of Northwest Utilities; Turlock Irrigation District; International Brotherhood of Electrical Workers, Local 125 (IBEW 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 (Salem Chamber); Strategic Economic Development Corporation; Clackamas County Business Alliance; Columbia Corridor Association; Associated Oregon Industries; Westside Economic Alliance; Portland Business Alliance; Association of Oregon Counties; the Wilsonville Chamber of Commerce; SEDCOR, Morrow County; Oregonians for Food and Shelter; Oregon Farm Bureau Federation; 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, Oregon. 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

A. Load Forecast and Resource Need

1. Parties' Positions

The Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, and the Northwest Environmental Defense Center (NEDC) (collectively referred to as the Coalition), as well as NW Energy Coalition (NWEC); 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 Boardman.

The Coalition, NWEC, 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.[5] NWEC 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.[6]

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.[7] 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

[5] Coalition's Sept 1, 2010 Comments at 17-18 (Schlissel Technical Consulting, Inc. (Schlissel))
[6] NWEC's May 14, 2010 Comments at 5.
[7] Coalition's Sept 1, 2010 Comments at 16-17 (Schlissel).

example, the December 2009 forecasts show reductions of 157 megawatts (MW) in peak load and 152 average MW (MWa) in annual energy during 2015.

NWEC, the Coalition, and EMO all argue that PGE's load forecasts are inconsistent with those of independent forecasters. NWEC 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) Draft Sixth Plan projected load growth for Oregon of 1.96 percent. NWEC argues that the appropriate comparison is to an adjusted load growth forecast for Oregon of 0.47 percent per year. NWEC calculated this adjusted growth rate after subtracting the NPCC's forecast of future energy efficiency from its medium-load forecast.[8]

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.[9] Staff contends 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 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.

PGE responds that its forecasts appropriately incorporate data from both the recent and distant historical past. PGE acknowledges that load growth exceeded the forecasted average rate of 1.9 percent only once since 2000, but adds that that historic annual growth exceeded 1.9 percent during sixteen of the last twenty-eight years.[10] PGE also notes that the differences between its March 2009 and December 2009 load 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 of 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.[11]

2. Commission 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

[8] NWEC's May 14, 2010 Comments at 5.
[9] Staff's Oct 15, 2010 Comments at 9.
[10] PGE's Sept 28, 2010 Comments at 14.
[11] *Id* at 13.

the context of PGE's overall resource needs. 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 held by the Company.

In an IRP, 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 forecast 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 NWEC that PGE's projected average annual growth in load is significantly higher than that projected by NPCC. PGE correctly compares its forecasts with embedded energy efficiency to NPCC'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 in terms of economics and demographics. 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.

B. Natural Gas Price Forecast Method

1. 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, Staff, and the U.S. Energy Information Administration (EIA).[12] 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.[13]

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.

[12] Coalition's May 19, 2010 Comments at 4-10 (Schlissel).
[13] Coalition's Sept 1, 2010 Comments at 12 (Schlissel).

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. PGE notes that comparing PIRA's 2009 forecast to these 2010 forecasts is misleading because most forecasters reflected a downturn in prices for 2010.[14] 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.[15]

2. 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 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.

C. Boardman

1. Parties' Positions

PGE requests that the Commission acknowledge continued coal-fired operations at Boardman as outlined in the Company's BART III proposal submitted to the DEQ on July 30, 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.

As part of its BART III proposal, PGE proposes the following compliance actions to meet Oregon Regional Haze Plan and Oregon Utility Mercury Rule standards:

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;

[14] PGE's Nov 1, 2010 Comments at 13-14.
[15] *Id*.

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.[16]

Contingent on the results of the DSI pilot testing, PGE would commit to meeting a 0.4 lb. sulfur dioxide (SO_2) 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 SO_2 emissions without triggering an increase in emissions of particulate matter, then PGE proposes to meet an alternative SO_2 limit established by DEQ procedure based on the DSI testing. It is unclear whether the EQC will adopt PGE's BART III proposal.

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 Boardman 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 1 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 SO_2 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.[17]

PGE contends that its BART III proposal is superior to these alternatives, and observes that among the early closure options, those that keep Boardman operating 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 SO_2 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 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.[18]

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[16] PGE's Aug 10, 2010 Comments at 8-9.
[17] *Id.* at 10-13.
[18] *Id*. at 16.

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 Boardman 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.[19]

PGE argues that the backstop proposal 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 shutdown of Boardman in 2014 as a result of failure to install the dry scrubbers by the BART I deadline.[20] 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 CUB, RNP, Angus Duncan,[21] Oregon Environmental Council (OEC), and NWEC support the refined BART III plan. PGE also informed the Commission that PGE has committed to work with stakeholders in the Company's next IRP to evaluate and consider carbon-reduction options for replacement power.[22]

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

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[19] *Id*. at 15.
[20] *Id*. at 5; IRP Addendum at 124 (April 9, 2010).
[21] Angus Duncan, is an interested person in this docket, is the President and CEO of the Bonneville Environmental Foundation.
[22] PGE's Oct 29, 2010 Comments at 3.

The Physicians for Social Responsibility implored the Commission to consider the serious health concerns and costs associated with continued operation of Boardman 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, as well as some reply comments.

a. The Coalition

The Coalition characterizes PGE's proposed compliance actions as a plan to transition off coal in 2020–or never.[23] 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.[24]

The Coalition further argues that PGE uses unreasonably high natural gas prices in its IRP modeling and biases the results in favor of continued operation of Boardman and against early shutdown scenarios.[25] 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 believes that PGE has overstated its energy and capacity needs.[26] 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.[27]

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[23] Coalition's Sept 1, 2010 Comments at 1-2.
[24] *Id*. at 2-6 (Schlissel).
[25] *Id*. at 7-16.
[26] *Id*. at 16-18.
[27] *Id*. at 18.

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 costs and benefits of replacing some or all of Boardman's output with a mid-term power purchase agreement (PPA).[28] According to the Coalition a mid-term PPA strategy could be used to implement DEQ Options 2 & 3.

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.[29]

b. The Joint Parties

CUB, RNP, NWEC, OEC, Angus Duncan, EMO, Sierra Club, and NEDC, (collectively referred to as the Joint Parties) view the proposal to install BART I emissions controls to allow the continued operation of Boardman through 2040 as the most objectionable option before this Commission. They request the Commission 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.[30]

The Joint Parties support closing Boardman 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 regional 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 resource than replacement with only a base load natural gas plant.[31] The Joint Parties are confident that PGE could replace Boardman in the 2015/2016 timeframe with a diverse mix of resources. The Joint Parties concede the risk, however, that early closure would likely result in replacing the plant 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.

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[28] *Id*. at 19.
[29] *Id*. at 20-21.
[30] Joint Parties' Sept 1, 2010 Comments at 1.
[31] *Id*. at 2.

c. The NW Energy Coalition

The NW Energy Coalition (NWEC) joins the Joint Parties in recommending shutdown of Boardman no later than 2020. Like the Joint Parties, NWEC prefers an agreement between PGE, DEQ, and regional stakeholders on a mutually acceptable plan. As a result, NWEC recommends that the Commission only indicate the boundaries of an acceptable closure plan. According to NWEC, formal acknowledgement should only occur after an actual agreement to close Boardman is achieved.[32]

NWEC opines that not enough effort has been put into developing a resource strategy to replace Boardman.[33] NWEC urges the Commission to consider the state's carbon reduction goals and in the next IRP cycle to begin work on a comprehensive plan to achieve significant reductions in emissions. NWEC repeatedly argues 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. NWEC recommends that the Commission require future IRPs to include a risk metric that directly measures carbon dioxide emissions.

NWEC is most forceful in its objection to PGE's request for backstop acknowledgment of the BART I compliance actions.[34] NWEC argues the DEQ Option 3 with closure of Boardman in late 2015 or early 2016 is the better backstop. According to NWEC a comparison of the modeling results of PGE's BART I backstop proposal to DEQ Option 3 shows no significant difference on a cost basis. NWEC argues that the lower carbon dioxide emissions of DEQ Option 3 should be used to break this tie. NWEC suggests that the advantage in emissions could be even larger if Boardman is replaced with power sources cleaner than a natural gas-fired CCCT. NWEC scolds PGE for introducing new tie-breaking criteria, such as near-term rate impacts, inadequate time to develop replacement resources, and insufficient transition time for its employees and the Boardman community.

Although NWEC 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.[35] NWEC has repeatedly argued that the load forecast used by PGE in its IRP modeling is higher than the NPCC forecast. NWEC also asserts that PGE has overstated its resource need by deciding to lower its exposure to the wholesale power market. NWEC criticizes PGE for not analyzing its level of market exposure in this IRP. NWEC concludes that there is little need for quick and full replacement of Boardman by 2015.

Finally, NWEC 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.

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[32] NWEC's Sept 1, 2010 Comments at 1.
[33] *Id*. at 1-2.
[34] *Id*. at 2-6.
[35] *Id*. at 4.

NWEC argues that reliance on the market can provide the space needed in time to acquire a clean mix of replacement resources.

d. NIPPC

The Northwest and Intermountain Power Producers Coalition (NIPPC) offers no opinion regarding the cessation of coal-fired operations at the Boardman plant.[36] NIPPC emphasizes, however, that the shutdown risks being debated in this proceeding are largely ratepayer risks, and believes that diversifying ownership of generation resources is in the best interest of ratepayers. NIPPC says it is well established that 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.[37]

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 PPAs 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.[38] NIPPC argues that postponement of the evaluation of PPAs to the competitive bidding process makes PGE's IRP noncompliant with this guideline.

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.[39] 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 Proposals (RFP) process.[40] 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 replacement

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[36] *Id* at 2.
[37] *Id*. at 7.
[38] Order No. 07-002 at 3.
[39] NIPPC's Sept 1, 2010 Comments at 5.
[40] *Id*. at 8-9.

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

e. Staff

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

Staff primarily focuses its analysis of PGE's portfolio modeling on three metrics: (1) expected cost; (2) the average of the four worst deterministic futures; and (3) 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 PGE's 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 significant.

Staff agrees with NIPPC and NWEC 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, however, that the risk associated with the deliverability and cost of such power is not in the best interest of ratepayers.

Staff agrees with comments of other parties that 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. As previously discussed, Staff believes that PGE's resource gaps are significant and would be challenging to fill if Boardman were shut down in 2016.

Staff also agrees with the Coalition and NWEC that PGE's reference case natural gas price is slightly overstated. Staff notes, however, that PGE's response to the Commission's Bench Request, which tested a combined low natural gas price and 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.

f. Reply Comments

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.*[41] (emphasis in original).

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 the EPA allow it.[42]

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.[43]

2. 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 Option 1 with shutdown targeted for 2020
- DEQ Option 2 with shutdown targeted for 2018; and
- DEQ 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 (1) it is a low-cost option for ratepayers; (2) it mitigates the risk of future carbon regulation by closing the plant at the end of 2020; (3) it mitigates the risk of acquiring replacement resources by providing the time needed to evaluate and implement a reasonable replacement strategy; and(4) it provides the flexibility needed to test the effectiveness of DSI technology and to adapt the plant's operation to control both SO_2 and particulate matter (PM) emissions prior to the plant's closure.

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[41] CUB's Oct 29, 2010 Comments at 4.
[42] NWEC's Oct 29, 2010 Comments at 2.
[43] Group Comments at 2 (Oct 29, 2010).

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 base load 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 SO_2 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 SO_2 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.

As noted, 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 SO_2 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 regional stakeholders to develop low-carbon resource portfolios for consideration in its next IRP, CUB, NWEC, OEC, and RNP now support Boardman shutdown no later than 2020.

PGE proposes to reach the lower SO_2 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 the Company'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 and, 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.

Finally, 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.

D. Cascade Crossing

The Cascade Crossing Transmission Project (Cascade Crossing) is a proposed 500 kV transmission line connecting PGE's Boardman and Coyote Springs plants to the southern portion of the Company's service territory. The proposed project would begin at the 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, as well as improvements to two existing substations.[44]

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 for

[44] IRP at 187.

existing generators as an alternate to service furnished by the Bonneville Power Administration (BPA); and (5) improve reliability by providing additional transmission and reducing load on transfer paths parallel to Cascade Crossing, thus reducing the severity of currently limiting contingencies.[45]

PGE conducted a benefit-cost analysis of the Cascade Crossing transmission project to determine whether it should include Cascade Crossing 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 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. 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 Coyote Springs to Boardman 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 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 Coyote Springs to Boardman and a growth rate of 2.5 percent 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 percent in BPA's transmission rates after 2025.

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

[45] *Id*. at 189-190.

received by PGE, and updated information regarding PGE's generation facilities that would utilize the project.

1. 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.[46]

CUB does not recommend against acknowledging Cascade Crossing , but raises numerous questions and concerns. These include: (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; and (4) Should new transmission be a top priority for PGE?

Willard Rural Association (WRA) recommends that the Commission not acknowledge Cascade Crossing. WRA asserts that PGE made many forecasting errors, including: (1) overstating its load forecast; (2) understating the amount of transmission BPA will have in the future; (3) overstating the cost of BPA transmission; (4) underestimating the cost to acquire right of way for Cascade Crossing; and (5) understating the risk associated with an $823 million investment.

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 IRP 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 analyses (some done in response to a Staff data request) support PGE's proposal to build Cascade Crossing, as opposed to acquiring transmission in another manner.

2. Commission Resolution

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-

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[46] RNP's Sept 1, 2010 Comments at 3.

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. Pacific Power 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 PGE to provide a thorough update of the Cascade Crossing benefit-cost analysis in its next IRP, with the understanding that Commission acknowledgment of the Company's 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, each utility is required to show that its investment was a prudent decision. At that time, the utility 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.

E. Demand Response

1. Parties' Positions

Staff contends 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.[47]

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 Company's next full IRP.[48]

In response, PGE contends 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).[49]

2. *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 its 2009 IRP, without really explaining the change (other than to say now that it primarily assumes acquisition of firm DR resources). PGE has not made the progress we expected on acquisition of DR, e.g., 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 electric 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 the following directives at the time of its IRP update:

[47] Staff's Oct 15, 2010 Comments at 9-10.
[48] CUB's Oct 29, 2010 Comments 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).
[49] PGE's Oct 29, 2010 Comments at 7-8.

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

a. Its estimated cost per MW of capacity savings by demand response (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 Company's next IRP, and
c. An updated action plan for assessing (e.g., plans for pilot programs) and acquiring DR for the next 3 years.

F. Energy Efficiency

1. Parties' Positions

Staff concludes that PGE met the IRP guideline for conservation (IRP Guideline 6) with two exceptions. First, Staff states that PGE did not treat conservation voltage reduction (CVR) as a resource. Second, Staff states that PGE did not consider whether to include CVR in the action plan. Staff notes that the Energy Trust of Oregon identified technical potential for 19 MWa of savings from CVR in the Company's service territory.[50]

PGE replies that it views CVR as an operational efficiency, not a long-term resource planning issue. The Commission found that PGE complied with IRP 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.[51]

2. Commission Resolution

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

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

[50] Staff's Oct 15, 2010Comments at 10-11.
[51] PGE's Oct 29, 2010 Comments at 8-9.

G. Renewable Portfolio Standard Requirements

1. Parties' Positions

PGE proposes to acquire 122 MWa of renewable wind generation by the end of 2012 to achieve physical compliance with the Renewable Portfolio Standard (RPS) requirement for 2015. PGE asserts that banking renewable energy credits (RECs) from early renewable resource actions provides a significant cushion for "meeting RPS compliance."[52]

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, such as the later availability of 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 overemphasizes 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 recent passage of House Bill 3674. 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.[53]

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.[54]

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."[55]

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[52] IRP at 114.
[53] ODOE's May 14, 2010 Comments at 3.
[54] *Id*. at 4.
[55] PGE's Oct 29, 2010, Comments at 10.

2. 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. Accordingly, we adopt the following requirement

In its next IRP Update and in the next planning cycle, PGE must evaluate:

(1) The use of unbundled renewable energy credits (RECs) in its strategy to meet RPS Requirements for the entire planning period; and

(2) Alternatives to physical compliance with renewable portfolio standard (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.

H. Wind Integration Study

1. Parties' Positions

RNP recommends that the Commission not acknowledge the wind integration study PGE used to estimate costs to operate and acquire wind generation. RNP asserts that PGE's study includes an unusually high cost of reserves and has not been provided for stakeholders and the Commission to evaluate.[56] 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 agrees 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."[57] 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 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: (1) each

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[56] RNP's Sept 1, 2010 Comments at 1-3.
[57] Docket LC 48, Order No. 08-246 at 10 (May 6, 2008).

utility's costs depend on the unique characteristics of the utility's system; and (2) PGE's wind integration costs is comprised of several components, only one of which is comparable to the within-hour integration tariff.[58]

PGE also disputes RNP's and Staff's criticisms of the wind integration study process. PGE states that it included several stakeholders on its technical review committee to evaluate the Company's study approach, inputs and findings, and conducted a three-hour workshop to present the details of its wind integration study. PGE also notes that, in addition to the input it received from stakeholders the Company hired an independent examiner (IE) in late 2008 to "vet" the study for docket UM 1345, and that the IE concluded the study was a "thorough integration study."[59] Nonetheless, although it believes it has already complied with the requirement to produce a vetted wind integration study, PGE agrees with Staff's recommendation to include in its next IRP Update a wind integration study that has been vetted by regional stakeholders.[60]

2. 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 impose the following requirement:

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

I. Risk Metrics

1. Parties' Positions

Staff cautions the Commission about the possible misinterpretation of two risk metrics used by PGE in its 2009 IRP. PGE calculated the "Average of Worst Four Futures

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[58] PGE's Sept 27, 2010 Reply to Intervenor Response Comments at 18.
[59] PGE's Oct 29, 2010Comments at 11.
[60] *Id*.

Less the Reference Case Cost"[61] and "TailVar90 Less the Mean" risk metrics 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 that do not subtract the reference case or mean value from the high cost outcomes.

RNP and NWEC also take issue with these two risk metrics. NWEC asserts that these risk metrics are measures of spread or variability, and not measures of risk of bad outcomes. NWEC 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."[62] RNP asserts the metrics do not measure relevant risks.[63] RNP and NWEC also object to PGE's "Year-to-Year Variation" risk measure.[64]

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.[65] NWEC urges the Commission to direct PGE to improve future IRPs to correct the flaws in its risk analysis and portfolio scoring.[66] NWEC 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. NWEC recommends that the Commission require future IRPs to include a risk metric that directly measures carbon dioxide emissions.

In response to NWEC'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.[67] 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 measures 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.[68] PGE also rebuts NWEC's assertion its risk metrics assign no weight to future carbon regulation by indicating that the Average of Worst Four Futures and TailVar90 risk metrics do not combine or average high and low CO_2 price futures.

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[61] PGE also refers to this metric as the "Deterministic Portfolio Risk Variability vs. Reference Case." *See* IRP at 249.
[62] NWEC's May 14, 2010 Comments at 13.
[63] RNP's May 20, 2010 Comments at 3.
[64] *Id*.
[65] *Id*.
[66] NWEC's May 14, 2010 Comments at 14.
[67] PGE's Aug 10, 2010 Comments at 46.
[68] *Id*. at 47.

Staff agrees that the Year-to-Year Variance Metric is an important measure of the variability in costs.[69] According to Staff this specific metric obviates the need for the disputed metrics that can be misleading.

2. 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 NWEC'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.

J. Reliability

1. Parties' Positions

NWEC 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. NWEC 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. NWEC asserts that the EUE metric should not be used to judge the reliability of PGE's resource portfolios.[70]

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 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

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[69] IRP at 267; 285.
[70] NWEC's Sept 1, 2010 Comments at 6-8.

unserved energy that occurs *given* the occurrence of an unserved energy event. Staff echoes NWEC'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 NWEC'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.[71]

2. 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.

We direct PGE to work with Staff, NWEC, 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.

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[71] PGE's Aug 10, 2010 at 34, *citing* its 2009 IRP at 245-247.

III. CONCLUSION

PGE's 2009 IRP reasonably adheres to the principles of resource planning established in Orders No. 89-507 and 07-002 and is acknowledged with the following requirements:

In its next IRP, PGE must:

1. Include an updated benefit-cost analysis of the Cascade Crossing transmission project. 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. Provide the following:
   (a) Its estimated cost per MW of capacity savings by Demand Response (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. Consider Conservation Voltage Reduction (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 its next IRP planning cycle, PGE must:

1. Include a Wind Integration Study that has been vetted by regional stakeholders.

2. Evaluate the use of unbundled RECs in its strategy to meet RPS requirements for the entire planning period.

3. 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.

IV. ORDER

IT IS ORDERED that:

1. The 2009 Integrated Resource Plan filed by Portland General Electric Company is acknowledged with the requirements set forth in this order.

2. Portland General Electric Company will file its next Integrated Resource Plan no later than November 19, 2012.

Made, entered, and effective NOV 23 2010.

Ray Baum
Chairman

John Savage
Commissioner

Susan K. Ackerman
Commissioner