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September 27, 2010

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

Re: LC 48

Attention Filing Center:

Enclosed for filing in the captioned docket are an original and ten copies of Portland General Electric Company's Reply to Intervenors' Response Comments.

This is being filed by electronic mail with the Filing Center.

An extra copy of the cover letter is enclosed. Please date stamp the extra copy and return to me in the envelope provided. Thank you in advance for your assistance.

Sincerely,

V. DENISE SAUNDERS
denise.saunders@pgn.com

VDS:cbm
Enclosures
cc: LC 48 Service List (w/enclosures)

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

DOCKET NO. LC 48

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2009 Integrated Resource Plan.		**PGE REPLY TO INTERVENOR RESPONSE COMMENTS**

I. Introduction

Portland General Electric (PGE) submits these Reply Comments in accordance with the Prehearing Conference Memorandum issued on July 8, 2010. On August 10, 2010, PGE responded to comments received by parties on our IRP and provided an analysis of new options presented by the Oregon Department of Environmental Quality (DEQ) for installing emissions controls at the Boardman generating plant (August 10 Comments). On September 1, 2010, thirteen parties submitted comments in reply to PGE's August 10 Comments (September 1 Comments).[1] We address the issues raised in September 1 Comments in the same order that they were discussed in our August 10 Comments.[2]

II. Boardman

As with earlier rounds of comments, the vast majority of the September 1 Comments concern issues relating to the installation of emissions controls and early termination of coal-fired operations at the Boardman plant. PGE reiterates its appreciation for the time and consideration that parties in this docket have applied toward considering alternative approaches for dealing with a complex and important issue. We share the desire of the Joint Parties to "find an early closure solution that is both acceptable to DEQ and has broad-based support from the company and stakeholders." Joint Parties[3] at 2. PGE has been actively working toward this goal. We have had many meetings with DEQ and stakeholders in an attempt to find an acceptable solution and have submitted four different Best Available Retrofit Technologies (BART) proposals to DEQ since November of 2007. In this IRP docket, we substantially modified our initial action plan proposal to run Boardman through 2040 by submitting the 2020

[1] Sierra states that it reserves the right to supplement its Reply Comments, as necessary on the grounds that PGE submitted some data responses as Sierra was completing its Reply Comments. Sierra Exh.1 at fn 1. PGE responded to all of Sierra's August 17, 2010 requests within the ten days required by the Commission's rules. If Sierra wanted data responses from PGE sooner, it should have submitted the requests sooner. Sierra's failure to do so does not justify its unilateral reservation of the right to supplement Reply Comments.

[2] While we believe that we have addressed all material comments, we note that our silence on a particular point raised in the parties' Reply Comments should not necessarily be construed as a concession that we feel the point is valid.

[3] We provide a list of abbreviations used to identify parties in Appendix A.

proposal in our IRP Addendum and then, in response to stakeholder feedback, further modified that proposal with the BART III proposal described in our August 10 Comments. We are disappointed that despite our efforts, DEQ's latest options are, in the words of the Joint Parties, "problematic to different parties in some way." Joint Parties at 5. We have proposed a BART III alternative that adopts additional control technologies suggested by DEQ, meets state and federal environmental standards, avoids undue cost and risk for our customers, and allows transition time for our employees and the Boardman community. Unlike the Joint Parties we do not see another proposal emerging that is acceptable to DEQ, PGE and the stakeholders.

As we discuss below, we are out of time to develop yet another proposal. We need an acknowledgment decision from the OPUC in time to make a decision about whether to move forward with the scrubber investment in March of 2011. Moreover, we need to provide certainty concerning the future of the Boardman plant to our employees, customers, investors and the Boardman community. For the reasons set forth below, we urge the Commission to issue an Order at its November 9 meeting acknowledging our BART III proposal, contingent on Environmental Quality Commission (EQC) approval, and further acknowledging that the only prudent option legally available to us if our BART III proposal is not accepted by the EQC is to install the emissions controls required under BART I and continue operating Boardman through 2040.

A. *There is no time to develop another Boardman alternative*

The Joint Parties urge the Commission to acknowledge only Phase I of the clean air investments and thereby create "space for the Company, regulators and stakeholders to agree on a comprehensive plan to accomplish the responsible closure of Boardman..." Joint Parties at 7. Likewise, NWEC believes that the utility, regulators and stakeholders will eventually successfully negotiate an acceptable plan and that the Commission should hold off on acknowledging our proposed action plan and instead indicate the boundaries of an acceptable closure plan in its Order. NWEC at 1. Sierra requests that the Commission "order that PGE go back to the drawing board and develop a true "balanced and reasonable outcome" consistent with federal and state clean air laws and Oregon's greenhouse gas reduction goals.[4] Sierra at 2.

PGE has been actively working with regulators and stakeholders (including the Joint Parties) for the last two and a half years to come up with a mutually acceptable plan for discontinuing coal-fired operations at Boardman. As stated above, we have submitted four different BART proposals to DEQ and have significantly modified our initial proposal in this IRP docket. All of our proposals have been consistent with federal and state clean air laws. Moreover each plan has offered improvements in total emissions reductions, first by reducing the operating life, and thereafter by installing additional controls. Each successive Boardman 2020 proposal also has a correspondingly greater cost and impact on customer rates. We know that

[4] Sierra also claims that there are no real differences between BART II and BART III. Sierra at 2. This is simply wrong. As explained in our August 10 Comments, BART III includes additional controls (DSI and Selective Non-Catalytic Reduction) with incremental overnight capital costs of $34 million and incremental O&M of $15 million per year over BART II. These incremental differences do not include AFUDC, capital carrying costs or annual inflation. In addition, NOx is reduced from .23 lb/mmBtu under BART II to .19 lb/mmBtu under BART III. SO2 is reduced from .60 under BART II to .40 (subject to DSI testing) under BART III.

some of our stakeholders have also been working hard to come up with an acceptable alternative to the current DEQ options and our BART III proposal.[5] Despite these efforts however, it doesn't appear to us that such an alternative is emerging.

Moreover, the existing (and proposed) DEQ rules do not allow any additional time for an alternative to develop. Under the current rule adopted by the EQC on June 19, 2009 we have essentially two choices: install emissions controls and continue to operate Boardman until 2040 or cease coal-fired operations at the plant in 2014. Either choice offers no room for delay. We believe it is too late to implement a 2014 shut down as there is not sufficient time to obtain reasonably priced firm replacement power or provide a reasonable transition for employees and the Boardman community. If we install emissions controls, we need to order equipment by March 2011. As discussed in our August 10 Comments, the new DEQ options, as written, cannot be implemented and therefore do not allow any additional leeway in terms of timing. In short, we need a Commission decision on Boardman actions as soon as possible to ensure that we can take the steps needed to comply with DEQ rules.

B. Intervenors have not shown that 2015 is not too risky

Joint Parties claim that a 2015/16 closure is superior to any 2040 portfolio on a least-cost, least-risk basis. Joint Parties at 2. They believe that closure on this timeline is a viable option for the company. Joint Parties at 6. However, they provide no evidence to support either assertion. Sierra argues that PGE's analyses show that retiring the Boardman plant in 2015 is a lower cost alternative than operating it through 2040. Sierra, Exh. 1, 2-6. They present several figures showing the NPVRR of various portfolios to support their assertion. PGE does not dispute that the NPVRR of operating Boardman through 2040 is higher than operating it through 2015. What Sierra fails to consider, however, is that the NPVRR figures only account for expected costs. Sierra does not include the risk considerations that comprise 50% of the total portfolio score. The Commission's IRP Guideline 1 states that "risk and uncertainty *must* be considered." (emphasis added). Guideline 2 describes the measures that "*at a minimum*" must be used to evaluate risk. The primary goal of IRP, as articulated by the Commission in Guideline 1, is "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. (emphasis added). In fact, in adopting the IRP Guidelines, the Commission explicitly rejected the suggestion that the selection of a preferred portfolio should be based solely on least cost. *Re Investigation into Integrated Resource Planning,* Docket UM 1056, Order 07-002, at 6. When considering both costs and associated risks and uncertainties, a 2015 portfolio simply does not perform as well as a 2040 portfolio.

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[5] Joint Parties suggest that there are alternatives that could encourage broader support and potentially aid in meeting clean air regulations. They specifically suggest operating the plant differently and installing SO2 and NOx controls earlier. PGE addressed the potential cost impacts of a temporary shut down of Boardman at page 124 of the IRP Addendum. We also note that as a legal matter, regional haze emissions are analyzed on an hourly basis and regional haze impacts at Class I areas have not been shown to be seasonal, so any seasonal reductions of operations at Boardman would not, in and of themselves, ensure that we are in compliance with the Clean Air Act. Any alternative that involves installing emissions controls on a different timeline than those provided under the current DEQ and BART III options would need to be considered in the DEQ rulemaking process.

1. Intervenors are not realistic in their expectations concerning the timeline for a replacement resource

Sierra asserts that "[i]ndustry experience shows that the actual construction of a new combined cycle gas-fired unit can be completed in two to two-and-a-half years." Sierra at 18. Sierra therefore concludes that it is not unreasonable to expect that a replacement combined cycle unit could be ready for operations by 2016 even if another three to three-and-a-half years were included for planning and licensing activities. *Id.* NWEC questions whether a six to seven year development time frame is appropriate given the transmission, substation and site at Boardman. NWEC at 4.

According to Black & Veatch, an engineering, consulting and construction company with significant experience developing combined cycle plants in the Pacific Northwest, four to four-and-a-half years is the best case estimate for construction of a new combined cycle gas-fired unit, assuming we encounter no delays in the acquisition or delivery of equipment. *See*, letter from Black and Veatch included as Attachment A. Based on PGE's experience, an additional two years is necessary for the Commission's IRP and RFP processes. The breakdown of the timeline is as follows:

- Initial site selection and plant conceptual design - 6 months
- IRP and RFP processes to determine need for power and most economical means of acquiring power - 2 years from date of IRP filing
- Permitting – 2 years (can be done in parallel with IRP and RFP processes)
- Bids for power island and EPC - 6 months
- Delivery power island equipment – 20 to 24 months
- Erect and commission gas turbine – 9 to 10 months
- Commission plant - 4 to 5 months
- EPC contractor margin – 2 to 3 months

This timeline assumes no challenges and no appeals from the various decisions to site the plant. No environmental group commenting in this IRP has promised to expedite and not oppose the prompt siting of a CCCT replacement for Boardman.

Under the Commission's IRP Guideline 3a, PGE would not file an IRP identifying a replacement resource until two years after the Commission issues an acknowledgment order on this IRP. PGE needs approximately two years to conduct the modeling, analysis and public process necessary to file a complete IRP. Therefore, under the Commission's IRP process, the six to six-and-a-half year timeline set forth above would not start until PGE made an IRP filing in 2012 and would result in completion of a replacement CCCT at the end of 2018 at the earliest, assuming there are no delays in the permitting or RFP processes and no problems with equipment acquisition or plant construction.

As discussed later in these comments, any decisions about the location and type of resource used to replace Boardman will be addressed in later IRP and RFP processes. Even if the replacement resource were located at Boardman, the existence of transmission and substation equipment will not necessarily lessen the overall time for development; the replacement time depends more on the time for acquisition of steam turbines and the permitting and development of gas transportation in addition to the time required for the OPUC regulatory processes.

2. A bridging PPA is not a dependable option

Some commenters continue to assert that in the case of a 2015 closure, a bridging PPA could be used to extend the time needed to replace Boardman's output. NWEC at 5, Sierra at 19, NIPPC at 3. We address these comments in Section VII below.

C. Acknowledgment of 2040 backstop is necessary

The Joint Parties urge the Commission not to acknowledge the 2040 Boardman investment as a back-up plan. Joint Parties at 1. PGE, on behalf of its customers, must have a back-up plan in case its BART III proposal is not accepted by the EQC. Running Boardman through 2040 presents the best combination of expected costs and associated risks and uncertainties. As explained in our IRP addendum, we need to begin ordering equipment in March of 2011 to implement this alternative. Any delay will subject our customers to the increased costs and risks associated with mothballing the plant as discussed at page 130 of the IRP Addendum. Accordingly, we believe it is imperative that the Commission acknowledge that continuing to run Boardman through 2040 would be a prudent action should the EQC not accept our BART III proposal.

1. The investments that Joint Parties propose in lieu of Boardman emissions controls would only replace a small portion of Boardman's output

The Joint Parties list alternative generation investments that PGE could make in lieu of making the full suite of DEQ-approved controls at Boardman for operations to 2040 or beyond. Joint Parties at 4. Their examples actually underscore the challenges of replacing the output of Boardman. Looking at them one by one:

- Acquisition of EE: Joint Parties believe that investment in emissions controls could otherwise be used to acquire 180-200 aMW of EE. Joint Parties at 4. PGE is already proposing to acquire all EE achievable in its service territory. More precisely, PGE's plan relies on the ETO's estimates and acquires all EE that is 110% of the avoided cost rate or less for the ETO planning horizon. Additional EE would be priced at the marginal cost rather than the average cost that is suggested to arrive at the 180-200 aMW figure, with relatively small additional supply thereby being available.
- Wind generation: Joint Parties assert that 196 MW of wind generation could be built for the same amount invested in emissions controls. *Id.* 196 MW equates to approximately 60 aMW – roughly 20% of Boardman's annual output. Using the Joint Parties' assumed capital cost, to fully replace Boardman with wind would then require an additional $1.6 billion of investment (4 times $400 MM), which doesn't include the investment related to substantial new flexible gas generation, gas storage and new transmission infrastructure to bring the wind and firming gas generation to our load.
- Solar generation: Joint Parties believe that the money used to acquire emissions controls could otherwise be used to build 108 MW of solar generation. *Id.* 108 MW equates to

approximately 15 aMW, depending on location – roughly 5% of Boardman's output. As with wind, this doesn't include the cost for firming or any additional transmission needed. It also becomes evident, by comparing solar investment costs per MW against wind, that solar remains materially more expensive.

- Natural gas: Joint Parties believe that the investment in emissions controls could otherwise be used to build a 460 MW combined cycle natural gas plant. *Id.* PGE's IRP cost estimate for a CCCT indicates that \$400 million would be insufficient by at least \$200 million (our estimate includes AFDC, the Climate Trust payment, and associated substation/transmission capital, but is still less than the NWPCC 6th Plan). Even so, to present a more balanced picture of this investment alternative, we note that, depending on prevailing gas prices, only about one-third of the ongoing revenue requirement is related to the initial investment. We also note that a base-load gas plant is not the preferred choice of the Joint Parties.

Thus, contrary to the Joint Parties' assertion that "this amount of money will go a long way towards replacing a large percentage of the generation from the Boardman plant with cleaner energy sources," the investments that Joint Parties propose in lieu of Boardman emissions controls would only replace a fraction of Boardman's output.

2. Boardman's declining dispatch is considered in our economic analysis

Sierra observes that Boardman's economic dispatch declines over time as the cost of CO_2 regulation rises. Sierra, Exh. 1 at 20. It concludes that this "raises serious questions about the prudence of investing \$510 million for environmental upgrades on a coal-fired unit that would no longer be operating as a base-load unit."

Declining dispatch is not an issue for our BART III proposal which ceases coal-fired operations in 2020. For those portfolios that run Boardman through 2040, we have included both the investment cost and the economic dispatch of Boardman in our NPVRR analysis. Furthermore, decreasing the dispatch of Boardman appears to be consistent with the alternate approach suggested by the Joint Parties of operating Boardman seasonally as a potential economic alternative. *See*, Joint Parties at 7. It also appears that the resulting decline in emissions over time from the plant is consistent with Sierra's focus on CO_2 reductions. *See*, Sierra Exh. 1 at 23.

Finally, Sierra points to Boardman's unavailability during the peak summer months of 2009 to indicate that it can't be counted on when needed. Sierra Exh.1 at 22. When looking at reliability, the thirty year record of the plant must be taken into account, not a single incident. Using Sierra's logic, one could conclude that no given resource can really be counted on when needed because it is subject to untimely forced outage. This gets to the core of IRP planning – planning for sufficient energy and capacity to assure reliability. For instance, while there is a very high likelihood of Boardman being available during peak conditions, the same cannot be said for wind, as recent summer and winter load peaking periods corroborate.

3. Diversified Green with On-Peak Energy Target should not be pursued because it has a high execution risk

NWEC suggests the Diversified Green with On-Peak Energy Target portfolio would be a superior option to our Diversified Thermal with Green backstop. NWEC at 2. We did not choose the Diversified Green with On-Peak Energy Target portfolio because it is likely not achievable in the near term since it would require us to obtain 1,350 MW of wind (the equivalent of approximately three Biglow Canyon wind farms) by 2019. This would be in addition to the resources we are already proposing to acquire. In addition, given our already resource short position, we have not sought OPUC approval in this IRP for a planning target that exceeds our annual average energy metric. Our execution concerns with this portfolio are explained in detail in the IRP Addendum at 85 – 86.

D. Consideration of replacement resources is important and should be fully considered in future IRPs consistent with the Commission's IRP Guidelines

Joint Parties and Sierra point out that a replacement resource for Boardman does not have to be a natural gas plant. Joint Parties at 4-5, Sierra at 1, Exh 1 at 16. PGE agrees. Consistent with Commission Guideline 1, we will evaluate *all resources* on a consistent and comparable basis when considering a portfolio of resources that includes a replacement for Boardman. PGE used a natural gas CCCT as a proxy replacement resource in this IRP in order to replace it with another base-load resource. Under the Commission's IRP Guideline 4n, an IRP action plan for resource activities covers the next two to four years. Thus, any actions related to replacing Boardman in 2015 would be included in our 2011 IRP; and actions needed for a 2020 replacement would be part of a subsequent IRP action plan. As we've pointed out before, a longer time frame for developing a replacement strategy will provide more time for emerging renewable technologies to mature and will likely allow us to consider a broader range of replacement technologies.

NWEC asserts that PGE has only modeled 441 MW of CCCT and 248 MW of SCCT for Boardman replacement supply. NWEC at 1. We assume NWEC is referring to our BART III portfolio. NWEC is mistaken in its belief that the Boardman closure replacement strategy includes 248 MW of SCCTs. *See*, IRP, Section 10.4, Item 3, paragraph 2. We do not add capacity (e.g., SCCTs) in our 2020 portfolios as a replacement for Boardman. Rather, it is added as a capacity resource to all portfolios to meet PGE's one-hour load plus reserves. Nor have we considered solely a CCCT for replacement supply for Boardman. In response to OPUC Staff data request #1, we considered portfolios that replaced Boardman in 2014 with 50% wind or with 50% market purchases. The former proved materially more expensive, the latter materially more risky. Because these alternatives did not perform well, we have not continued to consider them.

E. A later start for federal CO_2 regulation could favor BART III over earlier closure proposals

We agree with Joint Parties that it is unlikely that carbon regulation at the federal level will begin by our assumed 2013 date. Joint Parties at 3. Joint Parties however assert that carbon regulations will expand over time, making regulatory risk unacceptably high. *Id.* While we are not willing to speculate about additional regulation that may take place in the 2020s or later, we note that our BART III proposal is not subject to this particular risk. In fact, the probable effect of a later start to federal CO_2 regulation will be to economically favor a 2020 closure over proposals for earlier closures if the reduction glide path is similarly delayed, as demonstrated in our analysis with the future simulating CO_2 compliance costs delayed by one year: from 2013 to 2014. Attachment B hereto lists all portfolio costs by future and shows that the cost advantage of Bart III over DEQ 2015 increases from $47 million to $55 when the CO_2 tax is introduced one year later.

But we also don't believe the carbon regulatory risk for Boardman operations to 2040 that is described above is high. This is the case because, our backup plan, BART I, under the reference case CO_2 assumption, has limited downside exposure with regard to Boardman after the mid-2020s, based on the economic dispatch captured in our analysis. *See,* Sierra Exh. 1, figure R9. On the contrary, there is a greater potential for upside value should the cost of carbon compliance be less than that found in our reference case.

Regarding the posited regulatory expansion, the federal legislative proposals that we incorporated into our analysis by proxy (Waxman-Markey and Kerry-Boxer) have aggressive reduction glide paths that culminate in economy-wide CO_2 reduction targets of 83% below 2005 levels by 2050. IRP at 98/99. That is the reason why the compliance costs incorporated in our analysis have a "hockey stick" shape through time. *See,* IRP, figure 6-2. Hence, we believe that our analysis already incorporates the Joint Parties' assumptions regarding regulatory expansion.

III. Cascade Crossing

Two parties commented on our proposed Cascade Crossing transmission project. RNP generally commented in support of the project and recommended alternatives for future updates. Willard made a number of arguments and unsupported generalizations in opposition to the project.

A. PGE will provide updates on its progress towards achieving project milestones. However, acknowledgment should not be conditioned on the milestones

RNP recognizes that the project will directly facilitate wind interconnections and, more generally, can provide links between eastern wind, solar, and geothermal resources and western load centers. RNP at 3. RNP is generally supportive of the needs and cost-benefit analysis that PGE has employed and, in particular, supports efforts to right-size the transmission line for future use. RNP supports acknowledgment of Cascade Crossing so long as it can be responsibly sited and developed within the parameters of a sensible and timely cost benefit analysis. RNP recommends that the Company be required to return to the Commission to update the inputs to its needs and cost benefit analysis in a future IRP or IRP update. Alternatively, RNP recommends that Commission acknowledgment be subject to the milestones that PGE set forth on page 22 of its Reply Comments, with any significant deviations from those milestones requiring additional review in a future IRP. RNP at 3-4.

PGE appreciates RNP's support for the Cascade Crossing transmission project and agrees with RNP that the line can play an important role in delivering energy from renewable resources to our customers. PGE has no objection to updating the inputs to its needs and cost benefit analysis in a future IRP or IRP update. We oppose RNP's alternative recommendation that acknowledgement be subject to the milestones we discussed in our August 10 Comments. Commission guidelines provide that an IRP will be acknowledged when it is "reasonable, *based on information available at the time." Re Investigation Into Integration Resource Planning*, Docket UM 1056, Order No. 07-002 at 10 (emphasis added); *see also Least-Cost Planning Investigation*, Docket UM 180, Order No. 89-507 at 11 ("[a]cknowledgement of the plan means only that the plan seems reasonable to the Commission at the time the acknowledgement is given."). The Commission's guidelines recognize that all utility planning encompasses uncertainty and requires only that utilities consider the uncertainties in their planning and that the preferred portfolio represents the best combination of expected costs and associated risks and uncertainties. Accordingly, the Commission has acknowledged IRPs containing major resources that were in the planning stages, understanding that it would be possible that the relevant facts could change. *Re Portland General Electric Company*, Docket LC 33, Order No. 04-375 at 10 (July 20, 2004) (acknowledging plan that included acquisition of generic 350 MWa high-efficiency gas-fired resource); *Re Investigation Into Least-Cost Planning for Resource Acquisition by Northwest Natural Gas Company*, Docket LC 29, Order No. 00-782 (Dec. 11, 2000) (acknowledging plan that included the South Mist Pipeline Extension). PGE has shown that Cascade Crossing is reasonable based on the information available at this time. PGE will continue to update the Commission on its progress towards achieving project milestones. Therefore, in accordance with the Commission's Guidelines and past practice, any acknowledgment decision can require PGE to provide updates on its progress towards achieving project milestones but should not be conditioned on such milestones.

B. Cascade Crossing is necessary to accommodate changing generation patterns and to meet PGE's FERC obligations

Willard continues to compare the difference between PGE's historical load growth and forecast load growth to support its opposition to the Cascade Crossing transmission line. Willard at 1-2. We reply generally to comments on our load growth forecast in Section IV below. What Willard fails to recognize however is that PGE is not proposing to construct Cascade Crossing solely or even primarily, to accommodate load growth. Changes in the region's generation patterns and federal requirements related to accommodating interconnection requests are greater drivers for the project than load growth.

Power flows on the interconnected electric transmission system are determined by the location and amount of generation, the location and amount of load, and the interconnection of transmission lines and substations. The most recent additions to the Northwest generation portfolio have been wind generation plants, most of which are located east of the Cascades. This is expected to increase in the future. When these plants operate at or near full capacity, the gas-fired plants on the west side of the Cascades are economically displaced and shut down. This creates heavier flows on the existing east-to-west transmission paths which is causing the existing transmission lines to load near their rated capacity. In addition, there may be new flexible gas fired units located on the east side to firm up the variable wind resources. Hence, this generation dispatch pattern, with wind and wind firming resources on the east side displacing thermal generation on the west side, creates heavy loading on the existing system and drives the need for additional transmission capacity. As we explain in our IRP and our August 10 Comments, PGE in particular needs additional east to west transmission capacity to access renewable resources on the east side of the Cascades so that it can meet its Oregon RPS requirements.

Another factor driving Cascade Crossing is PGE's obligation to accommodate generation interconnection requests under its Open Access Transmission Tariff (OATT). Consistent with Federal Energy Regulatory Commission (FERC) requirements, PGE's OATT provides a process by which entities can submit requests to connect generation projects to PGE's transmission system. PGE is required to process these requests according to certain procedures set forth in the OATT. The procedures require PGE to study the feasibility and system impacts of any requested interconnection and provide an estimate of the costs of any new facilities that must be constructed to accommodate the request. PGE is required to tender a Large Generator Interconnection Agreement (LGIA) to any party completing the study process. If the LGIA is executed, PGE is required to construct, at the Interconnection Customer's expense, any new facilities (called Network Upgrades) needed to connect the generation facility to PGE's transmission system. The interconnection customer receives transmission credits for any amounts advanced for Network Upgrades.

Currently PGE has requests for 3210.9 MW in its generation interconnection queue; 2792.4 MW would require construction of the Cascade Crossing line as a Network Upgrade. A copy of PGE's generation interconnection queue as of the date of this filing is included as Attachment C hereto. The queue is posted and maintained on PGE's public OASIS site: http://www.oatioasis.com/PGE/PGEdocs/Active%5F%2D%5FGenerator%5FInterconnection%5FRequests%5F9%2D01%2D2010%2Epdf. Since filing its IRP in November 2009, PGE has received requests from third-parties to interconnect an additional 1100 MW of energy – 500 MW of which was requested after PGE filed its August 10 Comments. Willard may believe the amount of requested interconnection capacity is "absurd;"[6] however the requests are valid and PGE is legally required to treat them as such. PGE recognizes that the amount of requests far exceeds the expected capacity of our proposed Cascade Crossing line. Should all of the requests advance through the full OATT interconnection process, PGE will be required under FERC rules to expand Cascade Crossing or construct another line at the Interconnection Customer's expense. As discussed above, PGE will continue to provide the Commission with updates on Cascade Crossing, including updates on the status of interconnection requests.

C. Costs of the Willamette Valley Upgrade

Willard indicates a lack of clarity about the cost of the Willamette Valley upgrades. The total cost for the Cascade Crossing Transmission Project used in our IRP analysis includes an estimate of approximately $47 million (2009 $) for the Willamette Valley upgrade. This estimated cost includes the procurement and construction costs for the structures and conductors and associated equipment to be built entirely within PGE's existing right-of-way for the Bethel

[6] Willard at 3.

to Monitor to McLoughlin 230 kV line, based on $1 million per mile plus the cost for terminating the new line in the Bethel and McLoughlin substations.

D. PGE has provided conservative estimates of its right-of-way costs

Willard continues to complain that PGE's right-of-way acquisition costs are too low. Willard at note 2. Willard offers no support for its contention. PGE has included what it believes to be conservative estimates based on its long experience in acquiring rights of way for various generation, distribution and transmission projects. PGE will inform the Commission in subsequent IRP updates if the acquisition costs are significantly higher than what we estimated.

E. BPA's McNary to John Day line does not mitigate the need for Cascade Crossing

Willard again raises BPA's McNary to John Day line, apparently in an attempt to show that Cascade Crossing is unnecessary. Willard at 5. The addition of the McNary-John Day 500 kV line expanded the capacity of the West of McNary path (from the current 3000 MW to the new value of 4500 MW mainly due to the addition of the new McNary-John Day 500 kV line) and is expected to be in-service by February, 2012. We have included BPA's ATC postings from BPA's OASIS at Attachment D. These postings show 383 MW of ATC on the West of McNary path in 2015. This indicates that most of the capacity brought about by the addition of the McNary-John Day 500 kV line has already been committed, and that only 383 MW of service is still available. Given that PGE has 2792.4 MW of generation requests in its queue, the ATC on BPA's McNary to John Day line is nowhere near enough to mitigate the need for Cascade Crossing. Moreover, since the BPA line terminates at John Day, anyone wishing to bring energy to Portland would need to acquire additional transmission capacity from John Day to Portland.

F. The FERC Settlement referenced by Willard has no relevance to Cascade Crossing

Willard's reference to FERC penalties at page 5 of its comments has no relevance to the Cascade Crossing project. The penalties are part of a settlement agreement between FERC and PGE and relate to allegations that PGE improperly used certain scheduling numbers during the 2002 to 2008 time period and did not match network resources with transmission capacity used to serve retail customers in accordance with FERC rules during the years 2002-2005.[7] *In re Portland General Electric*, 131 FERC¶61,224 at ¶10 (2010). Such allegations have absolutely no bearing on PGE's current and future need for transmission capacity to access resources east of the Cascades.

G. There has been significant opportunity for public comment on Cascade Crossing

Willard states that the OPUC has held a single workshop concerning Cascade Crossing and appears to complain that the public has had insufficient opportunity to contribute to the process. Willard at 5. PGE's IRP process began over two years ago. We have held nine

[7] FERC found that the activities were not the result of manipulation, deceit, fraud or material misrepresentation in an attempt to harm customers. *In re Portland General Electric*, 131 FERC¶61,224 at ¶10 (2010). PGE neither admitted nor denied the allegations. *Id.* at ¶ 13.

stakeholder meetings. The IRP has been discussed at four Commission meetings. The Commission devoted one technical workshop solely to Cascade Crossing. This docket provides parties with four opportunities to submit comments on PGE's draft and final IRP.

In addition to the IRP process, there has been a significant public outreach to inform the public about the Cascade Crossing project and accept comments. This includes three separate mailings to property owners and a wide range of policy makers and stakeholders; eleven open houses along the route (which were preceded by paid advertising and news articles in local papers); presentations to several groups, including the Marion County Commission and the Marion County Farm Bureau; and a separate Cascade Crossing section on the PGE website which includes information about the OPUC process and a link to PGE's IRP. The public has been encouraged to submit comments to PGE through the website and at each of the open houses.

In addition, the state and federal agencies responsible for permitting the project have done significant outreach, with support from PGE. This included five public scoping meetings (preceded by a mailing, paid advertising and news articles), plus a joint agency/PGE website (http://www.cascadecrossingproject.com/) to explain the project and accept formal comments. One page on the joint website includes a section on the IRP process, with links to the OPUC where the public can comment on PGE's IRP.

In short, the public has had reasonable opportunity to raise issues with regard to Cascade Crossing at the OPUC and in other forums. As with the proposed Boardman actions, PGE needs direction from the OPUC in order to move forward with the next steps necessary for development of the line.

IV. Resource Needs, including Load Growth and EE

A. Reductions in recent load forecast do not warrant a change in PGE's proposed resource actions

Sierra states that PGE has overstated its need for capacity and energy from the Boardman plant. Sierra, Exh. 1 at 16. In support of its contention, Sierra states that figures used by PGE in its August 23 presentation to the Commission "ignore the numerous actions that PGE is proposing to take to add gas-fired and renewable resources." The figures that Sierra references are load-resource balance graphs which properly do not include actions that we are proposing. The traditional practice for IRP in Oregon is to first present the situation as is -- to demonstrate the need -- before proposed demand and supply actions. The IRP then proposes an Action Plan to fill the need.

Sierra and NWEC both suggest that reductions in load forecasts should significantly alter PGE's actions. Sierra at 16; NWEC at 4. We disagree for two reasons:

First, the load forecast decline is not as large as it may seem. The December forecast incorporates EE associated with Senate Bill 838 funding, which we previously incorporated outboard of the load forecast. This accounts for 37 MWa of the reduction between the IRP and more current load forecasts. In short, this is not a change to the load forecast net of EE. Another significant component to the lower forecast is a 39 MWa decline due to a recession-driven reduction in demand by a very limited set of large industrial customers. This hopefully will be a short-lived decline and full plant operations will resume as the economy improves. Such has typically been the case for large PGE customers.

Second, while load forecasts have declined since the IRP was filed, they still support our actions. Sierra points to a decline in load of approximately 150 MWa by 2015. Sierra at 17. This is really between 74 and 113 Mwa when the above adjustments are considered. This decline needs to be placed in the context of our resource actions, which total 873 MWa. *See*, IRP Addendum at 117. Of this 873 MWa, 100 MWa is targeted for short to mid-term market purchases, with another 66 MWa related to existing contract renewals. Reductions in both of these actions would be more than sufficient to address the load decline. In particular, PGE will have no assurance that the renewal of 66 MWa of contract resources will occur until negotiations are complete

We should also note that Boardman provides 314 MWa of energy and 375 MW of capacity in 2015. See IRP at 27, Table 2-2. This is close to triple the decline in load reduction identified by Sierra, after adjusting for EE. *See*, Sierra at 17. The reduction in our load forecast is not sufficient to replace Boardman or alleviate our risk of replacing expiring power purchase agreements.

NWEC also references a study by "Western Electricity Coordinating Council's (WECC) State and Provincial Steering Committee (SPSC), which contracted with Lawrence Berkeley National Lab (LBNL)." The study makes an additional outboard EE adjustment for new federal lighting and appliance standards. NWEC cites a reduction by 2020 of 182 MW. See NWEC Attachment A. But the reduction to annual energy is much lower -- about 110 MWa. Even if the adjustment is appropriate, this is about one third of the energy modeled from Boardman; it does not obviate our need for new resources, and certainly is not a replacement for Boardman. However, we believe there are potential issues with making the adjustment. The EE savings from these new standards may overlap with the ETO. Also, to the extent that prior standards have been in place and are being supplanted, only incremental savings from new standards should be applied. In the Pacific Northwest, we have a strong history of adoption of EE measures, which is in turn embedded in our load forecast. Thus, new programmatic savings are actually necessary in order to maintain the reduced load growth that was muted by historical savings.

Finally, reduced loads impact all portfolios similarly. PGE's IRP includes a low load growth future as a sensitivity. IRP at 236. The portfolio rankings of the low load growth future are identical to those of our Reference case. That is, our portfolio rankings do not change based solely on a low load growth assumption.

B. PGE's load forecast is reasonable

Sierra and EMO also continue to question PGE's load forecast growth rate. Sierra, Exh. 1 at 16; EMO at 1. Sierra continues to believe that PGE's load forecast should reflect the most recent past, not a longer-term view. Sierra, Exh. 1 at 18. Sierra attempts to challenge PGE's historic energy growth rates on the grounds that PGE has reached or exceeded 1.9 percent annual growth in energy requirements in only a single year since 2000. Sierra ignores the fact that eleven of the last twenty-eight years exhibited growth rates of 2.7% or higher. Moreover, sixteen years -more than half - were at or above the 1.9% mark. Going forward, our load forecast relies on third-party state of Oregon economic forecasts for in-migration, employment, etc. An economic recovery will lead to higher load growth.

EMO also criticizes our load forecast but offers no persuasive evidence or analysis to support its position. Its question as to whether it's wise to replace 0-10 year data with 10-30 year old data indicates that it does not understand our forecast methodology. PGE did not 'replace' any data as suggested – we include the most recent data along with older data.

EMO also includes an EIA graph showing electricity demand growth from 1950 through 2035 as its supporting analysis. This graph however, is not relevant, as it covers the entire United States -- it is not Pacific Northwest, Oregon, or PGE specific. One would expect different growth rates throughout the country. It is also not clear what growth rate EMO would propose to use from the graph.

EMO suggests that "anywhere from 50 to 100 percent of power needs projected from Boardman in the 2015-2020 period will 'disappear' once PGE's forecast is corrected." This statement lacks any analytical backup. EMO makes no demonstration of how the need for a baseload plant that provides 15% of PGE's customers will simply disappear. There is no proof that the need for Boardman will simply disappear – in fact our analysis shows the opposite – see PGE's IRP in general, Chapter 3 in particular.

NWEC incorrectly characterizes our stance on the NWPCC load forecast. NWEC at 4. We have consistently argued that our load forecast is largely consistent with the NWPCC – especially in the years covered by our Action Plan. *See,* August 10 Comments at 25; IRP at 37. NWEC's suggestion that we "now discount the relevance of the Council's numbers," is misplaced. NWEC at 4. We have appropriately noted the reasons for the differences between PGE's and the Council's forecasts. In particular, we note PGE's forecast focuses on our specific service area whereas the Council assesses a larger non-homogeneous region. Also, the Council forecast assumes conservation will exceed load growth for a few years approximately seven years in the future. PGE's forecasts do not show conservation in excess of load growth. These important distinctions must be considered in any fair assessment of projected load growth.

C. Distributed Energy Resources

Pareto comments for the first time to recommend practical tools by which the IRP could have a contingency plan in case of large-scale adoption of distributed energy resources by PGE customers. We appreciate Pareto's comments but note that they go beyond the scope of a Response to PGE Reply Comments since PGE's Reply Comments did not address any of the issues raised by Pareto. Nonetheless, we have reviewed Pareto's comments and will consider their recommendations in future IRPs.

V. Fuel Price Forecasts

A. PGE should not update selective assumptions

Sierra complains that our August 10 Comments use the same natural gas prices as those used in our IRP. Sierra Exh 1 at 7. Sierra believes the natural gas prices are unreasonably high and therefore bias the continued operation of Boardman. Sierra, Exh 1 at 7-16. Sierra presumably would have us rerun our IRP portfolios and change only the natural gas prices (and possibly load although our discussion above shows that would be of no consequence). Sierra apparently does not consider that lower gas prices may impact other parameters used in our IRP analysis. In addition, to provide a fair and balanced analysis, we would also need to model changes to other factors (such as CO_2 prices). It would not be good practice nor would it provide a sound basis for decision-making to redo our IRP and update only one or two assumptions. Nor would it be consistent with Commission IRP Guideline 1 which requires that consistent assumptions and methods be used in evaluating all resources.

Moreover, PGE receives quarterly updates to gas price forecasts. Our long-term load forecasts are updated three to four times per year. It is not practical, given the analytics required, to run new IRP portfolios every time a new forecast is prepared. However, to address the possibility of changes in assumptions, PGE runs sensitivities to test our portfolios against possible futures. In this IRP we have evaluated futures consisting of high and low gas and high and low load among others. We believe the use of the sensitivities is a good approach to help ensure informed decision-making, without engaging in constant assumption updates, during a time of frequent economic and regulatory change

We also take exception to the extent that Sierra implies that the gas forecasts used in our IRP are in any way biased. PGE does not prepare its own forecasts. Instead we rely on the forecasts of the PIRA Energy Group (PIRA), an unaffiliated third-party that has no incentive to bias their forecasts in any way that affects PGE.

PGE also objects to Sierra's statement that we have misrepresented deviations of EIA forecast gas prices versus subsequent actuals (SC R3, Ex 1 at 15) and/or singled out a few instances of underestimation. As reported at page 30 of our August 10 Comments, we looked at long-term averages of EIA forecasts for any given year from 1996 to 2008 and calculated that their forecasts tend to underestimate actual gas prices. *See*, PGE's analysis provided in Attachment 111-B which was provided in response to PEAC Data Request No. 111 and is included as Attachment E to these Comments.

Finally, we apologize for inadvertently indicating that Sierra had not provided us with all of the information needed to understand Sierra's gas price figures. We realize now that Sierra did provide us with relevant workpapers which upon examination indicated flaws in Figures 1 and 4 and confidential Figures 2, 3 and 5 of Sierra's May comments – namely that Sierra's representations of the gas prices used in PGE's IRP were not accurate. Contrary to Sierra's assertions, PGE was not confused about Sierra's gas prices. *See*, Sierra Exh 1 at n. 5. Rather, Sierra's prices contained a number of inaccuracies. We note that although Sierra doesn't say so, it has apparently corrected these inaccuracies in Figures R5 and confidential Figures R4, R6 and R7 of its September 1 Comments.

B. Coal prices

Sierra continues to criticize PGE for not considering the potential for higher coal prices in any of its scenarios. Sierra at 21. As we explained in our August 10 Comments, we did incorporate large future increases in our delivered coal price forecast as part of our reference case. August 10 Comments at 32. Sierra cites investor reports prepared by Peabody - a leading coal producer - to support its contention that PGE should use significantly higher coal forecasts.[8] The reports that Sierra cites appear to be forecasting prices for 8800 BTU coal from the Powder River Basin (PRB).[9] The coal that PGE purchases and on which we base our IRP modeling is the lower ranked 8400 BTU coal from the PRB. The price for 8400 BTU coal is typically cheaper than the 8800 BTU coal, even after accounting for the difference in heating values. This is in part due to lesser demand and market potential for the 8400 BTU coal. There are also a limited number of customers with enough pulverizer and boiler capacity to burn the lower ranked coals without a decrease in output. Because of the lower heating value, 8400 BTU coal does not compete as well as the 8800 BTU coal with Eastern or Illinois Basin coals, or even international coals. Further, when the buyer is far away from the PRB, freight is a major cost component of the delivered cost of coal. So when there is demand for PRB coals, particularly from utilities in the east or mid-west or even the south, they are more likely to buy the 8800 BTU coals to lower their average delivered cost per heat input.

Not only do the forecasts that Sierra rely on pertain to a different grade of coal but the graph showing a price range of $29-$36/ton cited by Sierra appears to be for price parity with Central Appalachian (CAPP) coal. The same graph shows a PRB market price forecast of about $15/ton during the same time period. It is speculative at best to suggest that there is parity price support for PRB in the $29-$36/ton range based on CAPP pricing.

In short, the investment reports relied upon by Sierra to suggest that PGE's coal forecasts are too low do not pertain to the type of coal used by PGE and generally show a much lower forecast for PRB coal than that cited by Sierra in its September 1 Comments.

VI. Wind Integration

RNP was the only party to comment on PGE's wind integration study (WIS). RNP is a valuable contributor to the process of deriving the integration costs of Variable Energy Resources (VER) in the Pacific Northwest and we are disappointed that their comments generally expressed dissatisfaction with our WIS. However, we believe that the reasons for their

[8] PGE relies on forecasts prepared by EIA, a government agency and PIRA, an independent energy consulting firm neither of which has any apparent reason to bias its forecasts. We would question the prudence of relying on forecasts used in a coal producer's investment report for our resource planning.

[9] Rick Navarre, President and Chief Commercial Officer, *Expanding Markets and Peabody Growth Opportunities*, 2010 Analyst and Investor Forum, June 17, 2010, at page 41. Christina A. Morrow, Vice President, Investor Relations, *Jefferies 6th Annual Global Industrial and A&D Conference*, August 10, 2010. p.23.

dissatisfaction stem from a misunderstanding of the actual costs incurred by utilities when integrating VER generation.

A. *PGE's WIS was vetted by regional stakeholders and RNP was actively involved in PGE's WIS process*

RNP states that "PGE has not produced a study whose detailed methodology and results have been made available for review, much less 'vetting' by regional stakeholders." RNP at 1. In its Order reviewing our 2007 IRP, the Commission issued the following condition:

> In the next planning cycle, include in the analysis a wind integration study that has been vetted by regional stakeholders

Re Portland General Electric Company, Docket LC 43, Order No. 08-246 at 11 (May 6, 2008). PGE has satisfied this condition. A detailed description of the study and the study process is included at pages 125 to 130 of our IRP. PGE started the study over two years ago. We engaged a Technical Review Committee (TRC) consisting of members from the Utility Wind Integration Group, the American Wind Energy Association, the National Renewable Energy Laboratory, and RNP to evaluate our study approach, inputs and findings. On September 19, 2009, PGE conducted a three-hour presentation to regional stakeholders, including the OPUC Staff and RNP, to convey the details of its wind integration study. During the presentation, PGE made its internal study team, including its outside consultant who specializes in quantification of wind integration costs, available for questions. A copy of the presentation is included as Attachment F hereto. PGE believes that the level of detailed information discussed with the regional stakeholders, including the OPUC and RNP, satisfies the conditions set forth in Commission Order 08-246.

We are surprised with RNP's assertion that their involvement did not go beyond a "preliminary stage." RNP at 2. PGE launched the WIS on June 3, 2008 with a detailed presentation to the members of the TRC. This meeting included much of what was discussed in the regional stakeholder meeting on September 19, 2009. After the initial meeting, the PGE internal study team met with the TRC on a bi-weekly conference call to discuss certain issues that came up during the modeling process. In addition, RNP's consultant made an on-site visit to PGE's office to review our model development.

RNP complains that "[n]o detailed response was given (on which inputs the reserve costs were sensitive to), and no further opportunity for comment on the completed study was offered." RNP at 2. PGE's internal wind integration study team performed several sensitivity studies based upon the request of TRC members, including requests from RNP's representative. Sensitivity study results that were included in the September 19, 2008 regional stakeholder presentation are as follows:

- Bid/Ask Spread Pricing (slide 22)
- Boardman O&M Costs (slide 23)
- Diurnal Shaping in Scenarios (slide 24)
- Scaling of NREL Wind Data (slide 25)

Stakeholders had the opportunity to ask questions about these results at the meeting. PGE remains open to comments on this or any part of its WIS as it moves into the next phase of the study process.

As stated in our IRP, we are continuing with the second phase of our study to further refine our research. We will continue to keep RNP and other regional stakeholders involved in and apprised of our efforts.

B. The amount of wind energy required for PGE's preferred portfolio is driven by RPS requirements not integration costs

RNP states that it "cannot have confidence in PGE's assessment of how much wind energy is appropriate for its portfolio until we have some level of confidence in the wind integration costs that it attributes to new wind resources in its modeling." RNP at 1. However, the level of wind to be integrated into the PGE system is driven by the Oregon RPS requirement, not the wind integration costs attributed to new wind resources. By 2015, PGE must be able to meet 15% of its load with renewable resources. Since wind energy is the predominant economic resource at this time, PGE has concentrated on the acquisition of that resource. For the 2008 wind integration study, PGE assumed that level of wind energy to be 1,100 MW of wind energy based upon the best possible load estimate for 2014 at the time.

C. The wind integration costs of other utilities cannot be used to determine the cost of integrating wind into PGE's system

RNP notes that its employee "observed that the reserve cost results appeared anomalous, based on his experience with other regional utility studies." RNP at 2. We want to be clear that wind integration study results from various utilities cannot be compared on an equal footing due to the unique characteristics of the system being studied. For example, Arizona Public Service (APS) has published a wind integration study with a published cost of integrating VERs of $3.35/MWh.[10] This low integration cost is due to the impact of flexing multiple natural gas generating units to integrate only 550 MW of nameplate wind capacity. APS is able to decrease the output of many generating units in order to meet its balancing capacity needs.

Avista Corp produced a wind integration study in March 2007 that identified integration costs of $8.84/MWh. This is lower than PGE's costs of $11.75/MWh. However, closer scrutiny shows several reasons for this difference: Avista's study integrates only 600 MW of wind energy, a large portion of which resides in the southern Oregon coast at Cape Blanco. In addition, Avista is in load/resource balance with a large amount of low cost, flexible hydro. Furthermore, the level of geographic diversity depicted in this study would cause any integration cost to be lower than if the study was strictly integrating 600 MW of Columbia Basin wind energy.

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[10] located in the Wind Integration Study Library on the Utility Wind Integration Group's website: http://www.uwig.org/opimpactsdocs.html

PGE's wind integration costs may appear to be higher than other utilities on the surface, but direct comparison of wind integration study costs is not truly possible due to the unique characteristics of the geographic diversity of the wind plants in the study, the nameplate capacity of the wind generation, and the balancing resources available to the specific utility performing the study.

D. It is not appropriate to compare PGE's wind integration study cost results to a Balancing Authority Area's within-hour integration tariff

RNP comments that "[t]he results of PGE's study reflect an imputed cost of reserves—$16.96/kW-month—that is more than the cost of a new combustion turbine and is higher than the imputed cost of reserves in the Puget Sound Energy (PSE) wind integration rate proposal recently rejected by FERC ($14.91/kW-month)." RNP at 2. RNP also states that "PGE should continue to use the BPA wind integration rate to model new wind resources until such time as it is prepared to engage fully with stakeholders in review of its methodology and results."[11] *Id.* at 3.

PGE's wind integration cost is comprised of several components, of which reserves are one component. Dividing our total wind integration cost into the incremental reserve requirement does not provide a sound basis for comparison to the cost of a new CT.

As for the comment that PGE's cost of reserves is higher than the cost of the PSE wind integration rate proposal, it would stand to reason that this would be the case. As mentioned previously, the costs of wind integration are not easily comparable and legitimately vary across utility systems. The wind industry appears to agree that when it comes to a utility self-integrating wind, there are more costs to wind integration than simply the in-hour balancing costs.

- APS' wind integration cost of $3.35/MWh is comprised of three components: Day-Ahead Uncertainty, Hour-Ahead Uncertainty and Within-Hour Regulating.
- Avista Corp's $8.84 MWh wind integration cost represents two major categories: within-hour (Wind Shape, Regulation, Load Following) and Forecast Error (Hour-Ahead Uncertainty).
- Idaho Power splits wind integration costs into two main categories: within-hour (regulating reserves and load following reserves) and additional reserves to cover the expected short-term wind generation forecast error over the next hour (Hour-Ahead Uncertainty). *See, http://www.idahopower.com/AboutUs/PlanningForFuture/WindStudy/default.cfm*

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[11] RNP states that "BPA's rate, which PGE pays for all of its wind generation, is approximately $5.70/MWh—less than half the $13.50/MWh rate (in 2014 dollars) that PGE has applied to new wind generation in this IRP." RNP at 3. RNP is mistaken in that PGE does not pay the BPA Wind Balancing Service Rate "for all of its wind generation." PGE only pays the BPA rate for its 450 MW Biglow Canyon Wind Farm. PGE's other wind generation (100 MW) is paid for under power purchase agreements, not the BPA tariff. RNP also incorrectly compares BPA's 2010/2011 tariff rate of $5.70/MWh to PGE's 2014 wind integration cost of $13.50/MWh.

- PSE's Wind Integration Team states that the cost to self-integrate wind into the PSE Balancing Authority Area falls into two categories: 1)within-hour balancing reserves (regulation and generation following); and, 2) the opportunity cost of reshaping the Mid-Columbia hydroelectric generation and dispatching the thermal units. (Day-Ahead and Hour-Ahead Uncertainty). *See, www.pse.com/SiteCollectionDocuments/2009IRP/AppH_IRP09.pdf*

On the other hand, when it comes to creating a tariff rate for wind integration, Balancing Authority Areas have only been including the within-hour costs.

- PSE BA's Schedule 12, Within Hour Generation Following Service, only covers the within-hour costs of wind integration. This service " is provided in order to make available sufficient fast-start and quick-responding generation capacity to follow and compensate for the *within-hour variations* in a wind generator's output." *See, www.oatioasis.com/PSEI/PSEIdocs/Proposed_PSEI_Schedule_12.pdf*
- The Bonneville Power Administration's Wind Balancing Service only covers the within-hour costs of wind integration. The service "is comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserves (which compensate for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour)." All three of these services are within-hour only. *See, http://transmission.bpa.gov/business/Rates/documents/2010_Rate_Schedules_10_01_09.pdf*

It is simply not appropriate to compare PGE's wind integration study cost results to a Balancing Authority Area's within-hour integration tariff, or to another utility's wind integration costs for the aforementioned reasons.

VII. Power Purchase Agreement Market Reliance

A. A bridging PPA is not an option for early termination of coal-fired operations at Boardman

1. A solicitation for PPAs or indicative proposals would not be timely nor would it provide reliable information for making a decision about the viability of discontinuing coal-fired operations at Boardman as early as 2015

NIPPC and Sierra assert that PGE should issue a solicitation for PPAs or indicative proposals from IPPs and Merchant Plant owners. Sierra Exh 1 at 19; NIPPC at 5. PGE contends that doing so would neither be timely nor would it provide reliable information for making a decision about the viability of closing Boardman as early as 2015.

First, conducting such a solicitation would not allow PGE to meet the timelines associated with DEQ requirements. Under the current BART rule and schedule for meeting the installation of RH BART controls, PGE would potentially need to install a semi-dry flue gas desulphurization system (Scrubber) by July 2014. To meet this deadline, PGE would need to initiate the engineering and procurement process for the Scrubber in early 2011. Likewise, if a new Regional Haze Plan is adopted for Boardman by the EQC based on the current DEQ proposals, PGE would still need to install a Scrubber as well as selective non-catalytic reduction (SNCR) by 2014 to run the plant to 2020 or beyond. Again, under this scenario PGE may find it necessary to move forward with purchasing emissions control equipment early in 2011 in order to meet these installation timelines.

NIPPC proposes that PGE should issue a Request for Information ("RFI"), utilize the results to re-evaluate its alternatives, and then file another addendum to the IRP. NIPPC at 5-6. As evidence that pursuing such a process would be feasible, NIPPC cites an RFI issued by Northwestern Energy in 2009 for a relatively small amount of new supply (25 to 75 MW) with a more immediate need. The process proposed by NIPPC both fails to recognize the time-sensitive nature of the BART decisions for Boardman and the lack of utility that such a non-binding price discovery exercise would provide to PGE and the potential respondents.

Northwestern issued its RFI on August 17, 2009 with responses due roughly 45 days later on September 30, 2009. NIPPC at Attachments 2 and 3. Allowing for a reasonable timeframe for development of an RFI similar to that issued by Northwestern, and review and scoring/validation of proposals, it is unlikely that PGE could conduct such a process in less than three to four months. Incorporating the information into our IRP analysis and subsequently issuing a new addendum would take several additional weeks. This does not account for additional time that would likely be required for intervenor comments on the addendum, Staff's report and reply comments to Staff's report. In addition, given the high interest in this IRP docket and the historically robust involvement of Staff and stakeholders in Oregon Investor Owned Utility (IOU) procurement processes, it is likely that additional time would also be needed to seek stakeholder and staff input on the RFI prior to development and issuance. Given these time requirements, issuance of an RFI as suggested by NIPPC would likely delay Commission review of PGE's IRP and Boardman recommendations until mid-to-late 2011.

In addition, a non-binding RFI could potentially be viewed unfavorably by wholesale market participants. In bidder workshops connected with PGE's 2008 renewable resource and 2003 all-source RFPs, potential bidders expressed concerns about wasting time and money to participate in a potential "price fishing exercise." We are skeptical about whether plant owners would be willing to participate or take the time necessary to assemble the information required to evaluate potential PPA candidates under a non-binding RFI that does not lead directly to a procurement or bid negotiation process. It also appears clear that one of the purposes of the 2009 Northwestern RFI cited by NIPPC was the possible pursuit of a streamlined procurement process. In the introduction of the RFI, Northwestern indicates that one of the potential outcomes of the RFI would be to enter directly into bi-lateral negotiations for either PPAs or asset purchases for the projects included in the RFI. PGE would not be able to pursue such a path or offer similar prospects in any RFI conducted prior to the acknowledgement of its IRP. The Commission's Competitive Bidding Guidelines 1, 7 and 9 require that an RFP be issued in accordance with a company's last acknowledged IRP.

We are also skeptical as to whether the price and non-price terms provided under a non-binding RFI would be reliable enough to inform a decision with respect to the cost and risk of replacing Boardman in the near term since an RFI would lack the rigor and oversight associated with an RFP conducted pursuant to the Commission's Competitive Bidding Guidelines. Given the fact that the RFI price and non-price information would not be binding or even lead to negotiations that could become binding, PGE would have no assurance that the responses represent valid offers for future PPAs to replace Boardman. In fact, under such a process there would be a potential incentive for respondents to provide "overly optimistic" or aggressive prices and conditions. If PGE were to rely on the results of an RFI to make a decision to close Boardman early and rely on mid-term PPAs, we would be placing our customers at risk if the information provided in the RFI were ultimately not borne out. Moreover, if PGE was placed in a position where its only option was to pursue mid-term PPAs under urgent execution timelines, the Company would potentially find itself in the position of a "hostage buyer."

Finally, as pointed out in our August 10 Comments there is no assurance that plants included in an RFI would remain available for a PPA in a subsequent RFP. In fact, recent history has shown that the ownership and commitment circumstances of IPP and merchant owned plants can change rather quickly. In a period of less than two years (from February, 2007 – December, 2008) three Pacific Northwest IPP combined-cycle natural gas plants representing over 1,000 MW of generating capacity were sold to load serving entities, and were therefore taken off the market for mid-term PPAs. *See*, August 10 Comments at 35. At the same time, the largest thermal IPP plant in the region is also under pressure to shutdown early. TransAlta, the owner/operator of the roughly 1400 MW Centralia coal-fired power plant in Washington State recently executed an MOU with the state to enter into discussions to reduce greenhouse gas emissions and provide replacement capacity for the plant by 2025[12] An early closure of the plant would further limit IPP/Merchant supply options to replace Boardman.

2. It is not practical to expect that other IOUs would be able to offer PGE a PPA

Sierra criticizes PGE for not considering the potential to enter into a PPA with another utility. Sierra, Exh. 1 at 19. The notion of seeking bridging PPAs from other load-serving entities simply lacks real-world practicality, given the resource planning, procurement and ratemaking requirements that govern regional electric utilities. Other IOUs operate in state regulatory environments that are similar to Oregon's. In those regulatory environments utilities are generally able to add new resources to meet anticipated future customer energy and capacity requirements over the next few years, according to least-cost and least-risk planning standards. In Oregon, Commission IRP Guideline 4 allows PGE to include in its Action Plan resource additions and actions to acquire new resources that would be undertaken over the forthcoming two to four year period. Oregon also has a "used and useful" standard for including only those costs in customer rates that are utilized in connection with providing electric service to customers. Such standards exist, in part, as a check against utility expenditures and subsequent rate increases that are not prudent and necessary to ensure current and ongoing, reliable service. In addition, utility consumer advocacy groups have successfully argued for ever-increasing efficiency and cost consciousness for regulated gas and electric companies. In response, utilities

[12] *See*, http://www.transalta.com/newsroom/news-releases/2010-04-27/transalta-and-washington-state-agree-formal-talks-transitioning-ce.

and regulators have generally adopted much more of a "just-in-time" and "only if necessary" approach to pursuing expenditures that increase customer rates, such as those associated with acquiring new generation supply. As a result, regional utilities generally only build and acquire new generation when the capacity and/or energy are needed currently or will be needed within a few years. This strategy of pursuing approximately balanced portfolios (as opposed to acquiring new generation long before it would be needed) is widely employed by Northwest utilities and significantly diminishes the likelihood that these entities would maintain excess supply for more than a few years or entertain selling mid-term PPAs from existing base-load plants.

Additionally, most of the large, load-serving entities in the region (which also happen to be the owners of most of the base-load, natural gas CCCTs), have issued their own RFPs for new generation supply in the last few years, including Pacific Power in December 2009,[13] Puget Sound Energy in January 2010,[14] Avista Utilities in September 2009,[15] Idaho Power in April 2008 and May 2009[16] and Northwestern Energy in September 2010 and August 2009.[17] These recent solicitations suggest that, much like PGE, other large regional utilities face a near-term need for new supply. Given these circumstances, it seems unlikely that other utilities would be willing to enter into mid-term power sales arrangements with PGE at the same time that they are seeking their own new resources.

Finally, as hydro power and its highly flexible capacity diminishes as a proportion of regional load, and new, very low capacity value wind and solar resources are added, the region is quickly transitioning from a historically capacity rich state to a condition of capacity tightness. This concern is further amplified by the near exclusive addition of variable energy wind resources over the last few years with their associated integration requirements. Given the heightened capacity concerns of regional utilities and the need to hold additional reserves for wind integration, sales of any excess energy and capacity by these entities has been done on only a very short-term basis over the last several years, typically no further than the daily or month-to-quarter ahead markets. In such an environment we believe that it would be highly unlikely that a regional load-serving utility would be willing to enter into a forward-start, mid-term PPA to enable PGE to replace Boardman as soon by 2015.

3. Three of the four merchant-owned plants discussed in PGE's August 10 Comments are not likely to be able to obtain firm transmission to PGE's system. It's likely uneconomic for the fourth to do so

Sierra and NIPPC assert that PGE has not presented sufficient evidence as to whether four merchant / IPP plants identified in NWPCC databases as "unsubscribed," and therefore potentially available for mid-to-long term PPAs, can deliver energy on a firm basis or at a reasonable cost to PGE. Sierra, Exh 1 at 19; NIPPC at 4. An examination of BPA's OASIS

[13] *See*, http://www.pacificorp.com/sup/rfps/2009asr.html.

[14] *See, http://www.pse.com/energyEnvironment/energysupply/Pages/pse2010RFP.aspx*

[15] *See, http://www.avistautilities.com/inside/resources/renewables/Documents/ 2009_AVISTA_RENEWABLE_ENERGY%20REQUEST_FOR_PROPOSALS.pdf*

[16] *See*, http://www.v1energy.com/news/top-stories/584-idaho-power-selects-langley-gulch-power-plant and http://www.idahopower.com/NewsCommunity/News/upClose/showupClose.cfm?prID=2443

[17] *See, www.northwesternenergy.com/documents/rfp/RFPElectricityFirm-9-10.pdf and www.landsenergy.com/northwestern_rfi/2009%20NWE%20RFI.pdf*

indicates that none of the four IPP/Merchant plants identified on pages 36-37 of PGE's August 10 Comments hold BPA system reservations which would enable firm transmission to PGE's system under current rules and system constraints. Attachment G shows screen shots from BPA's OASIS showing transmission reservations associated with each plant. These show that there are no confirmed reservations for transmission to PGE's system. In addition, we believe that the transmission reservations associated with three of the plants (Big Hanaford, Grays Harbor and Hermiston) would not qualify for a redirect to PGE's system on a firm basis for any significant quantity under current system conditions. With respect to the Klamath Falls plant, we are not able to determine whether Iberdrola could redirect any of its existing transmission rights to deliver energy to PGE's system. We note, however, that two wheels would be required to reach PGE's system (COB to John Day and John Day to Portland) thus resulting in higher costs. In addition, as we noted in our August 10 Comments, Klamath Falls may not be an economically viable seller to PGE for mid or long-term sales, as the plant is well-situated to sell into the California wholesale market at materially higher prices than those in this region.

It should also be noted that it is not clear whether the Hermiston Power Project remains substantively uncommitted and available for mid-to-long term PPAs. On January 11, 2010 Calpine Corporation (the owner/operator) announced an agreement with Los Angeles Department of Water and Power (LADWP) to provide up to 270 MW of wind firming / integration services.[18] Under announced terms of the agreement, Calpine would leverage the flexibility of the Hermiston Power Plant and its Pacific Northwest contract transmission rights to firm and integrate energy from the Windy Point Wind Farm in Klickitat County, Washington. Since the duration of the contract was not specifically cited in the press release, it is not clear whether the plant could meet the requirements of the LADWP agreement while also providing a mid-term PPA that would commence as soon as 2015. Regardless, this announcement further reinforces our concern that the limited number of current uncommitted, dispatchable, base-load plants could further decline due to changes in commitment or ownership, increasing the risk that PGE would be unable to obtain firm, reasonably priced PPAs to replace Boardman in the 2015 timeframe.

Firm transmission issues proved to be a challenge in PGE's 2008 Renewable Resource RFP for many of the bidders. This was recognized in the Final Report of the Independent Evaluator submitted in Docket UM 1345. Of the initial thirty eight bids, twenty were retained for the Initial Short List. Thirteen of the twenty initial short list projects were ultimately found to lack firm transmission to PGE. An additional project was deemed to require two transmission wheels to reach our service territory, making the project uneconomic.

4. PGE did not "abandon" the near-term bridge PPA option without explanation

Sierra and NIPPC allege that we do not comply with Guideline 1 because we abandoned the near-term bridge PPA option in our most recent filing without explanation. NIPPC at 3-4; Sierra Exh 1 at 19. We assume they are referring to our Boardman through 2011 portfolio. We removed this portfolio when we presented the new DEQ options because a 2011 Boardman

[18] A copy of the press release is posted at: http://phx.corporate-ir.net/phoenix.zhtml?c=103361&p=irol-newsArticle&ID=1373566&highlight=).

closure is no longer an option given that we are now in late 2010. Our elimination of this portfolio had nothing to do with a PPA and everything to do with the assumed closure date in that portfolio. We informed parties that this portfolio was no longer under consideration on page 9 of our August 10 Comments.

5. PGE used a bridging PPA for the 2017-2021 time period but not for 2015 to avoid producing a distorted comparison of NPVRR

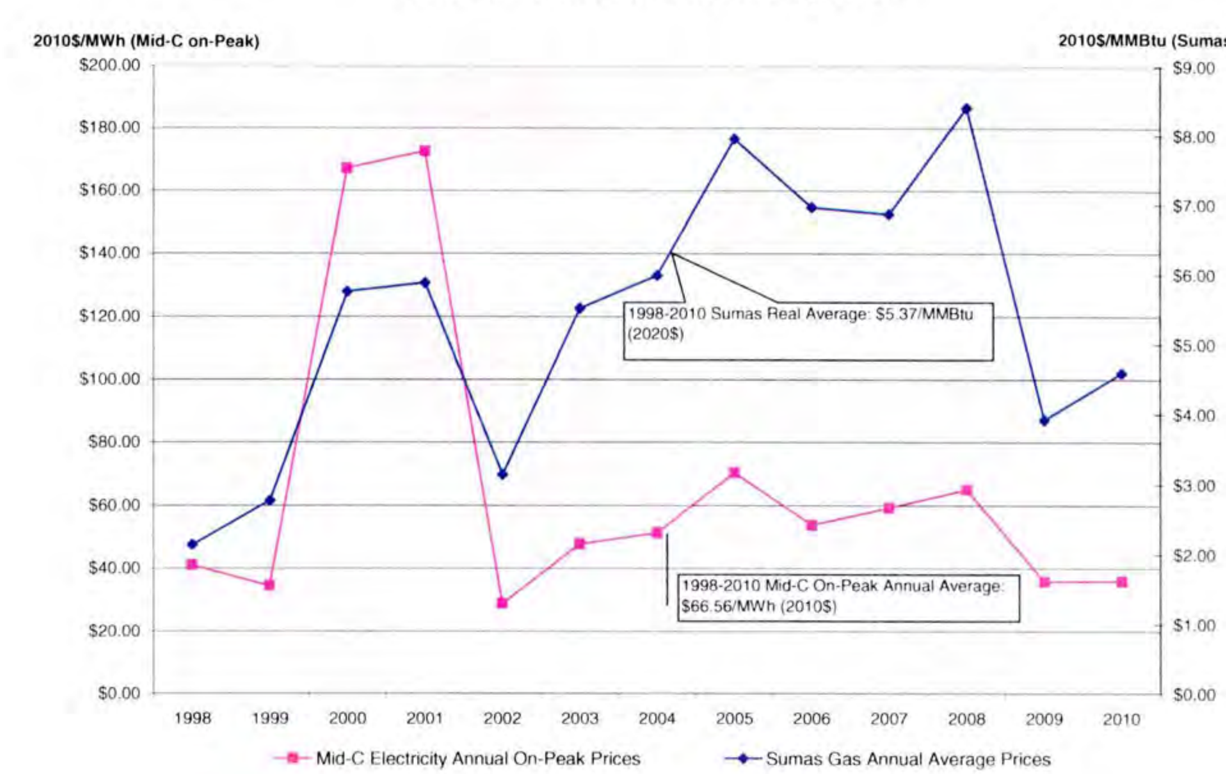
Sierra and NIPPC both complain about the PPA added for 2017-2020 in the 2020 closure cases. Sierra Exh. 1 at 19; NIPPC at 5. We describe the methodology for meeting capacity needs on page 221 of the IRP. When new capacity is added after 2019, as in the 2020 Boardman closure portfolios, a short-term bridging contract is used to ensure that these portfolios are not long for the remainder of the analysis through 2040. These PPAs are priced as fully-allocated CCCTs. Once replacement power is added in 2021, these portfolios have the same capacity going forward as all other portfolios in the study. This is simply a modeling convention to keep all portfolios on the same capacity basis. It is used to comply with Commission IRP Guideline 1, which requires that all resources be evaluated on a consistent and comparable basis. Had PGE not included a bridging PPA, the 2020 cases would have included SCCT long-term resources that would have resulted in a PGE long position and penalized those portfolios compared to other portfolios, giving a distorted comparison of NPVRR.

6. Parties comments do not alleviate concerns about the market risks associated with discontinuing coal-fired operations at Boardman before 2020

NWEC asserts that PGE has overstated the risk of an early Boardman closure. NWEC at 5. NWEC appears to suggest that wholesale electricity prices are likely to remain low because of the current recession and RPS requirements. *Id.* We disagree, as neither historical evidence nor a reasonable interpretation of indicators for future resource adequacy support the position.

First, the history of wholesale market prices for electricity and natural gas in the Pacific Northwest demonstrates that instances of very depressed (or very high) prices generally do not persist for long periods of time. Markets re-balance, finding a new equilibrium that reduces surpluses or deficits, adjusting prices to new levels. In fact, periods of unusually low or high prices are sometimes followed by an "over-correction" where prices reverse and move to the opposite extreme. As an example, the late 1990's exhibited very low wholesale market electric and natural gas prices in the Northwest. Over a relatively short period of time this condition rapidly reversed and we entered a period of extremely high prices in 2000 – 2001. We have seen further smaller cyclical changes of relatively high price periods following relatively low price periods, and vice versa, over the last decade. Typically, neither high nor low price periods persist for more than a few years. While a protracted period of depressed prices (from now through 2015/2016 and beyond), as NWEC suggests, may be possible, such a condition would not be consistent with the history of market prices for wholesale electricity and natural gas. The graph below represents Sumas gas and Mid-C electricity prices for the period of 1998 – 2010 and is indicative of the cyclical nature of prices and the rebalancing that occurs when prices reach unusually high or low levels:

PNW - Sumas Gas and Mid-C Electricity Prices



As pointed out in our August 10 Comments (pages 30-32), we also believe that it would be imprudent to expect currently low gas prices to persist for a long period of time when decreased prices are being driven in large part by rapid increases in supply resulting from a new extraction technique (natural gas fracturing) that is opening new supply sources. Given the limited history and relative immaturity of these supply sources and extraction methods, we should be cautious about projecting increased supply too far into the future. Increasing public outcry for tighter regulatory oversight of these new drilling methods is likely to reduce access to natural gas supply and increase finding and extraction costs over time.

With regard to regional load and resource balances, the NWPCC 6th Power Plan recognizes that a regional summer capacity problem may emerge by 2015, unless additional supply is built.

Finally, we do not believe that RPS requirements will reduce the market risk of replacing Boardman in the 2015 timeframe as NWEC suggests. In fact, the nature of RPS resource development may actually compound historical seasonal market price trends and increase price volatility. The vast majority of all renewable resources developed to meet RPS requirements in the Northwest are wind. Furthermore, the majority of all wind resources built or under development exist in the mid-and-lower Columbia River Gorge area in Oregon and Washington.[19] Many of these wind sites also share very similar seasonal production profiles,

[19] To view a geographical map, please link to http://transmission.bpa.gov/PlanProj/Wind/ and click on "Current and Proposed Wind Project Interconnection Map".

peaking in the spring and early summer with reduced energy output in the mid-to-late summer, fall and winter. The addition of so many intermittent resources that share common seasonal production profiles has indeed already had a dramatic impact on market prices (as indicated by NWEC), which will likely continue into the future. However, that impact may not be one of ongoing year-round depressed market prices as NWEC suggests. Rather it is more likely that we will see increased market price volatility with extremely low prices in the spring when both regional wind and hydro resources are peaking and electric demand is low (as has been the case the last few years), and increased prices when wind and hydro production diminish and loads increase in the summer and winter. While it is hard to predict if overall prices (average annual prices) will be higher or lower over time, it does appear likely that the addition of high volumes of intermittent RPS resources that are similar in seasonal production profile to each other and regional hydro production is likely to increase price variability in the future.

NWEC also suggests that the market price risk of replacing Boardman early must be acceptable to PGE since we have cited the risk of temporary closure in the event that either MACT or the Sierra Club lawsuit are not satisfactorily resolved. This is an incorrect interpretation of PGE's position and risk assessment. We do not believe that pointing out the risk of replacement supply for a temporary Boardman closure is any way analogous to the deliberate pursuit of a 2015 closure and the price and replacement supply risk associated with such a strategy. PGE's BART III proposal is designed to close Boardman in a timeframe that reduces uncertainty for customers while providing a reasonable time for transition to new resources. While we cannot eliminate all possible contingencies such as MACT and the pending litigation, and therefore pointed out these risks in our plan, doing so does not indicate that PGE finds the risk of market exposure for such a large portion of our customer electricity needs (as represented by Boardman) to be acceptable.

Finally, we must reiterate that market price risk is highly asymmetric. The potential for extreme adverse outcomes associated with being short in the electric and natural gas markets far outweigh the potential benefits. This fact was clearly demonstrated during the 2000 – 2001 time period where high wholesale energy market prices resulted in widespread and steep customer rate increases across the Western United States (including the Pacific Northwest), and left some utilities either bankrupt or on the verge of insolvency.

B. Benefits of independent power vs. utility ownership

1. NIPPC's cost analysis of Biglow Canyon is flawed

NIPPC attempts to use the capital costs of PGE's Biglow Canyon wind project to support a claim that "PGE is not necessarily equipped to manage and limit project costs as well as its competitors across all technologies." NIPPC at 7. It references a chart that it submitted in its February 2, 2010 Opening Comments which it alleges shows the high capital cost of Biglow Canyon Phases I and II relative to IPP developed wind projects. *Id. See also,* NIPPC February 2, 2010 Opening Comments at 13. It appears that the numbers that NIPPC uses in preparing its chart include only overnight capital, rather than overnight and capital carrying costs included in the PGE projects.[20] Even if consistent comparators are used, an examination that includes only

[20] PGE has submitted a data request to NIPPC asking for the data used in preparing the charts.

capital investment costs is not particularly useful when evaluating the cost of renewable projects to customers. PGE believes an approach that assesses delivered cost in $/MWh produced over the expected life of each project provides a more complete and useful measure of cost competitiveness and value to customers.

The capital measurement used in the NIPPC graph omits a number of elements that are important to consider when comparing different projects. A more comprehensive capital cost, in addition to AFDC, would capture the Balance of Plant and Project Substation costs, as well as Wind Turbine Generator (WTG) costs. PGE's cost metric takes into account all the elements that compose a net real levelized $/MWh delivered to customers. Such a comparison should include other key cost and value drivers, such as the capacity factor (CF), transmission and interconnection costs, and life cycle capital maintenance costs.

Only by using a comprehensive valuation approach (as used by PGE in its resource cost calculations) can the actual cost of delivered power to customers be determined. In addition to managing overnight capital costs, each project developer (IPP or utility) must make decisions that will optimize the cost per delivered MWh over the life of the project. There are complex issues with many factors influencing the ultimate cost of power delivered to utility customers, including:

- A more expensive WTG may in fact be cost effective if its power curve yields more energy over time.
- Proximity to the intended load center matters. Transmission costs can close the gap between differing wind site CFs. For instance, a 40% capacity factor wind farm that crosses multiple transmission systems to reach PGE's load (requiring multiple wheeling charges) may not readily compete with a 36% CF wind farm situated one wheel away. A single transmission wheel adds approximately $0.5/kWh of cost. In fact, using NIPPC's table of Capacity Factor and Cost per kWh delivered, a transmission wheel is equivalent in value to approximately 5% of capacity factor improvement. *See*, NIPPC September 1 Comments at 12.
- It is reasonable to presume that PPA prices include more than just the overnight capital required to build the project. A PPA price would also include the IPP's weighted cost of capital (required return to investors). This cost of capital is a direct result of their return on equity ("ROE"), cost of debt and capital structure. PGE can "balance sheet" finance its investment in wind, which gives customers a weighted cost of capital that is very competitive compared to an IPP's, which typically has higher equity return requirements and higher debt costs due to increased leverage and a riskier business model. An IPP would also be more likely to use project finance structures that carry more risk for investors, translating into higher cost of debt. All else being equal, for two projects with the same overnight capital cost and capacity factor, customers would receive the lowest price from a project owner who has the lowest weighted cost of capital.
- As discussed more fully in the IRP at page 208, utility ownership of generation resources also offers the unique benefits to customers of long-term access and control of the project site. This benefit is particularly important in the case of renewable resources where the generation capability is tied to a specific location or natural resource.

PGE evaluated the criteria described above in deciding to invest in the Biglow project. NIPPC's reliance on what appears to be an incomplete cost metric is not sufficient to draw any reasonable conclusions regarding the cost competitiveness of IPP projects versus PGE developed and owned projects.

2. PPA business risk mitigation is situational and dependant on specific contract terms

NIPPC seems to suggest that PPAs universally provide business risk mitigation for a utility and its customers. NIPPC at 6-7.[21] We believe that this issue is more appropriately addressed in a competitive bidding docket and that the RFP process, as set-forth by the Commission in its Order 06-446, is the proper forum for evaluating the relative business risk properties of any specific contract or resource, whether PPA or utility-owned.

Notwithstanding our objection to raising this issue in IRP comments, we believe that NIPPC has overstated the potential business risk mitigation benefits of PPAs as compared to utility-owned generation. Whether a PPA provides business risk mitigation for the utility depends on the specific resource associated with the PPA and the terms and conditions of the contract. If a contract passes the specific operating characteristics of the plant on to the purchaser, any business risk mitigation is minimal. For example, if a PPA is unit-contingent and tied to a specific generator (as in the case of a unit-contingent, natural gas tolling contract), the utility would not be insulated from two of the largest risks associated with the plant – the risk of fuel price changes and availability, and the risk of replacement power supply in the event of an unplanned outage. PGE's Mid-C contracts are illustrative of PPAs that provide minimal business risk mitigation, as plant operations and costs are largely passed through to the purchasers. As further detailed below, it is also unlikely that an IPP plant owner would be willing to insulate a purchaser from large legal and environmental risks associated with a specific fuel or generator. However, in the case of a portfolio-based PPA or a firm contract with liquidated damages, some business risk mitigation may be provided, so long as the seller has the credit and financial strength to stand behind the commitments and obligations of the contract.

3. PPAs generally do not insulate purchasing utilities from the risk of plant closures

NIPPC makes the blanket statement that "early closure of Boardman – highlights very well that a PPA is generally less risky to ratepayers than a utility ownership model." NIPPC at 7. This statement is both overly broad and misleading. NIPPC also cites PGE's contract with the Centralia coal-fired power plant as an example of the risk mitigation that a PPA could potentially provide to a utility in the case of increased environmental regulation and costs associated with power generation. PGE disagrees with this position. NIPPC provides no specific evidence

[21] NIPPC states that because PGE did not address NIPPC's contention that PPAs lower a utilities risk in our August 10 Comments that we have somehow conceded this point. We have not. We noted on pages 37 and 38 of our August 10 Comments that many of the issues raised by NIPPC were more relevant to an RFP process and that we were responding only to those relevant to the IRP. Moreover, we stated in footnote 1 of the August 10 Comments that our silence on a particular point raised in the parties' initial comments should not necessarily be construed as a concession that the point is valid.

where an IPP plant operator has absorbed such risk and insulated a purchasing utility from the costs associated with a plant closure or major environmental retrofits as Boardman is currently facing.

Under unit-contingent or asset-specific mid-and long-term power contracts, purchasers are generally not insulated from the regulatory uncertainties currently facing Boardman. Unit contingent and asset-specific contracts where the delivery of power is tied to a specific generator (as opposed to a portfolio of assets) commonly contain provisions that excuse the seller from continued performance of the contract obligations if changes in future regulation or law either require a plant to cease operation or force major expenditures that would render continued plant operations uneconomic. This is precisely the risk facing PGE and Boardman currently, and it is a risk that an IPP seller would be unlikely to accept under a mid-to-long-term contract. It would indeed take a highly risk insensitive seller to enter into an agreement whereby they would be willing to insulate PGE from all regulatory and legal risks associated with power generation by agreeing to continue their contractual power delivery and price obligations even if a change in law or regulation required the plant to cease operations, or if the seller were forced to make significant new investments that rendered the plant uneconomic to operate under the terms of the PPA. Finding such an IPP seller or any entity to accept such uncontrollable, large-scale risks at any reasonable price is particularly unlikely in today's environment. In any event, assuming risk has a cost. If a developer takes on a risk, it will charge for it and likely charge a margin on top of it. The amount of the charge for this risk is only known if and when the final PPA is signed.

4. PGE has identified benchmark resources in accordance with Commission IRP Guidelines

NIPPC asserts that PGE plans to select (presumably as winning RFP bids) its Carty Generating Station and Port Westward II benchmark resources. NIPPC at 9. PGE has made no such claims or indications. As required in IRP Guideline 13, PGE identified these resources in its IRP as Benchmark Resources that we intend to include in a future RFP. We do so in order to ensure that market/IPP and utility, cost-based options are both available to customers. The fact that PGE has moved forward with early stage development and permitting for these potential generation projects does not bias PGE's future selection of resources in an RFP. Such development activities are necessary to determine if a project/site is viable for future construction, and whether the project would compete favorably against other generation alternatives in a competitive bidding process. Independent Power Producers also typically pursue early to mid-stage development activities for potential generation projects prior to submitting them in utility RFPs.

NIPPC also asserts that PGE's indication that the Cascade Crossing Transmission Project would still be needed under a Boardman early closure scenario provides further evidence of a bias for our benchmark generation resources. NIPPC at 8. Again, this is not correct. Our view that the Boardman site offers cost advantages for a potential replacement resource, and that the proposed Cascade Crossing transmission path runs through areas that are likely to see future development of renewable and/or thermal resources does not indicate a benchmark resource selection bias. It merely indicates that we believe that long-term operation of the Boardman Coal Plant is not a necessary condition for moving forward with the Cascade Crossing project.

NIPPC also recommends that the Commission order (or strongly suggest) that PGE solicit bids from IPPs for build-to-own replacement options at PGE sites in addition to other IPP offerings such as long-term PPAs. NIPPC at 8. A similar proposal was rejected by the Commission when it adopted its Competitive Bidding Guidelines. Order No. 06-446 at 5. NIPPC provides no evidence to indicate that such a requirement would benefit customers nor does it provide any rationale as to why the Commission should overturn its prior decision.

This, along with many of the other concerns raised in NIPPC's comments appear to be centered on providing an opportunity for IPP/market-based supply options to be considered and fairly evaluated for meeting the resource needs identified in PGE's proposed Resource Action Plan. We believe that the current Competitive Bidding guidelines address those concerns, and it is therefore not necessary for the Commission to further address the issues raised by NIPPC in this IRP docket.

5. Customers are best served when PPAs and self-build options are considered through the Commission's competitive bidding process

PGE believes that electric utility customers are best served by evaluating both wholesale, market-based supply options (PPAs), as well as utility cost-based, self-build alternatives for meeting current and future resource needs. NIPPC suggests that PGE should carve out a portion of its new resource requirements to be obtained exclusively from Independent Power Producers through PPAs. NIPPC at 9. NIPPC further indicates that "it could support a waiver request by PGE to proceed outside the Commission's RFP Guidelines with a specific amount of new gas-fired thermal capacity provided that amount did not exceed 40 percent of its total thermal resource acquisition requirements." NIPPC at 9. This would be done presumably to carve out a portion of new resource requirements to be met through utility, self-build options. NIPPC provides no evidence or persuasive arguments that doing so would serve the interests of PGE customers. Such a proposal, if pursued, would potentially deny PGE customers the alternative of considering market based supply options for a portion of our resource needs, and simultaneously deny customers the ability to consider a cost-based, utility-owned option for the remaining portion of our resource needs. It is not clear how such a proposal that inherently limits competitive bidding and RFP supply choices could possibly benefit PGE customers.

While unique circumstances or opportunities may require a utility to deviate from the standard competitive bidding process, PGE believes that the Commission's IRP and RFP guidelines provide a solid framework for ensuring that both IPP and utility-owned options are available to customers, and fairly evaluated and selected, while also providing the flexibility to react to unique opportunities and circumstances when necessary.

VIII. Fuel Emissions

A. PGE considers CO_2 emissions from all sources used to meet load

Sierra's belief that PGE would have the Commission focus only on the CO_2 emissions from its individually-owned or jointly-owned units is mistaken. Sierra, Exh 1 at 23. With the exception of a graph included in our August 10 Comments for the purpose of correcting a misstatement by Sierra, all figures, graphs and commentary in PGE's IRP filings include all emissions from all sources, including owned resources, contracts and net market purchases. This methodology is as described on page 273 of PGE's 2009 IRP.

Sierra cites a graph on page 42 of PGE's Reply Comments as evidence that we focus only on emissions from individually or jointly-owned units. This graph was used to correct Sierra's "apples to oranges" calculation of CO_2 emissions growth. *See*, Sierra, Exh 1 at 5. Sierra's growth rate was calculated off a base that included *only* PGE's generating resources, which it was comparing to future emissions that included all sources. In order to correctly calculate a growth rate, one has to start with a base that is consistent with the future being measured.

Further, Sierra's assertion that PGE "claims that its CO_2 emissions will be decreasing through 2030" is simply not correct. Sierra Exh.1 at 23. At the bottom of page 41 of the August 10 Comments, PGE clearly states that "the 2030 CO_2 emissions *from PGE-owned generation* are lower than 2007 emissions in all cases".

PGE agrees with Sierra that focusing only on the CO_2 emissions from company-owned units will be misleading, which is why PGE doesn't take that approach in its IRP, except to correct Sierra's mistake. PGE's figure on page 43, along with verbiage on page 42, clearly represents the growth in CO_2 emissions, including all sources, along with load growth.

IX. Portfolio and Risk Analytics Considerations

A. PGE's LOLP analysis does not reflect the reliability risk of the DEQ 2015 option

Sierra observes that the results of our Loss of Load Probability (LOLP) analysis appear to slightly favor earlier Boardman closures. Sierra Exh 1 at 24. Sierra is correct in its observation. However, this shortcoming also inadvertently provides an advantage to the DEQ 2015 proposal in our scoring.

For purposes of modeling the 2018 and 2020 closures, we assumed a new CCCT replacement resource could be in place, with its associated forced outage rate (FOR). This FOR is somewhat lower than what we assume for Boardman. Hence, results between different closure options are indeed similar and the 2018 and 2020 closures perform well, as we would expect.

However, for modeling convenience and consistency on the cost side of our analysis, we also assumed that a CCCT was in place for the DEQ 2015 option. Had we instead assumed reliance on the spot market (for up to two years), then the DEQ 2015 option would not have received the top score in this metric. This portfolio thus received an unintended advantage from this reliability metric. Elsewhere in these Comments, we address both the timeline to construct a replacement resource and the difficulties of obtaining a PPA in the 2015/16 time frame with its attendant reliability risk of relying on the spot market. Our comments about reliability risk with the DEQ 2015 option are based on the difficulty of obtaining reliable replacement power in this time frame.

Some context may also be useful. This reliability metric is a composite for the years 2012-2020, plus 2025, which tends to mask the seriousness of one large event (or several smaller events) in a given year within that period.

B. PGE's risk metrics measure carbon risk

With regard to CO_2 risk, NWEC and the Joint Parties assert that "by averaging portfolio scores of high and low carbon cost scenarios, PGE's risk metric essentially cancels out carbon risk." NEWC at 2; Joint Parties at 2. As detailed below, this is not the case.

Consistent with the Commission's IRP Guidelines, we performed sensitivity or scenario analysis on futures that have both higher and lower CO_2 costs.[22] In addition, we provided sensitivities for start years that are one year earlier and one year later. We, in fact, employ two deterministic risk metrics that capture the risk for both varying CO_2 costs and start years, among other risks. Neither metric simply adds results together for high and low CO_2 futures nor averages portfolio scores of high and low carbon cost scenarios.

One metric ranks portfolio performance based on risk exposure to the four worst futures. IRP at 257. For all portfolios, the worst futures have either high CO_2 prices, high gas prices, or a combination. Specifically, for the BART III portfolio, two of the four worst futures have high CO_2 prices. For our Diversified Thermal with Green 2040 portfolio, where CO_2 exposure continues another 20 years, three of the four worst futures are driven by CO_2 costs. That CO_2 is a driver to the outcome of this metric is evident from the chart on page 31 of PGE's August 23 Technical Workshop, which shows the best performing portfolios to be, in order, "Oregon CO_2 Goal", "Wind", and "Bridge to Nuclear.".

The other metric focuses on comparative portfolio robustness. IRP at 261. Here we both screen out portfolios that perform poorly under all the futures and recognize portfolios that perform well regardless of the future. We then combine these two results to present, in effect, a joint robustness probability of a given portfolio both avoiding bad outcomes and achieving good outcomes. Contrary to what is suggested, there is no portfolio in this analysis that simultaneously performs particularly well and particularly poorly such that a joint probability cancels out the results. While CO_2 is not isolated under this metric, it is certainly one of the primary drivers. Looking at the outcome of this metric, it is striking that the best performing portfolios are the lower cost early Boardman closure scenarios (BART II, BART III, and DEQ 2018) – portfolios that avoid longer-term CO_2 exposure. *Id.* at 33. Conversely, the worst performing portfolio is "Bridge to IGCC in Wy", which is the portfolio that adds a new coal plant.

NWEC recommends that in the future, the Commission should "make addressing the state's carbon reduction goals a critical and well-vetted component of portfolio testing and include a risk metric that measures CO_2 emissions directly." NWEC at 2.

[22] We use the same approach for natural gas prices and loads, but no one has asserted that we have no risk metric for these.

The first part of the NWEC's recommendation is addressed in Commission IRP Guideline 8 which specifically calls for modeling an "Oregon Compliance Portfolio". The second part of NWEC's recommendation, apparently suggests a stand-alone metric designed to look solely at CO_2 risk. Our interpretation of the Commission's IRP Guidelines 1 and 8 is that utilities need to factor in their analysis the *cost* of environmental compliance, not the physical level of environmental emissions. We believe that NWEC's request is better addressed by performing a separate CO_2 analysis of our portfolios, as we did in our IRP. *See,* IRP at 272-278. We also note that we have six futures that are designed to capture the impact of CO_2 risk; five of these adjust solely for CO_2 price. But we have many other risks to consider when looking at risk metrics. Trying to compartmentalize different sources of risk into separate metrics is problematic for two reasons:

1. If we employ a CO_2-specific risk cost metric, we'd need to do the same for natural gas prices and for several other uncertain inputs. This in turns creates the issue of how to weight or evaluate the importance of one metric against another. For instance, should natural gas price risk have more or less weight than CO_2 price risk? Under the current approach, these risks are quantified into a common unit – NPVRR dollars.
2. Isolating one risk component may miss the interplay between risks.

We believe, and current Guidelines seem to confirm, that, where possible, risk measures should examine deterministic risks to the portfolios *as a whole*.

C. Qualitative criteria need to be considered

NWEC is disturbed by PGE's use of decision criteria such as near-term rate impacts, market exposure risk, inadequate resource replacement time, and employee and community transition time, which are not part of our quantitative scoring. NWEC at 3. PGE has attempted to quantify risks and impacts that lend themselves to quantification and include those in scoring. Other items, such as those listed above (and execution risk), don't lend themselves well to quantification. They are, however, real factors that should be considered in major business decisions. Any business decision is going to be a mix of quantitative and qualitative factors.

D. PGE employs a reliability metric consistent with Commission guidance

NWEC asserts that our reliability metric is independent of the IRP portfolios and cites to page 79 of the IRP Addendum as support for its contention. Page 79 of the IRP Addendum presents a capacity adequacy sensitivity, which is indeed independent of the portfolios. But this was an adequacy sensitivity and does not serve as the basis for the reliability metric we employed. The reliability metric instead assesses 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. *See,* IRP at 245-247. For instance, our "Market" portfolio performs very poorly when assessing reliability although it does particularly well from an expected cost perspective. NWEC may be thinking back to our 2007 IRP, where PGE had understood the Guidelines to mean that solely a capacity adequacy sensitivity should be presented. The Order for that IRP clarified that the purpose of doing a reliability study was to inform the difference between differing portfolios from a reliability perspective, as in the "Market" example above. *See*, Order 08-246 at 20.

E. Optimization

PGE appreciates NWEC's clarifying comments regarding optimization. NWEC at 7. Rather than a blind optimization procedure based on only a single objective function, NWEC is suggesting a much more practical approach wherein we learn from good attributes that emerge from pure play portfolios. This may be a point worth considering further in our next IRP.

In particular, NWEC states that "two factors in the portfolios tested were found to be beneficial in reducing costs and risks, so it would be worthwhile to modify PGE's winning portfolios to reflect those results." *Id.* We believe the two factors being referred to are: 1) more reliance on a short strategy with dependence on short-term markets; and 2) more wind. *See*, NWEC initial comments at 13-14. A practical limitation remains the ability to change portfolio compositions based on the lumpiness of certain resource acquisitions, such as a CCCT. Further, we do not necessarily agree with the proposition that either a longer short position or more wind results in both reduced costs and reduced risks. When looking at risk vs. cost in our analysis (see, for instance, the efficient frontier chart on page 256 of PGE's IRP Addendum), we see that more wind does reduce risk, at the expense of higher cost. Conversely, a market position decreases cost but increases both cost and reliability risks.

F. While HHI differences are not large they are informative

Sierra restates their earlier complaint that the HHI differences are not large enough to use in comparing portfolios. We disagree. While the differences are small they are informative. The technological value is the same in the DEQ options due to the portfolio construction and the timing. We replace Boardman with another base-load resource, i.e., a gas plant and measure the Technological HHI in 2021. The date for measuring is due to the completion of the Boardman replacement.

The relative closeness of the Fuel HHI for the DEQ options is similarly due to replacing a base-load resource with another baseload resource. Again, while these values may be close they are still indicative of relative concentration levels of resources. As we stated previously we believe a more diverse portfolio is better that a less diverse portfolio, all else being equal.

G. Use of statistics in deterministic modeling

PGE appreciates NWEC's confirmation that they "do not challenge the idea that scenario analysis is much more important than stochastic analysis for the purposes of the IRP." NWEC at 7. We also note its supportive comment that questions the value of stochastic analysis for CO_2 prices, although we disagree with the reason given. Contrary to NWEC's contention, PGE's deterministic analysis does not "average high and low carbon cost futures in a way that makes carbon risk disappear" *See,* NWEC at 7; Joint Parties at 3. The risk metric that PGE employs in its deterministic analysis is a TailVar concept (not an averaging concept). The TailVar measure assesses the impact of the variation of one or more inputs relative to the reference case input.

Likewise, if CO_2 prices were assigned a distribution in the stochastic analysis, the risk associated with the CO_2 price uncertainty would not be masked by averaging, because the stochastic analysis also considers tail events.[23]

NWEC persists in recommending that stochastic analysis be applied "to provide the margins of error, or confidence limits, that inform deterministic analysis." NWEC at 7. We reiterate that applying statistical tests to a deterministic futures analysis is not appropriate because the cost differences between scenarios are structural and not stochastic. For example, consider two portfolios; one that emphasizes new CCCTs and a second that emphasizes new wind. Further, assume that alternative futures for these two portfolios are constructed with (1) reference case natural gas prices and (2) $1 per mmbtu lower natural gas prices (due to a fundamentals-based supply-demand shift for gas). The cost reduction resulting from the fall in gas prices will be greater for the CCCT portfolio than for the wind portfolio. But the reduced cost of the CCCT portfolio relative to the wind portfolio has nothing to do with the volatility of natural gas prices -- it is driven by an assumed cost reduction. That is, if the low gas price future comes to pass, the cost differences between scenarios will be realized (other things equal). Nor does innate volatility in gas prices help inform whether structural supply/demand changes are meaningful. Scenario (or "Futures") analysis is an exercise in *comparative statics*, a standard approach in economic analysis that provides meaningful results that stand on their own merits.

Since in the deterministic analysis the portfolio futures do not occur in the study as the result of some random sampling of a population of possible futures, it is inappropriate to conduct a statistical significance test on the differences in the mean costs. Hence, whether the differences in the cost reductions are *material* or meaningful is a matter for business judgment relative to overall *incremental* costs of the proposed new portfolio actions.[24] It follows that statistically-derived confidence intervals and margins of error have no place in deterministic scenario analysis. Thus, NWEC recommendations 4(a) and 4(b) are not appropriate.

H. PGE has always focused on meeting average annual energy targets in its IRP planning. There has been no strategy change

NWEC asserts that about 350aMW of our need is due to a strategic decision to reduce our exposure to the market. NWEC at 5. This is simply untrue. PGE's IRP has always focused on meeting average annual energy targets. For example in our 2007 IRP, Appendix A, page 3 we explain:

> We compute the energy balance in this IRP as the difference between the energy capability of our resources (plants, contracts and purchases) and the annual average load

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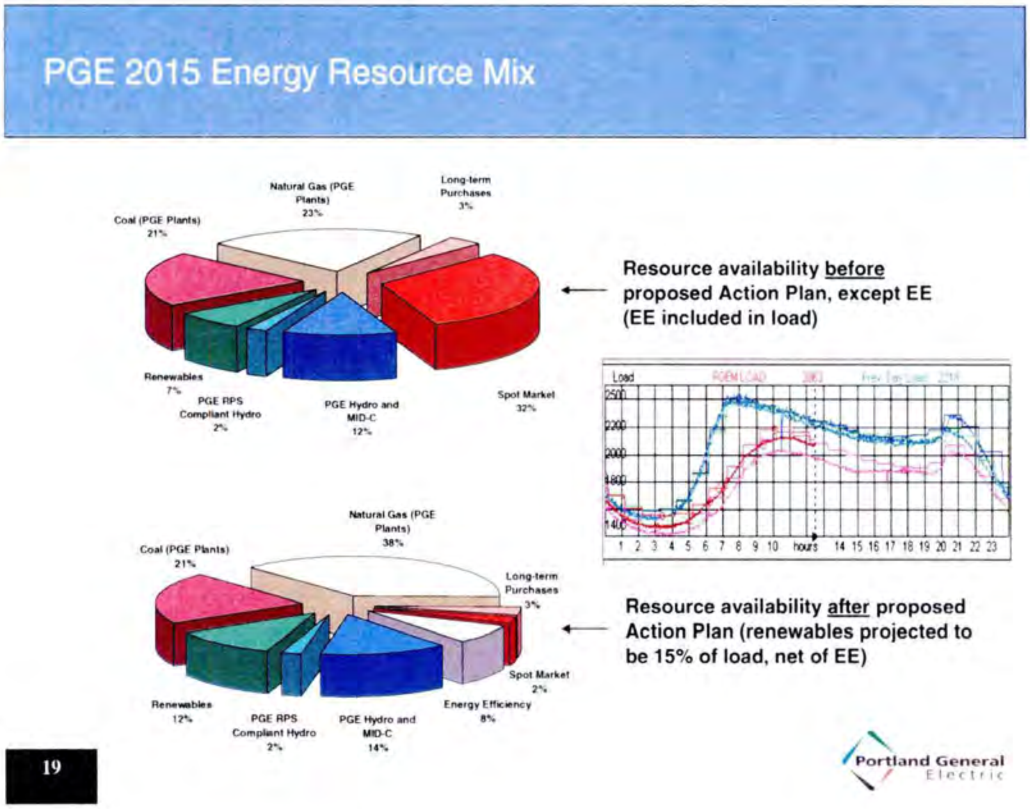
[23] While carbon costs get picked on (so as to favor prospects for an early Boardman closure), it is interesting that we have not seen a similar suggestion that high and low gas prices are averaged in a way so as to make gas price risk disappear, although the methodology for this and other futures is the same as for CO_2 costs.

[24] Using NWEC's example, it seems intuitive that a $500 MM difference on a $5 billion portfolio will be seen as more material to a decision-maker than a $500 MM difference on a $50 billion portfolio base. Beyond PGE's deterministic analysis, this is also recognized where statistical applications are appropriate. For instance, the Wikipedia article on "Coefficient of Variation", a metric in which a standard deviation is divided into its mean, adds: "The coefficient of variation is useful because the standard deviation of data must always be understood in the context of the mean of the data."

under normal weather and hydro conditions. Our candidate energy & capacity action plans identify resources needed to bridge this gap.

NWEC cites to the following slide from PGE's April 26 2010 presentation to the Commission (shown below) as proof of our changed metric.



This slide however simply shows PGE's resource mix, both before and after our proposed Action Plan, it is not indicative of a strategy change. The upper graph is the equivalent of our Market (or do-nothing) portfolio. NWEC is simply confused. Compounding its error, NWEC states, "without much discussion and no analysis, PGE changed its position on market exposure." page 9. As mentioned above, PGE did not change its planning metric. Moreover, the IRP does analyze a do-nothing approach versus other options. Our Market portfolio compares favorably on some metrics (cost), less favorably on other (reliability).

X. Conclusion

PGE appreciates the parties' comments and their involvement in our IRP process. As described above and in our other filings submitted in this docket, we believe that our 2009 IRP fully complies with the Commission's IRP Guidelines and that our Action Plan provides the best combination of expected costs and associated risks and uncertainties for our customers. We respectfully request that the Commission acknowledge our IRP and Action Plan.

Respectfully Submitted,

V. Denise Saunders
Assistant General Counsel
Portland General Electric Company

APPENDIX A

PARTIES	ABBREVIATION
Citizens' Utility Board, Renewable Northwest Project, NW Energy Coalition, Oregon Environmental Council, Angus Duncan, Ecumenical Ministries of Oregon, Sierra Club, and Northwest Environmental Defense Center	Joint Parties
Ecumenical Ministries of Oregon	EMO
Northwest Energy Coalition	NWEC
Northwest & Intermountain Power Producers Coalition	NIPPC
Pareto Energy	Pareto
Renewable Northwest Project	RNP
Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge & Northwest Environmental Defense Center	Sierra
Willard Rural Association	Willard

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PGE's 2009 Integrated Resource Plan

Attachment A

PGE's Reply to Intervenors' Response Comments

BLACK & VEATCH
Building a world of difference.

Portland General Electric
Combined Cycle Plant Schedule

B&V Project 162110
B&V File 14.0100
September 23, 2010

Portland General Electric
121 S.W. Salmon Street
Portland, OR 97204

Attn: Mr. Jaisen Mody

Subject: Combined Cycle Plant Schedule

Gentlemen:

This letter is in response to your request for information with respect to the schedule or timeline to permit, design, construct and commission a combined cycle plant.

From the initial decision to pursue additional generation facilities, there are two activities that will typically occur in series that determine the time from the decision to pursue additional generation to being able to dispatch power to support load.

The first activity is planning and permitting and includes the identification of a site, the determination of the technology which best meets the power needs, and the securing of the required permits to construct and operate the plant. In PGE's case this also requires demonstrating the need for the additional power through an approved Integrated Resource Plan (IRP), deciding to pursue a self build option, and proving through a competitively bid Request for Power (RFP) solicitation process that PGE is the low cost provider.

The IRP and RFP processes can occur in parallel with the permitting process. From PGE's past experience this IRP and RFP process can be expected to take approximately 2 years. Therefore the overall duration for the first activity including the site and technology selection is approximately 2.5 years.

The second activity involves the time from a decision to build to achieving commercial operation. This activity includes the following:

1. A duration of 6 months for preparation of specifications for the major power island equipment, receipt of bids, and bid evaluation.
2. Duration from order to delivery for large high efficiency combustion turbine units of 20 to 24 months (currently). HRSGs and steam turbines can be ordered and delivered in generally the same time frame.
3. A duration of 9 to 10 months from receipt of the combustion turbine at site to first fire. This includes erection, checkout, and lube oil flush.
4. A duration of 4 to 5 months from first fire to planned commercial operation. This includes steam blow to clean the steam piping, plant tuning and commissioning of the steam cycle, and performing the necessary tests to demonstrate the plant operates as specified. This duration depends on the complexity of the plant and the amount of testing required.
5. A duration of 2 to 3 months as margin between planned and guaranteed commercial operation. For an EPC contractor this margin is required to account for unforeseen events which can occur

during design, procurement, construction, and commissioning. This duration is dependent on the complexity of the project and the level of penalties imposed for not meeting the commercial operation date. Even if PGE elects to accept more risk and issue individual contracts for design, equipment, and construction, an equivalent margin should be applied to obtain a guaranteed completion date.

Based on the above an overall duration from decision to build to guaranteed commercial operation should allow 42 to 48 months.

The critical path for this second activity currently runs through delivery of the combustion turbine, and based on current market conditions, the duration from order to delivery for a large combustion turbine is 20 to 24 months. PGE should plan on a potential increase in this duration if the number of orders for new combustion turbines increases by the time PGE is in a position to place an order. It is also possible that the duration from order to delivery for steam turbines or HRSGs could also increase and the steam turbine or HRSG become the critical path to completion. Longer lead times for any necessary components could result in an overall increase in the time required from a decision to build to achieving commercial operation. Market conditions and available manufacture capacity will dictate the time from order to receipt of equipment.

The lower risk approach would be to complete the first activity (2.5 years) before starting the second activity (3.5 to 4.0 years). This would result in an overall schedule duration of 6 to 6.5 years. It is not necessary to complete the first activity before starting the second, and depending on how confident PGE is with respect to receiving all necessary permits and/or being selected the most economical bidder in response to the RFP process, the second activity could start before the first activity completes. Starting the bid and evaluation process for the combustion turbine before the first activity completes has the potential to reduce the overall schedule duration by six months to 5.5 to 6 years. Further reduction in the schedule is possible by placing the order for the combustion turbine before PGE is selected as the most economical provider in the RFP process, however PGE would incur significantly more risk as there is a substantial penalty associated with a canceled combustion turbine order.

Black & Veatch is a leading engineering and construction company with extensive experience in design and construction of power generating facilities. We have been involved in the design and/or construction of more than 100 combined cycle projects producing over 50,000 MW. These projects include many in the United States, including four with respect to the Pacific Northwest. Black & Veatch also provides support services to clients in selection of sites and permitting new facilities.

Please contact me if further details with respect to the typical schedule requirements for a combined cycle project.

Very Truly Yours,
BLACK & VEATCH

Jim Gettinger

Jim Gettinger
Project Manager and Associate Vice President

JEG

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PGE's 2009 Integrated Resource Plan

Attachment B

PGE's Reply to Intervenors' Response Comments

Portfolio Analysis Results

Net present value of revenue requirements 2010-2040 ($2009 millions)

Portfolio ->>	1	2	3	4	5	6	7	8	9
	Market	Natural Gas	Wind	Diversified Green	Diversified Thermal with Wind	Bridge to IGCC in WY	Bridge to Nuclear	Green w/ On-peak Energy Target	Diversified Thermal with Green
Reference Case	$27,211	$29,027	$29,288	$28,987	$28,891	$32,735	$29,853	$28,971	$28,674
High Gas	$34,213	$35,970	$34,181	$34,067	$35,312	$37,642	$34,707	$34,011	$35,310
Low Gas	$23,524	$25,099	$26,597	$26,201	$25,342	$29,986	$27,260	$26,087	$25,012
CO2 $45 per ton	$29,302	$30,956	$30,866	$30,618	$30,760	$35,144	$31,289	$30,528	$30,606
CO2 $65 per ton	$32,183	$33,520	$32,980	$32,809	$33,264	$38,270	$33,234	$32,576	$33,200
No CO2	$23,024	$24,945	$25,998	$25,595	$25,004	$27,757	$26,956	$25,626	$24,672
CO2 $20 per ton	$25,825	$27,707	$28,222	$27,885	$27,626	$31,106	$28,909	$27,900	$27,368
High Capital Costs	$27,419	$29,340	$30,062	$29,710	$29,314	$33,749	$34,063	$29,665	$29,046
High PGE Load Growth	$30,410	$32,225	$32,487	$32,186	$32,090	$35,934	$33,052	$32,170	$31,873
Low PGE load growth	$24,867	$26,682	$26,944	$26,642	$26,547	$30,390	$27,508	$26,626	$26,329
High Electricity Prices	$39,882	$25,266	$21,997	$24,158	$26,348	$32,046	$28,547	$22,576	$27,853
Low Electricity Prices	$19,054	$21,452	$23,716	$23,110	$21,748	$26,010	$24,748	$23,396	$21,201
No Incentives	$27,678	$29,493	$30,841	$30,658	$29,698	$33,205	$30,322	$30,642	$29,356
50 percent incentives	$27,445	$29,260	$30,065	$29,823	$29,295	$32,970	$30,088	$29,807	$29,015
Low Coal-High Gas-$65 CO2	$38,340	$40,028	$37,302	$37,302	$39,129	$42,693	$37,447	$37,218	$39,257
CO2 Start 1 year later	$26,951	$28,775	$29,064	$28,759	$28,645	$32,455	$29,631	$28,747	$28,424
CO2 Start 1 year earlier	$27,477	$29,289	$29,522	$29,224	$29,147	$33,024	$30,087	$29,206	$28,933
CO2 $12 per ton	$24,738	$26,648	$27,372	$27,009	$26,618	$29,801	$28,162	$27,036	$26,330
Aggressive EE	$26,600	$28,416	$28,677	$28,376	$28,281	$32,124	$29,242	$28,360	$28,063
Major Resources 1 Year Earlier	$27,209	$29,144	$29,518	$29,160	$29,021	$33,025	$29,893	$29,132	$28,775
Major Resources 1 Year Later	$27,212	$28,916	$29,083	$28,831	$28,771	$32,474	$29,673	$28,826	$28,577

Portfolio Analysis Results – cont.

Net present value of revenue requirements 2010-2040 ($2009 millions)

Portfolio ->>	10	11	12	13	14	15	16	17	18
	Boardman through 2014	Oregon CO2 Goal	PGE 2020 BART II	Diversified Green with wind in WY	Diversified Thermal w/ Green w/o lease	DEQ 2020 (Option 1)	DEQ 2018 (Option 2)	DEQ 2015 (Option 3)	PGE 2020 BART III
Reference Case	28,593	$30,375	$28,396	$30,828	$28,668	$28,758	$28,521	$28,546	$28,499
High Gas	$36,175	$35,006	$35,551	$35,946	$35,231	$35,971	$35,856	$36,036	$35,694
Low Gas	$24,517	$28,141	$24,532	$28,002	$24,958	$24,845	$24,560	$24,524	$24,590
CO2 $45 per ton	$30,293	$31,150	$30,152	$32,468	$30,575	$30,517	$30,274	$30,266	$30,261
CO2 $65 per ton	$32,596	$32,296	$32,544	$34,658	$33,142	$32,884	$32,628	$32,584	$32,622
No CO2	$25,281	$29,107	$24,952	$27,414	$24,755	$25,321	$25,113	$25,205	$25,062
CO2 $20 per ton	$27,470	$29,917	$27,227	$29,717	$27,369	$27,594	$27,374	$27,419	$27,338
High Capital Costs	$29,002	$34,993	$28,796	$31,735	$29,053	$29,158	$28,925	$28,953	$28,898
High PGE Load Growth	$31,792	$33,574	$31,595	$34,026	$31,867	$31,956	$31,719	$31,743	$31,696
Low PGE load growth	$26,248	$28,030	$26,051	$28,483	$26,323	$26,415	$26,178	$26,202	$26,155
High Electricity Prices	$26,400	$23,541	$25,554	$26,141	$27,477	$25,930	$25,860	$26,130	$25,654
Low Electricity Prices	$21,109	$26,914	$21,120	$24,822	$21,147	$21,399	$21,122	$21,115	$21,143
No Incentives	$29,275	$32,046	$29,078	$32,488	$29,350	$29,440	$29,203	$29,228	$29,181
50 percent incentives	$28,934	$31,211	$28,737	$31,658	$29,009	$29,099	$28,863	$28,887	$28,840
Low Coal-High Gas-$65 CO2	$39,942	$36,455	$39,389	$39,217	$39,323	$39,769	$39,664	$39,815	$39,491
CO2 Start 1 year later	$28,367	$30,206	$28,162	$30,597	$28,423	$28,518	$28,291	$28,321	$28,265
CO2 Start 1 year earlier	$28,832	$30,560	$28,642	$31,066	$28,923	$29,003	$28,766	$28,787	$28,746
CO2 $12 per ton	$26,588	$29,574	$26,309	$28,835	$26,340	$26,693	$26,472	$26,525	$26,429
Aggressive EE	$27,982	$29,764	$27,785	$30,217	$28,057	$28,148	$27,911	$27,935	$27,888
Major Resources 1 Year Earlier	$28,741	$30,707	$28,493	$31,102	$28,781	$28,856	$28,664	$28,642	$28,597
Major Resources 1 Year Later	$28,453	$30,079	$28,268	$30,574	$28,562	$28,662	$28,392	$28,462	$28,409

Portland General Electric

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Attachment C

PGE's Reply to Intervenors' Response Comments

PGE
Portland General Electric

This posting reflects the requirements of FERC Order 2003 for Large Generator Interconnection Procedures.

September 1, 2010

Active - Generator Interconnection Request Queue

Queue Number	Status	Request Date	Service Type (NR or ER)	Max Summer MW Output	Max Winter MW Output	Location	Interconnection Facility	Requested In-Service Date	Projected In-Service Date	Facility Type (combined cycle, coal, CT, ST, fuel type)	Comments
07-019 *	System Impact Re-Study	September 4, 2007	NR	385	385	Boardman, OR	Boardman Generation Plant Site	December 2012	June 2015	Coal	Completed SIS on 7/26/2010
07-020 *	System Impact Re-Study	September 4, 2007	NR	200	256	Coyote Springs, Boardman, OR	Coyote Springs Switchyard Site	December 2012	June 2015	Combined Cycle, NG	Completed SIS on 7/26/2010
07-025 *	LGIA signed	October 9, 2007	NR	200	200	Clatskanie, OR	PGE Beaver Generation Site	December 2011	June 2013	Gas	
08-030 *	System Impact Re-Study	May 12, 2008	NR	392	450	Boardman, OR	Boardman Generation Plant Site	June 2013	June 2015	Combined Cycle, CT	Completed SIS on 7/26/2010
08-032	SIS completed	September 15, 2008	ER	200	200	Vicinity of Ringling MT	Colstrip 500kV Transmission Line	December 2013	December 2013	Wind	
09-033 *	System Impact Study	January 5, 2009	NR	200	200	Vicinity of Maupin, OR	A new location on/near the Warm Springs Reservation	June 2013	June 2015	Wind	
09-034	Facilities Study	April 20, 2009	NR	18.5	18.5	Round Butte, OR	Round Butte 230kV Substation	January 2012	January 2012	ST Biomass	
09-035	System Impact Study	July 9, 2009	ER	401.4	401.4	Vicinity of Arlington,OR	Vicinity of Arlington, Oregon	March 2013	June 2015	Wind	
10-036	Feasibility Study	April 20, 2010	ER/NR	600	600	Wasco, OR	Vicinity of Wasco, Oregon	December 2014	June 2015	Wind	
10-037	Scoping Meeting	August 20, 2010	ER/NR	500	500	Gilliam County, OR	Vicinity of Gilliam County, Oregon	2015	June 2015	Wind	

PGE retains all studies for five years and will provide copies upon request, subject to PGE's CEII Procedures

*** These requests are from PGE's Power Operations Department (merchant function).**

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PGE's 2009 Integrated Resource Plan

Attachment D

PGE's Reply to Intervenors' Response Comments

Transmission Services

Long-Term Firm Available Transfer Capability (ATC)

Updated: 08/16/10

BPA Transmission Services determines Long-Term Firm (LTF) Available Transfer Capability (ATC) values assuming all lines are and will be in service. The firm ATC values currently posted on the BPA Transmission Services OASIS site include Total Transfer Capability (TTC) reductions for planned outages. These TTC reductions do not affect LTF ATC. As a result, the LTF ATC and TTC values posted on OASIS are lower than actual values used in LTF ATC evaluations. The Short-Term Firm ATC and TTC values posted on OASIS are accurate.

Until such time as BPA Transmission Services is able to post accurate LTF ATC on OASIS, the accurate LTF ATC and TTC values are posted on this spreadsheet.

			LONG-TERM FIRM AVAILABLE TRANSFER CAPABILITY (ATC)									
PATH NAME	**TTC (MW)**	**OFFER PRICE**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
South of Allston	2,052	1298.0000 (MW - Month)	0	0	0	0	0	0	0	0	0	0
Cascades North	9,900	1298.0000 (MW - Month)	958	906	752	716	706	700	681	631	564	531
Cascades South	7,700	1298.0000 (MW - Month)	1,102	979	1,033	950	910	875	840	780	741	674
Monroe-Echo Lake	1,500	1298.0000 (MW - Month)	378	294	313	314	309	307	309	304	300	296
North of Hanford	4,100	1298.0000 (MW - Month)	1,579	1,624	1,791	1,804	1,783	1,770	1,788	1,754	1,720	1,699
North of John Day	7,800	1298.0000 (MW - Month)	1,126	1,096	1,284	1,313	1,274	1,244	1,268	1,213	1,136	1,096
Paul-Allston	2,250	1298.0000 (MW - Month)	244	281	342	345	334	325	325	313	298	287
Raver-Paul	1,625	1298.0000 (MW - Month)	401	364	406	400	388	378	375	359	339	327
West of McNary	2,870	1298.0000 (MW - Month)	332	388	394	372	399	383	398	389	401	372
West of Slatt	4,100	1298.0000 (MW - Month)	177	249	238	274	267	265	289	281	268	261
John Day - COB	2,551	1293.0000 (MW - Month)	0	0	0	0	0	0	0	0	0	0
COB - John Day	1,442	1293.0000 (MW - Month)	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371
Big Eddy - NOB	2,621	1293.0000 (MW - Month)	0	0	0	0	0	0	0	0	15	15
NOB - Big Eddy	1,837	1293.0000 (MW - Month)	1,637	1,637	1,637	1,637	1,637	1,637	1,637	1,637	1,637	1,637
BCHA - BPAT	1,335	1298.0000 (MW - Month)	350	350	350	350	350	350	350	350	350	350
BPAT - BCHA	1221 - 1472	1298.0000 (MW - Month)	0	0	0	0	0	0	0	0	0	0
West of Garrison E>W	1,618	1298.0000 (MW - Month)	59	59	59	59	59	59	59	59	9	9
West of Garrison W>E	931	1298.0000 (MW - Month)	467	447	428	415	405	399	389	369	362	326
IPCO - BPAT	413	1298.0000 (MW - Month)	122	10	10	10	10	10	10	10	10	10
BPAT - IPCO	350	1298.0000 (MW - Month)	0	0	0	0	0	0	0	0	0	0
Malin230 - Hilltop345	300	1298.0000 (MW - Month)	195	187	181	180	181	181	181	181	181	181
Hilltop345 - Malin230	300	1298.0000 (MW - Month)	290	290	230	230	230	230	230	230	230	230
Montana Intertie E>W	185	1312.0000 (MW - Month)	169	169	169	169	169	169	169	169	169	169
Hatwai E>W	3,650	1298.0000 (MW - Month)	202	120	115	125	135	145	155	155	105	105
Projected Upgrade ATC (Target Start Date 10/1/2011)												
John Day - COB	2,825	1293.0000 (MW - Month)	0	0	0	0	0	0	0	0	0	0
Big Eddy - NOB	2,890	1293.0000 (MW - Month)	0	0	0	0	0	0	0	0	0	0
Conditional Firm Inventory												
South of Allston	2,051	1298.0000 (MW - Month)	226	226	226	226	226	226	226	226	226	226
Cascades North	10,450	1298.0000 (MW - Month)	932	932	932	932	932	932	932	932	932	932
Cascades South	8,500	1298.0000 (MW - Month)	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005
Monroe-Echo Lake	1,500	1298.0000 (MW - Month)	0	0	0	0	0	0	0	0	0	0
North of Hanford	4,100	1298.0000 (MW - Month)	371	371	371	371	371	371	371	371	371	371
North of John Day	7,800	1298.0000 (MW - Month)	557	557	557	557	557	557	557	557	557	557
Paul-Allston	2,250	1298.0000 (MW - Month)	425	425	425	425	425	425	425	425	425	425
Raver-Paul	1,625	1298.0000 (MW - Month)	247	247	247	247	247	247	247	247	247	247
West of McNary	2,870	1298.0000 (MW - Month)	418	418	418	418	418	418	418	418	418	418
West of Slatt	4,100	1298.0000 (MW - Month)	264	264	253	253	253	253	253	253	253	253

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PGE's 2009 Integrated Resource Plan

Attachment E

PGE's Reply to Intervenors' Response Comments

LC-48
PGE Response to PEAC Data Request No. 111
Attachment 111-B

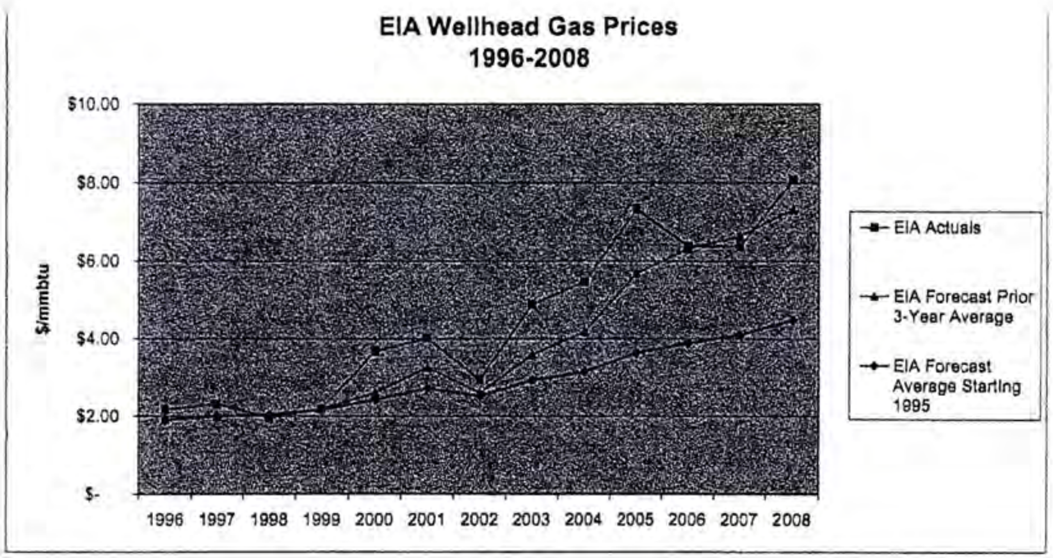
Natural Gas Price Forecast, EIA AEO since 1982

	Forecasted period	Real Lev. $2009	Nominal $ 1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
AEO 1982	1985-1990	$9.90	$ 4.32	$ 5.47	$ 6.67	$ 7.51	$ 8.04	$ 8.57											
AEO 1983	1985-1995	$8.44	$ 2.93	$ 3.11	$ 3.46	$ 3.93	$ 4.56	$ 5.26	$ 6.75	$ 8.25	$ 9.74	$ 11.24	$ 12.74						
AEO 1984	1985-1996	$7.06	$ 2.77	$ 2.90	$ 3.21	$ 3.63	$ 4.13	$ 4.79	$ 5.70	$ 6.60	$ 7.51	$ 8.42	$ 9.33						
AEO 1985	1985-1997	$5.21	$ 2.60	$ 2.61	$ 2.66	$ 2.71	$ 2.94	$ 3.35	$ 3.85	$ 4.46	$ 5.10	$ 5.83	$ 6.67						
AEO 1986	1986-2000	$5.94		$ 1.73	$ 1.96	$ 2.29	$ 2.54	$ 2.81	$ 3.15	$ 3.73	$ 4.34	$ 5.06	$ 5.90	$ 6.79	$ 7.70	$ 8.62	$ 9.68	$ 10.80	
AEO 1987	1987-2000	$4.66			$ 1.83	$ 1.95	$ 2.11	$ 2.28	$ 2.49	$ 2.72	$ 3.08	$ 3.51	$ 4.07	$ 4.77	$ 5.46	$ 6.16	$ 6.85	$ 7.54	
AEO 1989 (change in methodology)	1988-2000	$4.51				$ 1.62	$ 1.70	$ 1.91	$ 2.13	$ 2.58	$ 3.04	$ 3.48	$ 3.93	$ 4.76	$ 5.23	$ 5.80	$ 6.43	$ 6.98	
AEO 1990	1989-2010	$5.90					$ 1.78	$ 1.88	$ 2.09	$ 2.30	$ 2.51	$ 2.72	$ 2.93	$ 3.42	$ 3.90	$ 4.39	$ 4.88	$ 5.36	$ 6.12
AEO 1991	1990-2010	$4.78						$ 1.77	$ 1.90	$ 2.11	$ 2.30	$ 2.42	$ 2.51	$ 2.60	$ 2.74	$ 2.91	$ 3.29	$ 3.75	$ 4.31
AEO 1992	1991-2010	$4.54							$ 1.69	$ 1.85	$ 2.03	$ 2.15	$ 2.35	$ 2.51	$ 2.74	$ 3.01	$ 3.40	$ 3.81	$ 4.24
AEO 1993	1992-2010	$4.27								$ 1.85	$ 1.94	$ 2.09	$ 2.30	$ 2.44	$ 2.60	$ 2.85	$ 3.12	$ 3.47	$ 3.84
AEO 1994	1993-2010	$3.74									$ 1.98	$ 2.12	$ 2.27	$ 2.41	$ 2.59	$ 2.73	$ 2.85	$ 2.98	$ 3.14
AEO 1995	1994-2010	$3.63										$ 1.89	$ 2.00	$ 1.95	$ 2.06	$ 2.16	$ 2.40	$ 2.57	$ 2.90
AEO 1996	1995-2015	$2.88											$ 1.63	$ 1.74	$ 1.86	$ 1.99	$ 2.10	$ 2.19	$ 2.29
AEO 1997	1996-2015	$2.71												$ 2.03	$ 1.82	$ 1.90	$ 1.99	$ 2.06	$ 2.13
AEO 1998	1997-2020	$3.10													$ 2.30	$ 2.20	$ 2.26	$ 2.31	$ 2.36
AEO 1999	1998-2020	$3.09														$ 1.98	$ 2.15	$ 2.20	$ 2.32
AEO 2000	1999-2020	$3.02															$ 2.15	$ 2.23	$ 2.27
AEO 2001	2000-2020	$3.43																$ 3.39	$ 3.48
AEO 2002	2001-2020	$3.59																	$ 4.03
AEO 2003	2002-2025	$3.94																	
AEO 2004	2003-2025	$4.74																	
AEO 2005	2004-2025	$4.97																	
AEO 2006	2005-2025	$6.13																	
AEO 2007	2006-2025	$6.12																	
AEO 2008	2007-2025	$6.19																	
AEO 2009	2008-2025	$6.03																	
	2010-2025	$5.99																	
PGE 2009 IRP	2010-2025	$7.24																	
Actual		$3.40	$ 2.51	$ 1.94	$ 1.67	$ 1.69	$ 1.69	$ 1.71	$ 1.64	$ 1.74	$ 2.04	$ 1.85	$ 1.55	$ 2.17	$ 2.32	$ 1.96	$ 2.19	$ 3.68	$ 4.00
Average of forecasts since 1995														$ 1.91	$ 2.01	$ 2.04	$ 2.17	$ 2.42	$ 2.72
Actual - Average of forecasts since 1995	Nominal $													$ 0.26	$ 0.31	$ (0.08)	$ 0.02	$ 1.26	$ 1.28
	% over actual													12%	13%	-4%	1%	34%	32%
Average delta (Actual higher than forecast if positive)		27%																	
Average of the forecasts for the most recent 3 years														$ 1.91	$ 1.99	$ 2.03	$ 2.18	$ 2.61	$ 3.26
Actual - Average	Nominal $													$ 0.26	$ 0.33	$ (0.07)	$ 0.01	$ 1.07	$ 0.74
	% over actual													12%	14%	-3%	0%	29%	19%
Average delta (Actual higher than forecast if positive)		12%																	

Assumptions

inflation	1.90%
cost of capital	7.59%
real cost of capital	5.59%

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
$ 6.88	$ 7.64	$ 8.40	$ 9.15	$ 10.35	$ 11.54	$ 12.74	$ 13.93	$ 15.13															
$ 5.07	$ 5.77	$ 6.45	$ 7.29	$ 8.09	$ 8.94	$ 9.62	$ 10.27	$ 11.16															
$ 4.74	$ 5.25	$ 5.78	$ 6.37	$ 6.89	$ 7.50	$ 8.15	$ 9.05	$ 9.94															
$ 4.31	$ 4.81	$ 5.28	$ 5.68	$ 6.05	$ 6.46	$ 6.94	$ 7.23	$ 7.65															
$ 3.35	$ 3.59	$ 3.85	$ 4.18	$ 4.51	$ 4.92	$ 5.29	$ 5.56	$ 5.96															
$ 3.16	$ 3.56	$ 3.87	$ 4.27	$ 4.56	$ 4.85	$ 5.16	$ 5.41	$ 5.66															
$ 2.38	$ 2.48	$ 2.59	$ 2.72	$ 2.84	$ 2.97	$ 3.12	$ 3.29	$ 3.49	$ 3.73	$ 3.99	$ 4.28	$ 4.61	$ 4.96										
$ 2.21	$ 2.32	$ 2.43	$ 2.54	$ 2.65	$ 2.77	$ 2.88	$ 3.00	$ 3.11	$ 3.24	$ 3.38	$ 3.52	$ 3.71	$ 3.93										
$ 2.44	$ 2.52	$ 2.60	$ 2.69	$ 2.79	$ 2.93	$ 3.06	$ 3.20	$ 3.35	$ 3.48	$ 3.63	$ 3.77	$ 3.92	$ 4.08	$ 4.24	$ 4.44	$ 4.67	$ 4.91	$ 5.22					
$ 2.43	$ 2.53	$ 2.63	$ 2.76	$ 2.90	$ 3.02	$ 3.12	$ 3.23	$ 3.35	$ 3.47	$ 3.60	$ 3.73	$ 3.89	$ 4.08	$ 4.29	$ 4.48	$ 4.68	$ 4.89	$ 5.11					
$ 2.32	$ 2.40	$ 2.51	$ 2.66	$ 2.81	$ 2.97	$ 3.10	$ 3.20	$ 3.29	$ 3.39	$ 3.49	$ 3.59	$ 3.70	$ 3.83	$ 3.96	$ 4.10	$ 4.24	$ 4.41	$ 4.63					
$ 2.97	$ 2.74	$ 2.70	$ 2.83	$ 2.95	$ 3.06	$ 3.17	$ 3.25	$ 3.35	$ 3.44	$ 3.53	$ 3.64	$ 3.76	$ 3.90	$ 4.07	$ 4.26	$ 4.47	$ 4.72	$ 5.03					
$ 2.06	$ 2.53	$ 2.84	$ 3.01	$ 3.13	$ 3.23	$ 3.40	$ 3.52	$ 3.65	$ 3.82	$ 4.00	$ 4.16	$ 4.31	$ 4.48	$ 4.64	$ 4.83	$ 5.04	$ 5.27	$ 5.56					
$ 2.79	$ 3.26	$ 3.13	$ 3.15	$ 3.15	$ 3.30	$ 3.51	$ 3.70	$ 3.95	$ 4.12	$ 4.31	$ 4.47	$ 4.66	$ 4.82	$ 5.01	$ 5.18	$ 5.27	$ 5.42	$ 5.76	$ 5.93	$ 6.21	$ 6.51	$ 6.79	$ 7.07
	$ 4.97	$ 4.00	$ 3.72	$ 3.73	$ 3.86	$ 4.07	$ 3.97	$ 3.99	$ 4.30	$ 4.66	$ 5.02	$ 5.28	$ 5.69	$ 5.91	$ 6.12	$ 6.24	$ 6.39	$ 6.86	$ 7.39	$ 7.61	$ 7.89	$ 8.17	$ 8.44
		$ 5.38	$ 5.52	$ 4.95	$ 4.57	$ 4.23	$ 4.21	$ 4.18	$ 4.29	$ 4.51	$ 4.76	$ 5.08	$ 5.39	$ 5.43	$ 5.55	$ 5.86	$ 6.27	$ 6.68	$ 7.02	$ 7.27	$ 7.50	$ 7.83	$ 8.20
			$ 7.81	$ 7.16	$ 6.53	$ 6.27	$ 5.92	$ 5.89	$ 5.54	$ 5.81	$ 5.85	$ 5.88	$ 5.79	$ 5.86	$ 6.11	$ 6.52	$ 6.91	$ 7.17	$ 7.57	$ 7.90	$ 8.22	$ 8.62	$ 9.05
				$ 6.87	$ 7.00	$ 7.07	$ 6.61	$ 6.40	$ 6.03	$ 5.96	$ 5.87	$ 6.01	$ 6.04	$ 6.27	$ 6.63	$ 6.64	$ 6.69	$ 6.93	$ 7.06	$ 7.37	$ 7.70	$ 8.07	$ 8.22
					$ 6.37	$ 6.87	$ 7.17	$ 6.85	$ 6.61	$ 6.53	$ 6.41	$ 6.35	$ 6.33	$ 6.39	$ 6.60	$ 6.83	$ 7.07	$ 7.10	$ 7.08	$ 7.40	$ 7.72	$ 8.11	$ 8.47
						$ 8.06	$ 4.12	$ 4.81	$ 5.23	$ 5.41	$ 5.64	$ 5.94	$ 6.33	$ 6.69	$ 7.09	$ 7.50	$ 8.01	$ 8.62	$ 9.13	$ 9.39	$ 9.37	$ 9.60	$ 9.74
$ 2.95	$ 4.88	$ 5.46	$ 7.33	$ 6.39	$ 6.37	$ 8.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 2.53	$ 2.93	$ 3.15	$ 3.64	$ 3.88	$ 4.10	$ 4.47																	
$ 0.42	$ 1.95	$ 2.31	$ 3.69	$ 2.51	$ 2.27	$ 3.60																	
14%	40%	42%	50%	39%	36%	45%																	
$ 2.61	$ 3.59	$ 4.17	$ 5.68	$ 6.33	$ 6.63	$ 7.33																	
$ 0.34	$ 1.29	$ 1.29	$ 1.65	$ 0.06	$ (0.26)	$ 0.74																	
12%	26%	24%	22%	1%	-4%	9%																	



EIA Wellhead Gas Prices
1996-2008
$10.00
$8.00
$6.00
$4.00
$2.00
$-
$/mmbtu
1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008
EIA Actuals
EIA Forecast Prior 3-Year Average
EIA Forecast Average Starting 1995

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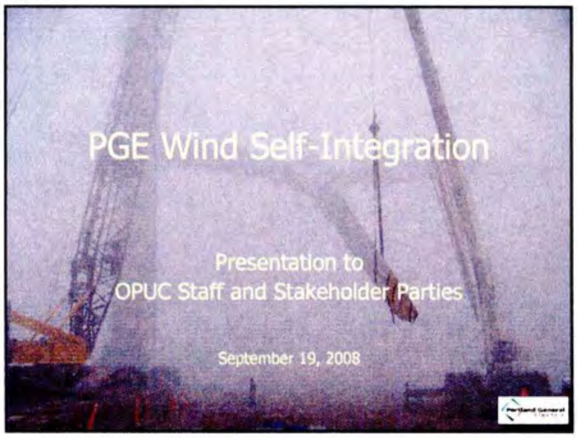
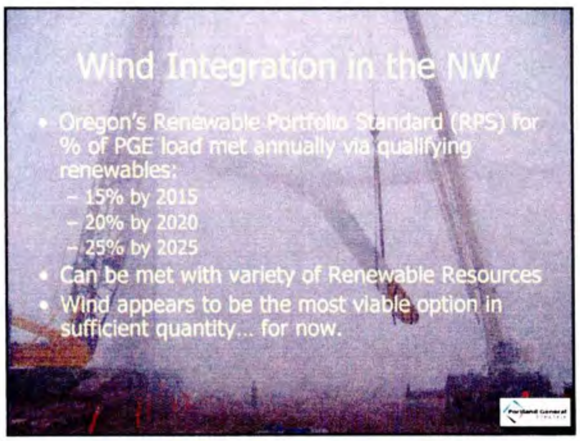
PGE's 2009 Integrated Resource Plan

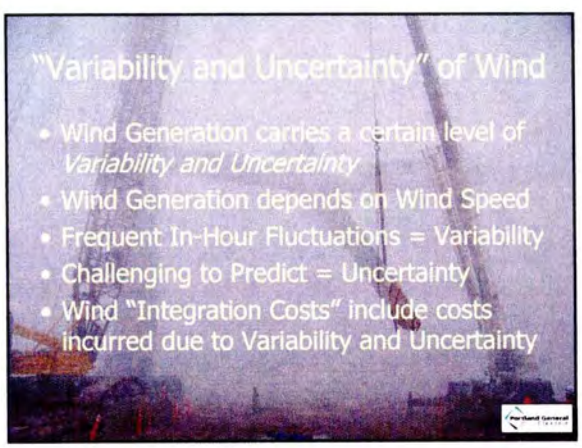
Attachment F

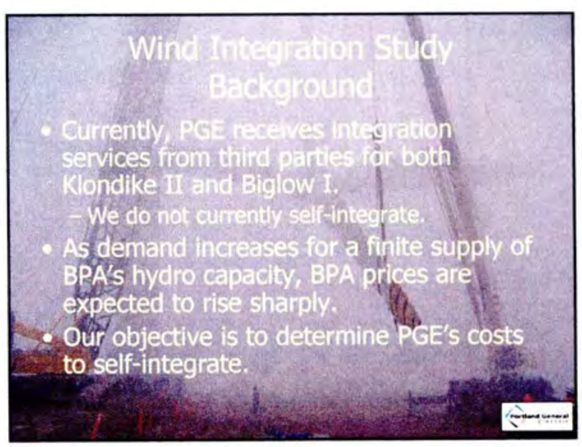
PGE's Reply to Intervenors' Response Comments


PGE Wind Self-Integration
Presentation to
OPUC Staff and Stakeholder Parties
September 19, 2008


Wind Integration in the NW
• Oregon's Renewable Portfolio Standard (RPS) for % of PGE load met annually via qualifying renewables:
– 15% by 2015
– 20% by 2020
– 25% by 2025
• Can be met with variety of Renewable Resources
• Wind appears to be the most viable option in sufficient quantity... for now.


Whisperings about the Wind
• "The Eccentric Nature of Wind" BPA Power
• "Intermittent" Resource
• "Wind needs a Dance Partner"
• "Hydro is ideal for balancing wind"
• Wind is Unpredictable
• Wind Power is Free
• Wind "Farm" (as opposed to Wind "Plant")


"Variability and Uncertainty" of Wind
• Wind Generation carries a certain level of *Variability and Uncertainty*
• Wind Generation depends on Wind Speed
• Frequent In-Hour Fluctuations = Variability
• Challenging to Predict = Uncertainty
• Wind "Integration Costs" include costs incurred due to Variability and Uncertainty


Wind Integration Study Background
• Currently, PGE receives integration services from third parties for both Klondike II and Biglow I.
– We do not currently self-integrate.
• As demand increases for a finite supply of BPA's hydro capacity, BPA prices are expected to rise sharply.
• Our objective is to determine PGE's costs to self-integrate.

What is "Integration Cost"?

- Conventional ancillary service – load following, regulation, etc.
- Variability increases costs due to in-hour fluctuations of wind generation
- Uncertainty increases costs due to unit commitment in Preschedule and Real Time
- Costs include variable O&M and fuel

Components of Integration Costs

- Day-Ahead to Real Time
  - Optimize system in Preschedule with current wind energy forecast
  - Long/Short position filled in Preschedule Market
- Real Time to Actual
  - Optimize system in Real Time with improved wind energy forecast
  - Long/Short position filled in Real Time Market
- In-Hour Balancing
  - Regulation and Load Following
  - Withholding PGE resources for capacity needs requires deficit be made up from wholesale market

Study Approach

- Use *What's Best*, a linear optimization program, to model, on an hourly basis, PGE's Power Operations.
- Using 11 dedicated computers to run studies for all hours of 2014, one week at a time.
- Rely on wind data from NREL's West Wide Wind Study.
- Engage Enernex as a recognized subject matter expert to assist in model design and to provide in-hour reserves calculations.
- Use a PGE internal Project Team, experienced in PGE system operations and power supply modeling.
- Met with volunteer Technical Review Committee on Bi-Weekly basis (see next slide…).
- Objective function is to minimize costs while meeting load.
- System attributes include variable operating costs, heat rates, ramp rates, scheduled outages for thermal plants.
- For hydro plants, includes various storage constraints, maximum flow rates, and schedule outages.

Technical Review Committee

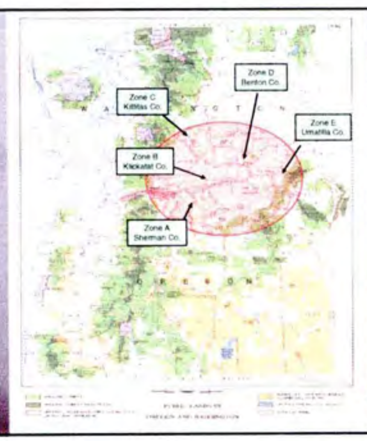
- Utility Wind Integration Group
  - Charlie Smith – Executive Director
- Renewables Northwest Project
  - Ken Dragoon – Research Director
- National Renewable Energy Laboratory
  - Michael Milligan – Analyst
- American Wind Energy Association
  - Brendan Kirby, Consultant
  - Michael Goggin, Analyst

Inputs and Assumptions

- 1100 MW of nameplate wind capacity.
- "High Diversity" (5 Zones).
- 2014 Load Forecast.
- 2014 Hydro Contracts (diminished hydro capacity).
- 2014 Medium Gas Price (PIRA) and Market Electric Power Price (Aurora) by hour.
- 2005 Hydro and Wind conditions.
- PGE's existing thermal system -- no additional flexible resource assumed.
- Pre-schedule Bid-Ask spread of \$0.50/MWh flat; ±\$0.25/MWh from Market Price.
- Real-Time Bid-Ask spread of ±10% of Market Price -- ±\$7.15/MWh.

PGE Wind Integration Study Diversity Scenario

Target: 1100 MW



PGE Resources Available to Provide Ancillary Services

PLANT	MID-C	Round Butte	Pelton	Boardman	Coyote	Port Westward	Beaver*
MW of Reserves Available (per unit)	219	70	24	50	100	171	50
MW of Reserves Available Total	219	210	72	50	100	171	150

- Assumes thermal plants are on AGC, which requires a modest additional one-time conversion cost.
- Assumes no significant flex capability on our minority interest in Colstrip 3&4 and on PGE's West-side run-of-river hydro.

* Three of six units of Beaver modeled, in Simple Cycle mode.

Incremental Fixed O&M Costs

- Costs are incremental fixed O&M costs associated with the ancillary services each Generating Resource provides.

PLANT	MID-C	Round Butte	Pelton	Boardman	Coyote	Port Westward	Beaver
O&M Wear and Tear Cost ($/ MWH)	0	$0.87	$2.27	$21.47*	$0.34	$0.27	$1.65
Loss due to inefficiency (MWa times Market Price)	0	6.3 x Mkt Price	1.4 x Mkt Price	0	0	0	0

* Same methodology was used to calculate incremental O&M for each plant.

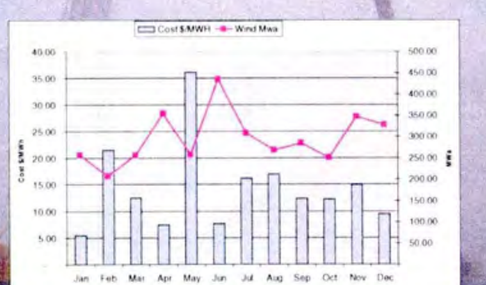
Calculation of Reserves Requirement

In-Hour Reserve Requirements

- Case A:- Pre-schedule Load Forecast and Flat Daily Actual Wind
- Case B:- Real-time Actual Load & Flat Daily Actual Wind
- Case C:- Pre-schedule Load Forecast and Pre-schedule Wind Forecast
  - (Wind Varies Hour to Hour)
- Case D:- Real-time Actual Load Forecast & Actual Wind
  - (Wind Varies Hour to Hour)

(Average MW)	Mid-C	Round Butte	Pelton	Beaver	PW	Coyote	Boardman	Total
Case A	116.5	19.4	1.8	0.5	8.7	21.6	0.3	168.9
Case B	115.1	14.8	1.5	0.8	9.6	24.0	0.3	166.0
Case C	159.1	57.8	6.2	5.0	45.4	66.0	1.4	340.9
Case D	157.5	28.8	2.4	5.8	50.0	67.7	1.7	314.0

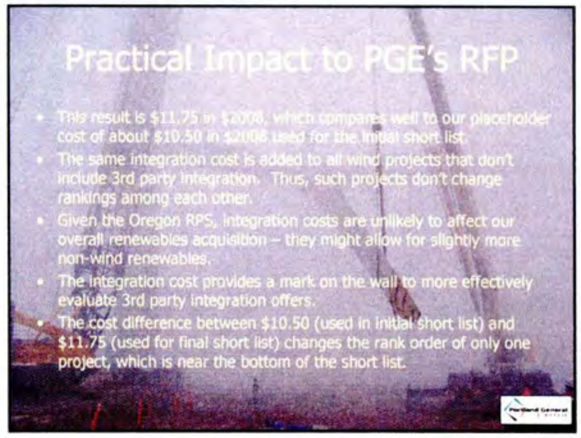
Monthly PGE Cost & Wind Output

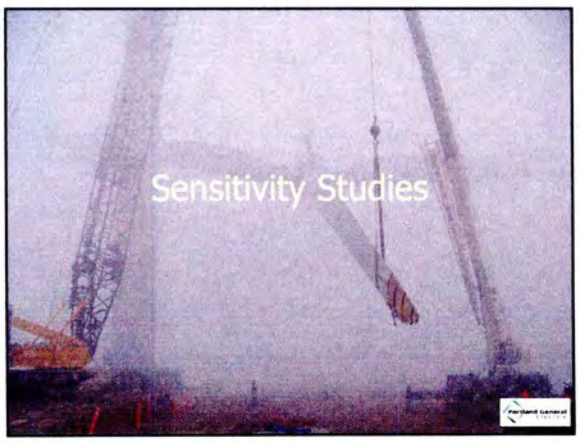


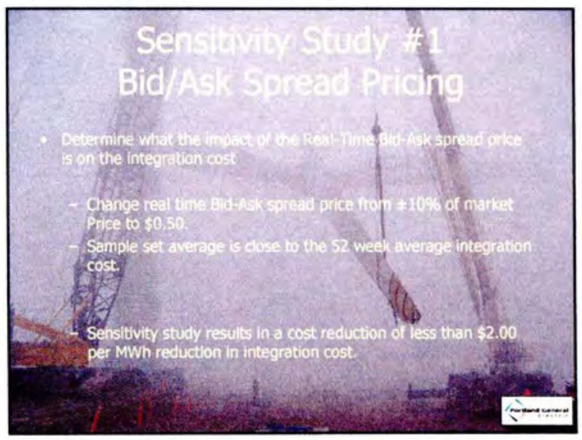
Cost Of PGE's Wind Integration

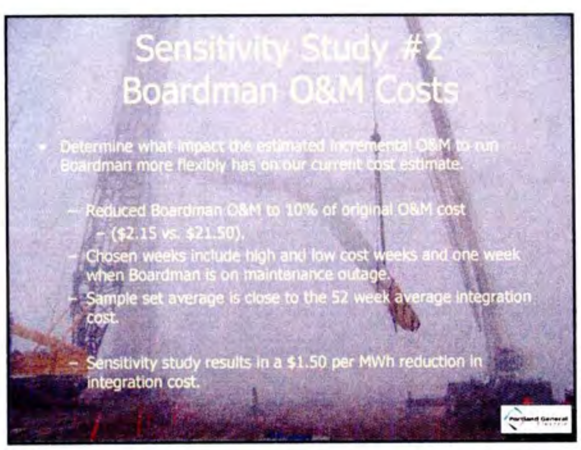
- Estimated to be $13.50/MWh to reach 2015 RPS compliance.
- Reasons this number may appear to be high:
  - It is expressed in 2014 nominal $. In $2008, this is closer to $11.75.
  - We have reduced access to mid-C hydro in 2014.
  - We have not included a new flexible thermal resource.
  - There is an opportunity cost to displace hydro from heavy load hours to light load hours.
  - PGE has a relatively limited amount of flexible thermal plants which have near-market heat rates.
  - PGE's uses a bid/ask spread of 10% of market to estimate real-time imbalance costs. (This adds < $2.00 per mwh to our cost.)
  - Actual NREL wind input data is uniformly less than forecast wind data.
  - Currently modeled geographically diverse wind data yields relatively little seasonal forecast error improvement.

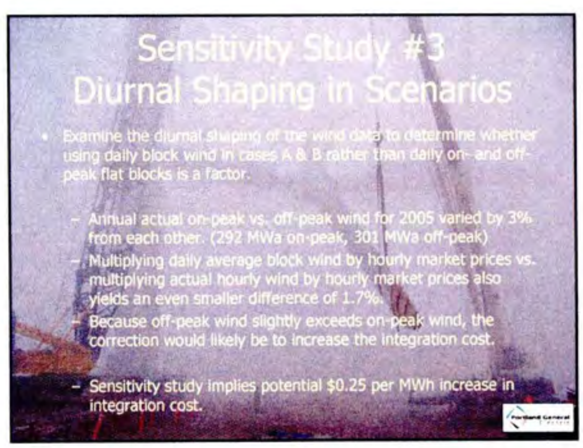

Factors that May Affect Cost
Revised NREL Wind Data
Inclusion of startup costs & minimum run time
Inclusion of a sliding scale on bid-ask spread
Inclusion of seasonal Hydro constraints
Inclusion of an additional flexible gas resource
Increased or decreased wind diversity

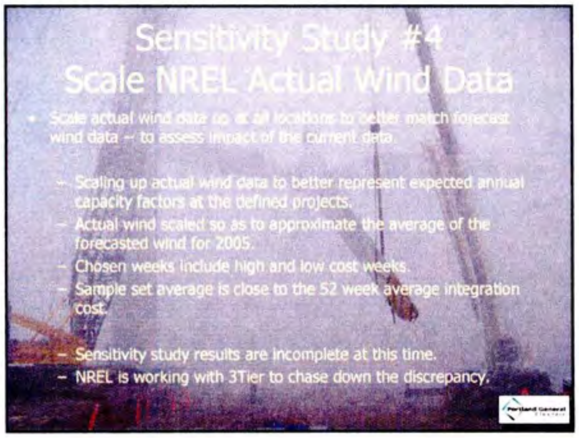

Practical Impact to PGE's RFP
This result is $11.75 in $2008, which compares well to our placeholder cost of about $10.50 in $2008 used for the initial short list.
The same integration cost is added to all wind projects that don't include 3rd party integration. Thus, such projects don't change rankings among each other.
Given the Oregon RPS, integration costs are unlikely to affect our overall renewables acquisition – they might allow for slightly more non-wind renewables.
The integration cost provides a mark on the wall to more effectively evaluate 3rd party integration offers.
The cost difference between $10.50 (used in initial short list) and $11.75 (used for final short list) changes the rank order of only one project, which is near the bottom of the short list.


Sensitivity Studies


Sensitivity Study #1
Bid/Ask Spread Pricing
Determine what the impact of the Real-Time Bid-Ask spread price is on the integration cost
– Change real time Bid-Ask spread price from ±10% of market Price to $0.50.
– Sample set average is close to the 52 week average integration cost.
– Sensitivity study results in a cost reduction of less than $2.00 per MWh reduction in integration cost.


Sensitivity Study #2
Boardman O&M Costs
Determine what impact the estimated incremental O&M to run Boardman more flexibly has on our current cost estimate.
– Reduced Boardman O&M to 10% of original O&M cost
– ($2.15 vs. $21.50).
– Chosen weeks include high and low cost weeks and one week when Boardman is on maintenance outage.
– Sample set average is close to the 52 week average integration cost.
– Sensitivity study results in a $1.50 per MWh reduction in integration cost.


Sensitivity Study #3
Diurnal Shaping in Scenarios
Examine the diurnal shaping of the wind data to determine whether using daily block wind in cases A & B rather than daily on- and off-peak flat blocks is a factor.
– Annual actual on-peak vs. off-peak wind for 2005 varied by 3% from each other. (292 MWa on-peak, 301 MWa off-peak)
– Multiplying daily average block wind by hourly market prices vs. multiplying actual hourly wind by hourly market prices also yields an even smaller difference of 1.7%.
– Because off-peak wind slightly exceeds on-peak wind, the correction would likely be to increase the integration cost.
– Sensitivity study implies potential $0.25 per MWh increase in integration cost.


Sensitivity Study #4
Scale NREL Actual Wind Data
• Scale actual wind data up at all locations to better match forecast wind data – to assess impact of the current data.
– Scaling up actual wind data to better represent expected annual capacity factors at the defined projects.
– Actual wind scaled so as to approximate the average of the forecasted wind for 2005.
– Chosen weeks include high and low cost weeks.
– Sample set average is close to the 52 week average integration cost.
– Sensitivity study results are incomplete at this time.
– NREL is working with 3Tier to chase down the discrepancy.


Wind Integration Study
Phase II Next Steps
• Incorporate start-up costs and minimum run times.
• Run the other two years (2004 and 2006) of historical wind and hydro conditions.
• Run cases at 450 MW and 775 MW to build a supply curve.
• Run an 1100 MW case composed entirely of Sherman county to better understand the impact of geographic diversity.
• Assess the impact of additional dispatchable resources.
• Assess sensitivity to high gas prices.
• Explore monthly or seasonal optimization runs to better honor annual constraints.
• Explore the cause for high-cost periods to assess whether we can take actions to pro-actively manage them.
• Assess the cost to integrate other intermittent renewable resources.


Conclusion
• Integrating Wind Generation in the future will be a challenge.
• Meeting this challenge calls for:
– New Flexible Resources
– Increased Use of Existing System Capacity
– Regional Cooperation
– Integration Market Products

LC 48

PGE's 2009 Integrated Resource Plan

Attachment G

PGE's Reply to Intervenors' Response Comments

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09-23 11:20 PDT

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Reservation Summary for: BPAT

Customer TEMU Incr ALL Path POR CENTRA Src Use DST

TP BPAT Class ALL Status All-Active POD ALL Snk Enter

Seller ALL Type ALL Time Active User Range Req Type ORIGINA Ref

New TSR | More Filtering | User Range | Columns | Save Query | Refresh | Disabled

AFC/Flowgate Reports | Hourly Summary | Spreadsheet | TSR Metric | TransAssign | Full Transfer | Old TSR Summary

Selected time range: **2010-12-07 00:00:00 PS** to **2015-09-21 01:00:00 PS**

Seller	Assign Ref ↑	TP	Customer	MW Req	MW Grant	Offer Price	POR	POD	Queued Time	Start Time	Stop Time	Status	Increment	Class	Type	Period
BPAT	74623384	BPAT	TEMU	100	100	1312.0000	CENTRALIA	JOHNDAY	2010-08-27 12:03:36 PD	2010-10-01 00:00:00 PD	2015-10-01 00:00:00 PD	CONFIRMED	YEARLY	FIRM	CF-PTP	FULL_PER
BPAT	74619696	BPAT	TEMU	100	100	1312.0000	CENTRALIA	JOHNDAY	2010-08-26 14:32:16 PD	2010-10-01 00:00:00 PD	2015-10-01 00:00:00 PD	CONFIRMED	YEARLY	FIRM	CF-PTP	FULL_PER
BPAT	73918209	BPAT	TEMU	100			CENTRALIA	BIGEDDY	2010-03-02 12:06:33 PS	2011-04-01 00:00:00 PD	2016-04-01 00:00:00 PD	STUDY	YEARLY	FIRM	POINT_TO_POINT	FULL_PER
BPAT	73918184	BPAT	TEMU	50			CENTRALIA	JOHNDAY	2010-03-02 11:55:28 PS	2011-04-01 00:00:00 PD	2016-04-01 00:00:00 PD	STUDY	YEARLY	FIRM	POINT_TO_POINT	FULL_PER
BPAT	72173050	BPAT	TEMU	50			CENTRALIA	BIGEDDY	2008-05-15 14:41:30 PD	2009-01-01 00:00:00 PS	2014-01-01 00:00:00 PS	STUDY	YEARLY	FIRM	POINT_TO_POINT	FULL_PER
BPAT	72173047	BPAT	TEMU	100			CENTRALIA	JOHNDAY	2008-05-15 14:41:30 PD	2009-01-01 00:00:00 PS	2014-01-01 00:00:00 PS	STUDY	YEARLY	FIRM	POINT_TO_POINT	FULL_PER
BPAT	72173046	BPAT	TEMU	100			CENTRALIA	JOHNDAY	2008-05-15 14:41:30 PD	2009-01-01 00:00:00 PS	2014-01-01 00:00:00 PS	STUDY	YEARLY	FIRM	POINT_TO_POINT	FULL_PER
													Total: 7 TSRs			

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Reservation Summary for: BPAT

Customer ALL | Incr ALL | Path | POR HERMIS | Src | Use DST

TP BPAT | Class ALL | Status All-Active | POD ALL | Snk | Enter

Seller ALL | Type ALL | Time Active | User Range | Req Type ALL | Ref

New TSR | More Filtering | User Range | Columns | Save Query | Refresh | Enabled

AFC/Flowgate Reports | Hourly Summary | Spreadsheet | TSR Metric | TransAssign | Full Transfer | Old TSR Summary

Selected time range: **2011-01-01 00:00:00 PS** to **2015-12-31 00:00:00 PS**

Seller	Assign Ref ↑	TP	Customer	MW Req	MW Grant	Offer Price	POR	POD	Queued Time	Start Time	Stop Time	Status	Increment	Class	Type	Req
BPAT	1801331	BPAT	CALP	308	308		HERMISTONCPN	JOHNDAY	2003-02-25 15:10:00 PS	2005-03-01 00:00:00 PS	2021-07-01 00:00:00 PD	CONFIRMED	YEARLY	FIRM	POINT_TO_POINT	ORIGI
BPAT	1601330	BPAT	CALP	228	228		HERMISTONCPN	BIGEDDY	2003-02-25 15:10:00 PS	2005-03-01 00:00:00 PS	2021-07-01 00:00:00 PD	CONFIRMED	YEARLY	FIRM	POINT_TO_POINT	ORIGI
												Total: 2 TSRs				

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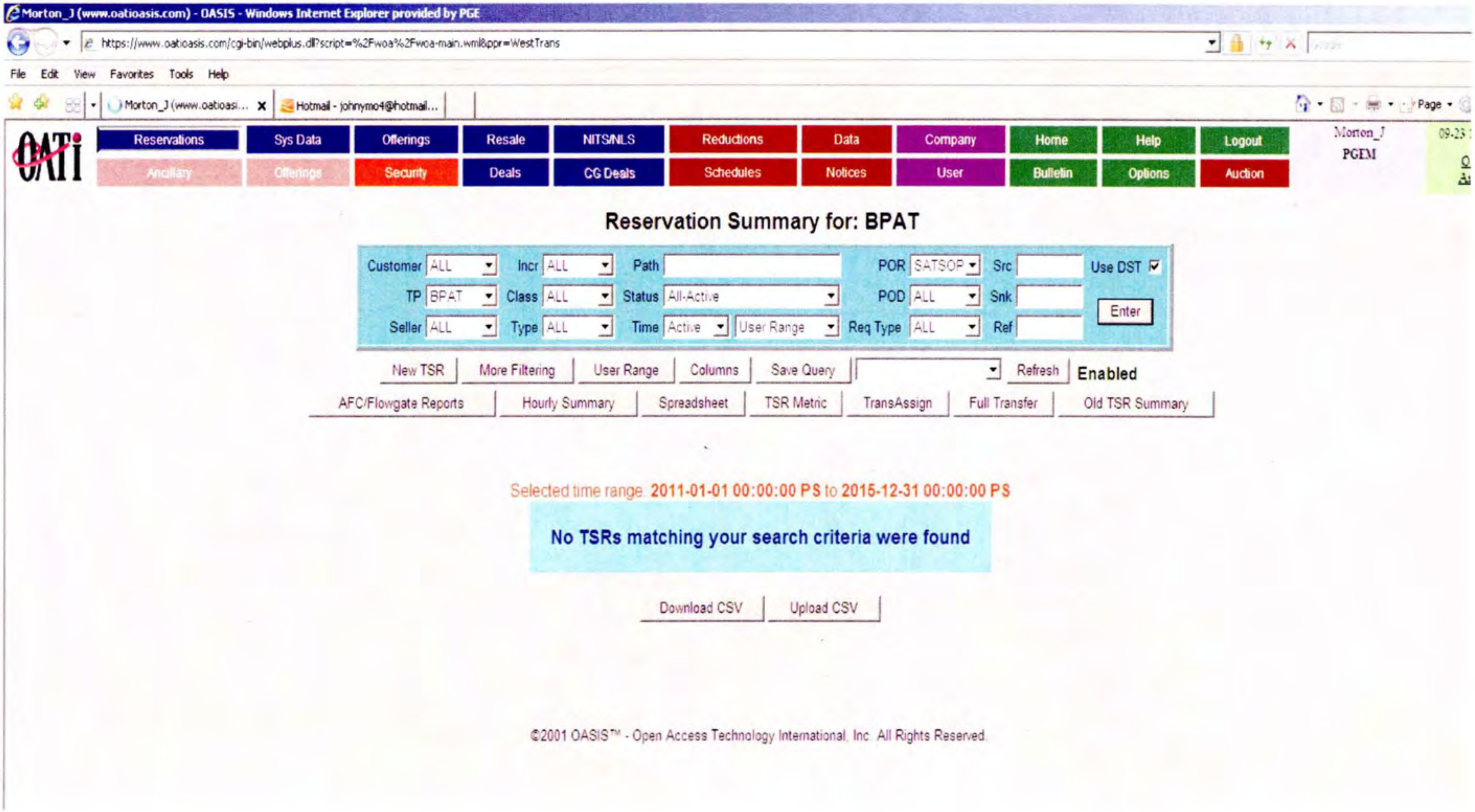
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Deals
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Schedules
Notices
User
Bulletin
Options
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Reservation Summary for: BPAT
Customer ALL
Incr ALL
Path
POR SATSOP
Src
Use DST
TP BPAT
Class ALL
Status All-Active
POD ALL
Snk
Enter
Seller ALL
Type ALL
Time Active
User Range
Req Type ALL
Ref
New TSR
More Filtering
User Range
Columns
Save Query
Refresh
Enabled
AFC/Flowgate Reports
Hourly Summary
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Old TSR Summary
Selected time range: 2011-01-01 00:00:00 PS to 2015-12-31 00:00:00 PS
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Reservation Summary: ALL

Customer	PPMI	Incr	ALL	Path		POR	COB	Src		Use DST ☑
TP	ALL	Class	ALL	Status	All-Active	POD	JOHNDA	Snk		Enter
Seller	ALL	Type	ALL	Time	Active / User Range	Req Type	ALL	Ref		

New TSR | More Filtering | User Range | Columns | Save Query | Refresh | **Enabled**

AFC/Flowgate Reports | Hourly Summary | Spreadsheet | TSR Metric | TransAssign | Full Transfer | Old TSR Summary

Selected time range: **2011-01-01 01:00:00 PD** to **2015-12-31 01:00:00 PD**

No TSRs matching your search criteria were found

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Reservation Summary: ALL

Customer PPMI | Incr ALL | Path | POR JOHNDA | Src | Use DST

TP ALL | Class ALL | Status All-Active | POD BPAT PC | Snk | Enter

Seller ALL | Type ALL | Time Active | User Range | Req Type ALL | Ref

New TSR | More Filtering | User Range | Columns | Save Query | Refresh | Enabled

AFC/Flowgate Reports | Hourly Summary | Spreadsheet | TSR Metric | TransAssign | Full Transfer | Old TSR Summary

Selected time range: **2011-01-01 01:00:00 PD** to **2015-12-31 01:00:00 PD**

No TSRs matching your search criteria were found

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I hereby certify that I have this day caused **PGE'S REPLY TO INTERVENORS' RESPONSE COMMENTS** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No. LC 48.

Dated at Portland, Oregon, this 27th day of September, 2010.

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