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February 4, 2013

***E-mail / US Mail***
puc.filingcenter@state.or.us

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
Salem OR 97301-2567

**Re: UM 1610 -- INVESTIGATION INTO QUALIFYING FACILITY CONTRACTING AND PRICING**

Attention Filing Center:

Enclosed for filing in UM 1610 are an original and five copies of:

Direct Testimony of Portland General Electric Company:

- **PGE Exhibit 100-101 Macfarlane/Morton**

This document is being filed by electronic mail with the Filing Center. Hard copies will be sent via US Mail. An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

This document is being served upon the UM 1610 service list.

Sincerely,

Jay Tinker

Jay Tinker
Manager, Pricing

JT:jlt
*encls.*
cc: UM 1610 Service List

## CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PGE DIRECT TESTIMONY** 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 obtained permission to receive hard copy service for OPUC Docket UM 1610.

Dated at Portland, Oregon, this 4th day of February, 2013.

Jay Tinker

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**2/4/13**

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**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

# UM 1610
# Investigation into Qualifying Facility Contracting and Pricing

**PORTLAND GENERAL ELECTRIC COMPANY**

Direct Testimony and Exhibits of

***Robert Macfarlane***
***John Morton***

Portland General Electric

**February 4, 2013**

# Table of Contents

# I. Introduction and Summary

**Q. Please state your name and position with Portland General Electric Company (PGE).**

A. My name is Robert Macfarlane. I am an analyst in Pricing and Tariffs. My qualifications appear in Section VIII of this testimony.

My name is John Morton. I am a specialist in Structuring and Origination. My qualifications appear in Section VIII of this testimony.

**Q. What is the purpose of your testimony?**

A. Our testimony responds to the UM 1610 Phase I issues list as distributed December 21, 2012. It addresses policy and rule changes for power purchases from Qualifying Facilities[1] (QF). We suggest that proposals in this docket should be evaluated based on the following principles:

1) Avoided cost should be calculated in an accurate and timely manner;
2) A balancing of interests between retail electricity customers and QFs;
3) Provide reliability in resource planning; and
4) Accountability to the utility's customers.

**Q. Please summarize your key recommendations and proposals.**

A. The testimony's foundation is that any proposed QF rule changes must be based on the principles listed above. PGE supports economic QF project developments and in this docket we offer proposals to balance QF and PGE customer benefits going forward.

We recommend:

- Lowering the eligibility cap for standard contracts from 10 MW to 100 kW;

[1] A Qualifying Facility is a cogeneration facility, or a small power producer as defined with the Code of Federal Regulations, Title 18-Conservation of Power and Water Resources, Part 292-Regulations Under Sections 201 and 210 of the Public Utility Regulatory Act of 1978 with Regard to Small Power Production and Cogeneration, Subpart B-Qualifying Cogeneration and Small Power Production Facilities.

- Setting standard contract terms using the current 20 year (15 fixed) for new contracts and 5 years for existing QFs;
- Continuing with the IRP as the standard for updating avoided cost prices;
- If an eligibility cap for the standard contract higher than 100 kW is approved, the avoided cost for standard contracts should be adjusted by the seven FERC adjustment factors;
- Defining the signal for demarcation between the resource sufficiency and resource deficiency periods in the traditional avoided cost as a non-renewable major resource addition, as identified in the IRP, for: 1) a base load resource, or 2) separate energy and capacity resources; and
- Avoiding levelization or partial levelization and retaining well-defined sufficiency and deficiency periods.

Overall, our testimony and standard contract proposals provide the Commission a framework from which QF development can proceed with all stakeholders receiving benefits.

**Q. What is the purpose of this docket?**

A. The Commission initiated Docket UM 1610 as an investigation into rules and policies associated with QF Contracting and Pricing. An issues list was approved and separated into two phases, with phase II concerning issues around interconnection and remaining contracting issues.

**Q. What is PGE's position on QF development?**

A. PGE seeks the development of a diverse mix of resources in our power supply portfolio. QFs can be a valuable partner in meeting load demands. However, QF contracting and pricing policies should adhere to the Public Utility Regulatory Policies Act of 1978 (PURPA) intent to use accurate avoided costs and reflect a balancing of interests between PGE's customers and QFs.

**Q. How is your testimony organized?**

A. Our testimony is organized to highlight the issue that PGE views as most pressing first: eligibility for standard contracts. Then, the testimony follows the issues list as distributed:

II. Eligibility Issues;
III. Avoided Cost Price Calculation;
IV. Renewable Avoided Cost Price Calculation;
V. Schedule for Avoided Cost Price Updates;
VI. Price Adjustments for Specific QF Characteristics; and
VII. Contracting Issues.

## II. Eligibility Issues

**Q. What is a standard QF contract and how is the standard contract used?**

A. The standard QF contract provides prices, terms, and conditions that are not negotiable. It allows the QF to avoid some of the transaction costs involved in selling power to the utility in a PURPA contract.

**Q. Should the Commission change the 10 MW cap for the standard contract? (Issue list 5A)**

A. Yes. PGE recommends that the Commission reduce the eligibility cap from the current 10 MW to 100 kW as originally set forth by OPUC Docket R 58, Order No. 80-568 and PURPA.

**Q. Please summarize why PGE supports lowering the cap for the standard contract.**

PGE recommends a 100 kW cap for the standard contract in Oregon because the current 10 MW cap:

- No longer reflects the capital costs associated with typical QFs under 10 MW projects and the relatively immaterial cost of negotiating a PPA for these projects.
- Imposes unreasonable costs on PGE and its customers and results in paying QFs prices that are significantly higher than avoided cost which could cost customers an estimated $6.8 million annually in excess of avoided cost *with only ten 10 MW QFs*.
- Is 100 times higher than the 100 kW cap recommended under PURPA.
- Is significantly higher than other states in the region, a factor that may push QFs in the region to sell to Oregon IOUs.

**Q. For what period was the original 100 kW standard contract cap applicable?**

A. The 100 kW cap was applicable from approximately 1980 to 1991. The cap was changed by the Commission in 1991 Order No. 91-1383, to 1 MW. Then, in 2005, the Commission in Order No. 05-584 changed it to 10 MW based on a finding that there were barriers to entry for small QFs.

**Q. Why did the Oregon Commission increase the eligibility cap to 10 MW?**

A. When the Oregon PUC raised the capacity cap in 2005, it did so in reliance on high transaction costs and other market barriers preventing successful negotiation of a power purchase agreement. If the capacity ceiling were raised, Staff agued, the QF would be in a better position to incur the negotiation costs. In its Order No. 05-584, the Oregon Commission notes that Staff and ODOE recommended an increase in the capacity ceiling from 1 MW to 10 MW based in part on the following:

> An increase in the eligibility threshold is warranted in order to recognize that transaction costs and other market barriers, such as the lack of transparency for negotiated QF contract rates, terms and conditions, prevent successful negotiation of a power purchase contract for QFs that are at or under 10 MW. ODOE represents that at 10 MW, negotiation costs become a relatively small fraction of total $10 million investment costs. (emphasis in original)

**Q. Why should the Commission change the eligibility cap for the standard contract to 100 kW?**

A. We recommend a 100 kW eligibility cap because:

- The Idaho Commission recently reduced the cap for solar and wind QFs to 100 kW leaving Oregon with a disproportionately large cap relative to the rest of the region;
- QF developers are sophisticated, well-funded entities capable of bilateral negotiations; and
- QFs larger than 100 kW have resources to pay the transaction costs associated with a negotiated contract.

With regard to the first bulleted statement, in 2011 the Idaho Public Utilities Commission (IPUC) ordered[2] the reduction of the eligibility cap for standard contracts from 10 MW to 100 kW for wind and solar QFs. The Order was partially in response to a joint petition filed by Idaho Power and Rocky Mountain Power which asserted that "the typical wind developer is no longer 'unsophisticated' about the QF process and small

[2] Idaho Public Utilities Commission Case No. GNR-E-10-04, Order No. 32176; made permanent in 2012 by Order No. 32697

projects (0.5-1.5 MW) ‘are no longer the norm’.” We believe this is the case in Oregon as well.

The current 10 MW eligibility cap to mitigate transaction costs is unnecessary and excessive. Based on PGE’s own renewable avoided cost model, the estimated capital cost for a wind QF facility based on size is as follows:

**Table 1: Estimated Capital Cost of QF, Using IRP Assumptions, Based on Capacity (2013 dollars)**

| **Facility Size** | **Estimated Capital Cost** |
|---|---|
| 10 MW | $21.3 Million |
| 5 MW | $10.6 Million |
| 3 MW | $6.4 Million |
| 1 MW | $2.1 Million |

If a facility is able to secure the financing necessary to build a 1+ MW facility, it also has the sophistication to negotiate a PPA and the incremental cost associated with that is negligible. These are not small unsophisticated business enterprises.

**Q. Does a 10 MW standard contract eligibility cap impose costs upon the utility and its customers above the avoided cost of energy and capacity?**

A. Yes. With the current implementation of PURPA in Oregon, the standard avoided costs do not necessarily reflect the specific characteristics of the facility which could increase the utility’s costs. For example, many new QFs generate electricity using a variable energy resource. When a QF using wind to generate electricity selects the traditional avoided cost, the utility pays the QF a price based on a base load combined cycle combustion turbine (CCCT) resource during the deficiency period. The CCCT proxy assumes that the resource is dispatchable, has a high mechanical availability factor, and a high degree of reliability. However, QFs backed by a variable energy resource (Wind and Solar) do not display these characteristics. Outside of the QF world, the Company would not pay the same price for the output of a dispatchable resource as it would for a variable energy resource since the Company must then incur additional cost to integrate the output of the variable energy resource into its system and provide the similar capacity to that of a CCCT. By pricing the QF contract at the same avoided cost curve of a CCCT, variable energy resource QFs have the effect of putting additional costs to customers. This concern is amplified since the threshold is 10 MW rather than 100 kW.

**Q. PGE has a wind integration study which puts a price on wind integration. Would a standard wind integration adjustment for variable energy resource QFs solve this problem?**

A. Partially. For an in-system wind QF, a standard wind integration adjustment would take care of more than a third of the difference. However, that still leaves a large subsidy from PGE customers.

**Q. Does PURPA allow standard rates for QF contracts that are higher than the utility's avoided cost for energy and capacity?**

A. No. Although it is our understanding that18 CFR § 304(b)(5) does allow rates based on estimates of avoided cost over a term to differ from avoided cost at the time of delivery, the initial estimates still must be no higher than avoided cost. 18 CFR § 292.304(c) discusses standard rates for purchases. 18 CFR § 292.304(c)(3) states:

> The standard rates for purchases under this paragraph:
> (i) Shall be consistent with paragraphs (a) and (e) of this section; and
> (ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

Paragraph (a) refers to 18 CFR § 292.304(a), which states:

> Rates for purchases.
> (1) Rates for purchases shall:
> (i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and
> (ii) Not discriminate against qualifying cogeneration and small power production facilities.
> (2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

As currently implemented, standard rate contracts allow rates to be higher than avoided cost at the outset of the contract (i.e., the filed rates are not adjusted to reflect the characteristics of the QF). This is inconsistent with 18 CFR § 292.304(a)(2).

**Q. How is the 10 MW eligibility cap particularly inconsistent with your understanding of PURPA?**

A. PURPA recommends the 100 kW eligibility cap. Unless the QF provides energy and capacity characteristics as valuable as those of the avoided resource, the utility and its customers pay higher than avoided cost prices for a standard contract. For example, variable resources such as wind and solar impose significant costs on the utility for availability, reliability, and dispatchability. Those costs are not present for the avoided resource in the traditional avoided cost model. Since the cap is 10 MW (10,000 kW), the costs are magnified 100 times those that would be present under the 100 kW cap. For a 100 kW project, the discrepancy exists, but is significantly less material.

**Q. Do all variable energy resource QFs impose integration costs on PGE?**

A. Yes. The cost of integrating[3] an in-system variable QF is estimated at $9.15/MWh in 2014 dollars. PGE's Wind Integration Cost Study Phase II is provided in Exhibit 101.

[3] The Wind Integration Study considers four elements of wind integration costs:
- Costs resulting from day-ahead wind forecast error (day-ahead uncertainty).
- Costs resulting from hour-ahead wind forecast error (hour-ahead uncertainty).
- Costs incurred in using generation resources to follow the wind generation trend within the hour (load following).

**Q. Why is the 100 kW eligibility cap significantly less costly to customers than the 10 MW cap?**

A. The 100 kW cap recommended under PURPA provides a way for small QFs and utilities to avoid the negotiation process for those QFs that, due to the small size of the QF, will not materially overprice the power for utility customers. For example, a major resource addition is one that is over 100 MW in capacity. Assuming all QFs build to the maximum capacity for a standard contract, it would take *one thousand* QFs under PURPA's recommended 100 kW cap to equal the capacity of one major resource addition. With a 10 MW eligibility cap, it takes only *ten*. At 10 MW, the cap would allow a couple of disaggregated 50 MW wind developments in a short period of time to get to the equivalent of a variable energy resource of 100 MW. Those projects could cost customers an estimated $6.8 million annually[4] more than it should. A power purchase agreement for such a "major resource addition" made by the utilities outside of PURPA runs the risk of being considered imprudent if it costs customers $6.8 million more than it should.

**Q. How much of that subsidy from PGE customers could be recovered with a standard wind integration adjustment?**

A. About $2.5 million, leaving customers subsidizing the QFs for $4.3 million.

**Q. The resource in the renewable avoided cost is variable. In that case does the QF impose costs for availability, reliability, and dispatchability on customers?**

A. Yes, however, PGE would have otherwise incurred costs for the avoided renewable resource. So, in that case, prices paid to the QF reflect the avoided cost of PGE. This

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- Costs incurred in using generation resources to follow within-hour departures of wind generation from the wind generation schedule (regulation).

[4] Based on the cost to adjust a 100MW wind plant for availability, reliability, and dispatchability

scenario assumes that the avoided renewable resource is a wind plant, which is the renewable resource identified in our most recent 2009 IRP and associated IRP updates.

**Q. Are there other factors that would support a lower standard contract cap in Oregon?**

A. Yes. Although PURPA set the threshold at 100 kW, State Commissions were granted latitude to change the standard contract eligibility cap as they saw necessary[5]. In the western region, Idaho (for wind and solar only) has a 100 kW cap, and Washington and Utah have a 1 MW cap. California has a sophisticated system that accounts for variability and other differences in resource characteristics. Oregon is the only state in the region with a 10 MW cap for standard contracts and pricing based on a base load resource for variable energy resource QFs.

**Q. What are the ramifications of a higher eligibility cap in Oregon than those of neighboring states?**

A. In light of Idaho's decision to lower their eligibility cap to 100 kW, Oregon's 10 MW eligibility threshold could attract QFs based on an artificially high price.

**Q. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract? (Issue list 5B)**

A. Lowering the eligibility cap to 100 kW, as was adopted in Idaho, will effectively prevent QFs from gaming by disaggregating to get under the eligibility cap for a standard contract. In the event that the cap is not lowered to 100 kW, the criteria used to determine a "single QF" for purposes of eligibility for the standard should include several factors:

[5] 18 CFR § 292.304(c)(2)

- the QF is not jointly interconnected with other QFs regardless of ownership;
- the QF has its own, separate interconnection agreement;
- the QF is not tied into the same transformer as another QF;
- the QF satisfies Bonneville Power Administration's General Small Generator Interconnection Procedures (SGIP) Eligibility Criteria[6];
- the QF does not have the same ownership, developer, or same permit as another QF within one mile or on contiguously owned property; and
- the QF was not part of the disaggregation of a larger development such as a wind farm.

**Q. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"? (Issue list 5C)**

A. No, the eligibility cap for a standard contract should be 100 kW regardless of QF technology. The 100 kW represents a fair demarcation between a "small project" to which barriers to entry may truly exist, and a project that has considerably more resources at its disposal.

**Q. Can a QF receive Oregon's Renewable Avoided Cost price if the QF owner will sell the Renewable Energy Credits (RECs) in another state? (Issue list 5D)**

A. No, PGE recommends the policy articulated in Commission Order No. 11-505 continue. In that order the Commission opined that, in renewable deficiency periods for the utility, a QF should be offered the renewable avoided cost price and provide the RECs to the power purchasing utility.

[6] Available at http://transmission.bpa.gov/ts_business_practices/Content/5_Interconnection_Procedures/SGI.htm

## III. Avoided Cost Price Calculation

**Q. Should the Commission retain the current method based on the cost of the next avoidable resource identified in the Company's current IRP, allow an "IRP" method based on computerized grid modeling, or allow some other method? (Issue list 1Ai.)**

A. The Commission should retain the current method. As decided by the Commission on pg. 27 of Order No. 05-584, the Commission held that in a resource-deficient position, the variable and fixed costs of a natural gas-fired Combined Cycle Combustion Turbine (CCCT) would be used to calculate avoided cost. In a resource sufficient position, QF capacity will be valued based on the market (that is, the monthly on- and off-peak forward market prices as of the utility's avoided cost filing). The current method provides a fair and accurate measure of avoided cost, and thus we recommend its continuation.

**Q. Should there be a distinction drawn between what resources trigger the deficiency period for renewable avoided cost and traditional avoided cost?**

A. Yes. The resource that triggers the deficiency period for the renewable avoided cost is clear. As it was decided in Commission Order No. 11-505 pg. 4-5,

> Although we recognize that the avoidable renewable resource likely will be a wind project, we decline proposals to adopt a wind farm proxy to calculate avoided costs during periods of deficiency. We share concerns raised by ODOE and CREA that the use of a wind proxy presents more difficulties than our use of a CCCT proxy to calculate standard QF rates.

Building on the Commission's decision, PGE recommends defining the signal for demarcation between the resource sufficiency and resource deficiency periods in the traditional avoided cost as a non-renewable major resource addition, as identified in the IRP, for: 1) a base load resource, or 2) separate energy and capacity resources.

**Q. Should the avoided cost methodology be the same for all three electric utilities operating in Oregon? (Issue list 1Aii.)**

A. To the extent practical, yes.

**Q. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized? (Issue list 1B)**

A. No. The utilities currently levelize the capital costs of a plant in real dollars for each year during the deficiency period. Any further levelization creates avoided cost prices that do not reflect the avoided cost of the utility for a given point in time. As argued in UM 1129, PGE views levelization or partial levelization of payments as an increased risk to customers, as it frontloads the payments going to QFs and imposes any default risk directly on customers.

PGE is concerned that offering QFs the option to "levelize" or "partially levelize" prices would irreparably blur this distinction between resource sufficiency and resource deficiency, and act as a de facto end run around true avoided costs.

**Q. Isn't levelization just a way of "flattening" prices over time? How does this move risk to customers?**

A. No. Levelization is not simply a "flattening" mechanism, but rather is a way of moving payments from one period to the other. It moves deficiency period avoided costs into the sufficiency period and front loads prices for factors that otherwise escalate in the later years of a contract term, such as fuel and O&M. Under the current methodology, there are clear demarcations between resource sufficient and resource deficient periods, and there are different costs associated with these periods. Levelization distorts these distinct periods, and pulls an inappropriate share of the capital costs of the project into the sufficiency period and causes variable costs to be front loaded in the price. Customers are therefore paying higher prices earlier than they would have otherwise, given the current environment.

**Q. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different from the market price? (Issue list 1C)**

**A.** No. Removing the sufficiency period for QFs seeking renewal of a standard contract creates a scenario where the QF receives higher-than-avoided-cost prices via the standard contract. Customers would therefore pay higher rates during the sufficiency period, which incidentally is the time they do not need the energy. It also represents an end run around contract term limitations and is in contradiction to the principles of resource planning. The utility conducts resource planning through the IRP process. If a contract for energy or capacity is set to expire, the utility doesn't assume that all contracts, QF or otherwise, will be renewed. If a QF contract is renewed, it's a new contract with then current avoided cost prices.

**Q. Should the Commission eliminate unused pricing options? (Issue list 1D)**

**A.** Yes. The Deadband Index Gas Price Option and the Index Gas Price Option should be eliminated. Additionally, if the current 20 year term is upheld, PGE recommends that for all contract years that exceed 15 years, only the Mid-C Index Option should be offered as the avoided cost price for the contract term in excess of 15 years. We support market based avoided costs, especially for longer-term QF contracts. The Mid-C index approach is preferable, but we would retain the Index Gas Price Option over strictly fixed price QF contracts.

## IV. Renewable Avoided Cost Price Calculation

**Q. Should there be different avoided cost prices for different renewable generation sources? (Issue list 2A)**

A. No. Avoided costs should be based on the resource the utility is avoiding. In the current resource plan, PGE avoids only wind. A distinction is drawn between variable and baseload resources based on the traditional (baseload) vs. renewable (variable energy resource) avoided cost. To achieve differentiation for different renewable resources, we support the use of the FERC adjustment factors to adjust for specific characteristics of different QF technologies and characteristics relative to the avoided resource, including for standard contracts, as discussed throughout this testimony. As the Commission decided in Order No. 11-505, the avoidable renewable resource is the next major renewable resource identified in the IRP.

**Q. How should environmental attributes be defined for purposes of PURPA transactions? (Issue list 2B)**

**A.** PGE proposes to use the industry-standard WSPP Agreement definition of Environmental Attributes in both our schedule and QF power purchase agreement. That definition is found in Service Schedule R, Annex 1 – Definitions[7].

[7] The form contract is available at: http://www.wspp.org/filestorage/current_effective_agreement_042312_updated_071212.

**Q. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless a different treatment is specified by the contract? (Issue list 2C)**

A. No, this is unnecessary. We are comfortable with current Commission decisions that the QF retains the renewable attributes unless specified in the contract.

## V. Schedule for Avoided Cost Price Updates

**Q. Should the Commission revise the current schedule of updates at least every two years and within 30 days of each IRP acknowledgement? (Issue list 3A)**

A. Timely and reliable updates are essential to the accurate calculation of avoided cost prices. The utility should update annually the following price inputs: 1) forward energy prices applicable during the resource sufficiency period; 2) gas prices used during the deficiency period; 3) fixed and variable O&M per the IRP or updated action plan; and 4) the timing of the demarcation between the resource sufficiency and deficiency periods; to reflect the most recent market trends and resource needs. The utility should update <u>all inputs</u>: 1) within 30 days of each IRP acknowledgement, 2) at least every two years, and 3) within 30 days of awarding a bid for the major resource acquisition on which the demarcation of resource sufficiency and deficiency periods is based. We recognize that other parties have concerns with less frequent updates and hopes that annual partial updates alleviate those concerns.

**Q. Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate? (Issue list 3B)**

A. No. The ideal solution is Commission flexibility to consider utility and QF or other party requests on a case-by-case basis. It would be difficult to craft a set of criteria that would fairly balance the interests of both retail utility customers and QFs in this changing and evolving sector of the regulatory environment. As stated above, partial annual updates may alleviate other parties' concerns regarding this issue.

**Q. Should the Commission specify what factors – such as gas price or status of production tax credit – can be updated in mid-cycle? (Issue list 3C)**

A. No. Similarly to the issue regarding whether there should be a specific criteria governing updates, it's important to provide the Commission with flexibility and adaptability.

**Q. Should there be any restrictions on what aspects of the avoided cost prices associated with negotiated contracts can be updated?**

**A.** No. There should be no restriction on what factors can be updated during the negotiation process. Negotiated contracts tend to be larger capacity projects, with higher payments from the utility. Therefore, it is imperative to provide accurate estimates of avoided cost. As discussed above, the filed costs are only estimates and thus the inputs used in avoided cost price calculations should be updated in addition to applying the adjustment factors for characteristics of the specific QF.

**Q. To what extent can data from IRPs that are in the late stages of review and whose acknowledgement is pending be factored into the calculation of avoided cost prices? (Issue list 3D)**

A. The utility should have the flexibility to use the almost acknowledged IRP if the IRP and the avoided cost prices are set to be on the agenda for the same public meeting.

**Q. Are there circumstances under which the Renewable Portfolio Implementation Plan should be used in lieu of the acknowledged IRP for purposes of determining renewable resource sufficiency? (Issue list 3E)**

A. No. In Commission Order No. 11-505, it was unambiguously decided by the Commission that:

> The IRP process [is] the appropriate venue for determining when a utility is resource sufficient or deficient. The derivation of a renewable avoided cost fits well within the same framework and allows issues relating to resource sufficiency or deficiency to be addressed as part of an integrated whole. The IRP preferred portfolio and Action Plan provide the basis for deciding when a renewable resource would be avoided by QF purchases.

In the short amount of time that has passed since that order was issued, the fact has not changed that the IRP Action Plan is what forms the basis for actual resource acquisitions – both renewable and non-renewable, not the Renewable Portfolio Implementation Plan.

## VI. Price Adjustments for Specific QF Characteristics

**Q. Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology? (Issue list 4A)**

**A.** Yes. In the interest of obtaining an accurate avoided cost calculation and ensuring a fair balancing of interests between utility customers and the QF, costs associated with integration of variable energy (intermittent) resources should be included in the calculation of avoided cost prices: sometimes as an addition, and sometimes as a subtraction. We are flexible on the implementation method, specifically whether the adjustment is included in the prices in the schedule or as an adjustment in the power purchase agreement. The nature of the adjustment depends on several factors including: 1) whether the avoided cost prices are based on a firm/base load resource or a variable resource; 2) whether the QF is generating using a firm/base load or variable resource; and 3) in the case of a variable off-system resource, whether energy is balanced on an hourly basis via transmission into the utility's system.

**Q. Please provide a description of the adjustments under the various scenarios.**

A. Table 2 below outlines the specific scenarios and corresponding adjustments.

**Table 2**
**Integration Adjustments for Various Scenarios**

| | Avoided Cost Basis | QF Energy | Integration Adjustment |
|---|---|---|---|
| 1 | Firm or Base Load | Base Load | None |
| 2 | Firm or Base Load | Variable, In-System | Subtract Integration I |
| 3 | Firm or Base Load | Variable, Off-System Balanced Hourly | Subtract Integration III |
| 4 | Variable | Base Load | Add Integration I |
| 5 | Variable | Variable, In-System | None |
| 6 | Variable | Variable, Off-System Balanced Hourly | Add Integration II |

Notes:
Integration I = full integration cost (cost for day-ahead uncertainty, hour-ahead uncertainty, load following, and regulation)
Integration II = partial integration (cost for hour-ahead uncertainty, load following, and regulation)
Integration III = partial integration (cost for day-ahead uncertainty)

**Q. Why is an adjustment for partial integration necessary in two of the scenarios?**

**A.** In scenario 3, the adjustment is applied for the cost of day-ahead uncertainty only. This is due to the fact that the variable energy resource balancing service (VERBS) through BPA only provides hour-ahead and intra-hour balancing. Day-ahead balancing of QF energy is provided by the utility. Since the underlying resource is either firm or base load, the utility doesn't incur the cost of day-ahead uncertainty for the avoided resource. Therefore, the QF is imposing the cost of day-ahead uncertainly on the utility by exposing the utility to such uncertainty.

Scenario 6 provides the opposite situation. The avoided resource is a variable energy resource integrated by the utility. The integration costs are not included in the avoided cost, because they would be provided separately by peaking resources. Therefore, the QF should receive an adjustment for hour-ahead and intra-hour integration similar to that provided by VERBS.

**Q. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract? (Issue list 4B)**

A. The transmission arrangements between the qualified facility (QF) and a third-party transmission provider are outside the scope of this docket. Transmission matters are outside the jurisdiction of the Commission. (Commission Order No. 12-494). The QF must acquire appropriate transmission services that enable it to comply with the terms and conditions contained in the power purchase agreement that the QF signs. Transmission costs are the responsibility of the QF.

However, if the avoided resource identified in the utility's IRP is outside of the utility's balancing authority and the utility incurs wheeling costs, then those costs should be included in the avoided cost calculation. This is currently the case for the resource identified in PGE's IRP and PGE includes those costs in the avoided cost calculation.

**Q. For the record, please recount the seven factors of 18 CFR 292.304(e)(2). (Issue list 4C)**

A. The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

> (i) The ability of the utility to dispatch the qualifying facility;
> (ii) The expected or demonstrated reliability of the qualifying facility;
> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
> (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

> (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
> (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.

**Q. How should the seven factors of 18 CFR 292.304(e)(2) be taken into account? (Issue list 4C)**

A. If the eligibility cap for standard avoided cost pricing is lowered to 100 kW, then these seven factors should be considered for all negotiated contracts whether they are additions or subtractions. Although, as discussed above, we believe that these adjustment factors are applicable to all QFs, it is impractical to make adjustments for project smaller than 100 kW on the basis of materiality.

However, if the Commission keeps the eligibility cap at 10 MW, then each of the seven factors should be used by the utilities to adjust the <u>standard avoided cost prices</u>. Adjustments to standard rates are expressly allowed by PURPA under 18 CFR § 292.304(c)(3) which states:

> The standard rates for purchases under this paragraph:
> (i) Shall be consistent with paragraphs (a) and (e) of this section; and
> (ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

Paragraph (e) in the reference above provides the list of the seven adjustment factors and (a)(2) states, "Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases." The use of the seven adjustment factors in standard rates is consistent with PURPA.

## VII. Contracting Issues

**Q. When is there a legally enforceable obligation? (Issue list 6B)**

A. PGE supports a rule that no legally enforceable obligation may be created more than one year before the QF has or will have power available or a demonstrated construction period if longer than one year. While the recent FERC opinion, Cedar Creek Wind, LLC, 137 FERC P 61006 (2011), stated that a state Commission could not limit the method through which a legally enforceable obligation ("LEO") may be created to an executed contract, the Commission may determine the date on which an LEO is incurred. West Penn Power Co. 71 FERC P 61,153 (1995) and Power Resources Group, Inc., 422 F.3d 231, 238 (2005). The Texas Commission has adopted a 90-day rule, which provides that no LEO can be established more than ninety days before the QF has power available, or will have power available. Thus, under this approach, QFs cannot game the system by locking down QF rates well in advance of commercial operation, and actual avoided costs are more likely to be reflected in prices paid to the QF. Moreover, filed avoided cost prices are much more likely to be accurate (not necessarily lower or higher) if the date on which the LEO and prices are established is close to the QF's actual delivery of net output. For these reasons, PGE recommends a similar approach, but with a rule that allows one year or a demonstrated construction period if longer than one year.

**Q. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract? (Issue list 6I)**

A. We recommend the current practice for a newly constructed QF: a contract term of up to 20 years with the last 5 years based on a daily market index. The current practice balances the interests of utility customers and fosters new QF development. It provides a way for the QF to recover their investment with adequate financing while limiting divergence from estimated avoided costs.

However, terms for existing QFs should not exceed 5 years. Those QFs generally have already recovered their investment and should no longer be financing a project.

## VIII. Qualifications

**Q. Mr. Macfarlane, please state your educational background and qualifications.**

A. I received a Bachelor of Arts business degree from Portland State University with a focus in finance.

Since joining PGE in 2008, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on pricing and regulatory issues.

From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, OR where I developed, prepared, and reviewed financial analyses used in investor vs. broker litigation.

**Q. Mr. Morton, please state your educational background and qualifications.**

A. I received my degree in accounting from Oklahoma State University.

I joined PGE in 2003 as a Risk Management analyst for Power Operations. Since then, I have worked in Real-time Operations, Merchant Transmission and currently hold a position in Structuring and Origination.

In 2008, I took a position at Highland Energy in Butte, MT as there Senior Short-term energy trader with a focus on physically trading energy throughout the WECC. I returned to PGE in January of 2009.

# List of Exhibits

| **PGE Exhibit** | **Description** |
|---|---|
| 101 | PGE Wind Integration Study Phase II (on CD) |

# PGE Wind Integration Study Phase II

Prepared by:

Portland General Electric

and

620 Mabry Hood Road, Suite 300

Knoxville, TN 37932

September 30, 2011

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## 1. EXECUTIVE SUMMARY

In 2007, given projections for a significant increase in wind generating resources, Portland General Electric (PGE) began efforts to determine forecast costs associated with self-integration of wind generation. This effort entailed developing detailed (hourly) data and optimization modeling of PGE's system using mixed integer programming (MIP). This study was intended as the initial phase of an on-going process to further estimate wind integration costs and refine the associated model.

In October 2009, PGE began Phase 2 of its Wind Integration Study and contracted for additional participation from EnerNex (a leading resource for electric power research, plus engineering and consulting services to government, utilities, industry, and private institutions), who provided input data and guidance for Phase 1. A significant driver of Phase 2 was the expectation that the cost for wind integration services, as currently provided by the Bonneville Power Administration (BPA), would increase significantly as growing wind capacity in the Pacific Northwest would exceed the potential of BPA's finite supply of wind-following resources.[1] In addition, it is PGE's contention that BPA's variable energy services rate and subsequent generation imbalance charges represent only a portion of the total cost to integrate wind, as calculated in this study.

A significant goal for Phase 2 of the Wind Integration Study was to include additional refinements for estimating PGE's costs for self-integration of its wind resources. As in Phase 1 of the Wind Integration Study, Phase 2 has also sought input, deliverables, and feedback from a Technical Review Committee (TRC) and other external consultants. Since launching Phase 2, PGE has reprogrammed and refined the wind integration model, updated the study, and also held public meetings to discuss progress and modeling

[1] On July 26, 2011, BPA posted the "Administrator's Final Record of Decision" for the BP-12 Rate Proceeding. The Variable Energy Resource Balancing Service Rate decreased by 4.7% for FY 2012-2013. Although the rate has decreased for this current rate period, PGE continues to anticipate future rate increases as the level of service provided by BPA continues to decline due to policy decisions such as BPA's "Interim Environmental Redispatch and Negative Pricing Policies" issued May 13, 2011.

details. The public meetings were attended by staff representatives from the Oregon Public Utility Commission (OPUC), the Oregon Department of Energy (ODOE) and other interested parties that have participated in PGE's 2009 Integrated Resource Planning proceeding (IRP – OPUC Docket No. LC 48). In addition to these public reviews, the Phase 2 data and methodology has been vigorously evaluated by the TRC and EnerNex, who provided valuable insight and information associated with wind integration modeling.

The Phase 2 model consists of mixed integer programming using the General Algebraic Modeling System (GAMS) programming and a Gurobi optimizer. This provides greater efficiency, calculation speed, and flexibility for the more rigorous requirements of Phase 2 calculations. Additional improvements in Phase 2 include:

- Three-stage scheduling optimization with separate Day-Ahead, Hour-Ahead, and Within-Hour calculations;
- Refined estimates of PGE's reserve requirements; and
- Isolation for cost purposes of the components of ancillary services (i.e., Day-Ahead uncertainty, Hour-Ahead uncertainty, load and Load Following for Wind, and Regulation).

The results of the study indicate that PGE's estimated self-integration costs are $11.04 per MWh and within the range calculated by other utilities in the region. Specific model assumptions are detailed below but, in short, reflect a potential 2014 state in which PGE seeks to integrate up to 850 MW of wind (to meet 2015 the Oregon physical RPS requirement) using existing (by 2014) PGE resources and associated operating limitations. This is intended to set a baseline from which subsequent remediation actions can be assessed. As the supply of variable resources and associated demand for flexible resources increases over time, subsequent phases of the Wind Integration Study can assess these changes.

## 2. INTRODUCTION

### 2.1 REASONS FOR THE PHASE 2 WIND INTEGRATION STUDY

Because wind integration costs directly affect PGE's resource acquisitions and their comparative economic evaluation, in Commission Order No. 10-457, at 25, the OPUC directed that:

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

Another driver to the Study is the expectation that BPA will reach the limit of its available wind-integrating resources in the not-too-distant future. Currently, BPA's Federal Columbia River Power System (FCRPS) provides a majority of the wind integration capability in the Pacific Northwest. However, with regional wind capacity increasing from 250 MW to 3,500 MW from 2005 to 2010, and expectations of an additional 9,000 MW during the next 5 years, PGE expects BPA's finite resources for integrating wind will become increasingly costly and constrained. Hence, PGE needs to understand its own integration capabilities and costs.

As PGE expands its wind generating capacity to satisfy the 2015 and 2020 Oregon Renewable Energy Standard (RES) requirements, PGE's IRP Action Plan has identified the need for both traditional seasonal capacity (to which the firm contribution of variable resources is assumed at 5% of nameplate) as well as flexible generation supply to integrate variable supply. Pursuant to the Action Plan, PGE is issuing two Requests for proposal (RFPs) to acquire:

- Up to 400 MW of additional wind generation to reach physical compliance with the 2015 RPS standard and

- Dual-purpose flexible resources to provide seasonal capacity and Dynamic Capacity[2] suitable for self-integration of variable wind generation.

This Wind Integration Study provides the estimated wind integration cost for evaluating wind bids (including PGE's own benchmark proposal) as well as the indicative dispatch requirement for a new flexible resource.

## 2.2 Study Assumptions

Phase 2 of the Wind Integration Study is based on existing PGE owned and contracted resources (as of 2014) plus 400 MW of additional wind generation as a proxy for meeting our Action Plan target of 122 MWa of new renewables. For generating resources, PGE has a varied mix of generation consisting of 1,827 MW of thermal generation (670 MW coal-fired and 1,157 MW gas-fired), 489 MW of PGE-owned hydro generation, approximately 300 MWa of long-term hydro power purchase agreements, and 550 MW of wind generation. (One-hundred MW of the wind plant receives long-term third-party wind integration and is not included for this study.) Because PGE is currently a "short" utility, the remainder of its load is covered by market transactions – term contracts and spot market purchases. Although future requirements for capacity and energy resources are identified in the most recent IRP (acknowledged by Commission Order No. 10-457), these were not included in the Wind Integration Study because they are not yet identified (RFPs are currently under development).

Because PGE's service territory resides entirely within Oregon, we are subject to Oregon's RES, which establishes increasing percentages of a utility's load that need to be met by renewable resources.[3] In order to meet this requirement, PGE's IRP also includes an additional 122 MWa of renewable resources to be installed by 2015. Because wind energy is the resource in this region that is currently available in economic quantity, PGE

[2] Dynamic Capacity is the capacity used/needed to balance the within-hour variability brought on by the combination of variable energy resources and load.
[3] The standard starts at 5% in 2011, then increases to 15% in 2015, 20% in 2020, and 25% in 2025.

has conservatively assumed for purposes of this study that the majority of the requirement will be met with wind – approximately 400 MW of new nameplate wind. As this represents a statutory requirement that directly impacts PGE's wind integration efforts, PGE included it in the current study. Additional assumptions within the model include:

- 2014 is the Wind Integration Study year.
- 2005 actual data was used for hydro flows, wind generation, and load forecast errors.
- 2014 Mid-Columbia (Mid-C) electricity market prices (as used for economic dispatch in the wind integration model) were simulated with AURORAxmp. This is the model used in the Integrated Resource Plan (as discuss in Section 5.3.2, below.
- PGE's 450 MW Biglow Canyon Wind Farm, located in Sherman County, Oregon, is self-integrated.
- The 400 MW of wind resources, for purposes of developing an annual capacity factor and hourly output profile, are assumed to be located east of Biglow Canyon in the Columbia River Gorge.
- PGE resources available to provide ancillary services:
    - PGE's contractual share of Mid-Columbia hydro generation, which diminishes over time;
    - Two-thirds of Pelton-Round Butte hydro generation
    - Beaver gas-powered generation, in both combined cycle and simple cycle modes.
- PGE resources not available to provide ancillary services:
    - Port Westward gas-powered generation
    - Coyote Springs gas-powered generation
    - Boardman coal-powered generation
    - Colstrip coal-powered generation

Specific details of PGE's resources and their effective uses for ancillary services are provided in Section 5.4.1, below.

In Section 3 of this report, we summarize the public process and third-party review undertaken to ensure that PGE has accomplished its goal to build an accurate representation of its potential for self-integration using base-line assumptions and robust modeling techniques. In Section 4, we describe the regional wind characteristics used to establish PGE's integration requirements during Day-Ahead, Hour-Ahead, and Within-Hour time frames. In Section 5, we provide a detailed description of PGE's wind integration methodology including the programming tools, data assumptions, modeling approach, and calculations for reserves and other variables. In Section 6, we provide a summary of the results and conclusions of our findings. Section 7 provides appendices of supporting detail and documentation.

## 3. PUBLIC PROCESS AND REVIEWS

An important objective of Phase 2 of the Wind Integration Study was to assure a robust review by external parties of the logic, assumptions, and data within the model to ensure their accuracy and thereby comply with the Commission directive to have a "wind integration study that has been vetted by regional stakeholders." (Op. cit.) To achieve this, several groups were invited to participate in PGE's efforts.

### 3.1 TECHNICAL REVIEW COMMITTEE (TRC)

PGE's TRC consisted of the following members[4]:

- J. Charles Smith, Executive Director, Utility Wind Integration Group (UWIG)
- Michael Milligan, Ph.D., Principal Analyst, National Renewable Energy Laboratory (NREL)
- Brendan Kirby, P.E., Consultant with NREL
- Michael Goggin, Manager of Transmission Policy, American Wind Energy Association (AWEA)

The constitution, functions and requirements of the TRC were determined in accordance with UWIG's "Principles for Technical Review Committee (TRC) Involvement in Studies of Wind Integration into Electric Power Systems" as provided in Appendix A.

The TRC provided timely guidance that improved both the study's methodology and data integrity. By means of periodic reviews, the TRC provided assistance on many issues including:

- Wind data development and research into 3TIER's wind modeling methodology;
- Research into NREL Mesoscale data (commonly known as "3-day seams anomaly");

[4] Brad Nickells, Director of Transmission Planning for the Western Electric Coordinating Council, was an original member of PGE's TRC. He withdrew due to a change in his job requirements.

- Definition of the time basis for deriving the Hour-Ahead forecast error;
- Identification of an error in the NREL wind data post power curve conversion;
- Distinguishing between Regulation and Regulating Margin.

In accordance with UWIG's TRC Principles agreement, PGE's TRC, in a joint letter displayed in Appendix B, "endorses the study methodology, execution, and this final report" of PGE's Phase 2 Wind Integration Study.

## 3.2 MIXED INTEGER PROGRAMMING CONSULTANTS

PGE employed two outside subject matter experts, Jeff Linderoth, Ph.D. and Jennifer Hodgdon, Ph.D to assist in the development of the mixed integer programming (MIP) based optimization model that PGE used to calculate costs associated with integrating wind into the PGE system. Dr. Linderoth translated PGE's model from the prior Excel-based software platform to the GAMS modeling language. Dr. Linderoth also provided guidance on model formulation and solution strategy, including guidance with selecting the Gurobi MIP solver. Dr. Hodgdon developed the Excel and visual basic code that controls model execution and data input and output.

Jeff Linderoth is an Associate Professor in the departments of Industrial and Systems Engineering and Computer Sciences (by courtesy) at the University of Wisconsin-Madison, joining both departments in 2007. He received his Ph.D. degree from the Georgia Institute of Technology in 1998. Professor Linderoth's research focuses on modeling and solving real-world, large-scale optimization problems. Specific research areas include integer programming and stochastic analysis for decision making under uncertainty. His research places a particular emphasis on developing high-performance, distributed optimization algorithms and software.

Jennifer Hodgdon is owner and Principal Consultant for Poplar ProductivityWare, Seattle and Spokane, WA. She received her Ph.D. degree from Cornell in 1993 and has more than fifteen years of experience as a professional software developer, using a variety of languages and operating systems for many different applications and in various industries.

### 3.3 PUBLIC MEETINGS

PGE held three public regional stakeholder meetings in which all members of the service list from PGE's 2009 IRP (OPUC docket LC 48) were invited to attend and provided the opportunity to examine in detail, the methodology of the study and the results. The meetings were held on February 23, May 18, and August 29, 2011 and attended by OPUC staff and other interested parties. An attendee list for each meeting is included as Appendix E. Attending by phone or in person were certain members of the TRC and EnerNex.

During these meetings, PGE provided detailed explanations of the modeling approach, methodology, data inputs, assumptions, bases for cost breakdowns and reserves, and the actual integration costs. PGE also answered numerous questions and engaged in extensive discussion regarding details of the Wind Integration Study.

As part of the February and May meetings, PGE requested that attendees provide comments and recommendations within two weeks of the meetings. PGE also submitted copies of the presentations, including the request for comments and recommendations, to all members of PGE's 2009 IRP service list. For the February meeting, PGE received no comments. Subsequent to the May meeting, PGE received comments from the Renewable Northwest Project (RNP) regarding several aspects of the study. A copy of the comments is provided as Appendix C. PGE's responses to those comments are provided as Appendix D. No other party filed comments.

# 4. WIND INTEGRATION ISSUES & METHODOLOGY – OVERVIEW

## 4.1 Wind Data Source

The development of wind power capacity factors and shapes representative of wind generation operations was established initially by using the NREL Western Wind Resource Database (WWRD). The database is a result of 3TIER Group's modeling of wind resources across the entire western United States to generate a consistent wind dataset at a 2-km, 10-minute resolution based on actual wind measurements for the years 2004, 2005 and 2006. The NREL database converted wind to power based on the power curve for Vestas V90 3MW turbines.

The WWRD database provided the following wind data for the study:

- Date and time (mm/dd/yyyy hh:mm:ss.sss)
- Wind speed (mph)
- Actual wind power output in MW at 10 minute intervals
- Day-Ahead forecast power in MW at 1 hour intervals
- Years 2004, 2005 and 2006
- Site Id
- Site location (Longitude, Latitude)

## 4.2 Wind Site Power Output

Virtual wind farms of 400MW in Gilliam County east of Biglow Canyon in the Columbia River Gorge and 450MW in Sherman County located in Biglow Canyon (see Figure 1, below) were developed by selecting multiple wind sites and aggregating the wind site outputs from the NREL database. Capacity factors for the 400 MW and 450 MW wind farms using the V90 turbines were 21.2% and 26.0% respectively.

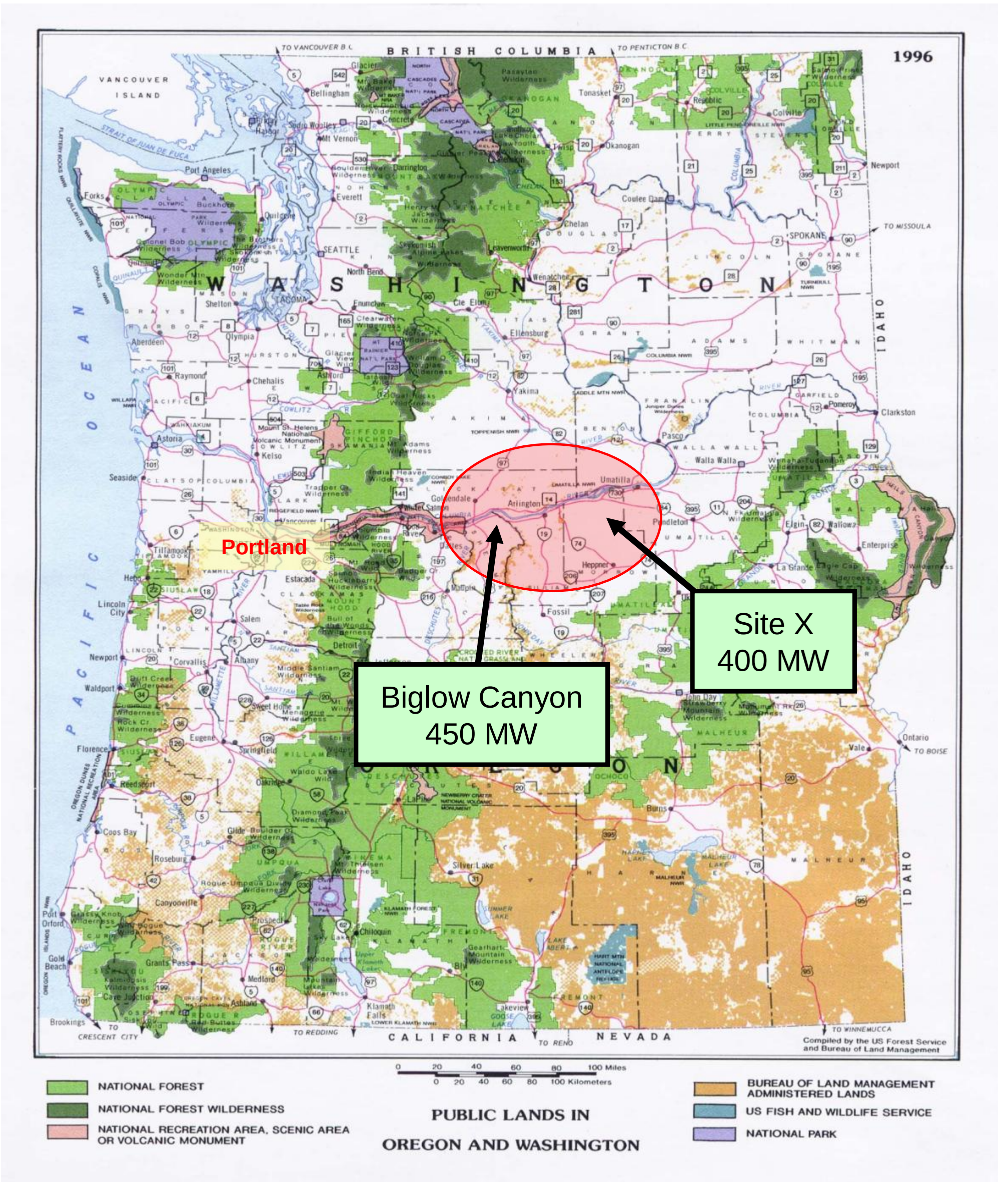


**Figure 1: Location of Biglow Canyon and Site X**

V90 turbines were not expected to be selected for use at these sites. Instead, a Siemens 2.3 MW turbine would be a more likely candidate considering the wind speeds in the region. The power curve for the Siemens' turbine is different from the V90 power curve in that it provides higher per unit output at lower wind speeds see Figure 2. Using the wind speed provided in the WWRD database and applying the power curve provides the turbine output. The resulting Siemens' 2.3 MW energy production increases the capacity factor for the 400 MW and 450 MW wind farms to 28.1% and 33.8% respectively (see Table 1).

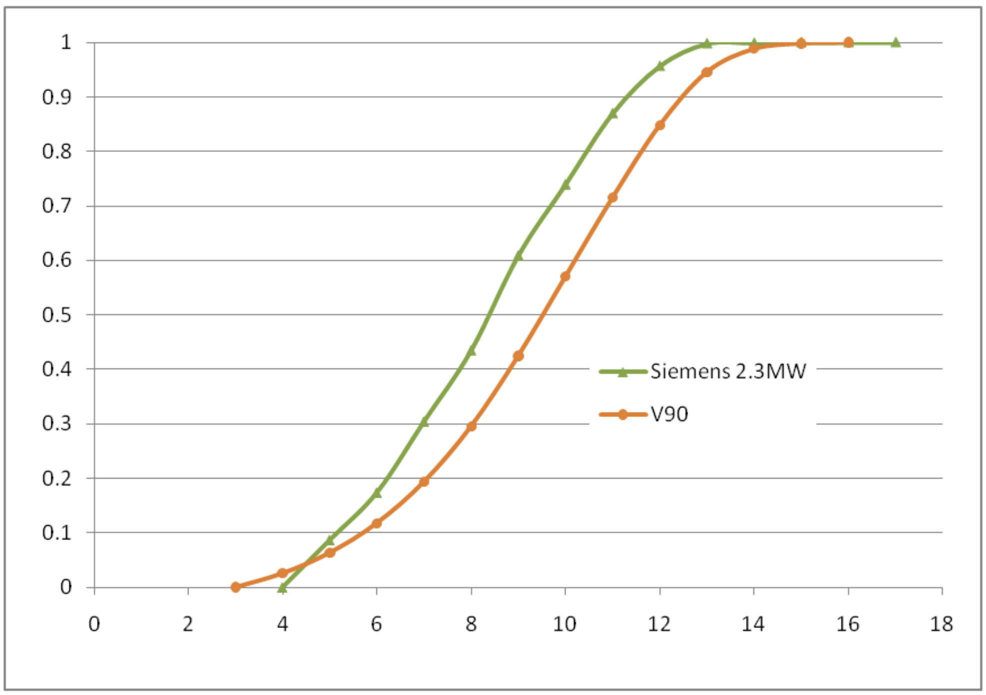


**Figure 2: V90 and Siemens 2.3 MW power curves**

**Table 1: Capacity factor comparison V90 vs. Siemens 2.3 MW turbines (V90 is used in NREL database)**

| Capacity Factors | 400 MW aggregated sites | 450 MW aggregated sites |
|---|---|---|
| V90 3.0 MW | 21.2% | 26.0% |
| Siemens 2.3 MW | 28.1% | 33.8% |

## 4.3 WIND SITE FORECASTS

Performing effective resource scheduling requires several inputs, one of which is a forecast schedule for load and resources. Short-term load forecasting for purposes of scheduling resources is complex and requires considering the combined effect of several parameters such as weather, day of week, time of year, historical patterns, and known events like holidays. The PGE's current operational schedule for forecasting loads (and associated resource needs) is shown in Table 2. Forecasts (load and resource) generated on Monday, Tuesday and Wednesday provide a one Day-Ahead forecast. The forecast provided on Thursday yields a one Day-Ahead forecast for Friday and a two Day-Ahead forecast for Saturday. The forecast for Friday provides a two Day-Ahead forecast for Sunday and a three Day-Ahead forecast for Monday.

**Table 2: Pacific Northwest Day-Ahead scheduling process**

| Scheduling Day | Scheduled Day |
|---|---|
| Monday | Tuesday |
| Tuesday | Wednesday |
| Wednesday | Thursday |
| Thursday | Friday and Saturday |
| Friday | Sunday and Monday |

The forecast wind data extracted from the WWRD database provides a one Day-Ahead forecast for *every day of the week*, which does not match current PGE scheduling practice. In other words, the Friday forecast is for Saturday, the Saturday forecast is for Sunday etc. In order to augment the NREL WWRD to reflect current PGE scheduling practices, PGE provided hourly forecast data to EnerNex from 2007 through 2010 for Biglow Canyon, along with the corresponding actual generation data. From this, it was

EnerNex

possible to derive the error statistics for the forecast of each Scheduled Day of the week. Figure 3, below, depicts the Mean Absolute Error (MAE) for each consecutive hour for one, two and three Day-Ahead forecasts.

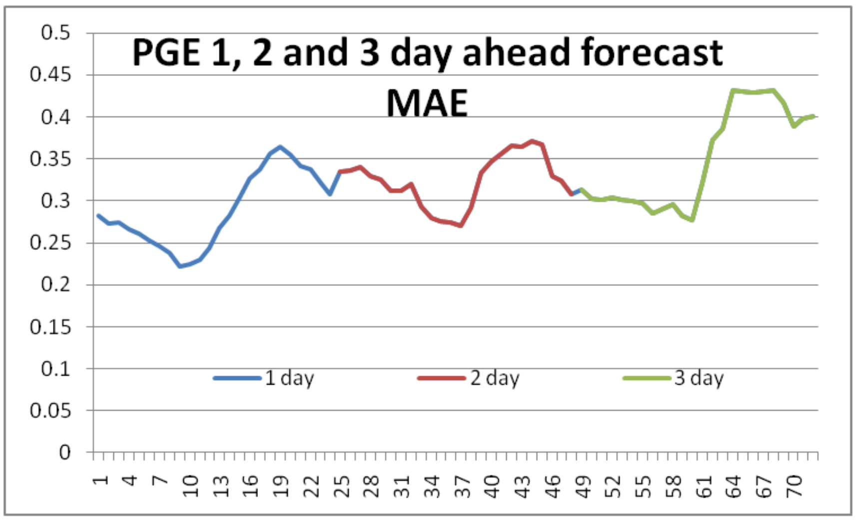


**Figure 3: Mean Absolute Error for PGE wind forecasts of 1, 2, and 3 days ahead**

As mentioned above, the WWRD forecast data provides only a Day-Ahead forecast not a two or three Day-Ahead forecast. Wind forecasts for Saturday, Sunday and Monday from the WWRD database would not represent the increase in forecast error that PGE experienced with the historical data. The Day-Ahead forecast from the WWRD database for Saturday, Sunday and Monday were modified for this study such that the forecast energy from the WWRD data would not change, however the forecast error would increase to approximate the same increase in error as the historical data. As can be seen in Figure 4, the Day-Ahead forecast was not changed, while the two Day-Ahead forecast was modified such that the forecast error increased by 14.1% and the three Day-Ahead forecast error increased by 24.1%. Although slightly higher than the PGE forecast error, the MAE for the adjusted WWRD forecast error for the one, two and three Day-Ahead forecasts are 17.8%, 20.3% and 22.1% respectively.

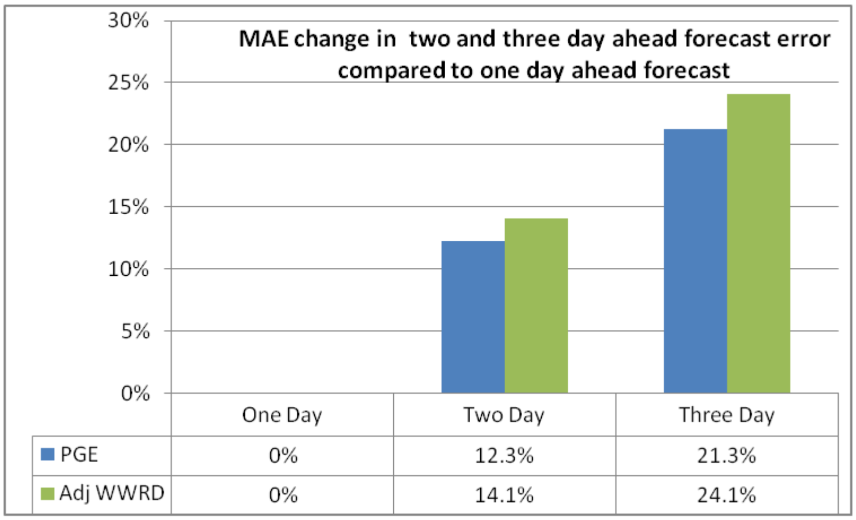


**Figure 4: PGE forecast compared to adjusted WWRD forecast**

# 5. WIND INTEGRATION METHODOLOGY

## 5.1 OVERVIEW

Phase 2 of the Wind Integration Study seeks to determine the effect on system operating costs resulting from the introduction of wind resources on PGE's system; specifically, of PGE employing its own generating resources to integrate 850 MW of wind capacity in 2014. The incremental costs of wind integration due to the incremental reserve requirements are isolated by modeling total system costs with and without the incremental reserve and other operational requirements. The cost of wind integration in this study is measured as the savings in system operating costs that would result if wind placed no incremental requirements on system operations. The cost savings are conditional on the ability of a given set of generation resources to adjust for the variability and uncertainty of wind generation.

In the remaining sections of this chapter, we will discuss:

- The need for Dynamic Capacity (Section 5.2)
- The modeling tools used by PGE in implementing the study (Section 5.3.)
- Data sources, data generation, and modeling assumptions (Section 5.4.)
- The logic and structure of the modeling approach (Section 5.5.)
- Methods for calculating incremental reserves for integrating wind (Section 5.6.)

## 5.2 THE NEED FOR DYNAMIC CAPACITY

One of the challenges that PGE faces as a system operator is that we are required to match our system generation to our system load while that load is constantly changing, moment-to-moment. As PGE adds variable generation, such as wind, to its portfolio of resources, that challenge becomes more demanding as both generation and load can change moment-to-moment. Addressing the challenge of matching total generation with load in real time requires flexible generation that can change production levels over a significant range of operations, and do so in a short time frame. PGE refers to this capability as Dynamic Capacity. The challenge facing scheduling entities in the Pacific Northwest is that currently power, predominantly from trades, is scheduled for no less than one hour blocks.[5] Consequently, any response to changes in load (and wind) must be managed with generators over which PGE has physical control and that have been positioned at the start of the hour to support such dynamic generation changes.

To provide Dynamic Capacity, utilities require certain types of generators. One type that cannot be employed is a base load generator that produces a constant amount of energy across the hour, as is shown in the "Energy" graph depicted in Figure 5, below. In this example, the generator has a maximum capacity of 50 MW and is producing 50 MW of energy for the entire hour. At the end of the hour, the integrated energy production will be 50 MWh and it provides no Dynamic Capacity.

When a generator is positioned to provide Dynamic Capacity, it does so by being able to operate through the entire nameplate range of the generator across the hour. This hourly generation profile will look like the "Capacity" graph in Figure 5, below. In this case the integrated energy production across the hour is 25 MWh.

When the generator is operated to provide both energy and capacity, the generation profile will look like the "Energy and Capacity" graph in Figure 5, below. In this example, the 50 MW generator is producing 25 MW of energy for the entire hour (25 MWh) and 25 MW of Dynamic Capacity range for the hour (12.5 MWh). At the end of the hour, the integrated energy production for the hour will be 37.5 MW.

[5] Recently, there has been movement toward allowing 30-minute scheduling in the Pacific Northwest.

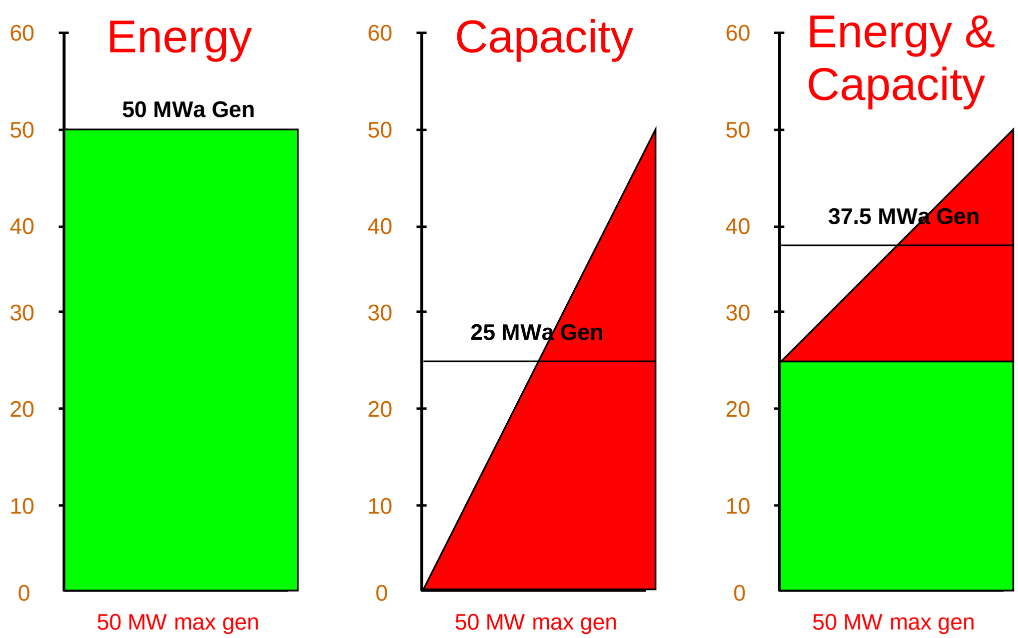


**Figure 5: Examples of 50 MW generator operating for one hour**

To fully address the demands of Dynamic Capacity, utilities must maintain a certain level of Operating Reserves. Generating capacity must be set aside from normal load serving operations for Load Following, Regulation, and Contingency Reserves (Spinning Reserves and Non-Spinning Reserves). Each of these has a capacity requirement and the capacity requirement is cumulative. Load Following and Regulation also have an energy requirement that must be assigned to the generator that is carrying the services. Contingency Reserves have requirements for storage (for hydro plants) or fuel (for thermal plants). For Hydro, the pond must have sufficient water to produce the energy reserved for the hour. For Thermal, fuel must be available to operate at the level of Spinning and Non-Spinning Reserves allocated for the hour. Table 3, below summarizes these requirements:

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**Table 3: Requirements for Operating Reserves**

| Requirement | Capacity | Energy | Fuel Source with Storage |
|---|---|---|---|
| Load Following | X | X | |
| Regulation | X | X | |
| Spinning Reserves | X | | X |
| Non Spinning Reserves | X | | X |

Figure 6 below, provides an example of the reserve requirements and modeling for Dynamic Capacity involving a generator with a minimum generation level of 5 MW and a maximum generation output of 55 MW. Within the hour, the unit can operate between 5 MW and 55 MW, providing 50 MW of Dynamic Capacity. When modeling this generator, we first reserve the capacity and energy production associated with Dynamic Capacity requirements. Any remaining operating range is available for *discretionary energy production*. In this case, the unit is providing 6 MW of operating range for Regulation. Throughout the hour, the generator will produce 3 MWa energy associated with supporting the 6 MW of Regulation range. This is reflected in Figure 6 as:

- ½ of the Regulation range is added to the minimum output to reserve this generating space for the downward Regulation requirement; and
- ½ of the Regulation range is subtracted from the maximum output to reserve this generating space for the upward Regulation requirement.

Consequently, the new minimum generation is 8 MW (5 MW + 3 MW), and the new maximum generation is 52 MW (55 MW – 3 MW).

The Load Following requirement is treated similarly to Regulation. However, it may be unidirectional since the load trend is typically rising in the morning and declining in the evening, Similarly, when wind is at zero it can only trend up and when wind is at full output it can only trend down. In the example in Figure 6, the Load Following range assigned to this generator is 20 MW, which means that the unit will produce 10 MWa of energy in the hour to provide 20 MW of Load Following range. This is reflected in Figure 6 as:

- ½ of the Load Following range is added to the minimum output to reserve this generating space for the downward Load Following requirement; and
- ½ of the Load Following range is subtracted from the maximum output to reserve this generating space for the upward Load Following requirement.

The new minimum generation is now 18 MW (8 MW + 10 MW) and the new maximum generation is 42 MW (52 MW – 10 MW).

Contingency Reserves (Spinning and Non-Spinning) do not have an hourly energy production until they are called upon. In the example in Figure 6, the unit is supplying 2 MW of Spinning Reserves and 2 MW of Non-Spinning Reserves. Both are subtracted from the adjusted maximum to reserve this capacity on the generator. At this point, the minimum after accounting for Contingency Reserves remains unchanged at 18 MW. The new maximum, however, is reduced to 38 MW (42 MW – 2 MW [Spinning] – 2 MW [Non-Spinning]).

As a result of these regulation, load following, and reserves requirements, the generator in Figure 6 has a remaining range to dispatch for discretionary energy production between 18 MW and 38 MW. In summary, the unit depicted in Figure 6 has the following generation capabilities:

- 5 MW of minimum generation
- 30 MW of Dynamic Capacity
    - 6 MW of Regulation
    - 20 MW of Load Following

- 2 MW of Contingency Reserves (Spinning)
- 2 MW of Contingency Reserves (Non-Spinning)

- 20 MW of discretionary energy.

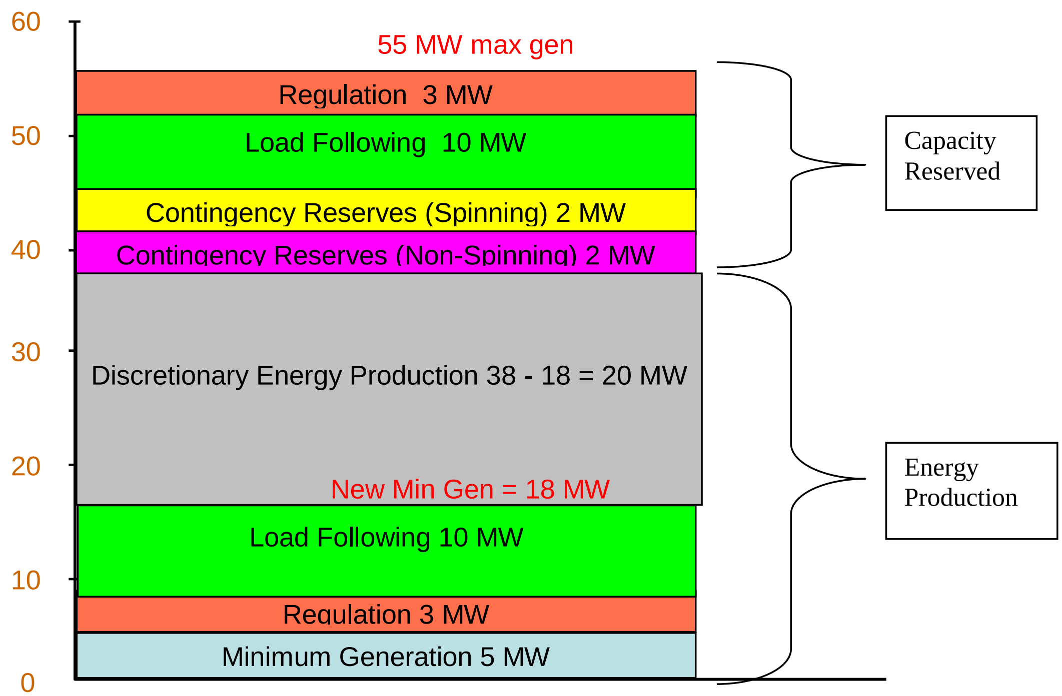


**Figure 6: Example of modeling a generator supplying Dynamic Capacity**

## 5.3 Modeling Tools

### 5.3.1 *System Optimization*

PGE has developed an hourly dispatch model to estimate operating costs for the PGE system. This is the principal model used in the Wind Integration Study. The model has a cost minimization objective function and a set of equations/inequalities which detail constraints on the operation of PGE's system. This model was constructed using three commercially available software products: GAMS, Gurobi, and Microsoft Excel. GAMS is used to program/compile the objective function and operating constraint equations.

Gurobi is used to solve the resulting constrained optimization problem. Excel (and associated VBA code) is used for data input, reporting model results, and overall model control.

GAMS is a high-level modeling system for mathematical programming and optimization. It consists of a language compiler and a set of integrated high-performance solvers. GAMS is tailored for complex, large-scale modeling applications, and facilitates the construction of large maintainable models that can be quickly adapted to new situations.

The Gurobi Optimizer is a state-of-the-art solver for linear programming (LP), quadratic programming (QP), and mixed-integer linear/quadratic programming (MILP and MIQP). It was designed to exploit modern multi-core processors. For MILP and MIQP models, the Gurobi Optimizer incorporates the latest methods including cutting planes and powerful solution heuristics. Models benefit from advanced presolve methods to simplify models and reduce solve times.

### 5.3.2 *Aurora Model*

PGE relies on the AURORAxmp Electric Market Model[6] in its IRP for developing the long-term forecast of wholesale electricity prices and for portfolio analysis, as detailed in Chapter 10 of PGE's 2009 Integrated Resource Plan.[7] AURORAxmp is a model that simulates electricity markets by NERC (North American Electric Reliability Corporation) area, detailing: 1) resources by geographical area, fuel, and technology; 2) load by area; and 3) transmission links between areas. As stated in the IRP, PGE uses it to conduct fundamental supply-demand analysis in the Western Electric Coordinating Council (WECC). AURORAxmp is also used to forecast 2014 hourly electricity prices for the Pacific Northwest. These prices were then input into the Wind Integration Model, see Figure 7.

[6] A more detailed description of the model is on the vendor's web-site http://www.epis.com/aurora_xmp/
[7] The Plan is available on Portland General Electric's web-site: http://portlandgeneral.com/our_company/news_issues/current_issues/energy_strategy/docs/irp_addendum.pdf

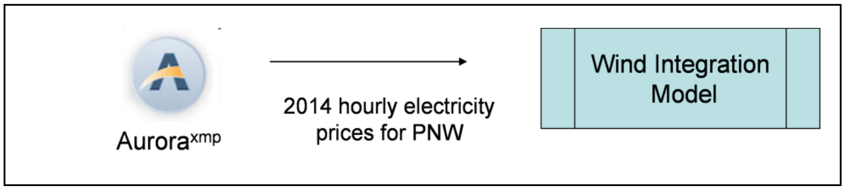


**Figure 7: Forecast of electricity prices for 2014**

The methodology and underlying assumptions used to project WECC prices to 2014 are detailed in the 2009 IRP Addendum, chapters 10.2 and 10.3 (see also Section 5.4.3, below). However, certain updated macroeconomic assumptions were used when new information was made available. More detail on this is provided in Section 5.4, below.

## 5.4 DATA ASSUMPTIONS

### 5.4.1 *Plants Available for Integration*

As noted in Section 2.2, above, PGE has a varied mix of generating resources but only a subset of these resources has the capability to provide the Dynamic Capacity required for wind integration. Specifically, we do not use the following thermal resources as part of our modeling:

- Port Westward (excluding the duct burner) – plant technology was not designed to provide Dynamic Capacity.
- Boardman – this baseload coal plant has a limited dynamic range. It is unavailable due to PGE's interpretation of BPA's Dynamic Transfer Operating and Scheduling Requirements Business Practice. (Please refer to PGE's reply to RNP Comments in Appendix D for more detail.)
- Coyote – unavailable due to PGE's interpretation of BPA's Dynamic Transfer Operating and Scheduling Requirements Business Practice. (Please refer to PGE's reply to RNP Comments in Appendix D for more detail.)
- Colstrip – PGE does not directly control the operation of this baseload coal plant.

As described in Section 5.2 above, for resources that are able to provide ancillary services, only the portion not used for discretionary energy production is available for Dynamic Capacity. A summary of PGE's resources and their specific ancillary services capabilities is provided in Table 4 and Table 5, below.

**Table 4: PGE's hydro and coal generation availability for ancillary services**

| | Operational Reserve | Mid-C | Round Butte | Pelton | Boardman | Colstrip |
|---|---|---|---|---|---|---|
| Energy | | √ | √ | √ | √ | √ |
| Capacity | Load Following | √ | √ | √ | | |
| | Regulation | √ | √ | √ | | |
| | Spinning Reserve | √ | √ | √ | | |
| | Non-Spinning Reserve | √ | √ | √ | | |

**Table 5: PGE's gas and other generation availability for ancillary services**

| | Operational Reserve | Port Westward | Duct Burner | Coyote | Beaver-SC | Beaver-CC | DSG |
|---|---|---|---|---|---|---|---|
| Energy | | √ | √ | √* | √ | √ | |
| Capacity | Load Following | | √ | | √ | √ | |
| | Regulation | | | | √ | | |
| | Spinning Reserve | | √ | | √ | √ | |
| | Non-Spinning Reserve | | √ | | √ * | √ | √ |

* Beaver has to be operating to provide both spinning and non-spinning contingency reserve.

### 5.4.2 *Fuel Prices*

PGE relies on independent third-party sources to project fuel prices. Specifically, to be consistent with our IRP methodology,[8] a combination of PIRA forecasts and PGE trading curves were used. Variable transportation costs were then added to the commodity price in order to compute the delivered cost of the fuel, which along with variable O&M, is used in the dispatch decision.

PGE used the most recent available fuel forecast, which is PIRA's February 2011 Scenario Planning forecast. PIRA's prices are confidential and, therefore, cannot be disclosed publicly.

[8] See Chapter 5 of our 2009 IRP, which is available on our web-site: http://portlandgeneral.com/our_company/news_issues/current_issues/energy_strategy/docs/irp_nov2009.pdf Note that when we filed the IRP in 2009, the short-term was defined as 2010-11 and long term as 2014 and beyond.

#### 5.4.3 *Regional Wholesale Electricity Prices*

PGE used AURORAxmp to generate the wholesale electricity prices used in the wind integration model for the dispatch of PGE generating resources. AURORAxmp simulates the fundamentals of supply and demand in the WECC and is the model used in PGE's 2009 IRP. Changes in assumptions since filing the IRP are listed below:

- Gas prices. The most recent forecast from PIRA dated February 2011 was used;
- Carbon regulation. It was assumed that no specific carbon regulation is in place by 2014 (the IRP assumed a CO2 tax starting in 2013);
- Wind shapes. EnerNex estimated hourly wind generation for most zones (geographical entities in AURORA's topology) in the WECC using NREL's Western Wind Dataset. PGE used the simulated hourly generation for 2005 to estimate wind generation hourly shapes for the areas in AURORA for which they were available. The year 2005 was chosen because the 2005 hydro year for this region was the closest to normal runoff conditions of the three years of NREL wind data.
- Hydro in the WECC. In consultation with the Northwest Power and Conservation Council (NWPCC), PGE implemented a few enhancements to the AURORAxmp default hydro tables. The intent was to better capture constraints on unused hydro capacity when used to meet reserves requirements. AURORAxmp is now prevented from relying on unused capacity of run-of-river plants to provide reserves, as it is not technically possible. In addition, capacity available for reserves is capped to the maximum sustainable capacity. To reflect potential operational constraints to regulate hydro generation, non-federal hydro is constrained when providing reserves. Also, per NWPCC recommendations, hydro generation in the Pacific Northwest (PNW) is shaped to correspond with the regional load instead of the load of the entire WECC.

The resulting average 2014 wholesale electricity price is $44.47 per MWh ($50.60 on-peak and $36.29 off-peak). In the Pacific Northwest, prices tend to peak in winter, when PNW load peaks, and in July-August, when California's load is peaking. Spring is typically a low price season, because of the abundance of hydro. Hydro is a major driver of prices in the Pacific Northwest. For modeling purposes we assume average hydro conditions.

Figure 8 below, shows the seasonal behavior of prices in the Pacific Northwest as simulated for 2014, assuming average water, wind, and load conditions.

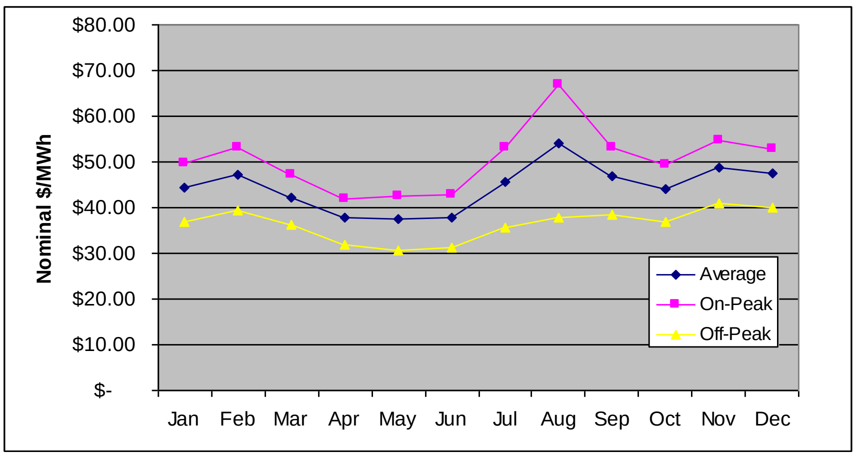


**Figure 8: 2014 Wholesale electricity prices for the Pacific Northwest, nominal $/MWh**

### 5.4.4 *Loads and Load Forecast Error*

For Phase 2 of the Wind Integration Study, PGE projected its 2014 load data by employing a three-step process using 2005 actual load and 2005 Day-Ahead and Hour-Ahead load forecast data. The wind data is based on 10-minute intervals for the necessary Within-Hour granularity.

<u>Step 1. Realign Days of Week</u>

PGE developed the 2014 load data from 2005 load data by first aligning the 2005 actual load data days of the week with the 2014 days of the week. Because January 1, 2005 fell on a Saturday and January 1, 2014 falls on a Wednesday, we used the first Wednesday of January 2005 (January 5th) for Wednesday, January 1st, 2014. Thursday, Jan. 6th, 2005 was then used for Thursday, Jan. 2nd, 2014, and so on. This step is important because the load and wind data must correspond to the same days for consistency in deriving the "load net wind" concept.

Step 2. Escalate 2005 to 2014

The realigned 2005 data was then scaled up to 2014 levels by an escalation factor equal to the percentage increase from PGE's 2005 average annual actual load to PGE's 2014 average annual forecast load. The realigned and scaled data was then used to develop the projected 2014 real-time load data in the model.

Step 3. Develop Hour-Ahead and Day-Ahead Forecast Loads

PGE's 2014 Hour-Ahead and Day-Ahead forecast load data was derived by summing the 2014 forecasted-actual load data (derived in steps 1 and 2 above) with the corresponding 2014 Hour-Ahead or Day-Ahead load forecast error data. Specifically, the 2014 Hour-Ahead and Day-Ahead load forecast error data was created by: 1) taking the difference between the respective forecasted and actual 2005 loads, and then realigning to the matching day of the week, and 2) scaling the actual 2005 Hour-Ahead and Day-Ahead forecast errors in the same way the 2005 actual load data was escalated to 2014 forecast load data (described in step 2, above).

### 5.4.5 *Water Year*

PGE selected 2005 hydro flows for use in the wind integration model as a proxy for 2014 hydro flows. Of the three years (2004-2006) of NREL wind data used in the Western Wind and Solar Integration Study (from which EnerNex derived the wind energy data), 2005 was nearest to a normal hydro year for the Pacific Northwest. PGE did not use a 3-year hydro average of those years because the resulting hourly averages would mask the interactive effect of localized weather on hydro flows and wind speeds. The inputs of the wind integration model are temporally aligned to try to capture the effect of weather creating volatility in loads, wind, and hydro, and the resulting effect on the system trying to provide the Dynamic Capacity to meet the reserve needs of such volatility.

Specific hydro data used in the wind integration model includes:

- Mid-Columbia hydro energy – this is treated as one resource in the model, so historical (2005) flows from Chief Joseph were used.
- Deschutes hydro project inflows – USGS daily average inflows from 2005 were the assumed inflows for Round Butte.
- Hourly energy for PGE's run-of-river hydro – PGE historical PSAS (Power Scheduling and Accounting System) data from 2005 was used as proxy hourly energy data for Oak Grove, North Fork, Sullivan, Faraday, River Mill, and PGE's portion of Portland Hydro Project. (These hydro facilities do not provide ancillary services for wind integration.)

#### 5.4.6 *Bid/Ask Pricing*

The wind integration model assumes virtually unlimited access to the energy market in the Day-Ahead and Hour-Ahead schedules. When the model chooses to purchase or sell energy in the Day-Ahead or Hour-Ahead stages to balance generation to load net of wind, there is an assumed bid/ask spread that affects the economics of using the market to meet load.[9]

In the model, the Day-Ahead market has a fixed bid/ask price of $0.25 per MWh. In the Hour-Ahead stage of the model, a sliding bid/ask spread is used as a function of the desired transaction block size based on the operational experience of PGE's Real Time Power Operations. Table 6, below, represents the assumed bid/ask percentage premiums that are applied to Hour-Ahead market purchases and sales.

[9] In the Within-Hour stage, the market is not available to meet load; PGE controlled resources are relied upon for balancing within the hour.

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**Table 6: Hour-Ahead assumed Bid/Ask percentages of market price**

| MW Range | Bid/Ask Percent of Price |
|---|---|
| 0 to <50 | 0 |
| 50 to <100 | 5% |
| 100 to <200 | 10% |
| 200 to <300 | 20% |
| 300 to <400 | 25% |
| >=400 | 30% |

### 5.4.7 *General Constraints for Hydro*

For hydro resources, PGE utilized data from PGE's contractual portion of the Mid-Columbia system and our share of the Pelton/Round Butte project, located on the Deschutes River in Oregon, to provide integration services in the optimization model. For both systems the hydro generation was limited to meet physical operating constraints specific to each system including minimum flow, minimum generation, maximum generation, water available, and pond elevations. In all cases, the projects were operated on a weekly basis, and pond volumes at the end of the week were set equal to pond volumes at the start of the week. This preserved the water balance within each week and allowed the weeks to be run independently. Because the model starts each week at midnight Sunday, the starting ponds are set to a position to allow either draft or fill at that point in time. This reflects PGE's actual operations. Specific constraints for each system are provided below.

<u>Mid- Columbia System</u>

The Mid-Columbia system utilizes an accounting concept of hourly energy inflow and pond elevation limits which is calculated in MWh terms. PGE's generation requests on the Mid-Columbia are combined with the signals of many other parties. This total generation request is then split among several plants providing generation. Because the signal is combined and blended and several units are responding, the individual unit movement away from its mechanical efficiency is very small. Generation plus spill, on an hourly basis at the Mid-Columbia, is allowed when the following conditions are met:

- Generation greater than minimum required generation and less than maximum capacity generation.
- Pond levels are below pond maximum and above pond minimum.

Finally, the available generation (based on historical hourly discharge data) is not impacted by a reduction in unit mechanical operating efficiency when the system is used to provide regulation or load following.

Deschutes River System

The Deschutes River system has three projects: Round Butte, Pelton, and the Pelton Regulating Project, which acts as a buffer to ensure that discharge for the three-project system is consistent throughout the day. The modeling reflects the capabilities of PGE's share of the dams.

This system has fairly restrictive discharge requirements that govern the rate at which the discharge can be changed. By having the model run for one week intervals, we simplified the discharge constraint to make discharge equal to inflow. This allowed the Pelton and Round Butte projects to move water from day to day and within the day. On an hourly basis, however, we ensured that the outflow from the Pelton Regulation Project was held constant.

PGE modeled specific aspects of the Deschutes system as follows:

- When the individual units operate to provide power, the volume of water needed to produce that energy is based on the relationship between MW production and water utilization (i.e., historical inflow and outflow data is converted to power based on MW/flow efficiency curves).

- When the individual units provide Load Following or Regulation, the reduction in mechanical operating efficiency is based on the difference between: 1) the average mechanical operating efficiency over the range of operation when providing Load Following and Regulation, and 2) the point-mechanical operating efficiency. This was applied as an increased cost factor in the cost calculation.
- For each hour, the model calculated the volume of water utilized as well as the resulting impact to pond elevations – both upstream and downstream.
- When the plants provide Spinning and Non-Spinning Reserves, there is a check to ensure that water exists in the upstream pond and space exists in the downstream pond to support the reserve operation for the entire hour.
- For the one week optimization with one-hour time steps, generation and spill are allowed at each project as long as the following operating constraints are met in each hour:
    - Outflow at Pelton Regulating Plant equals Round Butte inflow;
    - Hourly pond elevations are within project minimum and maximum allowable elevations;
    - Unit minimum generation meets but does not exceed maximum capacity.

#### 5.4.8 *General Constraints for Thermal Plants Providing Ancillary Services*

PGE's Beaver plant is the primary thermal resource for ancillary services in Phase 2 of the Wind Integration model, with the plant available in simple cycle and combined cycle modes. In simple cycle, Beaver has a 5 MW minimum production level and a 55 MW maximum output for each hour per turbine. Within each hour, the Beaver turbines are free to move between the minimum and maximum, although the number of turbines available at any hour is determined by the designated scheduled outage rate. When operating in combined cycle mode (if economic, per model criteria), Beaver is not available as a simple cycle resource. Consequently, the maximum movement for available gas turbines is between 40 MW and 55 MW.

A secondary thermal resource for ancillary services is PGE's Port Westward duct burner. This resource can fluctuate between zero and 25 MW, and is available only when Port Westward is operating. As with the Beaver plant, an operating efficiency curve converts fuel to MW production.

Finally, for hydro and thermal plants that provide ancillary services, generation was limited to what can be provided in 10 minutes for spinning reserves. For example, if a plant can ramp three MW per minute, then the model allows 30 MW ramping over 10 minutes, even if the plant has 100 MW of available capacity.

### 5.5 MODELING APPROACH

With the assistance of two external consultants, PGE has developed a mixed integer programming model to assess the incremental operating (non-capital) costs of integrating wind resources into PGE's system. The model is a "constrained optimization model" with an objective function to minimize total system operating costs given a set of operational constraints. These operational constraints include plant dispatch requirements (minimum plant up-times, minimum plant generation requirements, etc.) and system requirements (Contingency Reserves [Spinning and Non-Spinning], Regulation, Load Following, etc.). The model allocates the total system requirements (e.g., total Spinning Reserve requirements) to the individual generators to minimize overall system costs.

By altering the constraints in the model, the costs of different operational policies are isolated. For example, if the regulation constraint is relaxed (removed), the cost of providing regulation is calculated as the difference in the cost from a model run that includes the constraint and the cost from a model run that excludes the constraint. Similar types of analyses are possible for other ancillary services: Spinning Reserves, Non-Spinning Reserves and Load Following. The effect of changing constraints on least-cost plant dispatch can also be determined.

Currently the model optimizes plant dispatch and system operation for a single year (2014). Given the heavy computational requirements, each of the 52 weeks is run separately on an hourly basis although functions for reserve requirements are developed from 10-minute data.

Phase 2 of the Wind Integration Study considers four elements of wind integration costs:

- Costs resulting from Day-Ahead wind forecast error (Day-Ahead uncertainty)
- Costs resulting from Hour-Ahead wind forecast error (Hour-Ahead uncertainty)
- Costs incurred in using generation resources to follow the wind generation trend within the hour (Load Following)
- Costs incurred in using generation resources to follow Within-Hour departures of wind generation from the wind generation schedule (Regulation)

In order to distinguish between these four categories of costs within the model, the model is run in three stages corresponding to Day-Ahead, Hour-Ahead, and Within-Hour. At each stage, PGE's system is optimized subject to the operational constraints relevant at that stage. Commitments made in prior stages (e.g., purchase or sale commitments) are carried forward to the next stage as constraints. Total system operating costs at the third stage are used in assessing the costs of wind integration.

The model incorporates explicit reserves (reserved generation capacity) to address:

1) the Hour-Ahead uncertainty of wind;
2) generation resource requirements for Within-Hour Load Following for wind; and
3) generation resource requirements for Within-Hour Regulation for wind.

As explained previously, an element of "integration cost" is identified by running the model with and without the reserve constraint and observing the difference in total system operating costs between the two model runs.

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No reserves are specified in the model to address Day-Ahead wind uncertainty. The cost of Day-Ahead uncertainty is identified by comparing total system costs from a model run *with* Day-Ahead forecast error, to total system costs from a model run *without* Day-Ahead forecast error. Details of the cost estimation methods and results are presented in Section 6.1.

For defining the time basis for each Hour-Ahead wind forecast, PGE followed the TRC recommendation of using the average wind production for the 10 minute period ending at 20 minutes after the hour. As described earlier, the information for the Hour-Ahead forecast when using ten-minute averages, can come no later than 20 minutes after the hour since, operationally, schedules must be entered at 30 minutes after the hour. Initially, PGE modeled the Hour-Ahead forecast as the average of the *two* 10-minute wind generation data points between the top of the hour and 20 minutes after the hour. After much analysis and discussion between TRC members, EnerNex and PGE, it was decided that the single 10-minute persistence forecast was the most appropriate proxy for the Hour-Ahead data. This is because the mean absolute error of the persistence forecast for 20 minutes past the previous hour was less than the average of the value at 10 minutes and 20 minutes past the hour.

### 5.5.1 *Details of Modeling Approach and Results*

As discussed above, the costs of wind integration are identified by comparing total system operating costs, from a model run that incorporates the system requirements for wind integration, to total system operating costs, from a model run that excludes the system requirements for wind integration. We have segmented the costs of wind integration into five components:

- The "total" cost of wind integration including the costs due to Day-Ahead uncertainty, Hour-Ahead uncertainty, Within-Hour Load Following for wind, and Within-Hour Regulation for wind.
- The cost of wind integration due to Day-Ahead uncertainty alone.

- The cost of wind integration due to Hour-Ahead uncertainty alone.
- The cost of wind integration due to Within-Hour Load Following for wind alone.
- The cost of wind integration due to Within-Hour Regulation for wind alone.

To compute these component costs, the model is run incorporating all system requirements for wind integration. Next, the model is run with one or more of the wind integration requirements removed. The cost of the second run will be lower than the first run and this cost savings represents the cost of wind integration for the requirement that is absent in the second model run. To derive each of the cost components, six model runs are required, which are summarized in Table 7, below. For instance, to determine the cost of Hour-Ahead uncertainty, the difference between Run 3 and Run 1 is calculated. The overall cost of wind integration is the difference between Run 7 and Run 1. These calculations are summarized in Table 9 (see Section 6.1, below), which also includes the resulting cost estimates expressed on a dollar per MWh basis.

Additional details on the model runs are provided in Table 8 (with definitions for abbreviations following the table). This table details the constraints placed on the model at each of the three stages. For example, for Run 1 and the "Day-Ahead" stage, LF (W, L) indicates that the model incorporates reserves for Load Following for both wind and load. Similarly, R (W, L) indicates that the model includes reserves for Regulation for both wind and load, and UN (W, L) indicates that reserves have been included for both wind and load uncertainty. The rows labeled "Input" indicate the assumptions about hourly data for load and wind generation that apply to that stage in the model run.

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**Table 7: Model runs summarizing wind integration cost breakout**

| Identification | Description |
|---|---|
| RUN 1 | PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty of wind |
| RUN 2 | N/A* |
| RUN 3 | PGE doesn’t Integrate Hour-Ahead Uncertainty of wind |
| RUN 4 | PGE doesn’t Integrate Load Following for wind |
| RUN 5 | PGE doesn’t Integrate Regulation for wind |
| RUN 6 | PGE doesn't Integrate Day-Ahead Uncertainty of wind |
| RUN 7 | PGE doesn't Integrate Load Following and Regulation for wind, Hour-Ahead and Day-Ahead Uncertainty of wind |

* Run 2 was eliminated because, in testing, it provided no relevant information.

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**Table 8: Model runs detailing wind integration cost breakout**

| Model Stage / Scenarios | *Day-Ahead* | *Hour-Ahead* | *Within-Hour* | *Included Costs* |
|---|---|---|---|---|
| ***RUN 1*** | | ***PGE Integrates All*** | | |
| **Reserves** | LF(W,L), R(W,L) | LF(W,L), R(W,L), UN(W,L) | LF(W,L), R(W,L) | R(L,W), LF(L,W), DA-UN(L,W), HA-UN(L,W) |
| **Input** | Day-Ahead Load and Wind Forecast | Hour-Ahead Load and Wind Forecast | "Actual" Load and Wind | |
| **RUN 3** | | **PGE Doesn't Integrate HA-UN(W)** | | |
| **Reserves** | LF(W,L), R(W,L) | LF(W,L), R(W,L), UN(L) | LF(W,L), R(W,L) | R(L,W), LF(L,W),DA-UN(L,W), HA-UN(L) |
| **Input** | Day-Ahead Load and Wind Forecast | Hour-Ahead Load and Wind Forecast | Actual Load and Hour-Ahead Wind | |
| **RUN 4** | | ***PGE Doesn't Integrate LF(W)*** | | |
| **Reserves** | LF(L), R(L,W), | LF(L), R(W,L), UN(W,L) | LF(L), R(W,L) | R(L,W), LF(L), DA-UN(L,W), HA-UN(L,W) |
| **Input** | Day-Ahead Load and Wind Forecast | Hour-Ahead Load and Wind Forecast | Actual Load and Wind | |

| Model Stage / Scenarios | Day-Ahead | Hour-Ahead | Within-Hour | Included Costs |
|---|---|---|---|---|
| **RUN 5** | **PGE Doesn't Integrate R(W)** | | | |
| **Reserves** | LF(L,W), R(L) | LF(W,L), R(L), UN(W,L) | LF(W,L), R(L) | R(L), LF(L,W), DA-UN(L,W), HA-UN(L,W) |
| **Input** | Day-Ahead Load and Wind Forecast | Hour-Ahead Load and Wind Forecast | Actual Load and Wind | |
| **RUN 6** | **PGE Does Not Integrate DA-UN(W)** | | | |
| **Reserves** | LF(L,W), R(L,W) | LF(L,W), R(L,W), UN(L,W) | LF(L,W), R(L,W) | R(L), LF(L,W), DA-UN(L,W), HA-UN(L,W) |
| **Input** | Day-Ahead Load and Hour-Ahead Wind Forecast | Hour-Ahead Load and Wind Forecast | Actual Load and Wind | |
| **RUN 7** | **PGE Does Not Integrate LF(W),R(W),HA-UN(W) and DA-UN(W)** | | | |
| **Reserves** | LF(L), R(L) | LF(L), R(L), UN(L) | LF(L), R(L) | R(L), LF(L), DA-UN(L),HA-UN(L) |
| **Input** | Day-Ahead Load and Actual-Wind Forecast | Hour-Ahead Load and Actual Wind Forecast | Actual Load and Wind | |

Definitions for Table 8:

L = Load; W = Wind; LF = Load Following; R = Regulation; UN = Uncertainty;
DA = Day-Ahead; HA = Hour-Ahead;

## 5.6 Calculation for Reserves and Uncertainty

The wind integration model accounts for three categories of reserves: Regulation, Load Following (including forecast error), and Contingency Reserves. The Contingency Reserve requirement is defined by the WECC (i.e., 5% for hydro and wind, and 7% for thermal resources) with requirements split equally between Spinning and Non-Spinning Contingency Reserves. The model simulates the different reserve requirements as hourly constraints for resource scheduling and dispatch across each of the three time horizons: Day-Ahead scheduling, Hour-Ahead scheduling and Real Time dispatch (Within-Hour). EnerNex provided PGE with a methodology for estimating regulation and load variability parameters for Day-Ahead, Hour-Ahead and Real Time (Within-Hour) scheduling, as well as the Hour-Ahead forecast error. Currently, however, PGE does not explicitly set aside reserves for Day-Ahead forecast error for either load or wind generation. Specific modeling for the reserves, by category and time frame, are described below.

#### 5.6.1 *Regulation*

The reserves held for Regulation are intended to cover "short time scale deviations" in scheduled wind generation and load. We define a "short time scale deviation" for wind to be a ten-minute deviation off a trend of ten-minute wind generation data. Regulation is split into the following sub-categories (as derived by EnerNex): 1) Regulation for load-only, and 2) Regulation for load and wind.

The Regulation for load-only is assumed to be one percent of the total load for a ten-minute average load data point. This assumption is per page 7 in the October 2010 NREL paper[10], "for load-only the regulating reserve requirement was assumed to be 1% of the total load and assumed to be equal to three times the standard deviation of the load variability."

The additional regulation requirement due to wind on the system was determined by calculating the amount of regulation necessary at a wind production level in an hour. The ten-minute deviations of actual wind from a trend are calculated and then sorted by wind production level (i.e., 0 MW to 850 MW separated into equal sets of ten – deciles). To determine the variability in each wind production decile, we took the standard deviation of the ten-minute wind deviation data points in that decile. Using those standard deviations of the wind deviations for each wind production decile, and the average wind

[10] "Operating Reserves and Wind Power Integration: An International Comparison", Milligan, Donohoo, Lew, Ela, and Kirby *National Renewable Energy Laboratory* October 2010

production value of each decile, a least squares fit was generated to a quadratic polynomial. The quadratic function is then used to determine how much additional regulation is required due to wind at a particular production level of wind.

To calculate the regulation for load and wind, the October 2010 NREL paper again provided guidance: "since load and all wind variability on this timeframe were also considered to be independent of one another, the standard deviations of all wind and all load were then geometrically added together by calculating the square root of the sum of their squares." Thus, analogous to the regulation for load-only calculation, three times the standard deviation of load and wind variability will be held back as the hourly regulation requirement for load and wind (for additional detail, see Appendix G).

### 5.6.2 *Load Following and Hour-Ahead Forecast Error*

The reserves held for Load Following are intended to cover a longer time scale representing 1) the Within-Hour trend of load and wind, and 2) forecast uncertainty in the Hour-Ahead time frame. The three components of Load Following reserves are calculated (per the EnerNex methodology) as follows:

- Reserves are calculated in two steps. First, the difference in the maximum and minimum load in the hour is established as the range for load variability in the hour. Second, a PGE baseline was calculated by determining the percentage of the time that taking half of the hourly range of load variability in 2005 historical load data met the actual Load Following requirement for the hour. To be consistent with historical PGE operations, half of the hourly range for 2014 load is scaled to satisfy the PGE baseline percentage. This scaled hourly range is the Load Following for load-only reserves held back in the model. To keep the same level of reliability as when PGE integrated only load, additional reserves due to wind are added such that the baseline percentage is once again satisfied.
- Additional Load Following requirement due to wind (perfect forecast) – the calculated reserves will be based on the ten-minute deviations of a load-net-wind

trend from the hourly average load-net-wind amount. If the ten-minute deviations exceed the amount of reserves held for load-only, then additional reserves are needed. The model determines the amount of additional reserves by wind production level based on the wind generation variability within an hour (using 2004-2006 NREL wind data). After the wind variability is determined for each hour, at each production level, the result is calibrated such that, when it is summed with the previously established Load Following for load-only requirement, the resulting hourly reserve requirement maintains the PGE baseline requirement.

- Hour-Ahead forecast error due to wind – the calculated reserves are first based on the difference between the Hour-Ahead forecast of wind generation and the actual generation by production level of wind (based on the 2004-2006 NREL data). A new "forecasted" wind data stream is then created by adding the hourly forecast error to the corresponding hour's 10 minute wind data. The new "forecasted" wind is also used to define a new load-net-wind forecast. Next, the model calculates 10-minute deviations from the hourly average load-net-wind amounts by subtracting the average from the "forecasted" load-net-wind trend. This result is calibrated such that, when it is summed with the previously established Load Following for load-only and the additional Load Following due to wind requirements, the resulting hourly reserve requirement maintains the PGE baseline requirement. Please note that the addition of the forecast error reserve requirement is only relevant for the Hour-Ahead time frame.

#### 5.6.3 *Day-Ahead Scheduling*

In Day-Ahead scheduling, reserve predictions must be made for load variability and regulation for both load and wind generation. The Day-Ahead load forecast is input with a forecast error, but the model does not explicitly hold back reserves to cover the forecast error.

#### 5.6.4 *Hour-Ahead Scheduling*

For Hour-Ahead scheduling, reserve predictions for the load variability and regulation from the Day-Ahead Scheduling step must be recalibrated to account for the Hour-Ahead load and wind generation forecast. Since PGE explicitly holds back reserves for forecast error in Hour-Ahead scheduling, additional reserves are calculated as follows:

- Reserves to cover the load forecast error are derived from historical PGE information (i.e., 2005 load data escalated to 2014 levels, as described in Section 5.4.4.)
- Additional reserves held to cover the wind generation Hour-Ahead forecast error are determined by the EnerNex methodology described above.

Plant dispatch is recalibrated from the Day-Ahead schedule to reflect the different reserve, wind generation, and load requirements.

#### 5.6.5 *Real-Time Dispatch (Within-Hour)*

The forecast error reserve obligations that were established in the preceding Hour-Ahead scheduling step are released (where necessary) in the Real Time (Within-Hour) dispatch step, and the reserve requirements for load variability and regulation are recalibrated. Plant dispatch is also recalibrated from the Hour-Ahead schedule to reflect different reserve, wind generation, and load requirements.

Consequently, in each stage of the simulation, (i.e., Day-Ahead, Hour-Ahead and Within-Hour), the calculated reserve requirements for Regulation, Load Following, and Contingency Reserves are factored into the model's optimization of dispatching generation, capacity, and market resources.

#### 5.6.6 *Issues in Reserve Requirement Data Development*

As part of our model validation process, certain issues were discovered with the 2004-2006, 10-minute wind generation data from NREL. Resolution of these issues was

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coordinated and completed by consultation with the TRC. First, preliminary simulations indicated a Regulation reserve requirement that the TRC considered high. Their observations suggested that the source wind data displayed more 10-minute variability than the TRC would have expected. The following two sections describe these issues, the actions taken to address them, and the impact of the corrections. Note that all changes described below apply to the 10-minute wind generation data used to derive reserve requirements, but <u>not</u> the hourly wind generation values used in the production simulation.

<u>2004 Wind Generation Data</u>

EnerNex used 2004-2006 10-minute wind generation data to determine the functions that relate reserve requirements to production levels of wind. The 10-minute wind generation data (representing the output of a Siemens 2.3 MW unit at a particular wind speed) was developed as described in Section 4.1 and summarized below:

- Develop Day-Ahead, Hour-Ahead and Actual wind datasets.
- Identify the appropriate subset of the output of the NREL Western Wind Resource Database (WWRD) (i.e., 10 Vestas, 3 MW, V90 turbines at each of 32,043 sample locations) based upon the physical location of the two wind projects in the study.
- Apply the power curve of a Siemens 2.3 MW wind turbine to the wind speeds from the WWRD subset to convert the wind speed to the corresponding Siemens 2.3 MW unit output data.

For modeling purposes (as noted above), two projects make up the 850 MW installed wind capacity assumption: 450 MW at Biglow Canyon and 400 MW to be installed at a nearby site. Following up on TRC concerns, PGE discovered an error in the conversion of the 2004 Vestas data to the wind speed data for the 450 MW plant, which produced a higher variability in the short-term deviations in wind generation data. After the data was corrected, PGE verified that 2004 was the only affected year, and the Regulation requirement (i.e., ancillary service cost) derived from the 2004-2006 wind data was reduced.

Seam Issue with NREL dataset

Per the "Western Dataset Irregularity"[11] the NREL Western Wind Data Set had certain irregularities related to the aggregation of the mesoscale wind speed data samples at the different test sites. 3-TIER, who was responsible for the mesoscale modeling, had to separate the wind speed data samples into approximately three-day blocks for data handling purposes. After they combined the three-day data sets into one combined data set they noticed that there was reduced short term variability at the "seams" of the data sets. They then used an algorithm to impart more short term variability at each seam, which seemed to work correctly at the test-site level, but when aggregated the data displayed excessive short term variability. The TRC recognized this issue by observing PGE's high Regulation signal (short term variability) for the wind-penetration level. In consultation with the TRC, PGE removed the 24-hour period from hour 2200 on 1/1/2006 to hour 2150 on 1/2/2006. As a proxy for removing additional short-term variation introduced by the seam algorithm, a 24-hour period from the 2004-2006 data corresponding with every third day beginning with hour 2200 on 1/1/2006 was removed. Similarly, a 24-hour period beginning with hour 2200 on 12/31/2003 was removed.

[11] www.nrel.gov/wind/integrationdatasets/pdfs/western/2009/western_dataset_irregularity.pdf - A description of the Western Wind Dataset Seam Irregularity.

# 6. SUMMARY AND CONCLUSIONS

## 6.1 COST SUMMARY

PGE estimates that it would cost approximately $11.04 per MWH (in 2014$) to self-integrate 850 MW of wind generation in 2014 using existing PGE and contract resources. This result is a function of several factors including the assumptions and modeling techniques detailed above. In particular, the study reflects the existing limitation that the only current resources certain to be available for Dynamic Capacity are PGE's hydro projects with automatic generation control and the Beaver plant in both simple cycle and combined cycle mode, as applicable. Another significant factor is the impact of this high penetration level of wind generation into PGE's system, which has a current generation resource mix that remains "short" of total load. This places considerable demand on existing resources to provide reserves rather than energy and increases PGE's reliance on market purchases to cover Day-Ahead and Hour-Ahead uncertainty.

Specific components of PGE's estimated integration costs are summarized in Table 9, the derivation of which is described in Section 5.5, above. The sum of the components (Identifiers B through E) will not equal the total (Identifier A) because the interactive effect of the components and resultant resource dispatch within the model will vary between the runs.

**Table 9: Integration costs by component, year 2014**

| Identifier | Cost Saving For PGE | Run Delta Measures: | Cost/MWh ($2014) |
|---|---|---|---|
| A | RUN 7 – RUN 1 | **Cost of Wind Integration** Cost for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation | $11.04 |
| B | RUN 6 – RUN 1 | Cost for Day-Ahead Uncertainty | $3.44 |
| C | RUN 3 – RUN 1 | Cost for Hour-Ahead Uncertainty | $4.59 |
| D | RUN 4 – RUN 1 | Cost for Load Following | $1.03 |
| E | RUN 5 – RUN 1 | Cost for Regulation | $1.50 |

## 6.2 CONCLUSIONS

PGE believes that Phase 2 of the Wind Integration Study accurately simulates the constraints associated with existing conditions and available resources to estimate the costs attributed to the self-integration of 850 MW of wind generation in 2014. The study has been subject to regular and rigorous reviews from EnerNex, the TRC, and major participants in PGE's 2009 IRP, Docket No. LC 48. The TRC considers this study to be technically sound and have provided their unanimous endorsement. Regional stakeholders and PGE's Wind Integration Study Project Team have participated in three detailed public presentations regarding the intricacies of the study. The stakeholders have been provided the opportunity to examine, in detail, the methodology of the study and the results. They have also had the opportunity to comment on the methodology and make recommendations. In short, Phase 2 of the Wind Integration Study has been vetted in accordance with Commission Order No. 10-457.

Although the estimated costs for self-integration appear somewhat high compared to other utilities, they do not significantly exceed the range of costs found among utilities in the Pacific Northwest given the limitations and constraints discussed above. It must also be noted that the results of the study can vary materially, if alternative or additional flexible resources are available for ancillary services (see Section 6.3.3, below). With the availability of more efficient balancing resources that can provide Dynamic Capacity, PGE's wind integration model cost estimates are well within the range found in the Northwest. In addition, it is evident that utilities in the Northwest estimate higher than average costs compared to other regions, particularly those with regional transmission organizations. This may indicate the effects on other utilities' study results from the benefits of organized markets with independent system operators compared to study results from utilities operating in bilateral markets only such as in the Pacific Northwest. We summarize this effect in Figure 9, below.

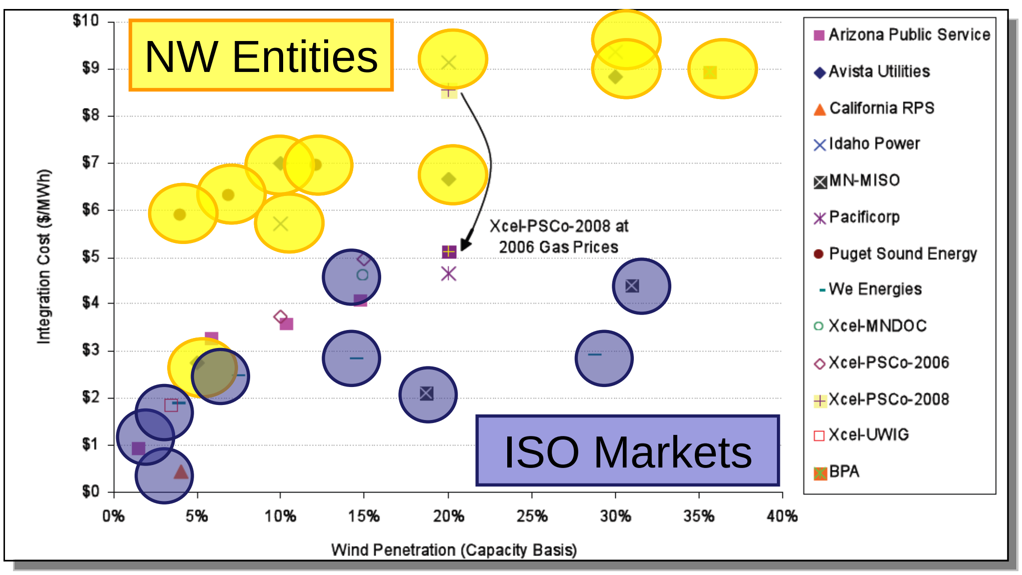


**Figure 9: Cost by utility in the WECC**

## 6.3 FUTURE POTENTIAL REMEDIATION

### 6.3.1 *30-Minute Scheduling*

In the Pacific Northwest, the Real Time energy market trades on an hourly basis and energy is purchased in one hour blocks. PGE and other Balancing Authorities (BAs) must manage any change in generation or system load across generators they control based on this time horizon. The current modeling methodology assumes one-hour energy markets, consistent with current regional practice. Moving to 30-minute scheduling would presumably reduce the amount of reserves needed to cover system load and generation movement due to the variability of wind within the shorter window. In a 30-minute market, BAs would be able to make energy transactions for a shorter time period. For this market to be viable, however, the transmission scheduling would need to migrate to the same time horizon. In addition, significant model changes will need to be made to PGE's current model to accommodate 30-minute scheduling, which include, but are not limited to: 1) restructuring the load forecast error calculation, 2) restructuring the incremental wind reserve calculations, and 3) modifying the hydro dispatch logic.

#### 6.3.2 *Energy Imbalance Market*

Currently, the WECC is considering a proposal to create an Energy Imbalance Market (EIM), which is a hybrid of a bilaterally based market and a centrally cleared market model. In the fully implemented EIM, parties must enter the market balanced between their energy and their load as demonstrated via schedules. If their generators do not perform as expected, or their load deviates from their projections, the EIM will provide the difference via a security constrained dispatch. Market participants will either pay or be paid for the difference between their actuals and schedules (i.e., their energy imbalance, paid to or by the EIM).

The expectation is that the EIM might be implemented in the next five to ten years. PGE will explore modifying a future Wind Integration Study to calculate system costs should PGE decide to participate in the EIM.

#### 6.3.3 *Additional Flexible Generation*

As stated earlier, the cost for wind integration is dependent on the characteristics of the system available to provide the moment-to-moment movement that is required to keep generation and system load in balance. If additional flexible resources are added to the PGE system, then the cost to provide wind integration will change. PGE is currently in the process of seeking up to 200 MW of flexible resources in its Request for Proposals for Capacity Resources (Docket UM 1535). It is expected that these new resources will be added to the portfolio in the 2013-2015 timeframe.

In order to further test the validity of its Phase 2 wind integration study, PGE revised the model assumptions to include a new efficient thermal resource with sufficient flexibility to provide Dynamic Capacity. For this purpose, and in accordance to what was assumed in the 2009 IRP preferred portfolio, we assumed PGE could employ two, 100 MW, LMS100, simple cycle combustion turbines along with the existing hydro resources and Beaver plant for ancillary services. The results from this secondary set of model runs is that PGE's estimated total cost for self-integration would be approximately $9.15 per MWh (in 2014$) after incorporating the additional resource.

We note that this modified total cost is within the range of wind integration estimates for Northwest utilities identified in Figure 9 above. This provides additional validation for the reasonableness of the model results. Specific wind integration cost estimates, which incorporate the LMS100 resource, are summarized in Table 10, below.

**Table 10: Integration costs by component with two additional LMS100 SCCTs**

| Identifier | Cost Saving For PGE | Run Delta Measures: | Cost/MWh ($2014) |
|---|---|---|---|
| A | RUN 7 – RUN 1 | **Cost of Wind Integration** Cost for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation | $9.15 |
| B | RUN 6 – RUN 1 | Cost for Day-Ahead Uncertainty | $3.61 |
| C | RUN 3 – RUN 1 | Cost for Hour-Ahead Uncertainty | $2.86 |
| D | RUN 4 – RUN 1 | Cost for Load Following | $0.75 |
| E | RUN 5 – RUN 1 | Cost for Regulation | $0.98 |

## 6.4 Next Steps for PGE's Wind Integration Study

Because variable generation resources place unique demands on system operation and reliability, PGE reiterates that understanding the physical needs and costs of wind integration is an ongoing effort. While PGE has not yet formulated a formal list of next steps, or tried to prioritize them, the following items are presented for further consideration. PGE's Wind Integration Study Project Team welcomes suggestions and feedback from stakeholders regarding prioritization or other study items may not be listed. In this regard, PGE wishes to recognize the suggestions that the RNP submitted in their formal comments to this Study, which are incorporated below. Future Phases of PGE's Wind Integration Study may include:

- Evaluating the net impact of moving to 30-minute scheduling;
- Evaluating the net impact of developing and operating a regional energy imbalance market;
- The value of adding additional flexible gas generation;
- How wind integration costs change with a higher or lower amount of variable resources to integrate;

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- Understanding the impact of a poor water year;
- Understanding the impact of a higher natural gas price; and,
- Exploring changes to scheduled maintenance outages.

The PGE Wind Integration Study Project Team will continue to evaluate and improve its modeling tools and software, as needed, and will also continue to monitor the industry for Wind Integration Study best practices.

## 7. LIST OF APPENDICES