Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204

November 23, 2011

Via Electronic Filing and U.S. Mail
Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

Re: LC 48

Attention Filing Center:

In accordance with Commission Orders 10-457 and 07-002, Portland General Electric Company ("PGE") hereby submits an original and five copies of its 2011 Integrated Resource Plan ("IRP") Update in the above-captioned docket. PGE's 2009 IRP was filed with the Commission on November 5, 2009 and acknowledged (with conditions) on November 23, 2010, in Commission Order 10-457.

The 2011 IRP Update is being submitted for informational purposes only. PGE is not proposing changes to its 2009 IRP acknowledged Action Plan, nor are we seeking acknowledgment of a revised Action Plan. As such, no action is required by the Commission.

This is being filed by electronic mail with the Filing Center. An extra copy of the cover letter is enclosed. Please date stamp the extra copy and return to me in the envelope provided. Thank you in advance for your assistance.

Sincerely,

V. DENISE SAUNDERS
Associate General Counsel
denise.saunders@pgn.com

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

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PGE 2011 INTEGRATED RESOURCE PLAN UPDATE** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No. LC 48.

Dated at Portland, Oregon, this 23rd day of November, 2011.

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Portland General Electric
2009 Integrated Resource Plan

2011 Integrated Resource Plan Update

November 23, 2011

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Executive Summary

Pursuant to the Commission's Competitive Bidding Guidelines (Guideline 3g), PGE submits this Update to its acknowledged 2009 IRP. PGE is not proposing changes to the acknowledged Action Plan or seeking acknowledgement of a revised plan. As such, this Update is an informational filing that focuses on the following elements in accordance with the Commission's Guidelines:

- An update to our Action Plan implementation activities;
- An assessment of the impact to the Action Plan of various forecast changes; and,
- Inclusion of supplemental information required in this Update by Commission Order No. 10-457.

A primary focus of this Update is to examine new projections for future customer demand and resulting portfolio balance, and other changes in IRP assumptions that have occurred since the plan was acknowledged, as well as our assessment of the net impact of these changes to our Action Plan.

While we are not requesting acknowledgement of a revised Action Plan, we do address a change in expectations with respect to the renewal of a contract resource that is included in the existing resources section of the plan, a revised energy efficiency (EE) forecast from the Energy Trust of Oregon (ETO), and an updated estimate for our RPS portfolio balance. The Update also addresses anticipated differences in timing for the acquisition of new resources identified in the Action Plan. The timing differences are driven by changes in schedule and expected completion of the company's supply-side Requests for Proposals (RFPs).

As we evaluate changes that have occurred with respect to our projected portfolio balance and external environment, we primarily focus on two key factors of our Action Plan:

1. The target volumes and timeframes for new resource additions.
2. The target portfolio mix resulting from implementation of the Action Plan.

When considering the overall effect of the updated IRP assumptions, we believe that no changes to the acknowledged resource Actions are warranted.

One of the assumptions that we revise in this Update is the forecast for future customer demand. This Update incorporates a lower load forecast reflective of ongoing weakness in the economy and a change in five year customer opt-out elections for cost-of-service supply. However, the reduction is offset in part by announcements of major new industrial / high-technology facilities and associated incremental electricity demand. As a result, the change in forecast for future customer demand, along with additional efficiency improvements at our existing generation facilities, reduces the projected deficit in our load-resource balance in 2015 from 873 MWa to approximately 682 MWa. This is a reduction in new energy resource requirements of roughly 192 MWa.

Regarding future supply, we incorporate the aforementioned updates to EE, existing resources and RPS. The result of these changes is a reduction in projected 2015 energy resource additions of approximately 132 MWa.

The net impact of these changes to demand and supply is a modest improvement to our projected load-resource balance in 2015 of roughly 60 MWa. Our 2009 IRP reflected a deficit of 64 MWa after the addition of new long-term resources from the Action Plan (excluding short-term market purchases). Our updated portfolio balance projection for 2015 reflects a small deficit of 4 MWa after the addition of new long-term resources from the Action Plan (excluding short-term market purchases).

While this net change is not sufficient to warrant a revision to our Action Plan for new energy and capacity resources, it does allow PGE to be more flexible with respect to the timing for acquisition and commercial operation of new baseload resources. The modest reduction in net deficit also better positions the Company to accommodate schedule delays encountered thus far in gaining approval for and implementing the 2011 Request for Proposals. In addition, the acknowledged Action Plan includes "built-in" flexibility elements that enable the company to respond to variations in load and the timing for new resource additions. One such flexibility element is the use of short- and mid-term market purchases of 100 MWa. As stated in the IRP, this element allows the Company to adapt to modest near-term load variations and timing differences related to the procurement and start of longer-term resources.

With respect to external and market conditions, we address several factors including an updated natural gas price forecast, delayed expectations for CO_2 costs levied on energy, uncertainty of continued tax benefits for renewable resources, and changes in capital costs for new generation. When compared to our 2009 IRP assumptions, gas prices have fallen, the likelihood of near-term or significant CO_2 costs is lower, and renewal of Federal and State tax benefits for renewable resources (at current levels) is less certain. At the same time, capital cost projections for most new generation builds have gone down, reflecting continued weakness in the general business climate, and resulting decreased demand for new projects. However, we do not believe that the revised expectations for carbon policy, gas prices and generation capital costs prompt a deviation from our acknowledged Action Plan.

The revised expectations for natural gas and carbon costs tend to advantage high-efficiency, natural gas-fired plants over other electric generation technologies and fuel sources. While uncertainty about renewable resource tax benefits has increased since our IRP was filed, the practical effect is limited due to growing State RPS obligations. We must continue to remain compliant with RPS targets which increase significantly over time. At the same time, the reduced capital cost estimates for new generation project types positively impacts the cost of most new resource types. Accordingly, we expect the overall effect of the above factors to be beneficial in implementing our Action Plan. Ultimately, the results of our forthcoming supply-side RFPs will further inform and refine the cost estimates for new electric generation.

These updated assumptions for natural gas prices, carbon policy and electric generation capital costs, when considered in total, continue to favor our action plan approach of ceasing coal-fired operations at Boardman in 2020, adding new efficient gas-fired power plants to meet our baseload energy and flexible capacity needs, and adding new renewable resources to maintain compliance with the Oregon RPS. Thus, we believe that the updated assumptions summarized above (and outlined in more detail later in this update) remain supportive of moving forward with our acknowledged plan.

In addition to updating assumptions used in our analysis of new resources, we also update our analysis of the Cascade Crossing Transmission Project (Cascade Crossing). This includes updates on the status of: project permitting, route surveying, coordinated planning, WECC Path Rating Process, project timeline, capital expenditures and the economic analysis.

The updated information shows that Cascade Crossing continues to have positive economic and risk mitigation benefits. As demonstrated in PGE's 2009 IRP, Cascade Crossing can also improve system capability and reliability, and provides other benefits to PGE's customers. The significance of the project is further demonstrated in its selection by the Obama Administration's Rapid Response Team for Transmission as one of seven transmission projects to serve as a pilot demonstration for streamlined federal permitting.

Cascade Crossing remains an effective option for ensuring reliable delivery of existing and future generation from sources on the east side of the Cascades to our west-side demand centers in the Portland Metro Area and Willamette Valley. Accordingly, in this Update we do not anticipate any changes to the Action Plan related to Cascade Crossing.

The following briefly outlines the content of our IRP Update:

Chapter 1 presents an update to our overall load/resource balance. This chapter also provides a status update to our resource acquisition activities since filing the IRP, including a status update on the RFPs.

Chapter 2 presents more detail about load and resource changes, as well as various externally-driven cost and regulatory updates.

Chapter 3 provides an update to our Demand Response efforts and related discussion as required in the Order.

Chapter 4 provides an update to our RPS compliance position and discusses the potential use of Banked and Unbundled RECs as required in the Order.

Chapter 5 presents a status update to emissions reduction investments pursuant to the Boardman 2020 Plan.

Chapter 6 updates transmission planning and identifies a revision to the construction and in-service date for Cascade Crossing.

Chapter 7 presents a summary of our vetted phase 2 wind integration study. (The full study is included as an appendix.)

1. Action Plan Implementation

PGE's 2009 Integrated Resource Plan (IRP) Action Plan proposes the acquisition of new energy resources to meet a projected deficit of 873 MWa by 2015. It also includes new capacity resources to meet a projected winter deficit of 1,724 MW by 2015. The Plan further seeks to acquire 40,000 dekatherms per day of pipeline transport and/or natural gas storage and construction of a new transmission line, Cascade Crossing. Finally, the IRP includes the BART III / Boardman 2020 plan for the Boardman power plant which adds new controls over the next few years to meet the emission reduction requirements of the Oregon Utility Mercury Rule and the Federal Regional Haze Rule, and ultimately ceases coal-fired operations at the plant in 2020.

Since acknowledgement of the IRP Action Plan, we are moving forward with implementation of the supply-side resource actions through the development of energy, capacity, and renewable resource Request for Proposals (RFP). In accordance with the Commission Guidelines for Competitive Bidding, we are working with an Independent Evaluator (IE) chosen by the OPUC. On May 23, 2011, we submitted a Final Draft RFP in Commission Docket No. UM 1535, requesting both year-round flexible and seasonal capacity products. On September 27, 2011, the Commission issued Order No. 11-371 directing us to issue a combined capacity and energy RFP. In response to the Commission order, we are preparing a combined energy and capacity RFP. We anticipate that the Commission's procedural process for review of the combined RFP will take approximately two months and anticipate an acknowledged RFP ready for issuance in Q2 or Q3 2012.

In addition, we are preparing a draft RFP to acquire the new renewable resources identified in our Action Plan. We are currently working with the IE to prepare scoring criteria and models to evaluate the economic performance and risk of the bids we will receive. More discussion on the status of our RFPs is found in Section 1.3 below.

We continue to work with the ETO to achieve the targeted energy efficiency savings identified in the Action Plan. As detailed in Section 2.3, the ETO has revised downward the expected savings due to the application of more conservative assumptions for program success and a lower level of State funding. With regard to other types of customer-based resources, we are on pace to acquire the dispatchable standby generation (DSG) targeted in our plan, and we are rolling out new demand response programs and pilots.

In this chapter we summarize changes to our resource need since filing the IRP and our progress in implementing the IRP Action Plan.

1.1 PGE's Proposed Action Plan: An Update

Our Action Plan proposes the acquisition of the energy resources listed in Table 1-1 to fulfill average annual energy needs by 2015. Our projected 2015 resource deficit is reduced from the levels projected in the 2009 IRP due to load forecast reductions and increased five-year opt-outs, along with efficiency improvements to existing resources. The 2009 IRP projects a 2015 energy deficit of 873 MWa while the IRP Update projects a 2015 energy deficit of 682 MWa.

Table 1-1: Comparison of PGE's Energy Action Plan

Annual Energy Action Plan for 2015	2009 IRP MWa	2011 IRP Update MWa	2011 IRP Update Change MWa
PGE Load Before EE Savings [1]	**2,752**	**2,669**	**(83)**
Remove 5-year Opt-Outs	(28)	(128)	(99)
Existing PGE & Contract Resources	(1,850)	(1,860)	(9)
PGE Resource Target	**873**	**682**	**(192)**
Resource Actions			
Thermal:			
CCCT	406	406	-
Combined Heat & Power	2	2	-
Renewable:			
ETO Energy Savings Target[2]	214	169	(45) [2]
Existing Contract Renewal	66	-	(66)
2015 RPS Compliance	122	101	(21)
To Hedge Load Variabilityy[3]:			
Short and Mid-Term Market Purchases	100	100	-
Total Incremental Resources	**909**	**778**	**(132)**
Energy (Deficit)/Surplus	36	96	(60)
Total Resource Actions	**873**	**682**	

[1] 2009 IRP load used PGE's March 2009 load forecast. The IRP Update uses PGE's September 2011 forecast. The 2011 forecast is increased to include 49 MWa of EE achieved by ETO in 2009 and 2010 for a correct comparison with the 2009 IRP.
[2] Cumulative EE estimates by 2015 in the 2011 IRP Update are adjusted to include the EE achieved in 2009 and 2010 for a correct comparison with the 2009 IRP. See Section 2.3 for more detail.
[3] Up to 100 MWa. Actual purchases will depend on balancing needs.
Numbers may not foot due to rounding.

The revised demand forecast results in a reduced 2015 resource requirement of 192 MWa. However, these demand reductions are largely offset by revised resource expectations for the renewal of an existing contract, a modest reduction in the estimated amount of new renewables to meet the 2015 RPS standard, and a downward revision to the energy efficiency forecast from the ETO. These changes lower our projected 2015 energy availability by approximately 132 MWa.

In aggregate, the forecast changes for demand and supply net to a modestly lower annual average energy need in 2015, compared to the IRP filing. On a net basis, our projected 2015 resource deficit is reduced by 60 MWa.

Table 1-1 shows an updated energy load-resource balance including the acknowledged Action Plan resources that we are pursuing. It compares the updated assumptions to those of the 2009 IRP and highlights that no revision to the Action Plan is necessary given that the Update change to the 2015 portfolio balance is relatively small at 60 MWa. This change is also within the 100 MWa of short and mid-term purchases targeted in the Action Plan to hedge load variability and timing differences for adding new long-term resources.

Figure 1-1 shows that, post-2015, we quickly become short again even after all items in our 2009 IRP Action Plan are fulfilled.

Figure 1-1: Energy Load-Resource Balance to 2021 after Action Plan Acquisitions

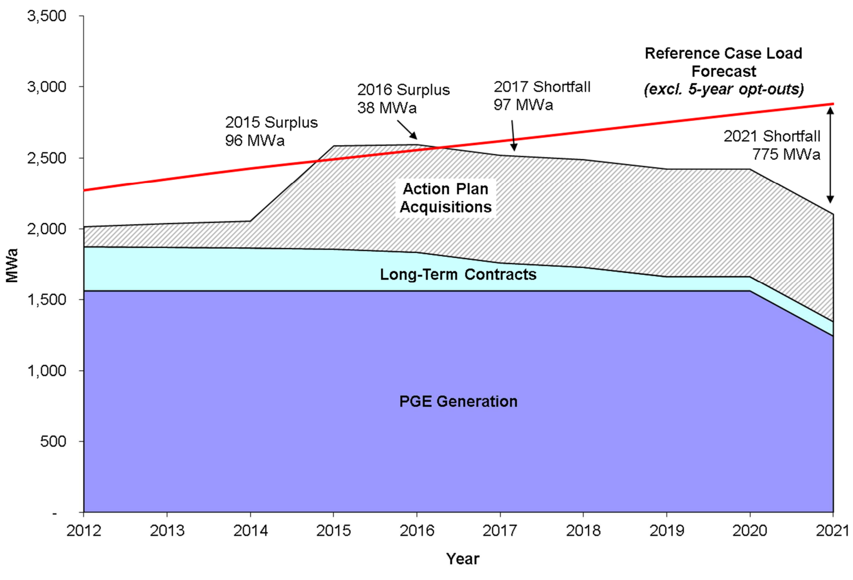


Table 1-2 shows the detail of PGE's overall load and resources in 2016. More detail about the load and resource changes since our IRP filing is found in Chapter 2.

Table 1-2: Comparison of PGE's Energy Action Plan: 2016 Look

Annual Energy Action Plan for 2016	2009 IRP MWa	2011 IRP Update MWa	2011 IRP Update Change MWa
PGE Load Before EE Savings [1]	**2,815**	**2,735**	**(79)**
Remove 5-year Opt-Outs	(28)	(130)	(101)
Existing PGE & Contract Resources	(1,834)	(1,836)	(2)
PGE Resource Target	**952**	**770**	**(182)**
Resource Actions			
Thermal:			
CCCT	406	406	-
Combined Heat & Power	2	2	-
Renewable:			
ETO Energy Savings Target[2]	247	199	(48)
Existing Contract Renewal	66	-	(66)
2015 RPS Compliance	122	101	(21)
To Hedge Load Variabilityy[3]*:*			
Short and Mid-Term Market Purchases	100	100	-
Total Incremental Resources	**943**	**808**	**(135)**
Energy (Deficit)/Surplus	(9)	38	
Total Resource Actions	**952**	**770**	

[1] 2009 IRP load used PGE's March 2009 load forecast. The IRP Update uses PGE's September 2011 forecast. The 2011 forecast is increased to include the EE achieved by ETO in 2009 and 2010 for a correct comparison with the 2009 IRP.
[2] Cumulative EE estimates by 2015 in the 2011 IRP Update are adjusted to include the EE achieved in 2009 and 2010 for a correct comparison with the 2009 IRP. See Section 2.3 for more detail.
[3] Up to 100 MWa. Actual purchases will depend on balancing needs.
Numbers may not foot due to rounding.

Table 1-3 and Table 1-5 highlight the changes to the 2015 IRP forecasted winter and summer capacity needs as a result of the changes to loads and resources discussed above. PGE's winter capacity need is virtually unchanged from the levels cited in the 2009 IRP. The summer capacity need is lower by approximately 130 MWs. However, this reduction in summer capacity need can be largely absorbed through adjustments in market purchases for a short period of time. As shown later in Figure 1-2, we again revert to material capacity deficits in both winter and summer by 2017 even after all IRP resource actions are fulfilled.

Table 1-3: Comparison of PGE's Winter Capacity Action Plan

January Capacity Action Plan for 2015	2009 IRP 2015 MW	2011 IRP Update MW	2011 IRP Update Change MW
PGE Load Before EE Savings [1]	**4,295**	**4,222**	**(73)**
Remove 5-year Opt-Outs	(31)	(144)	(112)
Operating Reserves[3]	205	183	(22)
Contingency Reserves[4]	245	232	(12)
Existing PGE & Contract Resources	(2,989)	(3,012)	(23)
PGE Resource Target	**1,724**	**1,481**	**(243)**
Resource Actions			
Thermal:			
CCCT	441	441	-
Combined Heat & Power	2	2	-
Renewable:			
Existing Contract Renewal	167	-	(167)
2015 RPS Compliance	18	15	(3)
To Hedge Load Variability:			
Short and Mid-Term Market Purchases	100	100	-
		-	
Capacity Only Resources:			
Flexible Peaking Supply	200	200	-
		-	
Customer-Based Solutions (Capacity Only):			
DSG (2010-2013)	67	67	-
Demand Response	60	70	10
Seasonally Targeted Resources:			
ETO Capacity Savings Target	315	248	(67) [2]
Bi-Seasonal Capacity	202	202	-
Winter-Only Capacity	152	152	-
Total Incremental Resources	**1,724**	**1,497**	**(227)**
Capacity (Deficit)/Surplus	1	16	

[1] 2009 IRP load used PGE's March 2009 load forecast. The IRP Update uses PGE's September 2011 forecast. The 2011 forecast is increased by 72 MW to include the EE achieved by ETO in 2009 and 2010 for a correct comparison with the 2009 IRP.

[2] Cumulative EE estimates by 2015 in the 2011 IRP Update are adjusted to include the EE achieved in 2009 and 2010 for a correct comparison with the 2009 IRP. See Section 2.3 for more detail.

[3] Approx. 6% of generation; excludes reserves for action plan acquisitions.

[4] 6% of PGE net system load excluding 5-year opt-outs.

Numbers may not foot due to rounding.

Table 1-4: Comparison of PGE's Winter Capacity Action Plan: 2016 Look

January Capacity Action Plan for 2016	2009 IRP 2016 MW	2011 IRP Update MW	2011 IRP Update Change MW
PGE Load Before EE Savings [1]	**4,384**	**4,307**	**(77)**
Remove 5-year Opt-Outs	(31)	(146)	(114)
Operating Reserves[3]	205	183	(22)
Contingency Reserves[4]	249	236	(13)
Existing PGE & Contract Resources	(2,989)	(3,012)	(23)
PGE Resource Target	**1,817**	**1,567**	**(250)**
Resource Actions			
Thermal:			
CCCT	441	441	-
Combined Heat & Power	2	2	-
Renewable:			
Existing Contract Renewal	167	-	(167)
2015 RPS Compliance	18	15	(3)
To Hedge Load Variability:	100	100	-
Capacity Only Resources:			
Flexible Peaking Supply	200	200	-
DSG (2010-2013)	67	67	-
Demand Response	60	70	10
Seasonally Targeted Resources:			
ETO Capacity Savings Target	364	293	(71)
Bi-Seasonal Capacity	202	202	-
Winter-Only Capacity	152	152	-
Total Incremental Resources	**1,774**	**1,542**	**(231)**
Capacity (Deficit)/Surplus	(43)	(25)	

[1] 2009 IRP load used PGE's March 2009 load forecast. The IRP Update uses PGE's September 2011 forecast. The 2011 forecast is increased by 72 MW to include the EE achieved by ETO in 2009 and 2010 for a correct comparison with the 2009 IRP.

[2] Cumulative EE estimates by 2015 in the 2011 IRP Update are adjusted to include the EE achieved in 2009 and 2010 for a correct comparison with the 2009 IRP. See Section 2.3 for more detail.

[3] Approx. 6% of generation; excludes reserves for action plan acquisitions.

[4] 6% of PGE net system load excluding 5-year opt-outs.

Numbers may foot due to rounding.

Table 1-5: Comparison of PGE's Summer Capacity Action Plan

August Capacity Action Plan for 2015	2009 IRP 2015 MW	2011 IRP Update 2015 MW	2011 IRP Update Change MW
PGE Load Before EE Savings[1]	**3,903**	**3,761**	**(142)**
Remove 5-year Opt-Outs	(31)	(161)	(129)
Operating Reserves[3]	194	172	(22)
Contingency Reserves[4]	225	208	(17)
Existing PGE & Contract Resources	(2,822)	(2,846)	(23)
PGE Resource Target	**1,468**	**1,134**	**(334)**
Resource Actions			
Thermal:			
CCCT	441	441	-
Combined Heat & Power	2	2	-
Renewable:			
Existing Contract Renewal	167	-	(167)
2015 RPS Compliance	18	15	(3)
To Hedge Load Variability:			
Short and Mid-Term Market Purchases	100	100	-
		-	
Capacity Only Resources:			
Flexible Peaking Supply	200	200	-
		-	
Customer-Based Solutions (Capacity Only):			
DSG (2010-2013)	67	67	-
Demand Response	60	70	10
Seasonally Targeted Resources:			
ETO Capacity Savings Target	210	167	(43) [2]
Bi-Seasonal Capacity	202	202	-
Winter-Only Capacity	-	-	-
Total Incremental Resources	**1,468**	**1,264**	**(203)**
Capacity (Deficit)/Surplus	(1)	130	

[1] 2009 IRP load used PGE's March 2009 load forecast. The IRP Update uses PGE's September 2011 forecast. The 2011 forecast is increased by 49 MW to include the EE achieved by ETO in 2009 and 2010 for a correct comparison with the 2009 IRP.
[2] Cumulative EE estimates by 2015 in the 2011 IRP Update are adjusted to include the EE achieved in 2009 and 2010 for a correct comparison with the 2009 IRP. See Section 2.3 for more detail.
[3] Approx. 6% of generation; excludes reserves for action plan acquisitions.
[4] 6% of PGE net system load excluding 5-year opt-outs.
Numbers may not foot due to rounding.

Table 1-6: Comparison of PGE's Summer Capacity Action Plan: 2016 Look

August Capacity Action Plan for 2016	2009 IRP	2011 IRP Update	
	2016 MW	2015 MW	Change MW
PGE Load Before EE Savings[1]	**4,003**	**3,846**	**(158)**
Remove 5-year Opt-Outs	(31)	(163)	(132)
Operating Reserves[3]	194	172	(22)
Contingency Reserves[4]	230	212	(18)
Existing PGE & Contract Resources	(2,822)	(2,846)	(23)
PGE Resource Target	**1,574**	**1,220**	**(354)**
<u>Resource Actions</u>			
Thermal:	441	441	-
CCCT	2	2	-
Combined Heat & Power			
Renewable:			
Existing Contract Renewal	167	-	(167)
2015 RPS Compliance	18	15	(3)
To Hedge Load Variability:	100	100	-
Capacity Only Resources:			
Flexible Peaking Supply	200	200	-
DSG (2010-2013)	67	67	-
Demand Response	60	70	10
Seasonally Targeted Resources:			
ETO Capacity Savings Target	243	197	(46)
Bi-Seasonal Capacity	202	202	-
Winter-Only Capacity	-	-	-
Total Incremental Resources	**1,501**	**1,295**	**(206)**
Capacity (Deficit)/Surplus	(73)	74	

[1] 2009 IRP load used PGE's March 2009 load forecast. The IRP Update uses PGE's September 2011 forecast. The 2011 forecast is increased by 72 MW to include the EE achieved by ETO in 2009 and 2010 for a correct comparison with the 2009 IRP

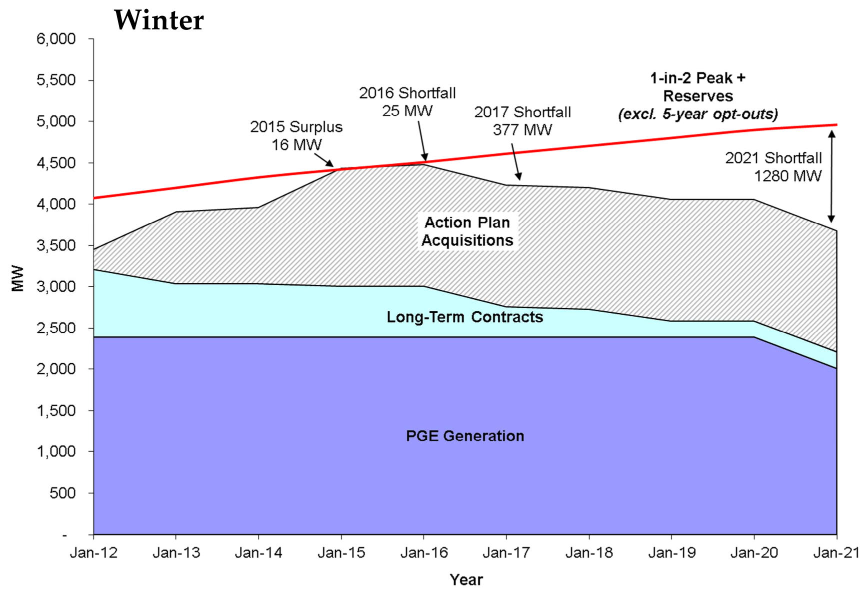
[2] Cumulative EE estimates by 2015 in the 2011 IRP Update are adjusted to include the EE projected by ETO in 2009 and 2010 for a correct comparison with the 2009 IRP. See Section 2.3 for more detail.

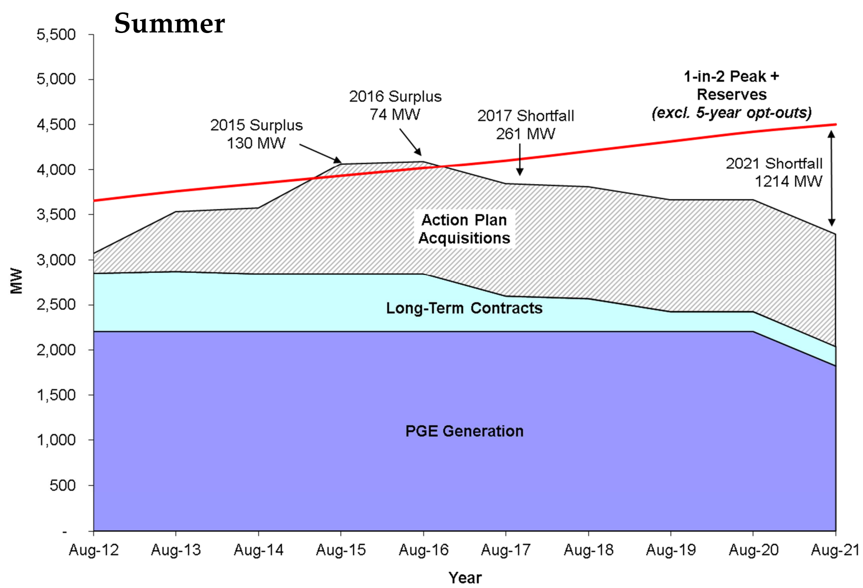
[3] Approx. 6% of generation; excludes reserves for action plan acquisitions.

[4] 6% of PGE net system load excluding 5-year opt-outs.

Numbers may not foot due to rounding.

Figure 1-2: PGE Winter and Summer Capacity Load-Resource Balance





Similar to the case with energy, we do not believe the changes identified in this IRP Update trigger a deviation from our Action Plan for capacity resources.

More detail about the load and resource changes since our IRP filing is found in Chapter 2.

1.2 Resource Acquisitions since the 2009 IRP

Since the Commission acknowledged the 2009 IRP, PGE has acquired both demand (customer-based) and supply-side resources. Demand-side additions include new dispatchable standby generation (DSG) capacity and energy efficiency gains. Supply-side resource additions include new solar and wind contracts.

Solar Contracts

The Bellevue and Yamhill Solar contracts provide for the purchase of photovoltaic power from enXco beginning in October 2011. The sites are both located near the town of Amity, Oregon, and consist of ground-mounted, fixed solar panels. The Bellevue site is approximately 12 acres and is expected to provide about 0.2 MWa of energy to PGE. The Yamhill site's projected output is 0.3 MWa of energy and consists of approximately 10 acres. Both contracts extend through 2036.

PGE has also entered into solar contracts with SunWay 2 LLC, which operates three rooftop solar arrays on ProLogis facilities in Northeast Portland. In addition, PGE has executed contracts with SunWay 3 LLC, to purchase solar power from seven rooftop solar arrays on ProLogis facilities in Clackamas and Multnomah counties. The SunWay 2 contract runs through 2028, and the SunWay 3 contracts run through 2029. Together these solar agreements provide approximately 0.5 MWa of energy to PGE annually.

Each of these solar contracts includes associated Renewable Energy Credits (RECs) and therefore help PGE meet the Oregon RPS compliance target.

Wind Contract

In late 2010, PGE entered into a power purchase agreement to acquire energy from the Patu Wind Farm, a Qualifying Facility (QF) located along the Columbia River Gorge, 112 miles east of Portland, Oregon. With a nameplate capacity of 9 MW, the project is expected to provide roughly 3 MWa of energy annually.

This contract, which expires in 2031, does not include associated RECs and therefore does not count toward PGE's RPS compliance target.

Energy Efficiency

The 2009 IRP relied on the ETO forecast of achievable energy efficiency savings. This forecast was incorporated into PGE's action plan, with a target of 214 MWa of cumulative savings from 2009 to 2015. The ETO estimates that PGE achieved cumulative EE savings of 46 MWa (49 MWa at busbar) in 2009 and 2010, which is substantially equivalent to the ETO target included in the IRP of approximately 48 MWa for those years. More discussion of the ETO's updated energy efficiency forecast can be found in the section 2.3.

Dispatchable Standby Generation (DSG)

At the time the IRP was filed, PGE had approximately 53 MW of online DSG capacity among 24 customers. Our Action Plan assumed that we could achieve 67 MW of additional DSG by 2013, for a total of 120 MW. As of May 2011, PGE had a total of 59 MW of DSG capacity online, 41.5 MW of projects under construction, and 24.5 MW of proposed projects in the pipeline. We are on track to achieve our IRP target for DSG.

Distributed Solar: Solar Feed-In Tariff

Since filing the IRP, PGE has, with guidance from the OPUC, initiated a solar feed-in tariff: the Solar Payment Option Pilot Programs (SPO pilot). The program commenced on July 1, 2010 and is based on PGE receiving a specified amount of solar capacity from our customers. For customers with small- and medium-size systems, the tariff is offered on a first-come, first-served basis. Small systems are those 10 kW and under. Medium systems are up to 100 kW. For these customers, there are two enrollment periods – April 1 and October 1 – per year for four years[1].

Large systems (with a maximum generating capability of 500kW) are awarded to customers based on the lowest bid price. For such customers, there is an annual Request for Proposal (RFP) on April 1 to submit bid prices for four years.

Table 1-7 shows the cumulative number of customers as of August 2011 and the solar generating capacity enrolled so far.

Table 1-7: SPO: Received Solar System Reservations

No. of Customers	Small	Medium	Large	Total
July 1, 2010	111	6	2	119
October 1, 2010	235	11	-	246
April 1, 2011	186	11	3	200
Total No.	532	28	5	565
Total kW				6,374

The SPO Pilot pays customers for the power their solar systems generate for 15 years at the applicable Commission-approved volumetric incentive rate. The Solar Photovoltaic Pilot Programs were created by House Bill 3039 and amended

[1] As of October 2011, the Oregon Public Utility Commission adopted new administrative rules changing some program implementation aspects of the pilot program. PGE's tariffs reflect the new pilot program requirements.

by HB 3690. The Bills require the OPUC to establish pilot programs to demonstrate the use and effectiveness of volumetric incentive rates (VIRs) for electricity delivered by solar photovoltaic energy systems. The pilot closes on March 31, 2015, or when the cumulative capacity on contracted systems reaches 25 MW AC for Oregon, whichever comes first. PGE's share of the 25 MW is 14.9 MW.

Demand Response

We have procured 10 MW of firm demand response resources and are on-track to acquire the additional 50 MW projected in the 2009 IRP. Chapter 3 provides a detailed discussion of our demand response activities in compliance with the Commission's directive in Order No. 10-457.

Other Resources

In the 2009 IRP, PGE assumed it would renew an existing power purchase agreement, which currently provides approximately 66 MWa of energy and 167 MW of winter and summer capacity. The current contract expires October 2012. In this Update, we have removed the expiring contract from our projected future resources due to increased uncertainty about the likelihood of renewal. This change is reflected in the tables above.

1.3 Request for Proposals

The 2009 IRP Action Plan included the issuance of RFPs for (1) flexible and seasonal capacity; (2) a high-efficiency combined-cycle natural gas plant (CCCT) and (3) new RPS compliant renewable resources. PGE issued an RFP for an Independent Evaluator in late January 2011 and on April 11, 2011 the Commission issued Order No. 11-111 approving the selection of Accion Group as the IE for all of the RFPs.

On March 22, 2011, the Commission opened Docket No. UM 1535 for PGE's issuance of a capacity RFP targeting 200 MW of flexible, year-round capacity, bi-seasonal (winter and summer) capacity of 200 MW, and 150 MW of winter-only capacity.

PGE engaged in an extensive public process for the development of the RFP in accordance with the Commission's Competitive Bidding Guidelines. We conducted two workshops, issued Draft and Final Draft RFPs for comment, and presented the Final Draft RFP at a Commission public meeting. PGE also worked extensively with the IE in developing the RFP. On September 27, 2011, the Commission issued Order No. 11-371 which, among other things, directed PGE to combine the Capacity RFP with its forthcoming baseload Energy RFP. To revise our RFP as directed by the Commission, we anticipate developing a new schedule that issues the combined Capacity and Baseload Energy RFP to the market in Q2 or Q3 2012. Selection of a final short list for capacity and baseload energy resources is anticipated by year-end 2012, or early 2013. We also anticipate releasing a Renewable Resource RFP in early-to-mid 2012 to fulfill the renewable energy actions from our Plan. The revised RFP schedules may result in delays of at least 12 – 18 months for acquiring new energy and capacity resources, when compared to our expectations at the time the IRP Action Plan was acknowledged in November, 2010. The Renewables RFP is expected to be conducted on a separate, but overlapping track from the combined Capacity and Baseload Energy RFPs.

As indicated in the 2009 IRP, we will submit the Port Westward Unit 2 and Carty Generating Station projects as benchmark resources in the combined Capacity and Baseload Energy RFP. In addition, we still intend to submit a wind resource as a benchmark in the Renewables RFP. The resource would be located in northeastern Oregon and would be operational in the 2012 – 2015 timeframe. We continue to believe that wind project(s) in the size range of 330-385 MW will fulfill our Action Plan target for maintaining physical compliance with our 2015 RPS obligations. However, we will consider options for the benchmark and other projects to be bid into the RFP at various sizes. Our overall goal will be to achieve the best combination of cost and risk in selecting new resources through the RFP that meet our IRP Action Plan target for new RPS-compliant renewable energy.

2. *Resource Requirement and Input Updates*

After incorporating updated assumptions for loads and resources, PGE continues to show significant deficits for energy and capacity prior to acknowledged Action Plan fulfillment. These deficits are only modestly lower than those outlined in our filed 2009 IRP. We plan to fill most of this need through the aforementioned Combined Capacity/ Baseload Energy and Renewables RFPs which are currently under development. The following provides discussion and further detail regarding the updated load forecast and reduced customer demand, new information on customer opt-out elections, revised EE projections from the ETO, and relevant supply changes.

2.1 Demand

This Update contains PGE's most recent long-term load forecast, dated September 2011. For IRP purposes, we identify annual energy needs assuming normal weather conditions. We report annual peak demand using 1-in-2 or 50% probability that the actual peak load will exceed the forecasted peak load during the stated time frame.

The IRP load forecast is net system load, inclusive of 5-yr opt-out customers and with embedded energy efficiency estimates. Table 2-1 below compares the projected 2015 annual energy and peak load requirement of the current forecast to that in the IRP filing.

Table 2-1: 2009 IRP vs. 2011 IRP Update Forecast

	Energy		Winter Peak		Summer Peak	
	2015 MWa	2012-30 Growth	2015 MW	2012-30 Growth	2015 MW	2012-30 Growth
Reference Case Forecast						
2009 IRP (March 2009 forecast)	2,752	2.2%	4,295	2.0%	3,903	2.5%
2011 IRP Update (Sept. 2011 forecast)	2,620	2.3%	4,149	2.1%	3,712	2.4%
Difference	(132)		(145)		(191)	

Between the two forecasts, the 2015 average energy fell 4.8%, the 2015 winter peak decreased 3.4%, and the 2015 summer peak fell by 4.9%. The 2012-30 overall long-term growth rates are relatively stable for energy and peaks.

The revised load forecast has several drivers:

- Achievement of energy efficiency savings in 2009 and 2010, which amount to approximately 46 MWa (49 MWa busbar)[2].
- The "Great Recession" that began in 2008 hit Oregon particularly hard. The state lost 148,000 jobs (8.5% of payrolls) between February 2008 and December 2009. PGE system load (deliveries to all end-use customers including those by Energy Service Supplier) was about 100 MWa lower in 2010 than in 2008. With the exception of the high-tech sector load, which actually rose in both 2008 and 2009 due to new customers, delivery of energy to other customer segments declined.
- A significant proportion of the load reductions can be attributed to lost or curtailed paper manufacturing. One major manufacturer is currently in bankruptcy proceedings. Other large customers have reduced paper production capacity.
- With the exception of the near term (2011 – 2016), when load is expected to accelerate above trend as a result of expansion by large high-tech customers (led by Intel's $3 billion D1X project), the long-term annual load growth rates are lower in our latest forecast than those in the 2009 IRP. The latest load forecast takes into account the recent economic downturn, adding one more "down" business cycle to the regression model.

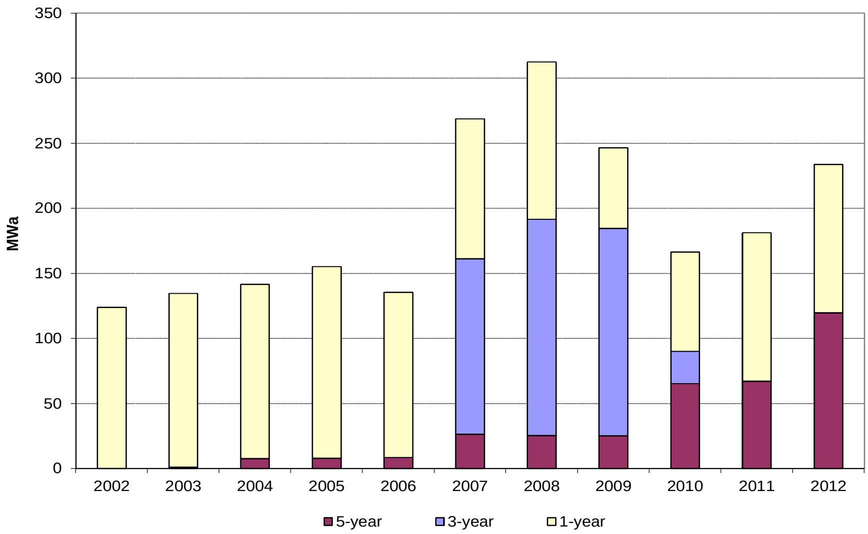
Compared to the 2009 IRP, summer peaks have decreased more than the winter peaks. Summer air conditioning peak demand is driven largely by commercial customers such as retail establishments. On the other hand, winter peak demand is driven by residential customers. Compared to the 2009 IRP, we anticipate slower growth in the commercial sector relative to the residential sector, contributing to a greater reduction to summer peaking than to winter peaking.

2.2 PGE's Cost-of-Service Load

In accordance with Commission Order No. 07-002, we remove expected 5-year opt-out load from our cost-of-service load for IRP planning purposes. The 2009 IRP estimated the 5-year opt-out load as 28 MWa. Our updated estimate, which uses customer election data as of September 2011, is 128 MWa.

[2] In Section 1.1 above, we adjusted the 2011 IRP load and added the EE achieved in 2009 and 2010 to the 2011 IRP load, for a correct load comparison of the IRPs.

Figure 2-1: Non-Cost-of-Service Customer Load by Duration of Election



From a long-term planning perspective, we do not know from one year to the next exactly how many eligible customers may choose a 5-year opt-out from Cost of Service (COS) rates. Figure 2-1 shows a break-out of non-COS customers by duration of election since inception of the programs. Customer opt-out and non-COS tariff elections have varied over time. Customer decisions for opt-out appear to be driven, at least in-part, by changes in expectations for wholesale energy market prices. This trend will likely continue as customers evaluate current market conditions and forecasts for energy prices over the next 3 – 5 years.

For capacity purposes, we have an obligation to serve as provider of last resort for all jurisdictional customers. However, given the guidance in Order No. 07-002 regarding our five-year opt-out customers, we are not acquiring resources in advance to meet any future capacity requirements associated with these customers. Instead, if necessary, we will meet any capacity needs for five year opt-out customers in the spot market.

2.3 Resources Update

Energy Efficiency

Energy efficiency (EE) continues to be a preferred option for reducing future energy needs. PGE utilizes projections prepared by the Energy Trust of Oregon (ETO) for new EE acquisitions. For this Update, we are using the most current ETO forecast, which was received in summer 2011.

Table 2-2 compares the annual incremental energy efficiency projections between the 2009 IRP forecast and the most current forecast for the period 2012-2021. The current ETO EE study forecasts that PGE will attain 13% less energy efficiency savings through 2021 than the projection included in our 2009 IRP filing. For the period of 2012 to 2015, the cumulative shortfall is about 35 MWa compared to our 2009 IRP filing.

Table 2-2: Comparison of ETO EE Forecasts for IRP (MWa)

Year	2009	2011	Difference	Cumulative Difference
2012	30.5	24.0	(6.4)	(6.4)
2013	35.2	24.2	(11.0)	(17.5)
2014	35.2	25.8	(9.5)	(27.0)
2015	35.2	27.4	(7.8)	(34.8)
2016	33.5	29.8	(3.7)	(38.5)
2017	31.1	23.8	(7.3)	(45.8)
2018	19.3	19.9	0.6	(45.2)
2019	15.0	17.0	1.9	(43.2)
2020	8.9	14.4	5.5	(37.7)
2021	8.9	13.1	4.2	(33.5)
Total 2012-2021	252.8	219.3	(33.5)	

Note: ETO June 2011 forecast without BETC mitigation.

The June 2011 ETO estimated savings for 2012 is 26.1 MWa. We then remove a portion of the ETO-assumed BETC savings (1.5 MWa) that are no longer funded by the State, consistent with our PGE Advice 11-25. We next further remove a portion of the Northwest Energy Efficiency Alliance (NEEA) market transformation savings (0.6 MWa) that are embedded in our loads, resulting in the adjusted PGE target shown on the table. We make similar adjustments to the ETO forecast for the remaining years.

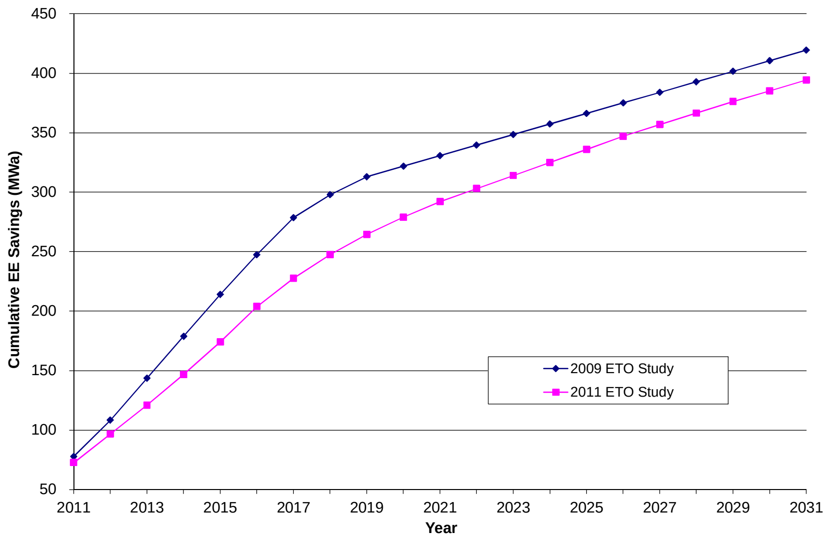
The projected cumulative shortfall (about 35 MWa) in 2015 differs from what we reported in Table 1-1 of the Action Plan (45 MWa in 2015) because of a two changes in methodology from our original IRP:

- In the 2009 IRP we assumed that the savings specified in Table 2-2 above were actual achieved savings for the year. In the 2011 update we assume we will achieve those targets by year-end to be consistent with the methodology used by the ETO. Because we look at annual average energy, this change reduces expected cumulative EE savings by approximately 12 MWa in 2015. This adjustment is not a reduction to what ETO expects to deliver, rather, our original IRP overstated the annual average savings;

- In the 2011 IRP update Action Plan we are grossing up the ETO estimate to include savings in transmission losses. This change increases expected EE by approximately 2 MWa in 2015.

Figure 2-2 graphically shows the cumulative savings over the ETO forecast horizon between the original and current forecasts.

Figure 2-2: Comparison of 2009 & 2011 ETO Forecasts



Costs to acquire the forecast level of EE savings have risen substantially since the 2009 IRP. On October 14, 2011, PGE filed Advice No. 11-25 requesting an increase in ongoing funding for the ETO of $14 million per year, effective January 1, 2012. This additional cost equates to an approximate overall rate increase of 0.9%.

One reason for the lower mid-term energy efficiency forecast is that the ETO takes a more conservative approach with their current study and forecast. They commit now to meeting at least 85% of their goal. In the 2009 study, the ETO base-case forecast assumed achievement of 100% of the EE goal.

Drivers to the reduced ETO EE savings forecast also include a decline in new customers due to the recession, incorporation of savings into state energy code updates for both new commercial and residential markets, and reduced lighting savings potential due to incorporation of CFL requirements in federal lighting standards. Changes in state energy code and federal standards are factored into load growth projections, reducing load forecasts.

In addition to the above, this summer the Oregon legislature passed measure HB 3672, which revised the BETC program. The revised BETC no longer provides incentives to businesses for implementing energy efficiency measures, as it had since 1979. For projects that were already slated to receive BETC funding, these incentives will be paid out of a current, one-time carryover funds balance at the ETO. For 2012 and beyond, the ETO forecast saving is reduced by about 1.5 MWa per year to reflect the discontinuation of BETC funding for EE.

Existing PGE Generation

Our aggregate generation capability from existing PGE owned plants has increased slightly in 2015 over what we predicted in the 2009 IRP due to the following:

- Coyote Springs: In the spring of 2011, the Coyote Springs gas-fired CCCT facility, located in Boardman, Oregon, underwent upgrades to its cooling system tower and turbine and exhaust system components. The upgrades increased expected overall plant capability by approximately 7% compared to the 2009 IRP, resulting in an average annual energy increase of 16 MWa. The upgrade was completed in Q3 2011.
- Other Thermal Plants: We updated the Boardman capacity to reflect its operations under the Boardman 2020 plan. This lead to a slight increase in available capacity (4 MW) compared to the original IRP assumption that reflected additional controls for operation through 2040. Maintenance outage calculation revisions for Colstrip and Port Westward have resulted in a total average annual energy output decrease of 6 MWa for the Colstrip and Port Westward plants.
- Hydro: the total average annual energy output of PGE hydro plants decrease by 9 MWa due to restrictions in operations after relicensing.

2.4 Conservation Voltage Reduction

OPUC Staff observed that PGE's 2009 IRP did not "treat conservation voltage reduction (CVR) as a resource" and did not consider "whether to include CVR in the action plan" (see OPUC Order No. 10-457 at 22). The Commission agreed with Staff and adopted the following requirement: "In its next IRP, PGE must consider conservation voltage reduction (CVR) for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings."

While PGE is not required to address CVR in this IRP Update, it seems appropriate to share our plans for evaluating CVR potential. The Energy Trust of Oregon (ETO) identified a total of 19 MWa of CVR available in PGE's territory over a 20-year study horizon[3].

Although voltage reduction has been shown to be effective in reducing energy usage at some other utilities, PGE needs to investigate how CVR will impact the PGE system specifically before attempting to implement CVR. As a first step, PGE will perform a study, primarily using simulation software, to assess what energy efficiency gains PGE can see from implementing CVR and how readily CVR can be implemented on the PGE system. PGE intends to conduct a PGE-specific CVR study which will consider two main criteria:

1. The effectiveness of CVR in terms of energy efficiency gains.
2. The ability to maintain acceptable power quality and reliability for PGE customers.

CVR can be implemented in several ways which vary in effectiveness, complexity and cost:

- The most basic option is Fixed Voltage Reduction. This simply means the reduction of voltage at the substation bus by a specified value that is deemed acceptable. This option is simple and inexpensive, but runs a high risk of dropping customer voltages below acceptable levels (114V)[4].
- The next option is Line Drop Compensation. In this option the feeder is modeled as impedance which is used to control the load tap changer (LTC) or voltage regulator to maintain an optimum bus voltage.
- The most complex option is Automated Feedback Voltage Control. This involves actually monitoring the end-of-line voltage and transmitting that voltage value back to the LTC or regulator to control the substation bus voltage.

The study that PGE plans to undertake will evaluate all of these options for energy savings and the associated cost to implement them, primarily by using simulation software

CVR effectiveness will be highly location specific. That is, effectiveness will depend on the specific feeder characteristics, including length, loading level, and specific equipment in use at the substation. The amount of CVR savings will also vary with time of day and year.

[3] ENERGY EFFICIENCY AND CONSERVATION MEASURE RESOURCE ASSESSMENT FOR THE YEARS 2008-2027. Prepared for the Energy Trust of Oregon, Inc. Final Report, February 26, 2009 by Stellar Processes and Ecotope.

[4] The PUC requires that voltage at the point of service (customer meter) not drop below 114V

The study results will provide a road map for future investigation through pilot projects and possible permanent implementation of cost-effective CVR.

2.5 Load-Resource Balance

The impact of the updates listed in the sections above is summarized in Figure 2-3. PGE's updated load and resources projection reveals an energy resource deficit of 632 MWa in 2015 (513 MWa including ETO EE projected savings). By 2021, the deficit grows to over 1,500 MWa (1,281 MWa with EE savings).

Figure 2-3: PGE Energy Load-Resource Balance to 2021

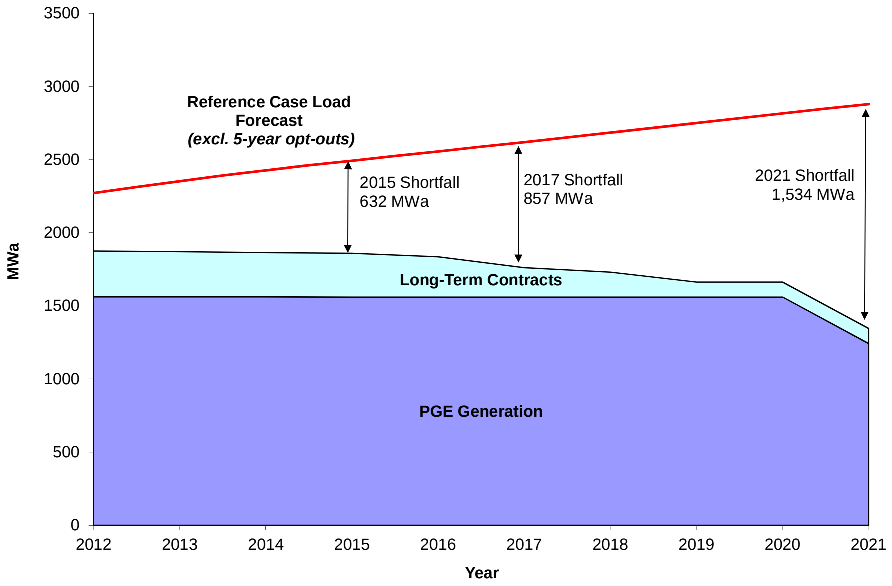


Figure 2-4 and Figure 2-5 show PGE's updated capacity needs for winter and summer, respectively. PGE remains significantly capacity deficit under the updated forecast. Our 2012 projected deficit is 859 MW in winter and 803 MW in summer. The expected capacity deficit, absent any additional capacity actions, or a provider of last resort obligation for 5-year opt-out customers, will grow to 1,409 MW in winter and 1,085 MW in summer by 2015.

Figure 2-4: PGE Capacity Load-Resource Balance – Winter

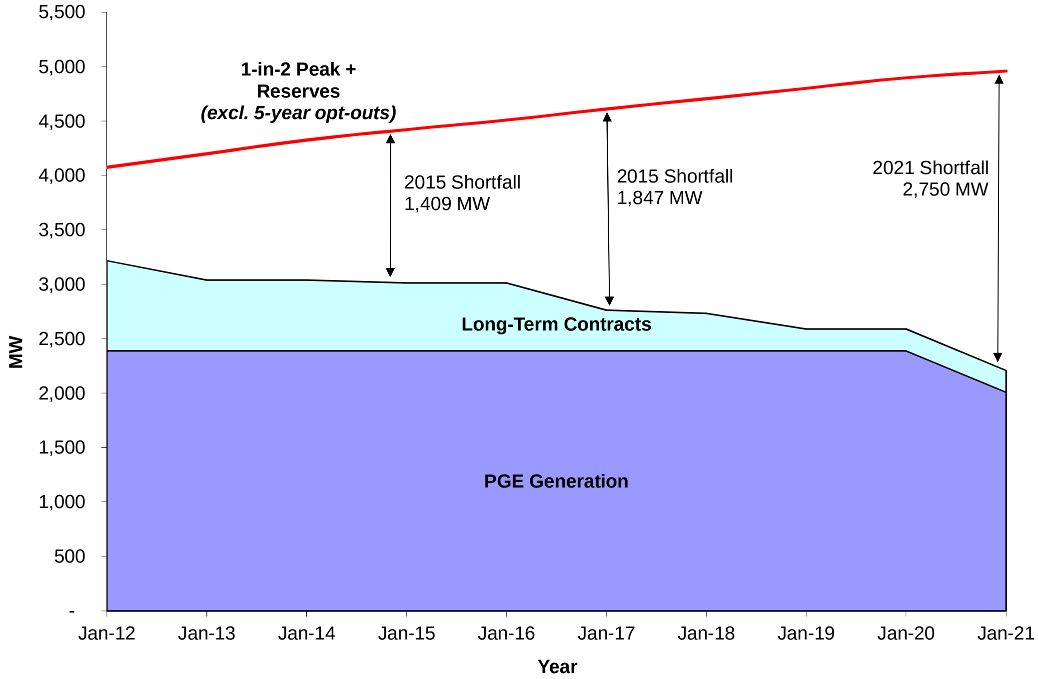
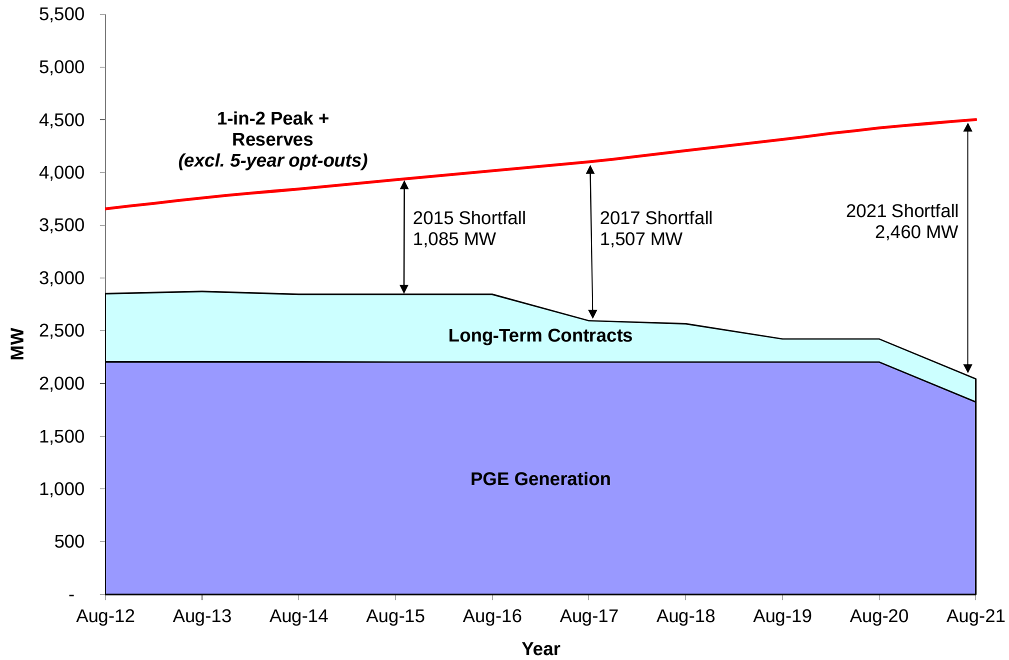


Figure 2-5: PGE Capacity Load-Resource Balance – Summer



2.6 Other Updates

The most significant assumption changes for this IRP Update (aside from the earlier described load-resource balance revisions) are:

- Lower long-term natural gas price forecasts; and,
- Reduced expectations for federal carbon policy, which is now unlikely to result in near- term CO_2 costs for electric generation as modeled in the 2009 IRP.

Since filing our 2009 IRP, we have also updated expected capital costs of gas-fired and wind resources, based on newer information, and revised projections for the long-term cost of capital.

On balance, these updates make gas-fired baseload resources more attractive, when compared to other generation resources, than was indicated in the 2009 IRP. We also believe that the revised assumptions continue to support our acknowledged IRP Action which focuses on additional EE, new efficient gas-fired generation, RPS renewables, new transmission and transitioning away from coal at the Boardman plant.

Fuel Prices

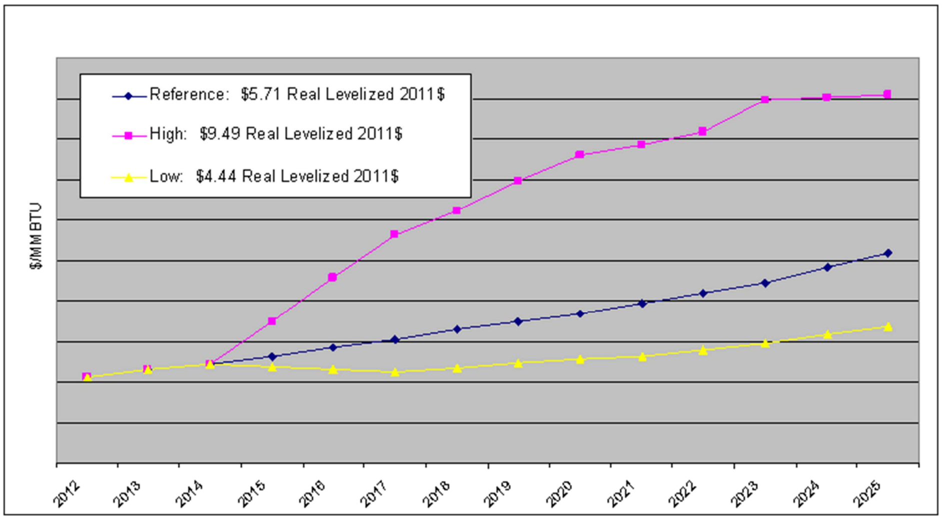
As stated in our 2009 IRP, PGE relies on independent third-party sources to project fuel prices. We updated the IRP forecasts using the most recent data available, PIRA's August 2011 forecast and the EIA's 2011 Annual Energy Outlook. To be consistent with our IRP methodology, we used the following approach:

- For natural gas, the forward market prices for the short-term (2012-14), PIRA's long-term forecast of natural gas by hub for the longer term (2017 and beyond) and interpolation between the two for 2015 an 2016;
- For coal prices, an average of PIRA and EIA coal price forecasts.

The average of Sumas and AECO prices, the gas hubs that are most relevant for the Pacific Northwest, is shown in Figure 2-6. The reference case has a real levelized average price of $5.71/MMBtu (2011$). In the high gas scenario the average price increases to $9.49/MMBtu and in the low gas scenario the average price decreases to $4.44/MMBtu.

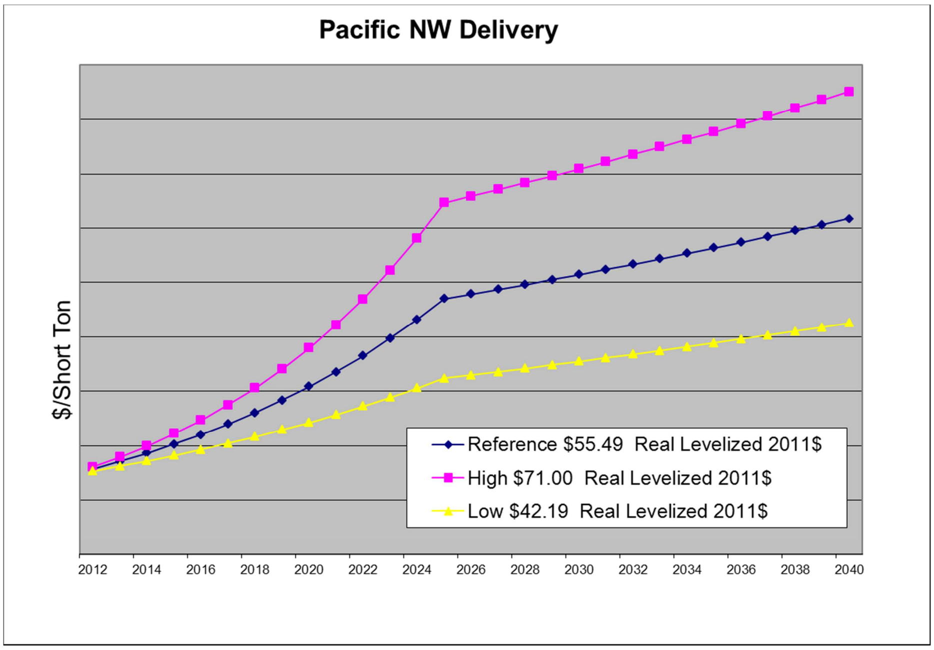
By comparison, the real levelized reference case natural gas price in the filed IRP was $7.88/MMBtu (2011$) for the same 2012-2025 period.

Figure 2-6: Average of Sumas and AECO Natural Gas Prices Long-term Forecast



Updated delivered coal prices (2011$) are shown in Figure 2-7 for the period 2012-2040. The real levelized reference case coal price in this Update is $55.49/ton as compared to a reference case price of $54.12 in the filed IRP for the same 2012-2040 period.

Figure 2-7: PRB 8,400 Btu/lb. Low Sulphur Coal Prices



Carbon Policy and PGE's Carbon Tax Update

Since the carbon cost and risk assumptions were developed for the 2009 IRP, the intensity of discussions amongst federal policymakers has significantly diminished. It is now clear that the political appetite to impose carbon regulations that would result in near-term or significant new costs on a fragile economy is low. Based on the current environment and political dynamics, we believe that it is reasonable to reduce expectations for carbon costs, at least in the near-term.

For modeling purposes, we now assume that a legislated compliance cost on CO_2, imposed via a tax or a clearing price for carbon credits/allowances, will not be in place until at least 2017. Assuming a 2 – 3 year lag in the effective date of any new legislative program imposing a price on carbon, 2017 appears to be a reasonable, conservative revision for the start of any future carbon costs on electric generation. While it also appears that future carbon costs may be reduced in overall magnitude given the protracted period of economic weakness, at this time we do not have sufficient new data, to make further adjustments due to a lack of new legislative proposals or analysis. Thus, we do not propose changing the forecasted nominal start price or growth rate assumptions for CO_2 costs in this Update. Instead, we will more broadly revisit carbon cost and risk assumptions in our next IRP.

Figure 2-8: CO_2 Reference Case Prices

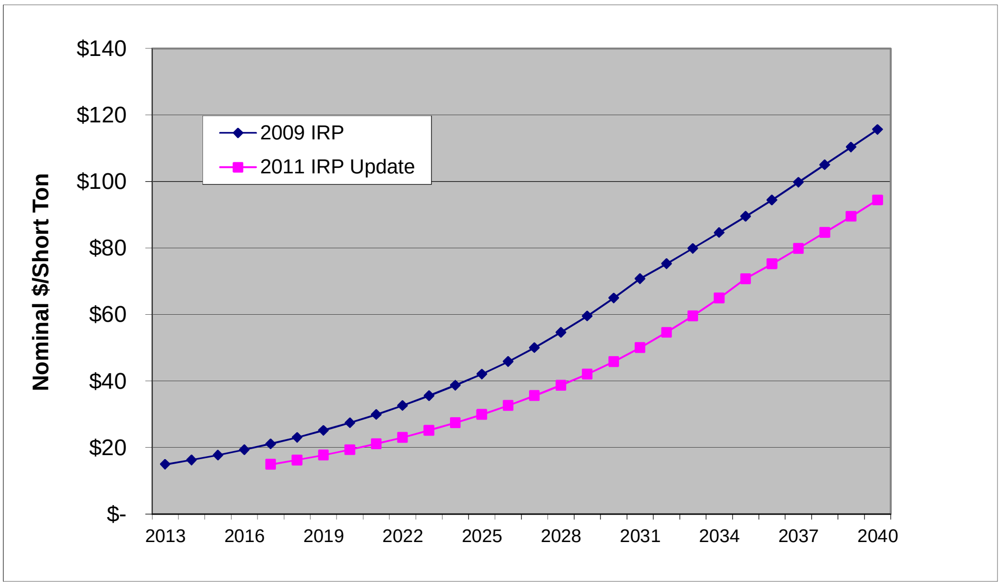


Figure 2-8 shows the effect of delayed implementation on costs. In this IRP Update, we postpone the implementation of carbon regulation and costs from 2013 to 2017.

Costs of Action Plan Resources

Capital Costs

PGE has updated overnight capital costs for the major generation types that are likely candidates to fulfill the new supply-side resource requirements identified in our Action Plan. Table 2-3 shows the detail of our changes for wind power plants, CCCTs, SCCTs and reciprocating engines. All updated estimates are based on studies or inquiries to electric generation vendors and equipment suppliers. The new resource cost estimates will be better informed and refined by the results of our forthcoming supply-side RFPs.

Table 2-3: Updated Resource Overnight Capital Costs (2011$/kW)

	2009 IRP	IRP Update	% Change
Natural Gas CCCT - Greenfield (G Class) w/duct burner	$1,356	$1,084	-20%
SCCT - LMS 100	$1,142	$1,289	13%
Reciprocating Engines	$1,465	$1,184	-19%
Wind Plant	$2,370	$2,053	-13%

When overnight capital costs were being researched for the PGE 2009 IRP, the costs of new generation projects were still experiencing the effects of a run-up in commodity costs during a strong economy. Later, the economic downturn reduced electricity demand for the U.S. and much of the world, resulting in a decrease in new power plants and capital projects more generally. Market pressure from the reduced demand for capital projects began driving down commodity and component costs, resulting in lower costs for most types of new electric generation. The exception to this trend is the LMS100 SCCT, which was a newer technology (Aero-derivative) and did not have a long, proven track record in 2008. Now, several units have been installed and the fleet is establishing an operating history. This has increased the acceptance and demand for the Aero-derivative units with purchasers, thereby driving the installed cost up. The trend for this specific type of generation seems to be unique when compared to the "softer" demand and lower trending prices for most other types of new electric generation and capital projects more broadly.

Production Tax Credit

In Table 2-3 above, consistent with our 2009 IRP, we assume ongoing renewal of the Production Tax Credit (PTC) for wind energy. The Federal PTC for wind energy is currently scheduled to sunset with new wind generating facilities placed in-service by year-end 2012, and the PTC for other technologies is scheduled to sunset in 2013.

In the 2009 IRP, we assumed full renewal over our planning horizon. We cannot predict the likelihood of a renewal of one or more years, or whether the incentive may be reduced from current levels. However, such reductions seem more likely now than they did when we filed the 2009 IRP, given the growing concern over federal budget deficits and spending.

Given the history of ongoing renewals of the PTC since its inception, we continue to assume renewal of the PTC benefit at current levels in this Update. Additionally, we do not have sufficient new data to support a revision in our current base-case assumptions for PTC at this time. However, we believe that the risk of reduced Federal tax benefits for renewable resources is materially higher in the current fiscal climate. Therefore, the risk of cost increases for new renewable resources (built after 2012 for wind and post 2013 for other PTC-qualified technologies) due to reduced tax benefits is substantively higher than what was assumed in the 2009 IRP. As is the case with CO_2, we will more broadly re-examine our expectations regarding ongoing tax benefits for renewable resources in the next IRP.

Business Energy Tax Credit

In the 2009 IRP, PGE assumed continuation of the Business Energy Tax Credits (BETC) in its then current form, which helped reduce the cost of qualifying renewables, as well as the cost for qualifying commercial and industrial Energy Efficiency (EE) projects. This summer, the Oregon legislature passed House Bill 3672, which revised the BETC program. The revised BETC is no longer applicable to utility-scale renewables projects. Thus, we no longer assume a BETC cost offset for such new renewable projects.

Wind Integration Cost

As mandated by the OPUC, PGE assessed the integration cost for wind to be used in the portfolio analysis. Chapter 7 reports the results of PGE's 2011 Wind Integration Study, which lead to a decrease of the projected wind integration cost from $13.50/MWh to $9.15/MWh (in 2014$).

Cost of Capital

Finally, financial assumptions have been updated to reflect changes in income tax rates, cost of debt, and expected long-term inflation, as shown in Table 2-4.

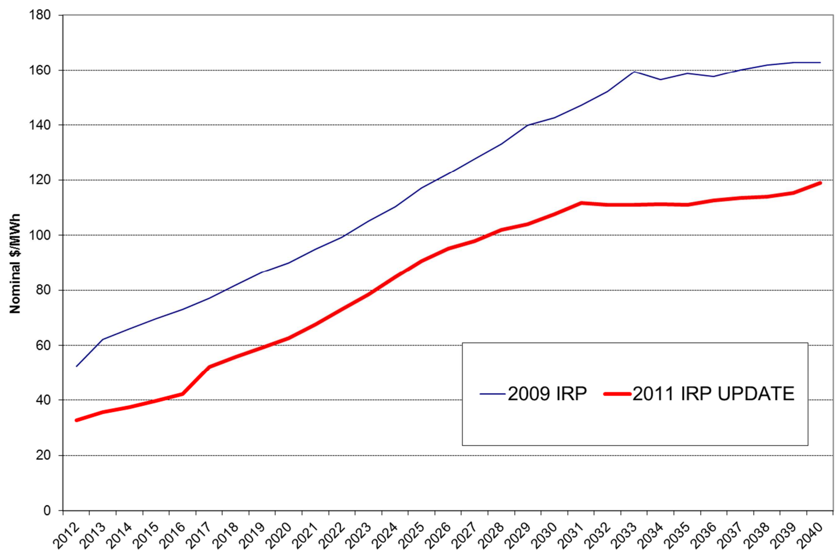
Table 2-4: Financial Assumptions

	2009 IRP Percentage	2011 IRP Update Percentage
Income Tax Rate	39.29%	39.94%
Inflation Rate	1.90%	1.84%
Capitalization:		
Preferred Stock	-	-
Common Stock (50% at 10.75%)	5.38%	5.37%
Debt (50% at 5.77%)	3.66%	2.89%
Nominal Cost of Capital	9.03%	8.26%
After-Tax Nominal Cost of Capital	7.59%	7.11%
After-Tax Real Cost of Capital	5.59%	5.17%

Long-Term Wholesale Electricity Prices

The combination of all the updates listed above leads to a reference case market electric prices forecast that is lower than the 2009 IRP (section 10.A.3). On a real levelized basis, revised prices in the Pacific Northwest are now projected at roughly $56/MWh (real levelized from 2012 to 2040 in 2011$) vs. $83 in the 2009 IRP.

Figure 2-9: PGE Projected Electricity Price – Reference Case



The primary drivers of this reduction are: a) in the shorter term, a lower WECC load, b) lower natural gas prices, c) delayed introduction of carbon costs, and d) lower wind integration costs.

3. Demand Response Update

In the following sections, we provide a comprehensive update of the progress in demand response (DR) procurement and programs since filing our IRP. In response to the Commission's direction in Order No. 10-457, we also address the following:

- The estimated cost per MW of capacity savings by DR type (firm vs. non-firm), and projected MW acquisitions by DR type for the next 5 years;
- A discussion of the steps PGE is taking to evaluate DR in the next IRP; and,
- An updated action plan for assessing (e.g., plans for pilots and programs) and acquiring DR for the next 3 years.

3.1 Progress in Demand Response Procurement since 2009

PGE has successfully launched several programs and pilots for the procurement of demand response (DR) resources. We identify two main types of DR:

- Firm, or non-discretionary, which are accounted for as capacity resources. We classify as "firm" the curtailment tariff and firm demand response peak capacity programs such as Automated Demand Response and the Salem Residential Pilot;
- Non-firm, which are elective and behaviorally driven and cannot therefore be relied upon to meet peak capacity needs until more is known about typical aggregate PGE participating customer response.

Firm Demand Response – Direct Load Control

Curtailment tariff

PGE filed the Schedule 77 Firm Load Reduction Pilot Program on December 23, 2008 (effective date July 9, 2009) and updated it on August 1, 2011 (effective date September 21, 2011). The pilot is offered to PGE's large non-residential customers that are able to commit to a load reduction of at least 1 Megawatt (MW) of demand at a single point of delivery. The 2009 IRP target of 10 MW per year for this schedule has been achieved. In conjunction with the tariff update, we are also increasing the expected target to 20 MW by 2015.

PGE can only initiate an event during six months of the year and each load reduction event is four hours. PGE initiates a four-hour load reduction event at its discretion by providing the participating customer with a notification. PGE may call up to twelve events per year. A minimum of one event will be called annually.

The cost estimate for 2012 is specified in the tariff[5] and is equal to a reservation credit of $3 or $6 per kW, depending on the advance notification requested. It is credited to the participating customers in January, February, March, August, September, and October regardless of whether or not a Firm Load Reduction Event was called. In addition to the reservation credit, PGE pays an energy charge equal to "the Firm Energy Reduction Amount times the lesser of the hourly Mid-Columbia Electricity Index (Mid-C) as reported by the Dow Jones or fuel cost per MWh for a Simple Cycle Combustion Turbine (SCCT)". Consequently, the cost for this program is less than that for PGE's automated demand response program (ADR – discussed below). This is appropriate because of the longer notice time associated with Schedule 77 (either four or 24 hours) as compared to ADR (10 minutes).

Firm Demand Response Peak Capacity Contracts

Automated Demand Response Pilot

In August 2008, PGE issued a request for proposal (RFP) for up to 50 MW of firm capacity to be acquired by December 1, 2012. The RFP targeted two broad customer groups:

- 25 MW for residential and small non-residential customers; and
- 25 MW for larger non-residential customers.

The proposals received for larger non-residential customers were successful and resulted in selection of a vendor and execution of a contract. We project that this program will meet the full 50 MW target by 2014, as projected in the 2009 IRP. Actual procurement in 2011 will be 5 MW through the ADR pilot, which was approved by Commission Order No. 11-182.

This program can be deployed for a limited number of hours, as its primary purpose is for peak reliability. Because ADR can respond within 10 minutes of notification, PGE could have some future potential to use the resource to address flexibility needs. However, such activities are limited because:

1) Most ADR callable hours must be available for their primary purpose of providing capacity, and

2) ADR represents decremental load only and cannot provide incremental load.

In the future, other automated demand response programs could have greater potential for helping address the challenges of variable resources. These

[5] Details are posted in the Portland General Electric web-site: http://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_077.pdf

possibilities include large-scale, direct control of appliances (see appliance market transformation, below) or use of two-way flows during electric vehicle charging (much further in the future).

The costs for this program are approximately equal to the least cost supply-side capacity alternative (i.e., an LMS100 combustion turbine) on an average levelized program basis. It is structured as follows:

- Eligible participants will be PGE's commercial and industrial customers with an annual average peak demand of 30 kW or more.
- Lighting and HVAC systems (heating, ventilation and air conditioning) are expected to be the primary sources of load reduction.

Table 3-1: Firm Demand Response Acquisitions by 2016

Year	Curtailment Tariff	Automated Demand Response Pilot		Total Demand Response
	MW	Summer (MW)	Winter (MW)	MW
2010Actual	10	-	-	10
2011	10	-	5	15
2012	20	10	10	30
2013	20	20	35	55
2014	20	50	50	70
2015	20	50	50	70
2016	20	50	50	70

Table 3-1 shows the current projected total demand response through 2016. We plan to achieve up to 70 MW by 2016 -- 10 MW more than what projected in the 2009 IRP.

Small Non-Residential Contracts

The proposals received for residential and small non-residential customers were less successful because: 1) they were not cost effective, and 2) none of the proposals included both summer and winter seasons. As a follow-up to that RFP, PGE issued a second RFP in 2010 to evaluate the potential for employing programmable communicating thermostats in a mass market residential direct load control program. This RFP was also unsuccessful because costs for the programmable communicating thermostats were too high. After PGE completes deployment of its automatic demand response and critical peak pricing pilots (discussed below), we plan to issue another residential RFP in 2012. Over time, we believe the cost of programmable communicating thermostats will decline and support the development of more successful proposals.

Water Heater Direct Load Control Pilot

PGE is developing a Water Heater Direct Load Control Pilot (the Salem Residential Pilot), which has the following characteristics:

- The pilot is implemented within the Salem Smart Grid project;
- Customers must be on the test feeders involved with the project;
- The maximum number of participants will be less than 100;
- Water heaters will respond to a radio signal;
- PGE will dispatch the water heater control via a radio signal triggered by a transactive control price signal from the Smart Grid project;
- The pilot will be operational from August of 2012 through 2014.

Because the water heater direct load control project is a very limited and non-scalable pilot within a larger smart grid demonstration project, it provides PGE with no potential MW acquisition from this initiative. Based on the results of this pilot, PGE may reevaluate the economics for expansion as a full program. Given the expectation of emerging technologies, however, PGE currently believes that the most cost-effective approach for this type of program will be through appliance market transformation, discussed in more detail below.

Non-Firm Demand Response Pricing Options

The cost of non-Firm DR programs is not easily summarized on a cost per MW basis, as the costs and demand curtailment estimates are currently uncertain. In addition, the tariff pricing options are designed to be rate-neutral. In the cases where PGE is pursuing internally-developed pilot programs, we are gaining a better understanding of costs, processes, and potential customer participation in the DR initiative proposed. Once the pilots are complete, PGE will have a better understanding of the typical aggregate cost per MW acquired for non-firm programs for a given group of participating customers.

Time-of-Day Pricing

As of January 1, 2011, PGE's long-standing Time-of-Day (TOD) tariff (for large non-residential Sch. 89 customers) was extended to Schedule 85 customers. Consequently, TOD pricing expanded from customers exceeding 1,000 kW of monthly demand to all customers with more than 201 kW of monthly demand. With completion of PGE's Advance Metering Infrastructure System (AMI – discussed below) and the increased potential for interval data, PGE plans to propose further expansion of TOD pricing to Schedule 83 (customers with monthly demand of 31-200 kW) in the future. The benefit of expanding time-of-day pricing is that it will encourage more customers to shift load based on price signals.

Time-of-Use Pricing

PGE offers a time-of-use (TOU) pricing option to residential customers and small non-residential customers with less than 30kW of demand. Time-of-use differs from time-of-day in that TOU pricing offers on-peak, mid-peak, and off-peak rates.

With the completion of AMI and expanded availability of interval data, there will be greater potential for TOU-type programs.

Critical Peak Pricing (CPP)

PGE is currently developing a CPP pilot and is scheduled to be launched November 2011.

The pilot program will employ a dynamic pricing structure, based on time-of-use rates, to encourage peak-load reduction during times of unusually high demand. The pilot is designed to accommodate up to 1,000 participants and is expected to be active from November 2011 through October 2013. Based on the results of the pilot, a residential CPP program may subsequently be made available to a broader group of customers. Until enough experience with customer response provides a reliable estimate of typical aggregate capacity savings, CPP is considered a non-firm resource.

Under the tariff, PGE will provide day-ahead notice to participants for expected critical peak day events. During a 4-hour "critical peak" period (Sundays and holidays are excluded and billed at off-peak rates), the customers' energy price will be approximately four times higher than normal. The goal is that the price signal will encourage customers to conserve energy during those hours. The pilot limits the number of times PGE can implement a CPP event to 10 times in the summer and 10 times in the winter. In order to develop the current CPP pilot in a reasonable time and cost (while retaining foundational functionality), its current design excludes enabling technology (e.g., communicating, programmable thermostats). As a condition of Commission approval for the CPP pilot, however, PGE will provide a report no later than early 2013 detailing the costs and efforts needed to implement a fully scalable CPP program upon completion of the pilot, assuming it is successful. In addition, because Phase 1 of CPP is a limited pilot, its cost is not indicative of its potential as a demand-side capacity resource.

Energy Tracker

By end-year 2011, PGE will introduce its Energy Tracker program to all customers. This represents an energy information tool that utilizes the interval data from AMI. Energy Tracker will provide customers with energy use information that can help identify-reduction and peak shifting strategies that customers may find valuable to implement. Such information includes:

- Determine how changes to a customer's end uses may impact their bill (e.g., adding/removing appliances);
- Determine energy usage trends plus how and when the most energy is used;
- View up to 24 months of historical bill data by: usage, cost (including Time of Use and Demand costs) and meter;
- Compare bills with the previous month or previous year;
- Compare their current tariff rate to other offered tariff rates and see how shifts in their usage might impact their bill; and
- View their interval data by hour, day, week, bill cycle or month.

In addition, Energy Tracker will allow customers to compare their home's energy efficiency with comparable homes in the region and provides suggestions to improve their efficiency. Finally, PGE's Customer Service Representatives (CSRs) are able to use customers' Energy Tracker data to enhance their ability to respond to energy-usage and billing-related questions.

Energy Information Service

PGE's large non-residential customers with greater than 30 kW of demand (Schedules 83, 85, and 89 customers) are currently eligible for Energy Information Service (EIS), an energy monitoring option that provides the most detailed information of any of PGE's services. As of June 2010, a total of 140 customers representing over 850 meters have signed up for EIS, which provides detailed graphs and charts depicting energy use in 15-minute intervals. By knowing when peaks occur, customers can analyze their processes and respond accordingly. In some instances, this information has helped customers know which processes they could shift to reduce peaks, or to participate in such programs as Demand Buy-Back or contract curtailment. EIS can be used to:

- Compare current operating data with historical information;
- View monthly, weekly, daily and hourly data;
- See when customer operations are using the most energy;
- Generate an "average day" profile and "peak day" profile for comparison;
- Identify abnormalities and trends in energy usage and help determine causes, such as hidden equipment problems;
- Optimize operations by adjusting energy use; and
- Monitor and track the effectiveness of energy-efficiency measures.

Appliance Market Transformation

PGE has been proactive in the effort to achieve appliance market transformation. In 2007, we established a working group along with Whirlpool and the Pacific Northwest National Laboratory that presented an award-winning paper at the Grid Interop forums. That paper addressed the potential for installing a standard interface (i.e., socket) on appliances that could accept low-cost communication devices.

In 2009, PGE worked with Whirlpool and the Electric Power Research Institute (EPRI) to define and create specifications for that socket. EPRI also recruited other utilities, appliance manufacturers, and communication device manufacturers to establish the EPRI Appliance Market Transformation Project.

In a separate but related effort (also begun in 2008), PGE was a participant in the "Home to Grid" (H2G) work group, which addresses appliance transformation. This effort is part of the National Institute of Standards and Technology (NIST) responsibilities for an overall interoperability roadmap under the Energy Independence and Security Act (EISA) of 2007. As part of this activity, PGE published two papers on appliance market transformation that allowed coordination of the principles and efforts of the EPRI and NIST projects.

Subsequently, at the request of NIST and EPRI, the Utility Smart Network Access Port (USNAP) Alliance formed to start the work of combining their specifications into a single specification. As a result of that effort, the USNAP Alliance and EPRI then created the Utility Smart Network Access Port, an interface/socket, that enables any Home Area Network standard, present and future, to use any communication method as a conduit into the home without adding additional hardware in the meter. This development has led to the following recent activities:

- In May 2011, a successful test was performed with prototype appliances containing the USNAP interface, plugged-in communication devices, and utility control software with demand response commands. "Plugfest" was attended by five appliance manufacturers, five communication device manufacturers, and several utilities including PGE. In addition, PGE submitted specifications to help define the common utility control commands;
- In June 2011, USNAP and EPRI presented the specifications for that socket to the H2G group, who recommended that the specification become a national standard. In October 2011, the Consumer Electronics Association (CEA) formally agreed to take on this work and will issue a CEA or ANSI (American National Standards Institute) standard for a low-cost modular interface/socket to communicate with appliances after they complete their process.

In addition to these efforts, The USNAP Alliance will market the new standard to appliance manufacturers and communication device manufacturers. PGE's on-going efforts will include encouraging local retailers to market appliances with this standard. With eventual incorporation of this standardized interface into appliances and the availability of low-cost communication devices, utilities will be able to efficiently coordinate appliance energy use under either direct load control or time varying price programs.

Finally, PGE plans to initiate, in late 2011, a very small pilot to install approximately five water heaters and "plug in" a Wi-Fi communication device. PGE will then use the customer's internet connection to test direct load control of the "smart" appliances. If successful, PGE will propose to expand the pilot to 100 customers in 2012/2013 to further test the system's viability. If the expanded pilot proves successful, PGE plans to propose a scalable water heater direct load control program.

Advanced Metering Infrastructure

In the 2009 IRP, PGE reported on our initial efforts to implement the Advance Metering Infrastructure (AMI) system. Since then, we have successfully achieved the following milestones:

- In August 2010, we completed meter deployment;
- In December 2010, we completed network installation;
- In June 2011, we completed all the information technology (IT) efforts to achieve the process improvements related to the AMI system, e.g., customer preferred due date, remote connects/disconnects, unaccounted for energy detection, etc.

3.2 Demand Response Evaluation Methodology and Next Steps

PGE believes that the methodology we used to evaluate DR in the 2009 IRP remains sound.

PGE will continue to evaluate demand response resources against the supply-side capacity resource alternatives, such as a simple-cycle CT. This is consistent with the discussion in Commission Order No. 05-584 and is also consistent with other PGE analyses for demand side capacity resources in recent years. For example, in Dockets UM 1514 and UE 229 (PGE's proposal for ADR approved by Commission Order No. 11-182), "the costs of ADR were compared to that of an LMS100 SCCT and found, on an average levelized program basis, to be approximately equal" (Stipulating Parties/100, page 13). PGE also estimated the benefits of a large-scale CPP program in its UE 189 scoping plan (PGE Exhibit 103) to be the avoided cost of a simple-cycle combustion turbine.

Simple-cycle combustion turbines represent the appropriate capacity benchmark because:

- They have the necessary flexibility that is not available in most other available supply-side resources;
- There currently is no liquid capacity market in the region;
- Longer-term capacity contracts can have a variety of conditions and notification times, which means they are not readily comparable; and
- In contrast, the LMS100 has 10-minute availability, similar to ADR, and therefore represents the least-cost, alternative resource.

Although the comparison is inexact, the SCCT provides the most reasonable basis for comparison. A CT can provide additional generation benefits by dispatching economically during non-critical demand periods, while demand response resources provide reduced environmental impacts and risk and diversity in PGE's capacity portfolio. DR offers reduced risk in the areas of resource development and construction as well as operational risks related to fuel prices, potential CO_2 costs, and pollution abatement. At the same time, a flexible combustion turbine offers ancillary services value that may only be achievable on the DR side through automated- / technology-enabled DR.

Steps to evaluate DR in the next IRP include:

- Update the market assessment estimate of the cost and potential for DR;
- Evaluate new pricing programs enabled by the adoption of smart meters;
- Issue a new RFP for residential peak capacity contracts; and
- Continue development of the programs and pilots described in Section 3.1 above.

3.3 Updated DR Action Plan

Our Action Plan for the next 3-yrs (to 2015) is the following:

- Pursue an ADR target of up to 50 MW by 2015;
- Issue an RFP for peak capacity contracts for residential and small non-residential customers by end-year 2012;
- Increase Schedule 77 (curtailment tariff) customers to up to 20 MW by 2015;
- Extend the time-of-day pricing option to all customers with more than 31 kW of monthly demand;
- Complete the pilots described above.

As of year-end 2011, PGE will have acquired 15 MW out of the 60 MW projected firm DR by 2015 targeted in the Action Plan. In addition, PGE has completed or is in the process of implementing the following:

- Water Heater Direct Load Control Pilot. Pilot will be operational in 2012;
- Extension of the time-of-day pricing option to all customers with more than 201 kW of monthly demand;
- Critical peak pricing pilot (November 2011);
- Phase I of the Energy Tracker to all customers (year-end 2011);
- Energy Information Service to all large non-residential customers with demand greater than 30 kW; and
- AMI system.

4. Renewable Portfolio Standard

On June 6, 2007, Oregon adopted a Renewable Portfolio Standard (RPS), ORS 469A. Among the requirements of the Oregon RPS, certain electric utilities must serve at least 25% of their retail energy load with RPS qualifying renewable resources by 2025, with interim targets of 5% by 2011, 15% by 2015, and 20% by 2020. Qualifying renewable resources include the following if the resource, or an improvement to the resource, has been placed into operation on or after January 1, 1995:

- Wind
- Solar photovoltaic and solar thermal
- Wave, tidal, and ocean thermal
- Geothermal
- Certain types of biomass
- Biogas from organic sources such as anaerobic digesters and landfill gas
- New hydro facilities not located in federally protected areas or on wild and scenic rivers, and incremental hydro upgrades up to 50 MWa per year from certified low-impact hydroelectric facilities.

Electric utilities can use, subject to certain limitations and independent verification, Renewable Energy Credits (RECs) or Green Tags to fulfill the RPS requirement. In meeting this requirement, the RPS identifies two classifications of RECs:

- Bundled, where the energy and REC are sourced from the same generating facility, and
- Unbundled, where the REC is purchased separately from the underlying power.

In both cases the qualified resources must be located within the boundary of the Western Electric Coordinating Council footprint (WECC).

In addition, the legislation allows for the ability of the electric utility to "bank" RECs from qualifying resources beginning January 1, 2007 for the purpose of carrying them forward for future compliance. To maintain the integrity of compliance, the origination of RECs is validated via the Western Renewable Energy Generation Information System (WREGIS). The legislation limits the maximum amount of annual RPS requirement that can be met with unbundled RECs to 20% and provides the option for electric utilities to make alternative compliance payments (ACP) instead of producing the required number of compliance RECs.

Given the above RPS provisions, PGE must meet at least 80% of each annual RPS requirement with some combination of current and banked, bundled RECs from qualifying physical resources. The practical effect of the RPS legislation is to promote the acquisition of renewable resources as the primary means of compliance, while allowing for flexibility in implementation to capture market opportunities, avoid short-term cost excursions and adapt to timing differences in securing new supply.

4.1 RPS Position and Action Plan Strategy

Our acknowledged IRP Action Plan targets the acquisition of sufficient new renewable resources to maintain physical compliance with the Oregon RPS standards. Specifically, the Action Plans seeks renewable resource additions to meet, at minimum, the 2015 RPS standard of 15%. At the time of filing the 2009 IRP, we projected a need for 122 MWa of new renewables to meet the Action Plan objectives. Due to a continued economic slowdown which has resulted in a reduced electric demand forecast for PGE, accompanied by increased customer five year opt-out elections, we now project a modestly reduced RPS need of 101 MWa.

However, due to the steep ramp of the RPS requirements over time, we also continue to forecast a significant need for qualifying renewable resources beyond 2015. Our RPS resource deficit increases to 261 MWa by 2020, 454 MWa by 2025, and 533 MWa by 2030, absent any new supply additions.

Although our Action Plan targets resource additions to maintain physical compliance with the 2015 RPS requirements, the amount of new renewable resources that we acquire to implement the Action Plan will depend on the cost and quality of bids received through our forthcoming RFP, as well as the specific characteristics of the underlying generation projects. Accordingly, we plan to issue a renewables RFP in 2012 that will seek to fulfill our IRP objectives, while remaining flexible with respect to project size and in-service date.

The following table presents our projected RPS compliance position through 2025.

Table 4-1: PGE Estimated RPS Position by Year (in MWa)

	2011	**2015**	**2020**	**2025**
Calculate Renewable Resource Requirement:				
PGE Retail Busbar Load net of EE	2,320	2,530	2,765	3,021
Remove 5-year Opt-Out Load	(67)	(128)	(132)	(132)
A) Net PGE Load	2,253	2,372	2,578	2,834
Renewable Resources Target Load %	5%	15%	20%	25%
B) Renewable Resources Requirement	**113**	**356**	**516**	**708**
Existing Renewable Resources at Busbar:				
Vansycle Ridge Wind	8	8	8	8
Klondike II Wind	26	26	26	26
Klondike II Stable Tariff Rate	(5)	-	-	-
Sales of RECs	-	-	-	-
Biglow Canyon Wind	161	161	161	161
Post-1999 Hydro Upgrades	9	9	9	9
Pelton-Round Butte LIH Certification	50	50	50	50
C) Total Qualifying Renewable Resources	**249**	**254**	**254**	**254**
Compliance Positions & RECs Banking:				
D) Excess/(Deficit) RECs Before New IRP Actions (C less B)	137	(101)	(261)	(454)
E) IRP Action Plan	-	101	101	101
F) Total PGE Renewable Resources (C plus E)	249	355	355	355
G) % of Load Served by RPS Renewables (F divided by A)	11%	15%	14%	13%
H) Excess/(Deficit) RECs w/IRP Actions (D plus E)	137	(0)	(160)	(353)
I) Cumulative Banked RECs After IRP Actions	**717**	**1,291**	**1,077**	**200**
J) Cumulative Non-LIH Banked RECs After IRP Actions	516	1,091	877	(214)

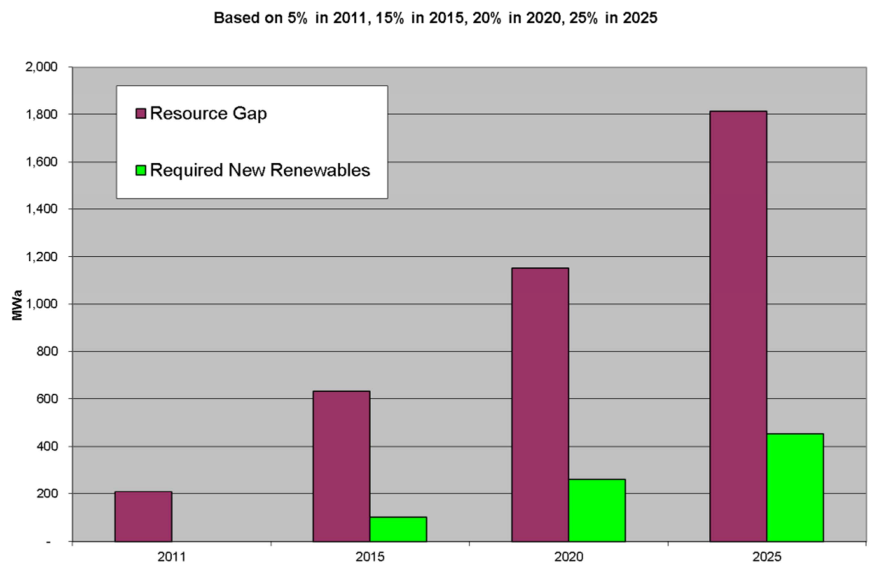
As illustrated in Table 4-1 above, our projected RPS resource deficits are significant when considered on an energy basis, and become even more challenging when converted to a nameplate generation requirement. To date, wind remains both the most available and cost-effective renewable resource. As such, it is reasonable to presume that wind will continue to provide a substantial proportion of the overall regional and PGE need for renewable energy. If we assume that our ongoing RPS needs continue to be met primarily with variable energy resources such as wind, the resulting requirement for new qualifying generation is large, and therefore suggests an implementation approach which manages to longer-term needs and cost/risk mitigation, rather than near-term compliance targets. Table 4-2 projects our future RPS requirements in terms of installed nameplate capacity for new wind generation.

Table 4-2: Wind Capacity Necessary for RPS Requirements

Time Period	Average Need (MWa)	Current Annual Generation (MWa)	Need as a % of Current Generation (%)	Shortfall (MWa)	Implied Wind Nameplate Capacity Needed (33% CF) (MW)
2011-2014	114	255	45%		
2015-2019	367	255	144%	112	339
2020-2024	536	255	210%	281	850
2025-2030	743	255	292%	488	1,480

At the same time, we also project significant future aggregate energy and capacity deficits (as discussed in more detail in Chapter 1 of this Update). This overall resource deficit exceeds our RPS renewable need through 2025 and beyond. Accordingly, qualified RPS resource additions serve the dual purpose of meeting our energy requirements and RPS obligations. This was the case for our renewable resource additions over the last several years (including Biglow Canyon Wind, Klondike Wind and new solar contracts). Figure 4-1 provides a current projection of our aggregate energy deficit alongside our RPS need at each of the upcoming RPS target change years (2015, 2020 and 2025).

Figure 4-1: Renewables Necessary to Meet RPS Requirements



4.2 Options for Achieving RPS Compliance

PGE has four primary options for achieving RPS compliance, subject to certain limitations – acquiring physical energy resources with bundled RECs, purchasing unbundled RECs, utilizing banked RECs (that result from previous REC acquisitions – both bundled and unbundled), and alternative compliance payments in lieu of physical resources or RECs. The company may also employ a mix of these strategies, either concurrently or at different points in time. Each of these strategies, as well as their potential benefits and limitations, are further discussed below:

- Physical Compliance – Means acquiring bundled RECs through the purchase of energy and associated renewable attributes from an RPS-compliant renewable generation source. Acquisition of bundled RECs can be achieved either through utility ownership or power purchase agreements. There is no limitation on the use of physical resources and bundled RECs for RPS compliance. Bundled RECs may also be banked indefinitely for future RPS compliance or monetization. For energy deficit utilities like PGE, physical compliance is particularly attractive when the costs of renewable resources are equivalent to, or lower than, the cost of non-renewable alternatives. In an environment where renewable resources are cost competitive (at or near the same cost) with non-renewable alternatives, a short utility is able to meet both its future energy requirements and its RPS obligation at a relatively small, or perhaps no additional cost. The acquisition of physical resources with bundled RECs also provides an ongoing or recurring source of supply to meet growing RPS compliance targets over time. Furthermore, utility owned resources or contract structures that provide extension rights provide access to site-specific renewable generation and RECs that may extend far beyond the initial life of the power plant and align with the long-term nature of the RPS requirement.
- Unbundled RECs – Are defined as RECs that are purchased separately from the electricity generated by a qualified renewable resource. The Oregon RPS limits the use of unbundled RECs to a maximum of 20% of the annual compliance obligation in each year. Given the relatively small proportion of unbundled RECs that may be used each year, this is not a primary strategy for achieving compliance, but instead would be used to compliment a physical resource / bundled REC strategy. In addition, unbundled RECs currently exhibit problems related to product definition and fungibility, as well as market fragmentation, lack of price transparency, and illiquidity. These structural problems increase the risk associated with reliance on unbundled RECs for RPS compliance, and further limit their practical use.

- Banked RECs –Are created when bundled or unbundled RECs are acquired or generated in advance of current RPS compliance requirements, resulting in a surplus of RECs. Banked RECs (both bundled and unbundled) may be stored indefinitely. However, unbundled RECs may only be used up to the 20% maximum per year for compliance, regardless of whether they were previously acquired and banked. There is no limitation on the amount of banked, bundled RECs that may be used for compliance. The banking provisions of the Oregon RPS provide an important flexibility mechanism for electric utilities. The RPS provisions allowed for the banking of RECs from qualified resources starting in 2007, three years prior to the first compliance year of 2011. As a result, once banked, RECs may be used as a balancing mechanism (to mitigate against timing differences in acquiring and constructing new renewable generation) or as a temporary alternative to physical supply in the event of adverse market conditions. However, the use of banked RECs is inherently limited, as banked RECs are only produced when physical supply / bundled RECs are acquired early or in surplus to current RPS obligations. They do not represent a "recurring" source of RECs for future compliance as is the case with physical renewable resources. Once banked, RECs are consumed for compliance as an alternative to physical supply, they are not replenished and deplete quickly due to growing RPS targets and increasing load. Therefore, the use of banked RECs should also not be considered a primary or long-run strategy for meeting RPS obligations.
- Alternative Compliance Payments (ACP) – Oregon legislation provides for the use of alternative compliance payments in lieu of acquiring bundled or unbundled RECs for meeting RPS obligations. However, it is clear that the ACP provision is only intended to provide a "safety valve" mechanism for extreme cases in which a utility is not able to achieve compliance through the acquisition of physical resources and/or RECs. The ACP provision is not intended to be used as a strategy for achieving RPS compliance over time. This is further evidenced by the pricing established for ACP payments, which provides an economic incentive to achieve compliance through other means. In Order No. 09-200, issued on June 12, 2009, the OPUC set the alternative minimum compliance payment at $50/MWh for the year 2011. This is the cost that a utility will incur for any REC deficits in the 2011 compliance year. The current ACP amount far exceeds the cost difference between RPS compliant resources and non-renewable generation alternatives, or any reasonable expectation for the price of unbundled RECs.

4.3 RPS Implementation: Key Factors for Strategy Development

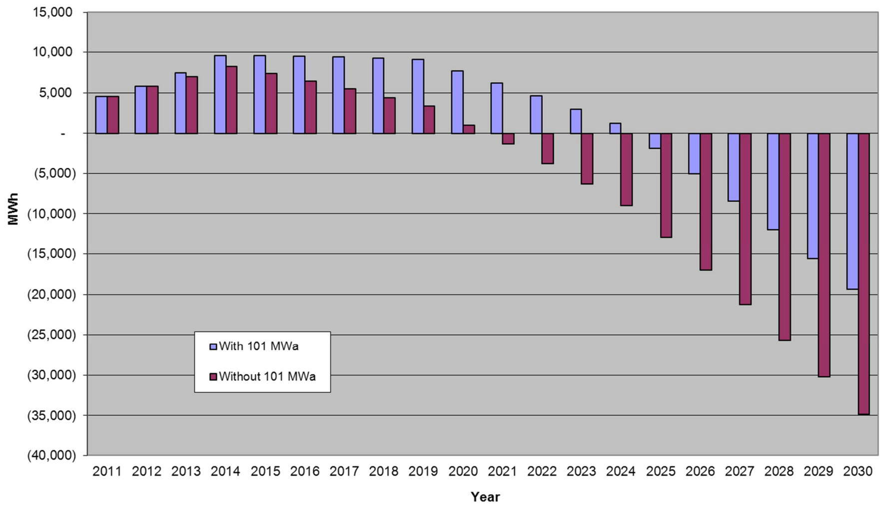
Our acknowledged Action Plan targets the procurement of additional new renewable resources to remain in physical compliance with Oregon RPS standards. More specifically, we are targeting the acquisition of additional renewable resources to be in physical compliance with, at minimum, the 15% RPS standard in 2015. As discussed in detail in our IRP (pages, 111 – 122), we believe that achieving physical compliance with the RPS provides the best balance of cost and risk for PGE and its customers, given current circumstances and future expectations – this is particularly true during the early years of RPS compliance when targets are increasing rapidly and competition amongst utilities to acquire renewable resources is high. We also recognize that the provisions of the RPS were established to incent the proliferation of new renewable resources and the achievement of long-run physical compliance. In addition, we note that the flexibility provisions in the RPS, such as acquisition of unbundled RECs, RECs banking, and the ACP are not long-term surrogates to renewable generation, but rather allow utilities to implement the RPS while minimizing significant adverse impacts to cost or reliability.

While we do not believe that unbundled or banked RECs should be the foundation or primary strategy for achieving long-run RPS compliance, they do provide valuable tools for ensuring flexibility in implementing our RPS strategy over time. Accordingly, PGE will continue to monitor signposts for future REC market development and results from upcoming competitive bidding processes to determine whether any strategy changes are warranted as we implement RPS compliance.

Further, the following key factors should be considered and monitored in developing and implementing an RPS compliance strategy:

- Growing RPS Obligations – Because future RPS requirements increase rapidly, deferring the procurement of qualified RPS resources needed for current or near term physical compliance increases the execution risk for later RPS compliance periods as compared to procuring such resources on a more measured pace over time. The "cliff" effect of such an approach could potentially have a significant adverse impact on future compliance costs and customer rates if prices for new renewables increase over time. If deficits became too large, it could also impair PGE's ability to acquire sufficient supplies to maintain RPS compliance. The graph below illustrates our rapidly growing renewable resource / REC requirement as we move beyond 2015 to the increasing compliance targets in 2020 and 2025.

Figure 4-2: Projected Cumulative REC Balance by Year (in MWa)



- Reduction or Elimination of PTC – Federal and state tax benefits are a significant driver to the cost effectiveness of renewable resources. Based on current estimates, the PTC is equal to roughly 25% of the total cost of energy from a wind project (on a utility revenue requirement basis). The Federal PTC for wind energy is currently scheduled to sunset with new wind generating facilities placed in-service by year-end 2012, and the PTC for other technologies is scheduled to sunset in 2013. If the current tax benefits are reduced or eliminated over time, the cost of renewable generation would increase considerably. The risk associated with reduction of tax benefits is both significant and increasingly likely. Given current federal and state budget deficits and growing pressure for deficit reduction, the probability of a continued extension of tax benefits at their current levels becomes more questionable. While we have not yet changed our reference case assumptions for PTC and ITC, we believe that the risk of reduction or elimination of these programs grows significantly over time. Unlike other signposts and indicators, reduced government tax incentives for renewable generation pose a potential "game changing event", where impacts would be potentially sudden and significant.
- Competition for Quality Sites – Unlike other types of electric generation that are less location specific, renewable resources are typically tied to an underlying natural resource at a specific site (e.g. wind plants are only viable when built at windy locations). Given the proliferation of RPS requirements across the Western United States and limitations on the availability of quality sites, we believe that increasing competition and the potential for resource scarcity represents a growing risk over time.

Ultimately, increased competition or reduced availability of sites could result in higher site acquisition, operating, and integration costs, and reduced capacity factors in the future. Unless offset by other developments (such as technology improvements), such supply challenges could result in substantial cost increases (on a per MWh basis) for future renewable resources. Further, constraints on available transmission continue to drive renewable generation development in areas that offer lower interconnection and transmission costs, therefore leaving for future development sites with more costly or less viable transmission access. As evidenced by the Wyoming Wind case in the IRP (2009 IRP, pages 153 to 157), incremental transmission costs to reach new and remote renewable resource areas can have a significant adverse impact on the cost of future RPS compliance. Table 4-3 provides current RPS targets for WECC states.

Table 4-3: RPS Requirement in WECC

	2010	2015	2020	2025 and after
Arizona	2.5%	5%	10%	15%
California	20%	27%	33%	33%
Colorado	5%	20%	30%	30%
Montana	10%	15%	15%	15%
Nevada	12%	20%	22%	25%
New Mexico	9%	15%	20%	20%
Oregon		15%	20%	25%
Utah				20%
Washington		8%	15%	15%

- Technology Advances – Technology innovations and improvements offer the potential to reduce manufacturing costs over time, particularly for less mature renewable resources technologies. This learning curve effect is generally driven by improved efficiency in manufacturing and production processes achieved via long-term economies of scale and increased competition. In the case of less mature renewable technologies such as solar, the benefits of economies of scale and competition continue to lower economic costs. However, for wind, any further technology-driven cost declines appear to be largely offset by the decreasing energy production capability of sites available for new construction. While it is difficult to predict the pace or degree of technology improvements for renewable generation over time, it is reasonable to presume that such improvements will occur. Since technology improvements in electric generation over time have generally been evolutionary and incremental, it seems unlikely that technology-driven cost reductions would either offset or overwhelm price impacts due to changes in aggregate supply and demand or government subsidies. Instead, technology improvements and any resulting cost reductions must be considered in conjunction with other key drivers for future cost and availability of renewable resources.

- Change in National Environmental Policy – As discussed earlier in this Update, changes in environmental policy could have a significant impact to the future cost and availability of both renewable and non-renewable resources. For instance, the passage of climate change legislation in the future would likely increase demand for renewable resources and reduce demand for fossil fuel resources, particularly for more emission-intensive generation types. At the same time, the implementation of a national RPS could have similar impacts. While it is difficult to predict the price impact of such policy changes in the long-run, it is reasonable to presume that, in the short-run, demand for new renewables would be amplified and near-term costs would increase while industry and markets adjust to the new policy.
- Integration Costs – Changes in the future cost of integrating and providing back-up capacity for variable energy renewable resources, such as wind, could have an adverse impact on the overall cost of RPS compliance over time. Currently integration costs represent a relatively small proportion of the total cost of new wind – we estimate the cost of wind integration currently to be roughly 11% of the total cost of energy for new wind generation. However, integration can become a more significant cost driver over time, particularly if a trend in cost increases or decreases develops and persists. We believe integration costs are likely to increase the future costs of renewable resources. As existing legacy regulating resources in the region (namely hydro) are consumed, it will become increasingly necessary to build new flexible thermal generation to absorb the variability of renewable resources and provide reliable back-up capacity. These new thermal generation additions are likely to provide upward pressure on the cost for integration in the long-run. At the same time, market transformations may temporarily or partially off-set some of these cost increases by improving overall regional generation and electric system efficiency. An example of this would be the development of effective sub-hourly energy trading and scheduling, or formation of capacity and ancillary services markets in the Northwest.
- Transmission Availability – The capability of the existing transmission system is decreasing due to the integration of additional resources and increased operational constraints. As a result, the potential cost of interconnecting and procuring transmission service will likely increase.

Therefore, to the extent a resource can capture existing available transmission or require only a minor system upgrade, the cost and complexity of acquiring transmission service will be reduced.

- Alternative Non-renewable Generation Costs – Changes in the cost for non-renewable generation alternatives could impact the cost effectiveness of future renewable resources. If price changes for non-renewable generation were significant, they could further influence demand and, in turn, the price for new renewables. The most obvious example of this type of scenario risk is the potential for significant changes in fuel prices for natural gas-fired generation. Over the last decade, we have seen both large increases and decreases in the current and forecasted price for gas. These fuel price changes have resulted in significant changes in the expected cost of new natural gas-fired generation, and, as a result, the relative cost-effectiveness of new renewables. Recent natural gas price reductions have resulted in lower expected costs for future gas-fired generation. While it is difficult to predict any further fundamental or structural changes in gas supply or market price, history has proven that such changes are possible.

4.4 RPS Scenario Analysis

In Order No. 10-457, the Commission directed PGE to evaluate, in its IRP Update, "the use of unbundled renewable energy credits (unbundled RECs) in its strategy to meet Renewable Portfolio Standard requirements for the entire planning period." The Commission also directed PGE to "evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources."

In assessing strategies for RPS compliance, it is important to recognize that cost estimates for building new generation resources become increasingly uncertain over time (the farther the new build occurs from today). In addition, certain RPS compliance cost factors such as future REC values are impossible to predict. While these uncertainties reduce confidence in predicting the future cost of RPS implementation strategies over long time horizons, conducting scenario analysis can be a useful tool in understanding the magnitude of potential adverse or favorable outcomes for alternative strategies, should changes in future circumstances occur. Accordingly, we address the Commission's directives in the following illustrative scenarios that test changes in costs for various RPS strategies based on potential changes in future environment and prices.

Unbundled RECS

As discussed earlier in this Update, unbundled RECs provide a potential tool to meet up to 20% of the RPS requirement each year. In situations where the projected cost of qualifying resources materially exceeds the price of non-qualifying alternatives, and Unbundled RECs are available at a price below the expected difference in cost between renewable and non-renewable generation this approach could potentially reduce compliance costs in the short-term.

Given that, through 2025, PGE's projected incremental resource needs exceed (on average) the incremental RPS requirement, we have two options for achieving compliance:

1. Rely entirely on bundled RECs (both current and banked) to meet RPS compliance.
2. Acquire bundled RECs to meet at least 80% of the RPS requirement and acquire a combination of non-qualifying electricity and unbundled RECs (up to the annual 20% annual limit) to meet the remaining need.

In order for the second strategy (acquisition of unbundled RECs in lieu of bundled RECs) to be effective, it should meet two economic tests:

1. The expected life-cycle, levelized cost for qualifying resources is higher than the like cost for non-qualifying alternatives at the time of the decision.
2. The cost of unbundled RECs is less than the cost difference between the qualifying resource and the non-qualifying alternative.

Table 4-4 illustrates the potential cost impact of pursuing a strategy with no unbundled REC purchases versus purchasing the 20% maximum each year, based on a "typically" sized renewable resource. For the example, we assume several cases with regard to unbundled REC prices:

- Unbundled REC price is equal to the cost premium for RPS renewables verses non-renewable alternative
- Unbundled REC price is less than the cost premium for RPS renewables versus non-renewable alternative
- Unbundled REC price is more than the cost premium for RPS renewables versus non-renewable alternative
- Unbundled REC prices start lower, but then rise over time.

Table 4-4: Example of Impact of Unbundled RECs on Resource Cost

Assumptions:		
Assumed "Typical" New Resource Annual Supply	50	MWa
Assumed Resource Life	20	Years
Assumed Levelized Cost of Non-Qualifying Resource	$88.00	Per MWh
Assumed Premium % for Qualifying Resources	5%	
Premium for Qualifying Resource	$4.40	per MWh
Implied Cost for Bundled RECs	$4.40	per REC
Annual RECs Generated from Qualifying Resource	438,000	

Cost Comparison of Three Cases

	Year 1	Year 10	Year 20
Case A: Unbundled RECs are (on average over time) same price as Bundled RECs			
Cost of Unbundled RECs (per MWh)	$4.40	$4.40	$4.40
Fill minimum 80% with Bundled RECs (000s)	$1,542	$1,542	$1,542
Fill maximum 20% with Unbundled RECs (000s)	$385	$385	$385
Total cost for RECs (000s)	$1,927	$1,927	$1,927
Total Levelized Resource Cost, with RECs (000s)	$40,471	$40,471	$40,471
Case B: Unbundled RECs are (on average over time) 20% less costly than Bundled RECs			
Cost of Unbundled RECs (per MWh)	$3.52	$3.52	$3.52
Fill minimum 80% with Bundled RECs (000s)	$1,542	$1,542	$1,542
Fill maximum 20% with Unbundled RECs (000s)	$308	$308	$308
Total cost for RECs (000s)	$1,850	$1,850	$1,850
Savings of B over A (000s)	$77	$77	$77
Savings of B over A (% of A)	4%	4%	4%
Cost impact to Total Resource Cost	**0.2%**	**0.2%**	**0.2%**
Case C: Unbundled RECs are (on average over time) 20% more costly than Bundled RECs			
Cost of Unbundled RECs (per MWh)	$5.28	$5.28	$5.28
Fill minimum 80% with Bundled RECs (000s)	$1,542	$1,542	$1,542
Fill maximum 20% with Unbundled RECs (000s)	$463	$463	$463
Total cost for RECs (000s)	$2,004	$2,004	$2,004
Cost of C over A (000s)	$77	$77	$77
Cost of C over A (% of A)	4%	4%	4%
Case D: Unbundled RECs start lower but end higher than Bundled RECs			
Cost of Unbundled RECs (per MWh)	$3.52	$4.40	$5.28
Fill minimum 80% with Bundled RECs (000s)	$1,542	$1,542	$1,542
Fill maximum 20% with Unbundled RECs (000s)	$308	$385	$463
Total cost for RECs (000s)	$1,850	$1,927	$2,004
Difference of D versus A (000s)	$(77)	$-	$77

As illustrated in the examples in Table 4-4, unbundled RECs are unlikely to have a significant impact to the overall cost of RPS compliance due to their restricted use (maximum of 20% per year). Even when unbundled RECs are available for 20% less cost than bundled RECs on an ongoing basis, and are employed maximally each year, the impact to the overall cost of RPS compliance is small. More particularly, the impact to the overall fully allocated cost for the new electric generation is diminishingly small as a percentage. In short, it appears that any potential benefits from the purchase of unbundled RECs, as opposed to the acquisition of qualified resources with bundled RECs, are likely to be minor and may not off-set the hedge benefit of producing recurring and cost-certain RECs through the acquisition of RPS qualified physical resources.

Alternatives to Physical Compliance

Earlier in this chapter we discuss the primary factors and indicators that should be considered when evaluating potential strategies for achieving RPS compliance (future expectations for PTC, resource availability, technology innovations, changes in environmental policy, etc.). While predicting whether future changes in circumstances will adversely or favorably impact the availability and cost of future renewables is uncertain at best, the decision-making process about whether to acquire RPS resources today versus deferring the acquisitions is relatively straightforward. If new resources are needed to satisfy an overall energy and capacity deficit, and new renewable resources are also needed for future RPS compliance (this is PGE's expected case scenario), it would make sense to acquire new physical renewable resources as long as those resources can be acquired at a cost that is roughly equivalent to the non-renewable generation alternative. In the event that the cost for new renewable resources is not equivalent to the non-renewable generation alternative, then the following decision approach may be appropriate:

1. If you expect RPS renewable resources to be available in the future, and uncertainties are biased toward the potential for material cost increases, it would make sense to purchase physical resources now, thereby reducing the risk of increased costs to achieve long-run RPS compliance.
2. If you expect RPS renewable resources to be scarce or highly limited in availability in the future, it would make sense to purchase physical resources today, thereby avoiding scarcity premiums or alternative compliance payments in the future. Banked RECs would then also be more valuable in the future as renewable resources become more limited in availability.
3. If you expect RPS renewable resources to be available in the future, and uncertainties are biased toward the potential for material cost decreases (as compared to today's cost), it would make sense to temporarily rely on banked RECs, deferring physical renewable resource purchases.

Table 4-5 provides an illustrative example regarding the potential impacts of meeting RPS requirements under various future scenarios for tax benefits, technology developments, quality of wind sites and integration costs. The scenarios below are based on the projected cost of constructing 101 MWa of new wind generation (our current estimate of the required amount of new renewables to maintain physical compliance with RPS standards in 2015) at various points in time between 2015 and 2020. The "alternative futures" were selected to provide a sense of relative magnitude of potential change in cost for RPS compliance based on key uncertainty factors for three different implementation strategies:

- Acquire new renewable resources to maintain physical compliance with RPS standards in 2015 (our acknowledged Action Plan strategy). For this case we do not change costs under alternate futures. Instead, we assume that by acting now we can eliminate uncertainty for key cost drivers. This is a simplified assumption that recognizes the risk mitigation benefit of near-term implementation, which reduces the likelihood of experiencing significant changes in external factors that influence the cost of RPS compliance. This illustrative approach provides insights regarding the change in risk due to increased uncertainty over time.
- Acquire new renewable resources to meet 50% of our need for 2015 RPS physical compliance by 2015, and utilize banked RECs to meet the remaining RPS obligation from 2015-2020. The remaining 50% of new renewables needed to meet the 2015 RPS compliance target is added in 2020. For this case we allow costs to change under alternate futures for renewable resources procured after 2015 (resulting from the delay in implementation and increased exposure to potential cost changes).
- Acquire new renewable resources to meet 50% of our need for 2015 RPS physical compliance by 2015, and utilize banked RECs to meet the RPS obligation from 2015-2017. The remaining 50% of new renewables needed to meet the 2015 RPS compliance target is added in 2017. For this case we allow costs to change under alternate futures for renewable resources procured after 2015 (resulting from the delay in implementation and increased exposure to potential cost changes).

Table 4-5 provides useful insights regarding the potential impact of key uncertainties associated with acquiring new renewable resources to meet RPS obligations over time. While any change to the cost drivers for new renewables can have an adverse or favorable impact to RPS implementation, a few key factors appear to pose the largest potential cost impacts – erosion or loss of tax benefits for renewables, material changes in capital costs, and changes in resource quality (as measured by wind capacity factors). Each of these factors was further discussed earlier in this chapter. In particular, the potential for reduced tax benefits for renewables represents a large potential cost risk with a reasonable likelihood of occurrence due to government budget deficit concerns.

Table 4-5: Illustrative Scenarios - RPS Strategies with Varied Futures

NPVRR 2011$ (000)	Reference Case	Overnight Capital Cost 10% Less	Overnight Capital Cost 10% More	PTC Erodes to 50%	PTC Eliminated	Integration Cost 50% More	Integration Cost 50% Less	Wind Capacity Factor Declines 2.5% (nominal)	Wind Capacity Factor Increases by 2.5% (nominal)
Strategies:									
2015 In-Service Wind	$991,666	$991,666	$991,666	$991,666	$991,666	$991,666	$991,666	$991,666	$991,666
50% - 2015 & 50% - 2017	$986,253	$946,591	$1,025,914	$1,044,592	$1,102,930	$1,012,873	$959,633	$1,027,226	$951,051
50% - 2015 & 50% - 2020	$975,940	$943,420	$1,008,460	$1,023,773	$1,071,607	$997,766	$954,113	$1,009,535	$947,076
Change from 2015 Strategy:									
50% - 2015 & 50% - 2017	$(5,413)	$(45,074)	$34,249	$52,926	$111,264	$21,207	$(32,033)	$35,560	$(40,615)
50% - 2015 & 50% - 2020	$(15,726)	$(48,246)	$16,794	$32,108	$79,941	$6,100	$(37,552)	$17,869	$(44,589)
Change from Ref Case Future:									
50% - 2015 & 50% - 2017		$(39,662)	$39,662	$58,339	$116,677	$26,620	$(26,620)	$40,973	$(35,202)
50% - 2015 & 50% - 2020		$(32,520)	$32,520	$47,834	$95,667	$21,826	$(21,826)	$33,595	$(28,863)

Notes:

27-year life for wind

For delay cases, bridge contract cost based on IRP

For 2015 and 2017 in-service wind is assumed replaced with like-kind renewable resource for RFP compliance

For the reasons cited throughout this chapter (and specifically in section 1.3 above), we believe that the uncertainties associated with future RPS compliance are biased toward the potential for increasing costs to acquire new renewable resources over time. Further, the fact that RPS compliance targets grow significantly through 2025 increases the risk of deferring procurement of new renewable resources, due to the compounding effect it would have on our already large future RPS obligation. On balance, we are persuaded that our Action Plan strategy for adding renewable resources to maintain physical compliance remains the best approach for meeting RPS. This is particularly relevant for a utility like PGE that projects ongoing energy deficits, as well as RPS resource deficits. As we move forward with forthcoming supply-side RFPs and further IRP research and analysis, we will remain responsive to new information and adjust our RPS / renewable resource strategy as necessary.

5. Boardman Updates

In its 2009 IRP process, PGE proposed an emissions control and operating plan for the Boardman plant to comply with both the federal Regional Haze Best Available Retrofit Technology requirements (BART III) and the Oregon Utility Mercury Rule standards. PGE's proposal was referred to as the Boardman 2020 plan. The Boardman 2020 plan proposed the installation of emissions abating technologies for NOx, SO_2, and mercury, and the early cessation of coal operations at Boardman in 2020. Table 5-2 provides a summary of the reduction targets for each of these emissions. The BART III plan was contingent on approval by the Oregon Environmental Quality Commission (EQC) and incorporation into the Oregon Regional Haze Plan. In the IRP process, PGE noted the risk that EPA's adoption of National Emission Standards for Hazardous Air Pollutants (NESHAPs) or the outcome of a pending Clean Air Act lawsuit could prevent PGE from implementing the Boardman 2020 plan. In Order No. 10-457, the Commission acknowledged PGE's Boardman 2020 proposal, contingent on EQC approval.

As discussed in detail below, the EQC has approved PGE's Boardman 2020 proposal and PGE is proceeding with full implementation of the plan. PGE has reached a settlement with the parties to the Clean Air Act lawsuit and the federal court has entered a Consent Decree resolving the litigation. PGE has actively participated in the EPA public comment process on the NESHAPs. EPA is expected to issue the final rules by the end of 2011. At this point, it is unclear whether the forthcoming EPA NESHAP ruling will affect our implementation of Boardman 2020.

5.1 Boardman BART Progress

The Oregon Department of Environmental Quality (DEQ) approved the Boardman BART III portion of the Boardman 2020 plan in December 2010 (the Mercury portion of the plan was approved previously), shortly after the acknowledgment of the 2009 IRP by the Oregon Public Utility Commission on November 23, 2010. A final rule approving the Boardman BART III-related portions of the Oregon Regional Haze state implementation plan (SIP) was published in the Federal Register in July [76 Federal Register 38977 (July 5, 2011)]. That rule took effect on August 4, 2011. Table 5-1 summarizes the BART III emissions controls and implementation status.

In conjunction with reduction in these haze causing emissions, PGE also proposed installation of controls to reduce mercury emissions to comply with the Oregon Utility Mercury Rule. We provide below details on our progress implementing the BART III and mercury reduction projects.

Table 5-1: Boardman 2020 Plan Proposed Controls

Controls	In-Service date	Status as of October 2011
Low NOx Burners / OFA	July 2011	Installation and testing completed.
Mercury Control	July 2012	Installation and testing completed.
SO_2 Control via DSI + Lower-sulfur Coal	July 2014	Selected DSI testing contractor. Testing completed in Q4 2011. Data analysis to be completed Q1 2012
SNCR	July 2014	Contingency plan if emission limits not met with LNB/OFA alone.

Low NOx Burners (LNB)

Project Description: This project consists of the replacement of the existing 32 burners and 8 over-fire air (OFA) ports with 32 new low NOx burners and 12 over-fire air ports to reduce NOx emissions by approximately 50%. This project also includes the upgrade of the boiler cleaning system with intelligent soot blowers and water cannons to counter-act the potential increase in furnace slagging from the LNBs. A combustion monitoring system is included to maintain proper tuning of the LNBs.

Status Update: Installation of the LNBs was completed during the 2011 Boardman annual outage maintenance period. The upgrades to the boiler cleaning system and addition of the combustion monitoring and optimization systems were also completed. The new systems went in service in early June and are operating well. Final construction closeout items are being worked on, performance testing was completed in Q3 2011, and the systems are achieving the targeted reductions to NOx emissions.

Mercury Control System (Hg)

Project Description: This project involves controlling mercury with the installation of a calcium halide injection system and an activated carbon injection system with the goal to reduce emissions by approximately 90% in order to meet the requirements of the Oregon Utility Mercury Rule.

Status Update: Installation, initial startup and performance testing of the Hg System were completed in Q3 2011. System tuning for optimum sorbent and chemical usage is underway. We remain confident that we will meet target emission levels by the July 1, 2012 deadline.

SO2 Controls

Project Description: The SO2 control project consists of the installation of a Dry Sorbent Injection (DSI) system to reduce SO2 emissions by approximately 50% from current levels. Full-scale testing begins late in 2011 to determine the effectiveness of the technology, its impacts on the mercury control system, and how it will affect compliance with proposed Maximum Achievable Control Technology (MACT) rules.

Status Update: Full-scale testing was completed in Q4 2011. Testing variants included coal type, SO_2 sorbent type, mercury sorbent type, injection location, injection temperature range, and injection rate. The test results, once available, will be evaluated to select the preferred system configuration for the production system installation. A preliminary engineering study and Engineering, Procurement and Construction (EPC) specification development are underway. Pending results of the DSI testing, procurement of a production system will occur in 2012, with installation expected in 2013/2014.

5.2 NESHAPs Rulemaking Impact on Boardman (MACT Update)

The Boardman coal plant is potentially affected by EPA's rulemaking to establish NESHAPs for coal and oil-fired electric generating units (EGUs) under Section 112 of the Clean Air Act (CAA).

Proposed rules were signed by the EPA Administrator on March 16, 2011. The comment period for those proposed rules closed on August 4, 2011. Under a revised court order, the Administrator of EPA is required to sign a final rule no later than December 16, 2011. The proposed rules address five pollutant categories: mercury, acid gases (HCL, HF), non-mercury metals (10 listed), dioxin/furans and non-dioxin/furan organic hazardous air pollutants (HAPs). For mercury, acid gases and the non-mercury metals, EPA proposes "maximum achievable control technology" or MACT standards. For dioxin/furans and non-dioxin/furan organic HAPs, EPA proposed "work practice standards" that reflect best operating practices for the type of boiler or unit being operated.

Sources affected by the proposed NESHAPs are required to be in compliance within 3 years of the effective date of the rule unless a statutory compliance extension is granted:

The significance of NESHAPs for PGE will be whether they are consistent with the EPA-approved plan for Boardman BART requirements, and with the Oregon Mercury Rule. Although the pollutants targeted by Boardman 2020 are not identical to those targeted by the NESHAPs, the overlap with Boardman 2020 controls may result in associated collateral emissions reductions of NESHAP-listed pollutants that could potentially satisfy the NESHAPs requirements.

Table 5-2: NESHAPS Summary Proposed Standards

Pollutants Regulated Under the Proposed NESHAPs	Boardman 2020 Controls	Proposed NESHAPs/MACT
Mercury (Hg)	Oregon Hg Standard: 0.6 lbs/TBtu (or 90% removal) no later than 2012	Proposed MACT: 1.2 lbs/TBtu or 0.008 lb/GWH (EPA proposed a 1.0 lb/TBtu standard)
Acid Gases (2 compliance options): HCL Or S02 may be an alternative surrogate	Oregon BART Requirement: BART levels for SO2 to be achieved with a combination of dry sorbent injection (DSI) and lower sulfur coal. 07/01/14: SO2 - 0.40 lb/MMBtu 07/01/18: SO2 - 0.30 lb/MMBtu	Proposed MACT: HCL* - 0.0020 lb/MMBtu or 0.020 lb/MWh Or SO2 – 0.20lb/MMBtu or 2.0 lb/MWh * DSI is effective at reducing and achieving the standard for HCL.
Non-Mercury Metals (3 compliance options): 10 individual metals (Sb, As, Be, Cd, Cr, Co, Pb, Mn, Ni, Se) Or surrogate = Total PM (filterable and condensable PM) Or total metals	N/A Oregon PM standard: 0.040 lb/MMBtu (filterable only) N/A	Standards listed for 10 individual metals in proposal at 76 **FR** 24976 at 25126-25127 Or 0.030 lbs./MMBtu (Total PM) Or 0.000040 lb/MMBtu 0r 0.00040 lb/MWh
Organics	N/A	Work practice standard (annual performance test)
Dioxin/Furans	N/A	Work practice standard (annual performance test)

Table 5-2 provides a comparison between the Boardman 2020 plan emissions reduction requirements and the proposed NESHAPs for existing EGUs.

As detailed in section 5.1, controls for Hg (activated carbon injection or ACI) and NOx (advanced combustion controls or low-NOx burners) have been installed at the plant. Testing of dry sorbent injection for SO2 and HCL reduction, along with the operation of the other new pollution controls for NOx and mercury, has been completed. However, the results analysis will not be available before the NESHAPs rule is to be signed by the Administrator. While there is uncertainty about the final form and targets of the NESHAPs rule, it is possible that Boardman may be able to comply with the NESHAPs rule with the controls installed for BART III and the Oregon mercury rules.

Both preceding and during the comment period on the proposed rulemaking, PGE provided extensive input to EPA on options for providing flexibility in the NESHAPs rule to allow for early coal cessation plans similar to Boardman.

If the NESHAP limits for one of the regulated pollutants cannot be met with current and planned Boardman 2020 plan control technologies, the Company will need to evaluate the cost of additional emission control technology (or other measures to meet such limits), unless the proposed rules are modified to provide flexibility for EGUs that have in place a federally enforceable shutdown plan.

5.3 Sierra Club Litigation Resolution

In July 2011, PGE reached a settlement with the plaintiffs – Sierra Club, Northwest Environmental Defense Center, Friends of the Columbia Gorge, Columbia Riverkeeper and Hells Canyon Preservation Council –to the lawsuit concerning alleged Clean Air Act violations at the Boardman coal plant. The federal court has entered a Consent Decree resolving the litigation. PGE contested the allegations while working with the plaintiffs to resolve the matter without further litigation.

6. Transmission Update

In Order No. 10-457, the Commission acknowledged the development of the Cascade Crossing Transmission Project (Cascade Crossing) and required PGE to provide an updated benefit-cost analysis in its next IRP. In this Update, we provide an update on our implementation activities and capital expenditures and include a summary economic analysis. We also provide an update on the Trojan / South of Allston addition described in the 2009 IRP.

6.1 Cascade Crossing

We continue to believe that Cascade Crossing will provide value as an integral part of PGE's long-term transmission strategy. It also continues to be recognized as an important component of regional transmission plans as evaluated and reported by the Northern Tier Transmission Group (NTTG) and the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC). The importance of Cascade Crossing is also exemplified by its selection by the Obama Administration's Rapid Response Team for Transmission as one of seven transmission projects that "will serve as pilot demonstrations of streamlined federal permitting and increased cooperation at the federal, state, and tribal levels."[6] In announcing the selection, the Secretary of Interior stated that "Transmission is a vital component of our nation's energy portfolio, and these seven lines, when completed, will serve as important links across our country to increase our power grid's capacity and reliability."

Implementation Activities

Permitting

PGE continues to move forward with the planning and permitting activities required to build Cascade Crossing. In May of 2010, PGE filed a Notice of Intent (NOI) with the Energy Facilities Siting Council (EFSC). Also, in May 2010, the U.S. Forest Service published a Notice of Intent in the Federal Register announcing the initiation of a federal Environmental Impact Statement process for Cascade Crossing. PGE received a Project Order from the Oregon Department of Energy (ODOE) in April, 2011. Currently we are conducting field surveys to assess the environmental and cultural impacts of the line and we are actively engaged with state and federal agencies and developing the necessary

[6] U.S. Department of Energy press release, Washington, D.C., October 5, 2011, http://energy.gov/articles/obama-administration-announces-job-creating-grid-modernization-pilot-projects

data and documentation for approval of Cascade Crossing. We plan to file a preliminary EFSC site certificate application in February 2012.

Project Route Surveying

In addition to gathering needed data for required permits, we are also conducting surveys to identify owners of land over which PGE will need to secure property easements for the placement of facilities or to access various sites. PGE will need to acquire easements and rights of ways prior to construction.

PGE is currently completing studies of potential alternative corridor segments for Cascade Crossing as part of its EFSC site certificate application and/or NEPA analysis. In addition to Cascade Crossing-specific considerations, potential transmission system upgrades in the Boardman area initiated by other utilities will be considered in determining the precise route and configuration of Cascade Crossing. Final route selection will also reflect survey findings related to environmental considerations and construction requirements.

Coordinated Planning

PGE continues to work with the Bonneville Power Administration (BPA), PacifiCorp, Idaho Power, and other utilities to coordinate transmission planning and to ensure adherence to all reliability requirements, and to meet the transmission needs of individual transmission customers, utilities and the region. We have entered into memorandums of understanding with BPA, Idaho Power and PacifiCorp to move toward agreements for the development of Cascade Crossing based on joint planning.

WECC Path Rating Process

For the single circuit configuration, we have completed the WECC Phase 1 rating process to establish a “Proposed Rating, “and have achieved Phase 2 status. Phase 2 studies are undertaken to establish a “Planned Rating.” We have not initiated the Phase 2 process for the single circuit configuration as we are awaiting the decision on the configuration of the project.

We have not yet entered the WECC path rating process for the double circuit configuration. We are working with adjoining transmission providers in advance to identify and resolve any impacts that may need to be addressed in our submittal. We anticipate submitting the required comprehensive progress report, which will initiate Phase 1 of the WECC rating process for the double circuit configuration, to WECC’s Planning Coordination Committee within the next six months.

PGE has revised its study results regarding Cascade Crossing’s potential capacity for the double circuit configuration from 2,200 MW to approximately 2,600 MW based on continuing capacity rating evaluations, including an updated path termination assumption[7]. The single circuit line rating remains at 1,500 MW. PGE is working with transmission providers that may potentially be impacted by Cascade Crossing to establish transfer capability ratings that will result in line capacity ratings used to manage power transfer.

Final ratings for the project's capacity additions to the West of Cascades-South path will result from review by WECC of load flow studies prepared by PGE with input from affected transmission providers.

We continue to work with other parties on project joint participation options. Joint ownership of major line segments is possible as described below. In addition, PGE will be conducting an open season to identify interested parties seeking generation interconnections and/or firm transmission rights on Cascade Crossing. The information gained from these activities will also influence the final design of the project including the route and sizing as either a single or double circuit line.

Timeline

PGE recently adjusted the projected in-service date for Cascade Crossing to late 2016 or 2017. The new projected in-service date reflects our current estimate of the time needed to acquire permits, finalize potential partnerships, coordinate planning for interconnections, select the final path and locations for substations, acquire needed easements, prepare engineering design and complete construction.

Milestones

We provide the following update to the major milestones discussed in the 2009 IRP:

- May 2010 – PGE submitted Notice of Intent to ODOE.
- May 2010 – U.S. Forest Service published NOI in Federal Register for the Cascade Crossing federal Environmental Impact Statement (EIS).
- April 2011 – ODOE issued Project Order for Cascade Crossing.
- Q1 2012 – Submit draft Application for Site Certificate to ODOE
- Q4 2012 – draft federal EIS anticipated.
- Q3 2013 through Q1 2014 – Federal and state permitting processes completed and orders issued.

[7] PGE's actual share of the capacity on this path will depend on the WECC path rating process and negotiations with other transmission providers.

- Q2 2014 – Begin Construction.
- Q4 2016 to Q2 2017 – Complete Construction.

Cascade Crossing Configuration Options

The extent to which third parties participate in Cascade Crossing will affect project route, project configuration, total project cost, and PGE's share of the costs. PGE continues to actively pursue options for third party equity participation. PGE intends to request approval from the FERC to hold an open season to obtain commitments for the purchase of transmission service over Cascade Crossing. The amount of qualified commitments we receive through the open season process will also influence the single or double circuit decision. PGE currently has received approximately 2,100 MW of generation interconnection requests from non-PGE entities, primarily for wind generation, and 1,091 MW of transmission service requests on Cascade Crossing. We anticipate that the open season will be conducted in Q2, 2012. For both the single and double circuit cases, we have evaluated alternative routes (Route A and Route B) around the Navy Bombing range (the Coyote Springs to Grassland segment). Route "A" denotes a Coyote Springs Substation to the Grassland Substation segment path around the Navy Boardman Bombing Range that follows a north and then west-side path. The Route "B" path follows the east-side and then along the south-side of the Bombing Range. From the Grassland Substation to the Willamette Valley, the route is essentially the same for the single or double circuit configuration.

Capital Expenditures

We summarize the estimated capital expenditures for single and double circuit options below. The single circuit configuration includes a single circuit from Coyote Springs to Bethel. The double circuit configuration is a single circuit from Coyote Springs to Grassland and a double circuit from Grassland to Salem. The updated capital expenditures are based on December, 2010 estimates provided by our engineering contractor. The single and double circuit cost estimates include a range of path options. The cost estimates listed in Table 6-1 are total project costs and do not include third party equity participation and/or cost-sharing of the portion of the line capacity from Coyote Springs to Grassland. That is, capital cost estimates include 100 percent of the costs for the Coyote Springs to Grassland line segment for both the single and double circuit configurations. Shared ownership with other utilities of the line segment from Coyote Springs to the Grassland Substation, which would reduce PGE's share of capital expenditures, is possible, but not included in the estimates.

Table 6-1: Cascade Crossing Total Cost Estimate, Million $2011

	Route A	**Route B**
Estimated Project Capital Expenditures –Single Circuit		
Coyote Springs to Bethel		
Substations and Related	$134	$134
Transmission-Structures	$354	$396
Transmission- Conductor	$106	$115
Permitting, ROW, Project Management	$104	$104
Total	$**698**	**$749**
Estimated Project Capital Expenditures –Double Circuit		
Single Circuit from Coyote Springs to Grassland Substation,		
Double Circuit between Grassland and Bethel Santiam		
Substations	$191	$191
Transmission-Structures	$514	$555
Transmission- Conductor	$171	$181
Permitting, ROW, Project Management	$104	$104
Total	**$980**	**$1,031**

Project Economic Analysis – Interim Update

Below, we provide an interim economic analysis based on updates to the models used for the 2009 IRP. We show results for four project configurations – two based on a single circuit configuration where PGE wholly owns the project and two cases based on a double circuit configuration with equity participation. These analyses represent a range of possible arrangements, although PGE expects the details to be further updated as project development continues.

The single circuit configuration is, as described in the 2009 IRP, a 500 KV line with a single circuit from Coyote Springs Substation to the Bethel Substation. For purposes of the information presented here, PGE is assumed to be the sole owner of the single circuit line. Shared ownership of the Coyote Springs to Grassland Substation portion of the line segment, with other utilities is possible.

The double circuit configuration includes the same single circuit line segment options from Coyote Spring to Grassland as that in the configuration above.

Equity participation is assumed as the base case in the double circuit configuration for the Grassland to the Willamette Valley segment. As noted above for the single circuit, equity participation in the Coyote Springs to Grassland segment is possible, but is not included in the economic analysis.

The economic analysis is a "Project Net Present Value" (Project NPV) of estimated costs (revenue requirements) and benefits (representing avoided costs and incremental revenue). The following Net Present Value amounts include updated costs with a late 2016 to early 2017 target in-service date.

Table 6-2: Cascade Crossing Interim Economic Analysis Results

	Single Circuit		Double Circuit with Equity Participation	
	Route A	Route B	Route A	Route B
Cascade Crossing NPV	$38	-$27	$131	$67

The Project NPV analysis represents one element of project analysis. It does not reflect many important benefits that are not represented in the economic analysis such as access to other markets, improved reliability, decreased losses in the region, ability to self-integrate variable resources, and economic development benefits from construction employment.

Consistent with the Commission's direction in Order No. 10-457, PGE will provide a future update to the Commission on Cascade Crossing, including a benefit/cost analysis.

6.2 Trojan-South of Allston

PGE is always looking for opportunities to enhance transfer capability and lower costs to our customers. We are continuing to work with other transmission providers in the region to explore such opportunities. As such we will continue to examine the Trojan/ South of Allston improvements described in the 2009 IRP. However, we do not intend to proceed with construction of the improvements in the near term. Until such improvements are developed, we will continue to deliver energy from our Beaver and Port Westward sites using our existing rights on BPA and PGE's transmission systems.

7. 2011 Wind Integration Study

In Order No. 10-457, the Commission directed PGE to include a wind integration study that has been vetted by regional stakeholders in its IRP Update. On September 30, 2011, PGE emailed copies of the Study to all members of its 2009 IRP service list and the Study is provided as Appendix A.

In developing the study, PGE engaged regional stakeholders in a public process that allowed for a full and thorough "vetting." PGE held three public stakeholder meetings in which all members of the service list from PGE's 2009 IRP (OPUC Docket LC 48) were invited to attend and were 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. During these meetings, PGE provided detailed explanations of the modeling approach, methodology, data inputs, assumptions, bases for cost breakouts for ancillary services and how incremental reserves levels are determined.

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 offered stakeholders the opportunity to submit formal comments and recommendations. Additional information on PGE's stakeholder vetting process is provided in Section 3 of the Study.

The fully vetted Wind Integration Report is included in Appendix A.

As a result of Phase II of the study, PGE will revise the wind integration cost to be used in the renewables RFP and in the next IRP from $13.50/MWh to $9.15/MWh (in 2014$). The Study results do not affect the 2009 IRP action plan.

2009 Integrated Resource Plan

2011 Update - Appendix A
Wind Integration Study Phase II

Portland General Electric

PGE Wind Integration Study Phase II

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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.

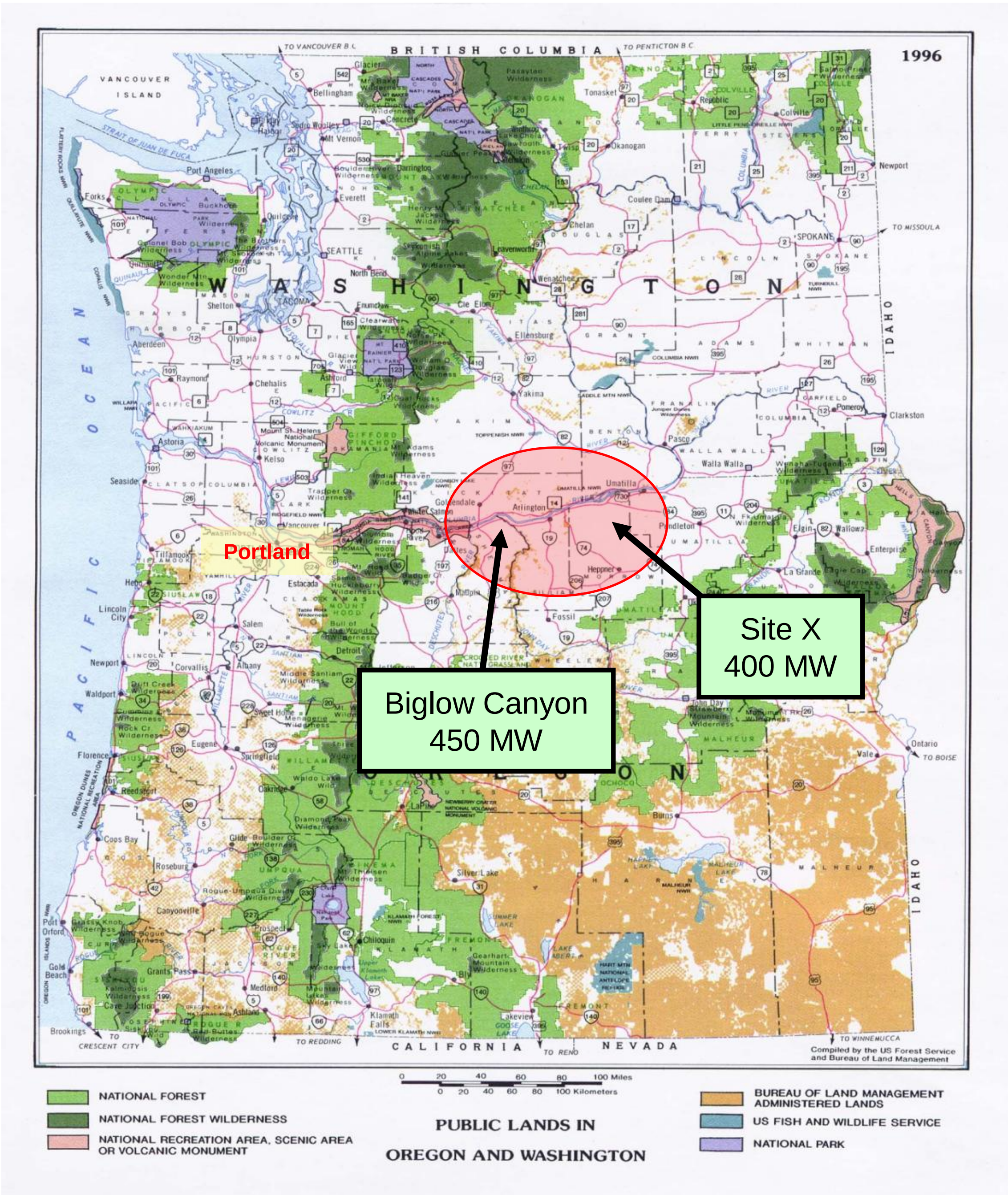


Figure 1: Location of Biglow Canyon and Site X

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).

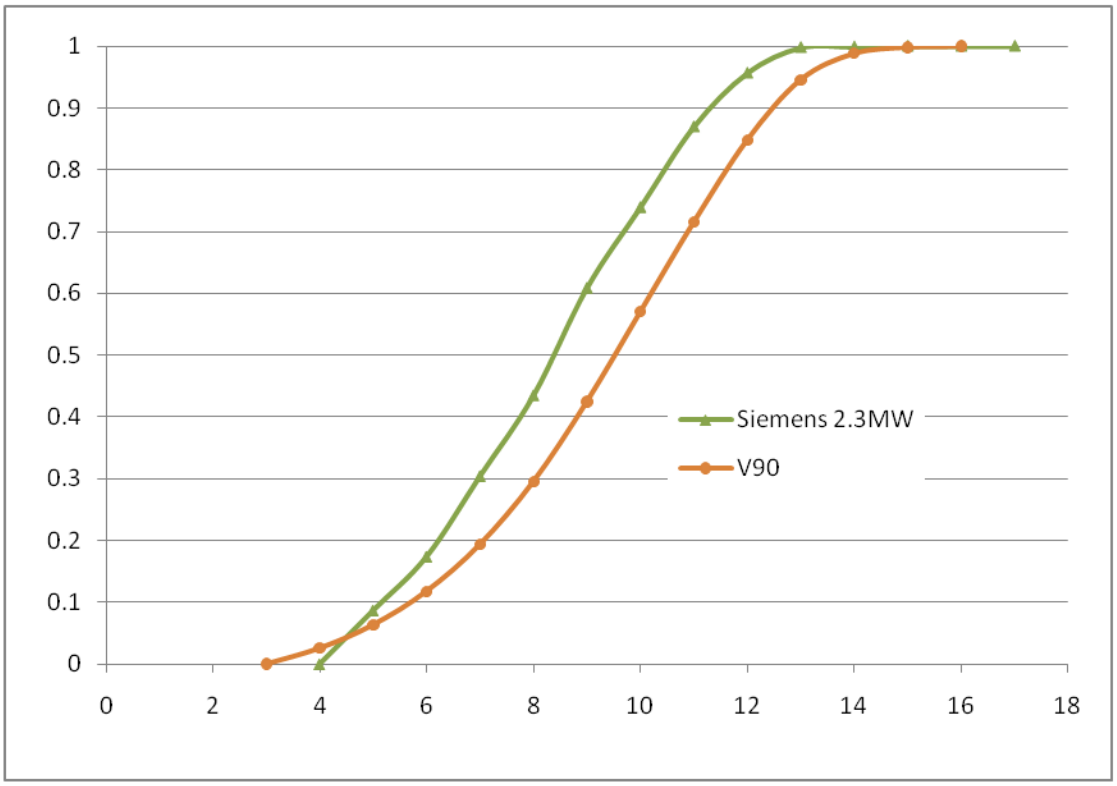


Figure 2: V90 and Siemens 2.3 MW power curves

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 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.

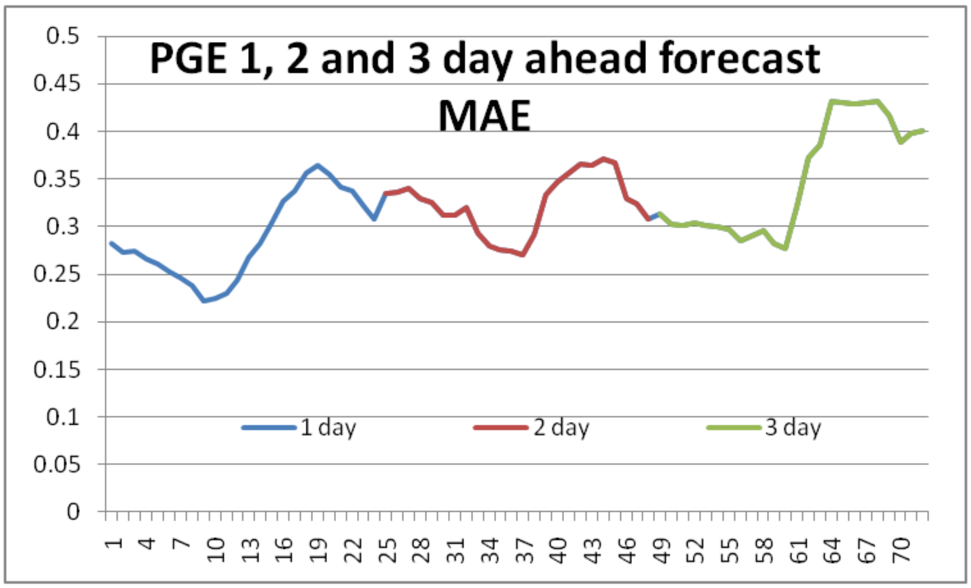
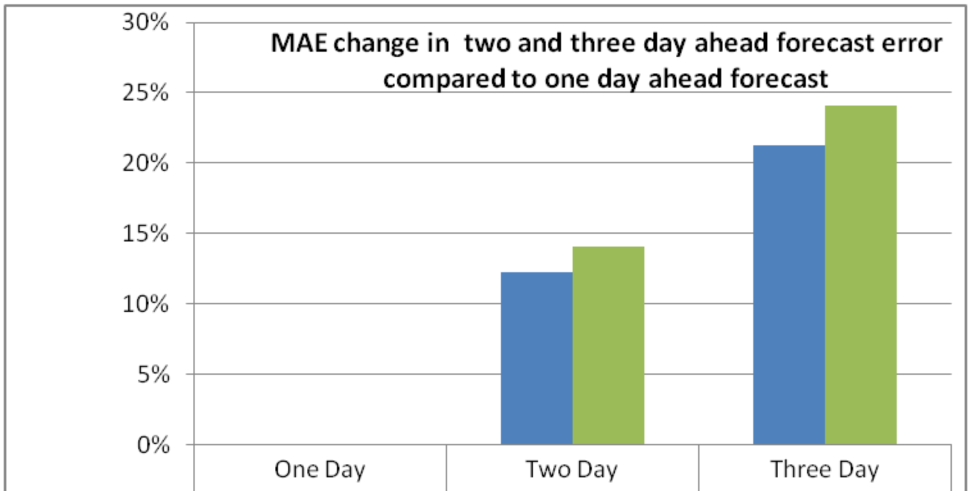


Figure 3: Mean Absolute Error for PGE wind forecasts of 1, 2, and 3 days ahead

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.



	One Day	Two Day	Three Day
PGE	0%	12.3%	21.3%
Adj WWRD	0%	14.1%	24.1%

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.

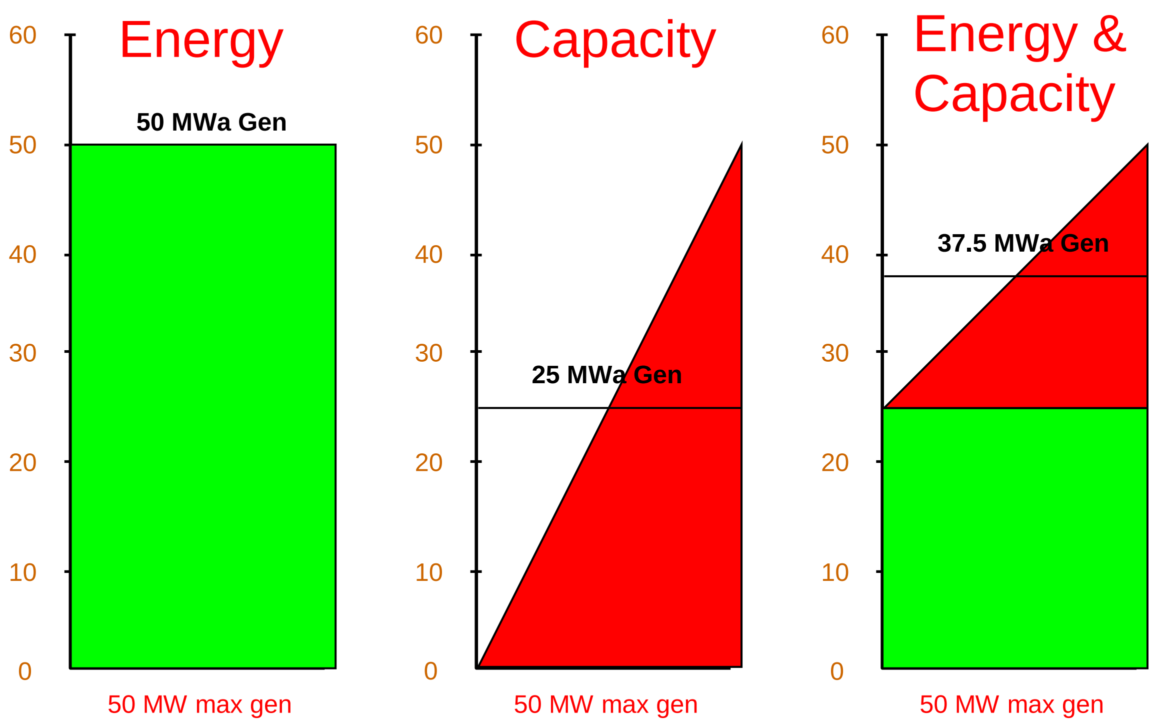


Figure 5: Examples of 50 MW generator operating for one hour

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:

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.

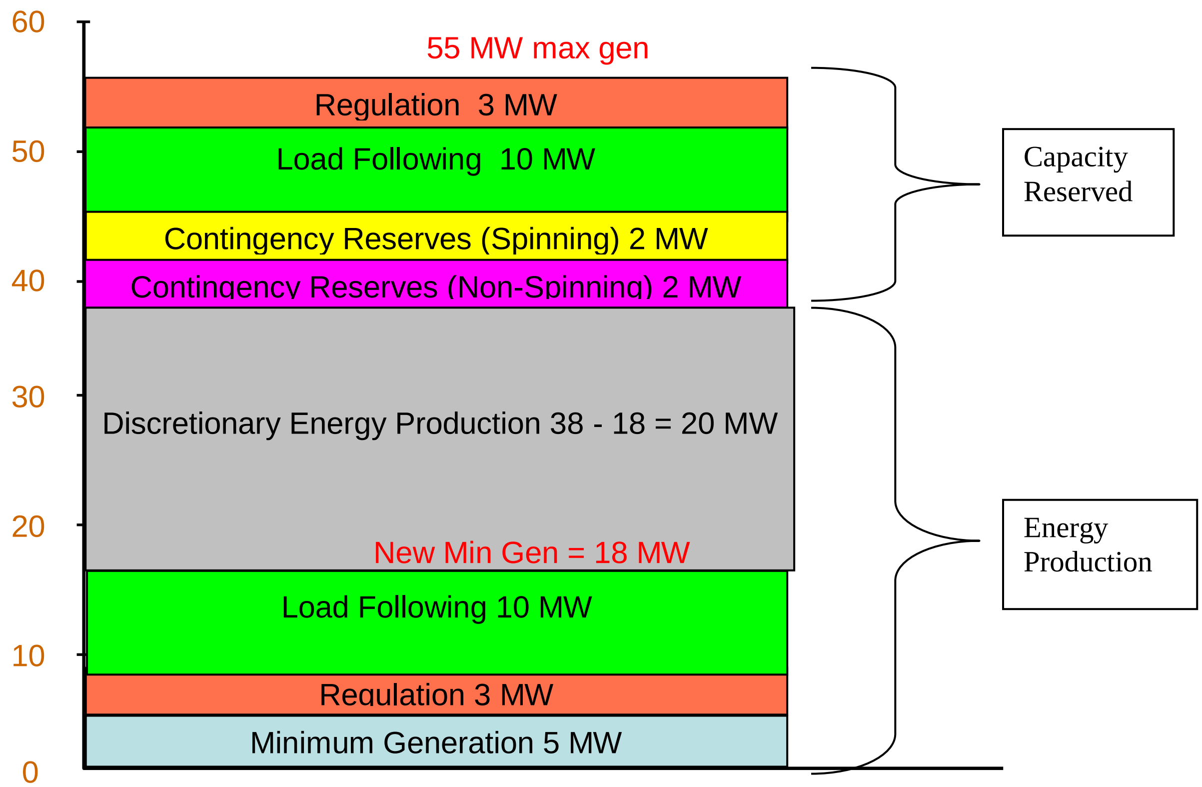


Figure 6: Example of modeling a generator supplying Dynamic Capacity

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

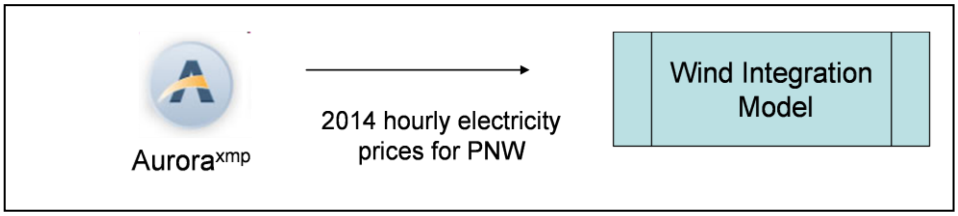


Figure 7: Forecast of electricity prices for 2014

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.

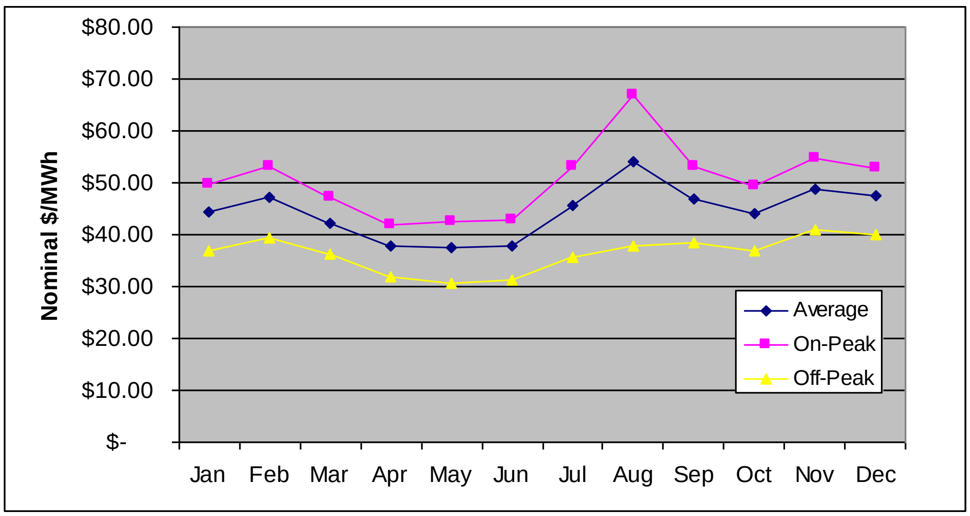


Figure 8: 2014 Wholesale electricity prices for the Pacific Northwest, nominal $/MWh

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.

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.

Mid- Columbia System

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.

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.

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.

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 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 not the hourly wind generation values used in the production simulation.

2004 Wind Generation Data

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.

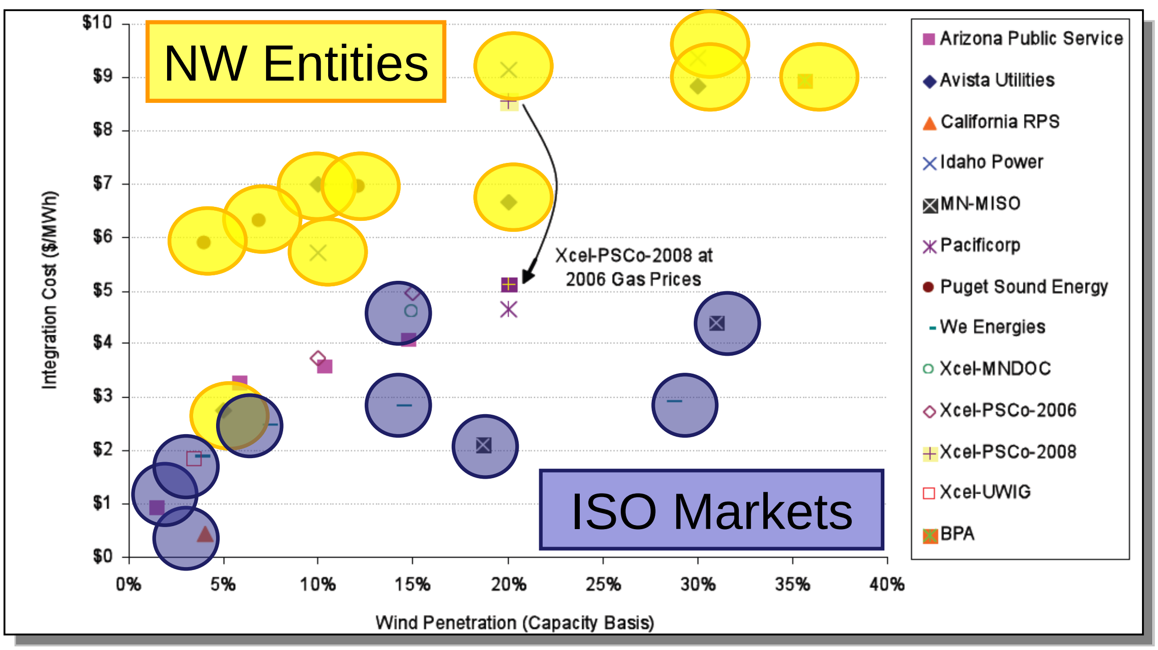


Figure 9: Cost by utility in the WECC

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;

- 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

Appendix A	Principles for Technical Review Committee Involvement in Studies of Wind Integration into Electric Power Systems
Appendix B	TRC Endorsement
Appendix C	RNP Comments
Appendix D	PGE Response to RNP Comments
Appendix E	Power Point Presentations from Public Meetings
Appendix F	Wind Integration Report by MBA Team from the University of Oregon
Appendix G	Detailed Reserve Calculations

Principles for Technical Review Committee (TRC) Involvement in Studies of Wind Integration into Electric Power Systems

What Will a TRC Provide?

A properly constituted TRC will assist the project sponsors in ensuring that the quality of the technical work and the accuracy of results will be as high as possible. TRC participation will also enhance the credibility and acceptance of the study results throughout the affected stakeholder communities. And TRC members will be qualified to carry the key messages of the study to their respective sectors.

What Is a Properly Constituted TRC?

TRC membership should include individuals that collectively provide expertise in all of the technical disciplines relevant to the study. A TRC facilitator should be selected from among the TRC membership. Sponsorship and facilitation of the TRC should be independent from, but closely coordinated with, the project sponsors and the team conducting the work. Observers from relevant government agencies and other interested parties may attend TRC meetings and be included in TRC communication at the discretion of the project sponsors. Alternatively, a separate stakeholder group can be considered in order to update interested parties on study progress and key results.

What are the TRC's Functions and Requirements?

The TRC will

- Review study objectives and approach, and offer suggestions when appropriate to strengthen the study.
- ❿ Help ensure that the study:
  - o Builds upon prior peer-reviewed wind integration studies and related technical work;
  - o Receives the benefit of findings from recent and current wind integration study work;
  - o Incorporates broadly supported best practices for wind integration studies;
  - o Is developed with broad stakeholder input.
- Engage actively in the project throughout its duration. In general, project review meetings should be held nominally on a quarterly basis; some meetings can be held telephonically, but some should also occur face-toface. A face-to-face kickoff meeting to establish and agree on the general direction of the work is required.
- Engender collegial discussions of methods and results among TRC members, the study team, project sponsors and other interested parties. The aim of these discussions is to improve accuracy, clarity and understanding of the work, and reach consensus resolution on issues that arise.
- Avoid public disclosure of meeting discussions and preliminary results. In general, findings should not be released until accepted and generally agreed upon by project sponsors, the study team and the TRC. When advisable, possible and agreed to by all project participants, interim progress reports can be provided to a broader stakeholder group.
- Ensure that findings are based entirely on facts and accurate engineering and science. Project sponsors need to embrace this aim so that the results and findings are objectively developed

and not skewed to support any desired outcome.

- Document results of TRC meetings and distribute meeting presentations and minutes.

To carry out these functions, the TRC requires

- Access to all relevant information needed to properly evaluate the work and the results. When required, TRC members will enter into confidentiality agreements to protect this information. In no case can certain information needed by the TRC be declared "off-limits."
- Assurance that the study results will be made public through published documentation or other suitable means, with the understanding that business-sensitive information will not be made public.
- Assurance that project sponsors will describe the project as having the benefit of expert review by a TRC only if the TRC has clearly expressed its acceptance of and agreement with the results of the study.
- Assurance that, in the event agreement is not reached by the TRC and other project participants, any reference to the TRC will be removed from the final report and any associated documents or publicity.

How Can Project Sponsor(s) and a TRC Agree To Conduct A Study in Accordance With These Principles?

Each can sign below:

__________________________________ for the Project Sponsor(s)

__________________________________ for the Technical Review Committee

Appendix B

From: Brendan Kirby [mailto:brendan@consultkirby.com]
Sent: Monday, August 15, 2011 2:33 PM
To: Ty Bettis; Alex Tooman
Cc: 'J Charles Smith'; 'Michael Milligan'; 'Michael Goggin'; kirbybj@ieee.org
Subject: TRC Endorsement of the PGE Wind Integration Study Report

Hello Ty,

The TRC wishes to congratulate you and the entire study team on completing the PGE Wind Integration Study Phase II. The TRC endorses the study methodology, execution, and this final report. The results naturally depend on the assumptions concerning balancing area and regional grid operating practices and scheduling opportunities. We have enjoyed working together on this project and feel it has advanced the state of the art in wind integration studies.

Thank you again

Charley Smith
Michael Goggin
Michael Milligan
Brendan Kirby

Renewable Northwest Project

May 31, 2011

PGE Wind Integration Study Team
c/o Brian Kuehne
121 SW Salmon Street
Portland, OR 97204

BY ELECTRONIC MAIL (to Brian.Kuehne@pgn.com)

Dear Wind Integration Study Team,

RNP wishes to thank PGE for the opportunity to participate in the public input process of the 2011 PGE Wind Integration Study. We appreciate the PGE staff time dedicated to detailing the company's methodology and the time spent considering RNP's recommendations.

PGE staff has developed an improved methodology, yet RNP could only support the results as constituting a base case characterized by conservative assumptions. While RNP remains concerned over the unusually high initial cost results, RNP recognizes that PGE has accommodated stakeholder input and staff has remained considerate, thoughtful, and helpful. We hope that this approach continues and would like to make three important suggestions.

1) Study Language Should Reflect Intended Use as Base Case

Initial integration cost results are significantly inflated by two conservative modeling assumptions. Despite the study's 2014 target year, the modeling ignores the purpose-built wind following capacity resource to be online by 2012 and the thirty-minute scheduling practice to be adopted by BPA in October 2011. Both elements will lower integration costs and will be available far before the target year. As stated by PGE staff during the May 18th presentation of initial results, the company made the two conservative modeling assumptions in order to establish a base case integration cost. Against the base case, PGE hopes to assess the true value of the capacity resource and thirty minute scheduling to be to PGE's system.

RNP recognizes the value of a base case as an intellectual exercise. However, RNP stresses that as a base case the modeled results are not yet appropriate to be used for ratemaking or for input into PGE's IRP. RNP requests that PGE include language, not yet present in the study, that makes clear PGE's intentions to use the conservative modeling assumptions only to create a base case. If the language is not clear, there is a danger that outdated modeling parameters will cause PGE to over-collect from their rate base or under-select wind resources in the IRP. Lastly, for the purposes of the IRP, PGE's wind integration modeling should consider the effect of additional resources likely to be available over the medium term, namely an Energy Imbalance Market or other within-hour wholesale power market.

2) Study Should Clarify Effects of BPA Policy Interpretations and Model Alternatives

RNP expects that PGE's assumptions regarding BPA policy have the single greatest effect upon PGE's initial cost results. PGE has assumed that the only resources the company may dynamically schedule out of BPA's balancing authority are the two PGE wind generation facilities. RNP finds this assumption inconsistent with BPA's Dynamic Transfer Capability policy and we add further that the proposed balancing process represents the least efficient option.

If PGE chooses to self-integrate wind resources outside its control area, it must dynamically transfer the facilities' generation out of BPA. BPA has proposed a dynamic transfer capability (DTC) policy to limit the within hour variability of power flows across BPA's transmission system. As detailed at BPA's DTC 101 Workshop on December 2, 2010, any attempt to dynamically transfer a wind project out of BPA's balancing authority is limited by DTC. DTC will also limit dispatchable resources attempting to balance wind generation from within BPA, but not necessarily limit dynamically scheduled exports of dispatchable resources out of BPA. In effect, BPA's DTC policy limits PGE's ability to import, from BPA, power that varies greatly within the hour

PGE's interpretation of BPA's DTC policy unduly limits PGE's available balancing portfolio. PGE cites DTC as the reason why the study has excluded all dispatchable generation located within BPA (hereafter 'intra-BPA') from providing capacity. However, the study's dynamically scheduled exports of BPA wind are equally limited by DTC policy. RNP requests that PGE make clear why this particular study assumption was made and furthermore comment on the substantial impact the assumption has upon integration costs. By not allowing PGE's intra-BPA dispatchable resources to participate in integration services, PGE has excluded Boardman, Coalstrip, and Coyote generating facilities from providing imbalance, load following, and spinning & non-spinning capacity services. As alluded to on slide 16 of the May 18th presentation, the excluded resources are the ones that can provide wind balancing services most economically. Consequently, PGE policy assumptions regarding BPA's DTC business practice may substantially increase PGE's balancing costs. Due to this potentially large effect, RNP believes that the wind integration study should clearly articulate the study's policy assumptions made and highlight the effect that decision has upon integration rates.

Secondly, RNP emphasizes that the study's balancing scheme is the least efficient option and encourages PGE to model additional, more efficient alternatives. By dynamically transferring only PGE's wind generation out of BPA, the variable power is not naturally smoothed by other intra-BPA wind, BPA load, or intra-BPA thermal generators. Under the current study design, the benefits of diversity with wind and load are forfeited, the use of the PGE's cheapest balancing resources is precluded, and the most expensive balancing resources are relied on in full. RNP recommends that PGE model two other balancing scheme alternatives:

a) PGE should consider netting intra-BPA wind generation with the output from Boardman, Coalstrip and Coyote and dynamically transfer the sum product into PGE's control area. As Boardman, Coalstrip, and Coyote shall only provide imbalance and load following service, their participation is unlikely to violate DTC limitations. The sum product can be fully integrated in PGE's territory with more moderate use of Beaver and Mid-C.

b) PGE should consider dynamically scheduling wind generation out of the BPA after the BPA has provided regulation service. The resultant import then may be fully balanced by load-following and imbalance services within PGE's territory. RNP believes that this scheme is more likely to be accommodated by BPA's DTC policy as it reduces the within hour variability of the dynamic transfer. Furthermore, RNP believes the scheme is more efficient as it allows PGE's wind generation to be naturally smoothed by BPA regional wind and load.

3) Study Should Further Validate Price Components

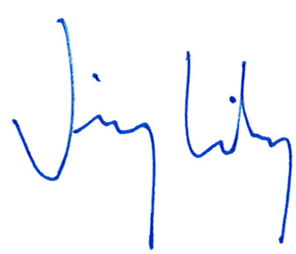
RNP is very pleased to know that collaboration with the technical review committee led to the identification of data errors partially responsible for unusually high regulation costs. RNP would like to commend PGE for promptly responding to those concerns and we look forward to the details of the discovered solution.

RNP remains concerned about PGE's day-ahead uncertainty costs. At $3.25 per MWh, the cost appears high for a Northwest utility flush with hydro, coal, and long term market resources. RNP acknowledges that day-ahead uncertainty of wind forecasts can lead to an under-optimized unit commitment, but questions how that effect compares to the day-ahead uncertainty of load forecasts and day-ahead market price forecasts. Furthermore, RNP questions whether PGE's methodology credits wind forecast uncertainty for situations when wind forecast uncertainty *improves* day ahead unit-commitments after inaccurate load and market forecasts. RNP suggests that PGE address regional stake holder reservations regarding day-ahead uncertainty costs by describing in detail how wind forecast uncertainty results in under-optimized unit commitment and how this effect can be mitigated by active trading in hour-ahead markets.

Conclusion

RNP again thanks PGE for considering these three suggestions. RNP can only support the initial results as a base case characterized by conservative assumptions. Should the study be used to inform decisions regarding rates and resource selection, RNP strongly advocates that the study's modeling parameters must be changed to more accurately represent available resources and available opportunities with increased efficiency. We look forward to PGE's draft report and our continued participation in the process.

Sincerely,



Jimmy Lindsay
Power Systems Analyst
Renewable Northwest Project

Response to Renewable Northwest Project (RNP) Comments Filed May 31, 2011

During the course of developing and vetting our Wind Integration Study, we invited all participating parties to submit written comments on two separate occasions. On May 31, 2011, RNP filed comments regarding PGE's Wind Integration Study. No other party filed written comments. For convenience, we have incorporated those comments as the prior appendix. PGE addresses RNP's primary concerns below, in the order they were presented.

1. Study Language Should Reflect Intended Use as Base Case

<u>New Capacity Resource</u>

Under item 1 of the RNP comments, RNP writes ". . . the modeling ignores the purpose-built wind following capacity resource to be online by 2012 and the thirty-minute scheduling practice to be adopted by BPA in October, 2011."

PGE has not ignored these items. As RNP points out, PGE created this set of assumptions to establish a "baseline" against which it could then subsequently assess the impact of varying mitigating actions. We have since tested a generic flexible capacity resource, as identified in the IRP Action Plan, into the wind integration model. This serves two purposes:

- For the capacity RFP, it provides an estimate of the kind of dispatch profile we could see by 2014 for this type of resource (given the other assumptions outlined in the study);
- For the renewables RFP, it provides an estimate of PGE's wind integration cost inclusive of this Action Plan generic flexible capacity resource.

Inclusion of a generic flexible capacity resource is covered in section 6.3 of the Wind Integration Report and was also vetted in the final public meeting held August 29th.

<u>Thirty-Minute Scheduling</u>

We address the status of 30 minute scheduling in section 6.3 of the Wind Integration Report. We agree that 30 minute scheduling will reduce forecast error. We are actively involved in regional discussions on this initiative.

At this at the point, we do not know what front-end and ongoing implementation costs will be. Transmission scheduling will also need to migrate to a 30-minute schedule. Thirty-minute scheduling involves market transformation at a regional level, rather than solely performing PGE system-specific modeling in isolation. The former informs the latter. Incorporation of 30 minute scheduling also presents logistical challenges for both data inputs and modeling, as the current model is currently constructed to run in one-hour increments. That must be doubled in terms of data and run time granularity.

When this topic has matured sufficiently, we will adapt the model and data for a subsequent phase of the Wind Integration Study.

Energy Imbalance Market

Toward the end of item 1, RNP states "[F]or the purposes of the IRP, PGE's wind integration modeling should consider the effect of additional resources likely to be available over the medium term, namely an Energy Imbalance Market (EIM) or other within-hour wholesale power market."

Please refer to section 6.3 in the Wind Integration Study for a brief discussion of the status of EIM. We agree that a properly structured EIM should benefit the region. We are active participants in WECC-level discussions to this end.

However, implementation appears to be five to ten years away. Front-end and ongoing implementation costs versus subsequent benefits are unknown at this time. Similar to 30-minute scheduling, impacts are largely a function of regional market transformation to which PGE can then evaluate PGE system-specific costs and benefits in light of understanding how the new market operates. When the EIM concept is mature, and an Energy Imbalance Market in which PGE can participate is operational, we will incorporate it in a future phase of our ongoing Wind Integration Study, and then subsequently include those results in an IRP.

2. Clarify Effects of BPA Policy Interpretations and Model Alternatives

Application of DTC to PGE Resources in BPA's Balancing Authority

Item 2 of the RNP comments contains a discussion related to Dynamic Transfer Capacity (DTC) from certain PGE dispatchable thermal generation through BPA's transmission system to PGE. RNP observes that PGE's cost to integrate wind would be lower if PGE's Boardman, Colstrip, and Coyote Spring plants could provide ancillary services. "However, the study's dynamically scheduled exports of BPA wind are equally limited by DTC policy. RNP request that PGE make clear why this particular study assumption was made and furthermore comment on the substantial impact the assumption has upon integration costs"

PGE would agree with RNP that DTC from the above identified plants would impact PGE's costs of wind integration. However, PGE launched Phase 2 of this Wind Integration Study July 15, 2009, over a year before BPA posted its draft version of the Dynamic Transfer Operating and Scheduling Requirements for customer comments. Version 1 of this Business Practice has only become effective April 7, 2011.

Due to this timing issue, it was determined by the PGE Study team, with input from subject matter experts within PGE Merchant's Power Operations, that it would not be prudent to include DTC scheduling rights from Boardman, Colstrip, and Coyote Springs in our modeling assumptions for Phase 2 of the Wind Integration Study.

Balancing Schemes / Model Alternatives
"RNP emphasizes that the study's balancing scheme is the least efficient option and encourages PGE to model additional, more efficient alternatives." RNP suggests that we could either dynamically transfer the sum product of wind and PGE thermal plants into PGE's control area, or, schedule the wind out of the BPA after BPA has provided regulation service.

PGE would agree with RNP that including more generation flexibility in the modeling would likely decrease the modeled cost to self-integrate wind energy. However, given the lack of clarity around BPA's DTC Business Practice mentioned above, PGE decided that in Phase 2 of the Wind Integration Study that DTC rights would only be assumed to be available to transport the wind resources, but not for the balancing resources.

PGE believes that improved access to flexible resources is the key to lowering the cost of wind integration in the Pacific Northwest. This is the reason PGE is actively participating in and, in some areas, leading the development of the various efforts in the WECC that will facilitate this improved access.

3. Study Should Further Validate Price Components

Day-Ahead Uncertainty Cost
Item 3 of the RNP comments calls into question the data and modeling PGE performed regarding day-ahead uncertainty. RNP voiced concerns in two areas:

First, "RNP questions whether PGE's methodology credits wind forecast uncertainty for situations when wind forecast uncertainty *improves* [emphasis in the original] day-ahead unit-commitments after inaccurate load and market forecasts."

Second, "RNP suggests that PGE address regional stake holder reservations regarding day-ahead uncertainty costs by describing in detail how wind forecast uncertainty results in under-optimized unit commitment and how this effect can be mitigated by active trading in hour-ahead markets."

Regarding the first point, PGE has developed a Day-Ahead forecast for load and a Day-Ahead forecast for wind as well as an Hour-Ahead forecast for load and an Hour-Ahead Forecast for wind. To isolate the cost due to Day-Ahead uncertainty in the wind forecast, the model is run with two different sets of inputs to the Day-Ahead run. Please refer to Table 8 in section 5.5.1., to see how PGE isolates the cost components for each ancillary service needed to integrate wind. In run 1, the Day-Ahead inputs include Day-Ahead load forecast and Day-Ahead wind forecast. In Run 6, the Day-Ahead inputs include Day-Ahead load forecast and Hour-Ahead wind forecast. The model is then launched for each run. In stage 1, Day-Ahead and Stage 2, Hour-Ahead the market is available to the model for purchases and sales of electricity. In each stage, the model must meet the operational constraints of meeting load every hour and supplying required ancillary services. To the extent that there is beneficial interaction between the Day-Ahead wind and Day-Ahead load forecast error, it is captured in the difference between these two runs. Further, in all the Day-Ahead runs there are no reserves held for uncertainty. This is consistent with PGE’s current operational practice.

In response to the second point, we are not aware that other regional stakeholders have reservations regarding this topic. We believe this topic was vetted in detail in the second Public Meeting and all parties have had an opportunity to ask specific questions on how PGE optimized for unit commitment and our assumed access to, and cost for, wholesale electricity purchases and sales. We have had a thoughtful review from both the third-party TRC and our topic-matter consulting expert, Enernex. They raised two data concerns that had an impact on day-ahead costs, which PGE addressed to their satisfaction. They have not raised concerns about the modeling methodology for day-ahead uncertainty.

PGE Wind Integration Study

List of Attendees to Public Meetings

Public Meeting held on 2/23/2011, Morning Session

Name	Organization
Kelcey Brown	OPUC Staff
Jim Hicks	OPUC Staff
Teresa Hagins	Northwest Pipeline
Vijay Satyal	Oregon Dept. of Energy
Megan Decker	Renewable NW Project
Jimmy Lindsay	Renewable NW Project
Gordon Feighner	Citizens' Utility Board
Ormand Hilderbrand	PaTu Wind Farm

Public Meeting held on 2/23/2011, Afternoon Session

Name	Organization
Vijay Satyal	Oregon Dept. of Energy
Gordon Feighner	Citizens' Utility Board
Teresa Hagins	Northwest Pipeline
Jim Hicks	OPUC Staff
Kelcey Brown	OPUC Staff

Make-up Meeting held on 3/17/2011, for 2/23/2011 Afternoon Session

Name	Organization
Jimmy Lindsay	Renewable NW Project
Ormand Hilderbrand	PaTu Wind Farm
Ken Dragoon	BPA

Public Meeting held on 5/18/2011

Name	Organization
John Sturm	Citizens' Utility Board
Gordon Feighner	Citizens' Utility Board
Vijay Satyal	Oregon Dept. of Energy
Trace Megenbier	Oregon Dept. of Energy
Doris Penwell	AOC/CREA
Paul Woodin	CREA
Maury Galbraith	OPUC Staff
Jim Hicks	OPUC Staff
Teresa Hagins	Northwest Pipeline
Jimmy Lindsay	Renewable NW Project
Marc Vatter	Economic Insight
Michael Lijienwat	PacifiCorp
Eric Arzalo	PacifiCorp
Brendan Kirby	TRC
Charles Smith	TRC

Wind Integration Study Stakeholder Briefing

Morning Session
February 23, 2011

Meeting Overview

Morning Session

- Project Overview
- General Modeling Approach
- Timeline

Lunch

- NDA Review

Afternoon Session

- Reserves Discussion
- Cost Component Breakdown
- In-depth Modeling Approach

Morning Session Agenda:

- Introduction
- Resources
- Scope
- Wind Data
- Model Inputs
- The Model
- Methodology
- Deliverables
- Next Steps

Introduction

- Evolution of PGE Wind Integration Study
  - Phase 1 to Phase 2
- Currently, PGE receives integration services from third parties for Klondike II (PPA), Vancycle Ridge (PPA), and PGE's Biglow Canyon Wind Farm.
  - We do not currently self-integrate.
- As demand increases for a finite supply of BPA's hydro capacity, BPA prices are expected to rise sharply.
- Our objective is to determine PGE's costs to self-integrate wind energy.
- No preliminary results will be provided in today's meeting.

Resources: PGE Project Team

- Ty Bettis, Merchant Transmission & Resource Integration
- David Weitzel, Ph.D., Rates and Regulatory
- Teyent Gossa, Fundamentals
- Ruth Burris, P.E., Fundamentals
- Peter Lyman, Ph.D, Fundamentals
- John Ollis, Financial Analysis
- Silvia Melchiorri, Integrated Resource Planning
- Stefan Brown, Ph.D., Resource Strategy
- Alex Tooman, Ph.D., Rates and Regulatory

Resources: Technical Review Committee

- J. Charles Smith, Executive Director
    - Utility Wind Integration Group (UWIG)
- Michael Milligan, Ph.D.
    - National Renewable Energy Laboratory (NREL)
- Brendan Kirby, P.E.
    - NREL
- Michael Goggin, Manager of Transmission Policy
    - American Wind Energy Association (AWEA)
- Bradley Nickells, P.E., Director of Transmission Expansion Planning
    - Western Electricity Coordinating Counsel (WECC)

Resources: External Consultants

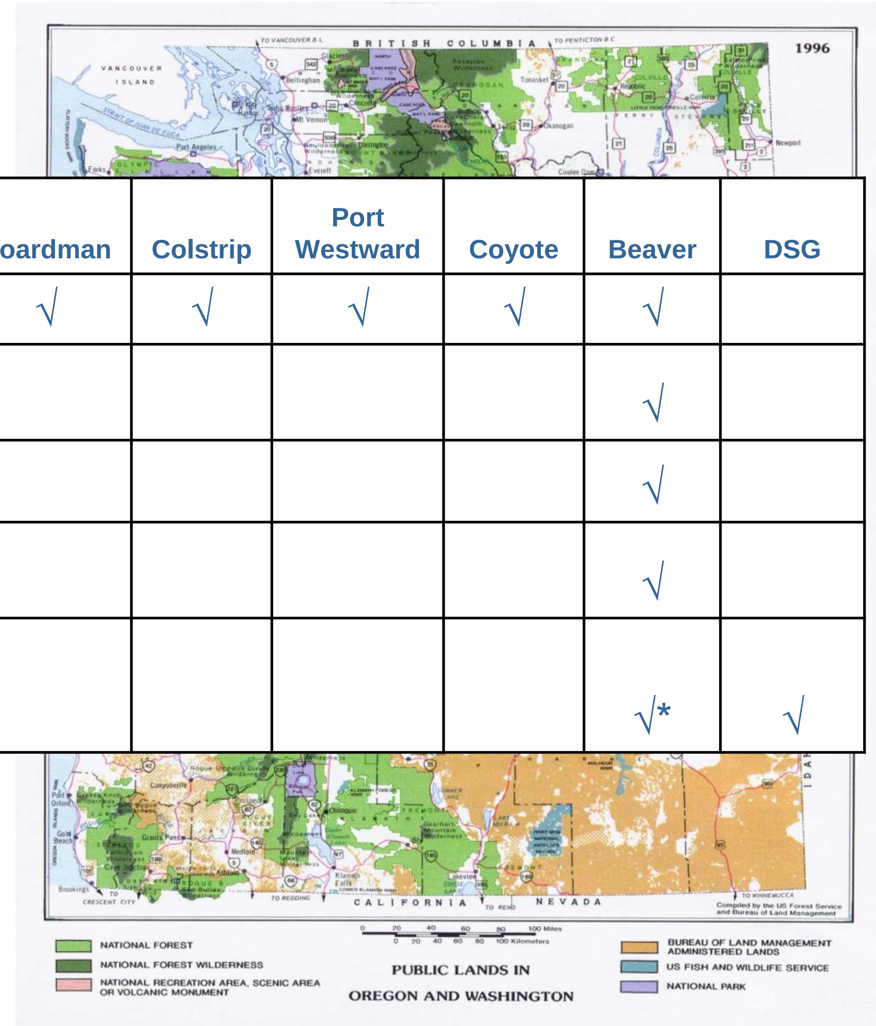
- Bob Zavadil, E.E., Executive VP of Power Systems Consulting
  - EnerNex Corporation
- Tom Mousseau, M.Ed., Principal Consultant
  - EnerNex Corporation
- Jennifer A. Hodgdon, Ph.D.
  - Poplar ProductivityWare
- Jeffrey T. Linderoth, Ph.D, Associate Professor
  - Department of Industrial & Systems Engineering
  - College of Engineering, University of Wisconsin-Madison

Evolution of a Wind Study

- Phase 1 used optimization model called "What's Best"
  - Run times were very long
  - Model would not solve with certain constraints
- Requested input from an optimization expert: Dr. Linderoth
  - Conducted a "bake off" between alternative solvers
  - Gurobi was chosen (faster, more flexible, user friendly…)
  - "Generalized Algebraic Modeling System" (GAMS)
  - State-of-the-art mixed integer programming system
- Dr. Linderoth transferred model from What's Best to GAMS
- What's Best model run on eleven PCs
- GAMS model run on one Intel Xeon "super computer" plus four PCs
- Significantly reduced run times and solution issues

Phase 2 Project Scope and Timeline

- Determine costs of integrating wind generation into PGE system



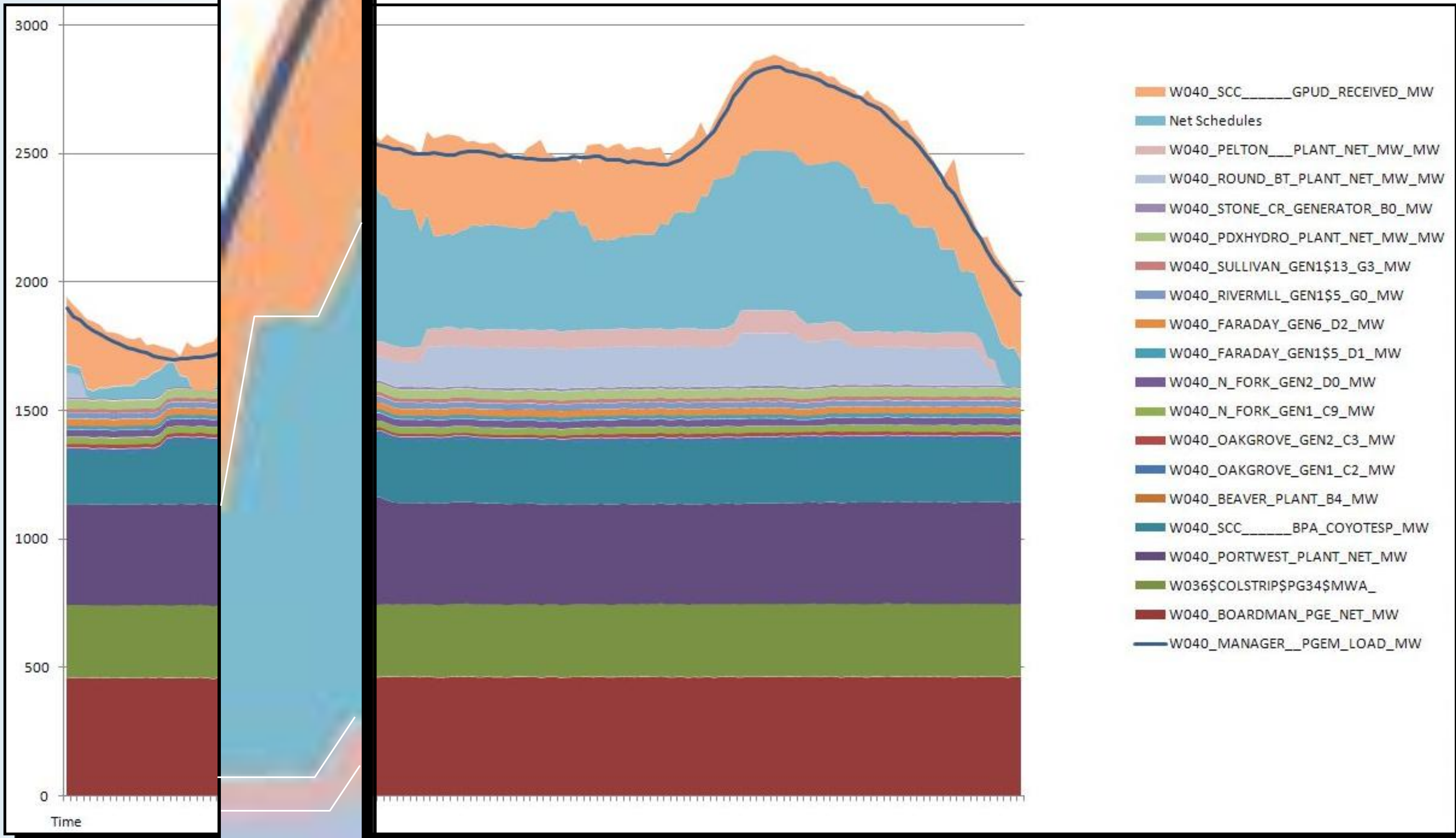
	Operational Reserve	Mid-C	Round Butte	Pelton	Boardman	Colstrip	Port Westward	Coyote	Beaver	DSG
Energy		√	√	√	√	√	√	√	√	
Capacity	Load Following (Load and Wind)	√	√	√					√	
	Regulation	√	√						√	
	Contingency Reserve-Spinning	√	√	√					√	
	Contingency Reserve-Non-Spinning	√	√	√					√*	√

- Projected completion of Wind Study
  - Q2 2011
  - Produce written report with help of EnerNex

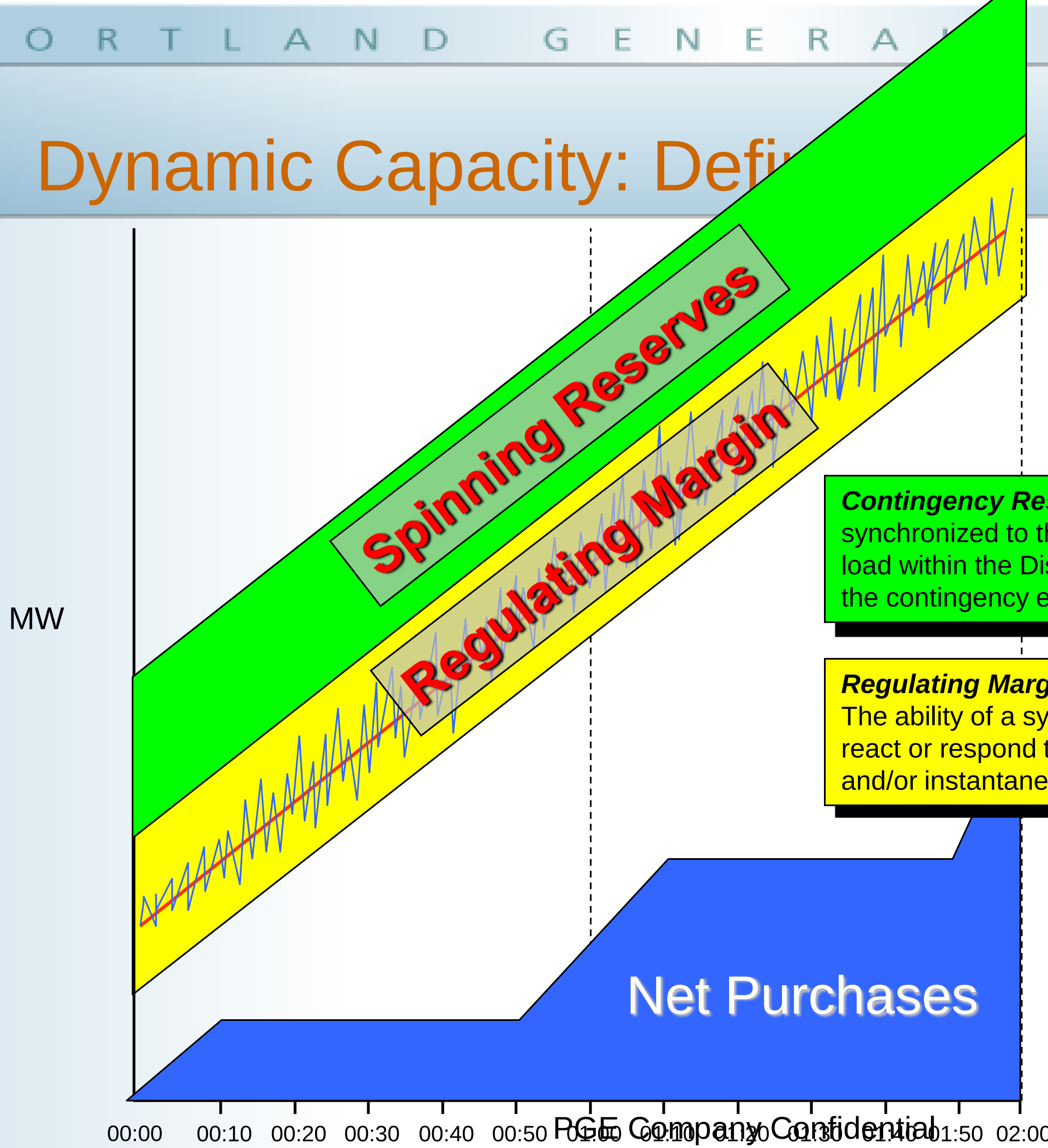
“Variability and Uncertainty” of Wind

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

Load /Resource Balancing



Dynamic Capacity: Defi



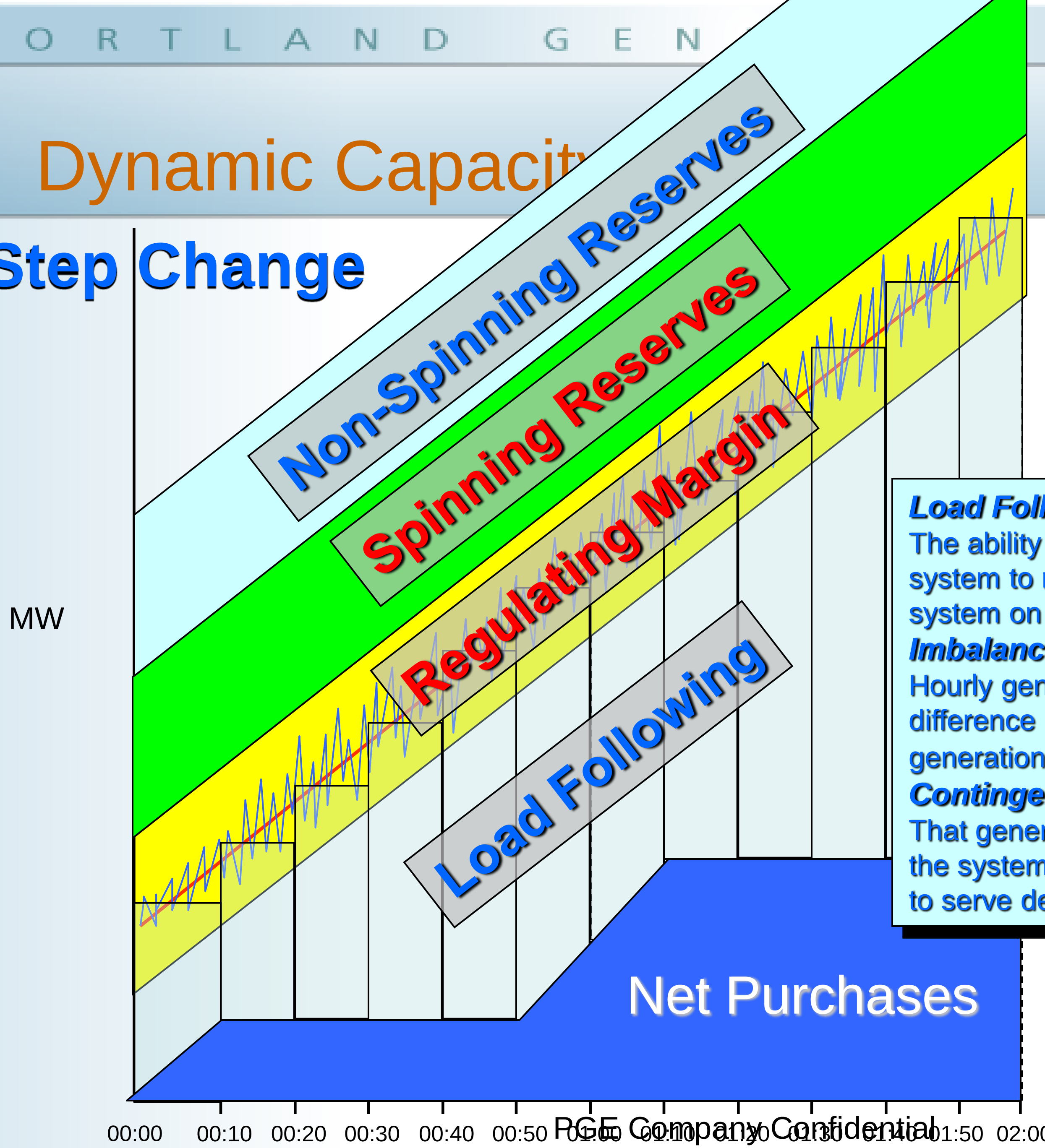
Fast Acting

***Contingency Reserves - Spinning**:* Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event, preferably on AGC.

Regulating Margin:
The ability of a system or elements of the system to react or respond to a change in system frequency and/or instantaneous load changes, typically on AGC.

Dynamic Capacit

Step Change **Fast Acting**

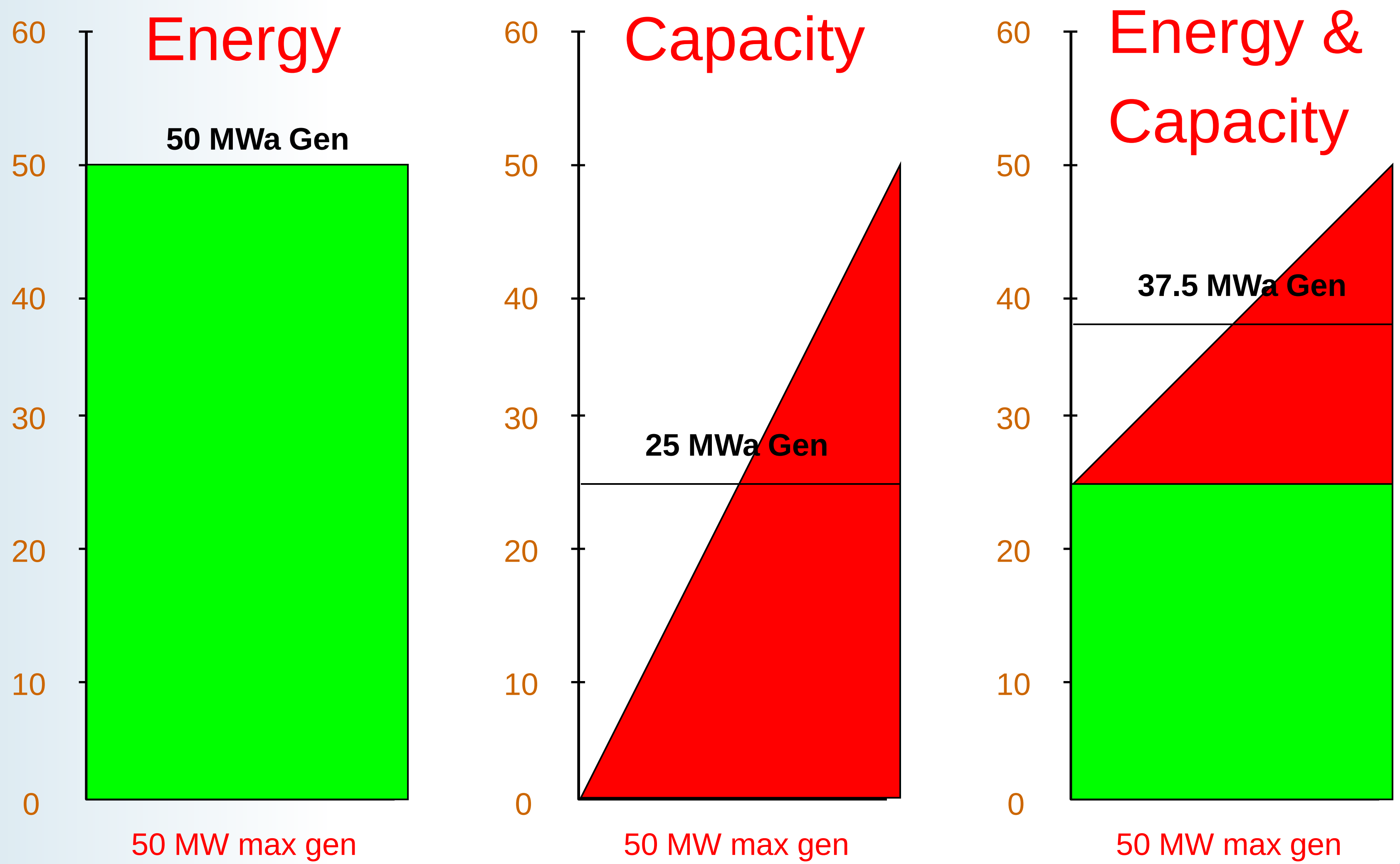


Load Following:
The ability of a system or elements of the system to react or respond to a change in the system on a 10-minute basis.

Imbalance:
Hourly generation necessary to make up difference between scheduled and actual generation.

Contingency Reserves – Non-spinning:
That generating reserve not synchronized to the system, but capable of being fully loaded to serve demand within 10-minutes.

Energy or Capacity?



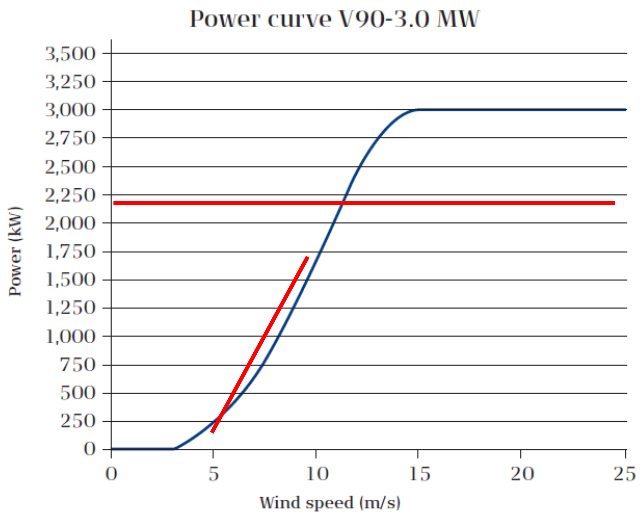
Components of Integration Costs

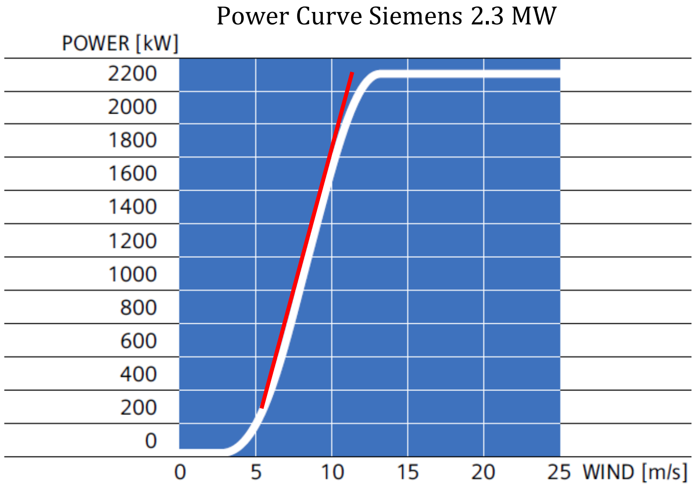
- Day-Ahead to Hour-Ahead
  - Day-Ahead Optimization
  - Optimize system in Preschedule with current wind energy forecast
  - Long/Short position filled in Preschedule Market
- Hour-Ahead to Within-Hour
  - Hour-Ahead Optimization
  - Optimize system in Real Time with improved wind energy forecast
  - Long/Short position filled in Real Time Market
- Within-Hour Balancing
  - Within-Hour Optimization
  - Regulation and Load Following

Withholding PGE resources for capacity needs requires deficit be made up from wholesale market

Wind Data Development for Ph2 Modeling

- NREL Western Wind Dataset
  - http://www.nrel.gov/wind/integrationdatasets/western/methodology.html
- Creates Day-Ahead and Actual wind speeds and generation output
- Developed for 2004, 2005, 2006
- EnerNex tailored wind generation output for PGE:
  - Used estimated wind speeds from WWD
  - Replaced power curve of Vestas V90 for Siemens 2.3 MW
  - More generation at lower wind speeds, typical of Columbia River wind regime

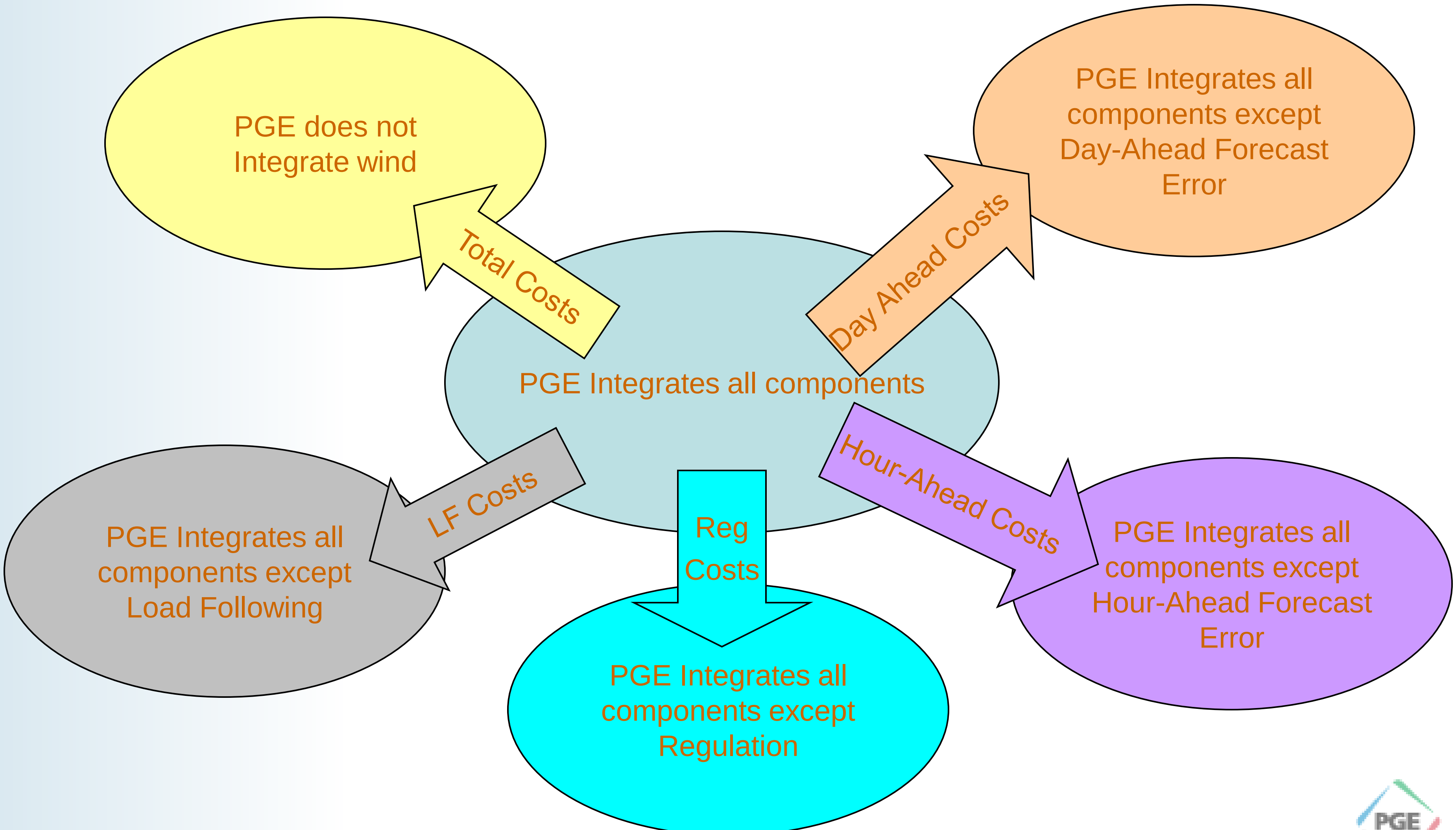




Regional Wind to Simulate NW Market Price

- Oregon RES requires 15% Renewables by 2015
- Created 2015 regional wind data for entire WECC footprint
- EnerNex identified proposed wind generation in current interconnection queues through 2014
- Used enough wind to satisfy individual state RES requirements
- Regional wind generation estimates used as static resource in Aurora to derive Mid-C market prices
- Fall 2010 PIRA natural Gas prices used in Aurora to simulate regional thermal dispatch
- Used Bid/Ask spread for purchases and sales in Wind Integration model
  - DA market is more liquid that HA market
  - DA = Fixed adder, No sliding scale
  - HA = Sliding scale

Scenario Runs to Derive Integration Costs



Other Uses for PGE Wind Integration Model

- Satisfying OPUC requirement for subsequent IRPs:
  - PGE will "include in its next IRP Update and in its next IRP planning cycle, a Wind Integration Study that has been vetted by regional stakeholders"
- Internal PGE Resource Studies
  - Any conclusions drawn from these studies will not be made public, nor will it be part of the Wind Integration Study final written report

Next Steps

- Stakeholder comment period based upon today's presentation
  - Comments due by COB of March 7, 2011
  - Send comments to Brian Kuehne (brian.kuehne@pgn.com)
- Next public Stakeholder meeting April 2011
  - Review of preliminary study results (if available)
  - Responses to stakeholder comments
- Second round of stakeholder comments based upon April meeting
  - Comments due approximately 2 weeks after stakeholder meeting
- Final stakeholder meeting (date TBD)
  - Produce Phase 2 final results
  - Supply written report
  - Possible comment period to follow

Questions?

Lunch and NDA Review

In order to participate in the second half of this meeting, PGE requires stakeholders to sign a non-disclosure agreement. Direct competitors of PGE are not allowed to participate in this discussion. No written materials will be provided. Thank you.

Wind Integration Study Stakeholder Briefing

Afternoon Session
February 23, 2011

Agenda

- Study Objective
- The Wind Integration Model
    - Development
    - Structure
    - Stages
    - Bid/Ask Spread
- Price Development
    - Regional Wind Data
    - Power/Gas Prices
- Wind Data – Forecast & Development
    - PGE System
    - Wind Forecast
- Load Net Wind
- Study Cost Components
- Generator Example
- Development of Calculations for:
    - Regulating Margin
    - Load Following
    - Forecast Error for Wind
- 3-Stage Diagram
- Model Runs to Isolate Costs
- Questions
- Next Steps

Main Study Assumptions:

- Existing PGE resources (at projected levels) are used to integrate a total of 850 MW of wind in 2014.
- The 850 MW of wind include 450 MW of Biglow and 400 MW of additional wind resources.
- Available hydro resources in the model reflect PGE's smaller share of the Mid C, Round Butte and Pelton in 2014.
- Beaver, a PGE-owned thermal resource, is available to integrate wind in 2014.
- Used 2005 as the year for hydro flows, wind data, and load forecast errors.

PGE's Plant Portfolio

	Operational Reserve	Mid-C	Round Butte	Pelton	Boardman	Colstrip	Port Westward	Coyote	Beaver	SB Gen
Energy		√	√	√	√	√	√	√	√	
Capacity	Load Following (Load and Wind)	√	√	√					√	
	Regulation	√	√						√	
	Contingency Reserve: Spinning	√	√	√					√	
	Contingency Reserve: Non-Spinning	√	√	√					√*	√

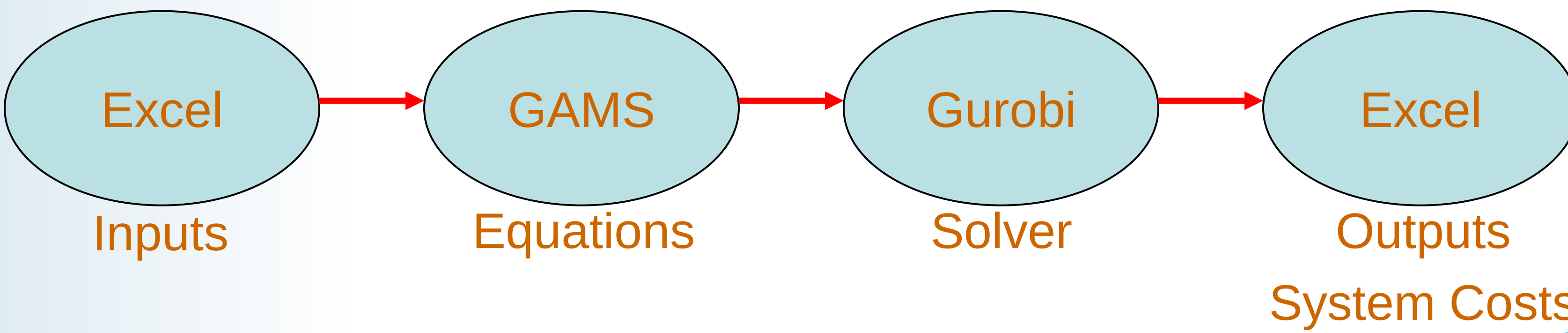
* Beaver has to be spinning to provide both spinning and non-spinning contingency reserve

Wind Integration Model: Development

- PGE has developed (in-house) an optimization model that dispatches PGE generation resources subject to constraints on system operation.
- The model employs mixed-integer programming (MIP) that permits non-linear constraints necessary to capture system operational requirements.
- PGE's optimization consultant (Dr. Linderoth) ran tests on alternative solvers.
  - Performance of solver is unique to PGE system.
  - Gurobi performed very well during the test.
- Execution times increase rapidly as the time horizon increases.

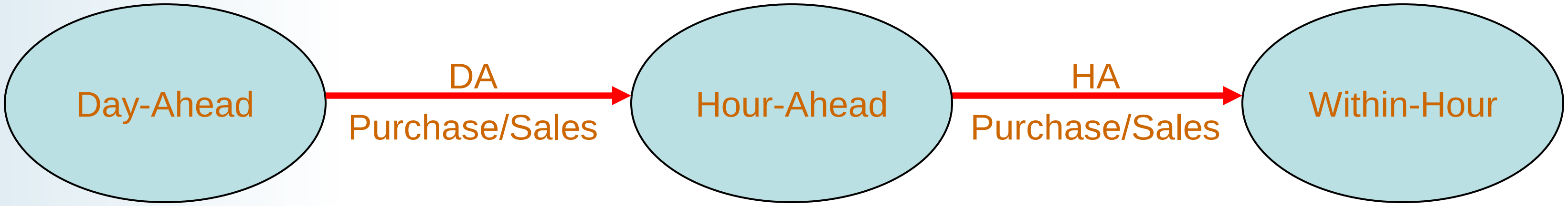
Wind Integration Model: Structure

Software	Function
GAMS	"Generalized Algebraic Modeling System" – Programming language used to generate equations.
GUROBI	State-of-the-art mixed integer programming software
EXCEL / VB	"Wrapper" used to handle I/O and coordinate the component programs.



Wind Integration Model: Stages

- One-year analysis consists of 52 one-week runs.
- Model is currently defined at a one-hour scheduling interval level.
- The model is run in three stages corresponding to:
  - Day-Ahead (DA)
  - Hour-Ahead (HA)
  - Within Hour (WH)
- Total system operating costs at the third stage are used in assessing the costs of wind integration.



Wind Integration Model: Bid/Ask Spread

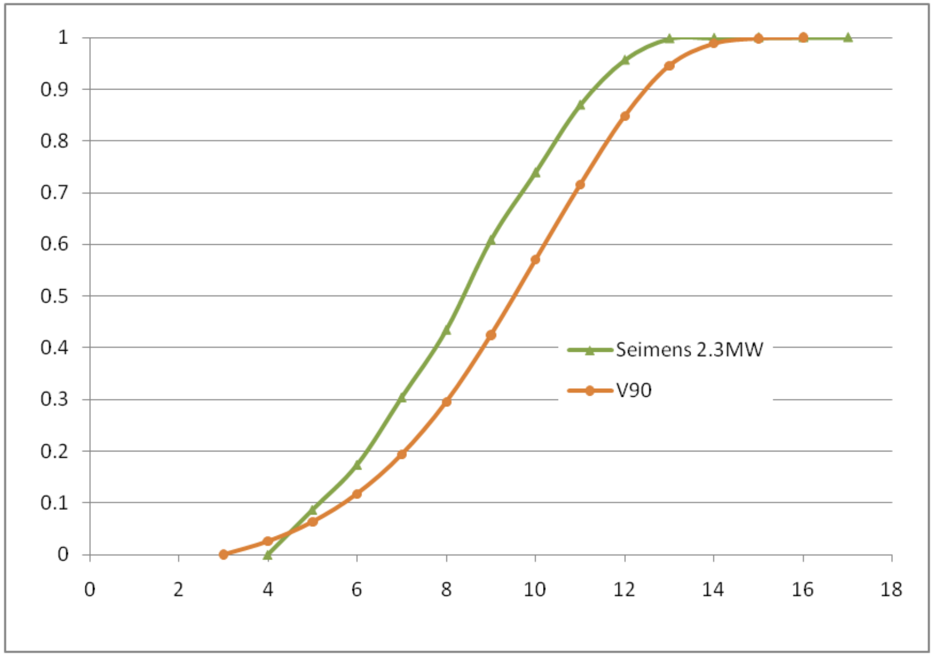
- Phase I
  - Day Ahead +/- $0.25/MWh
  - Hour Ahead +/- 10% of Price
- Phase II
  - Day Ahead +/- $0.25/MWh
  - Hour Ahead +/- Sliding Scale (see table)

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%

Northwest Pricing Development

Regional Wind Shape Development

- Wind grouped outside of PGE control area
  - 60 wind sites
  - 17 Aurora modeled areas
- 2005 actual power data extracted from NREL WWSIS database
- Power data applied to Siemens turbine power curve 10 min intervals
- Hourly data computed from 10 minute data



Wholesale Electricity Price for 2014

- Used 2009 IRP model: AURORAxmp set up as described in chapter 10A.2 of 2009 IRP Addendum.
- More precisely, we assume:
  - Default AURORAxmp projections on WECC load growth;
  - RPS compliance in every State that has one;
  - A reliability standard that adds sufficient resources in the WECC to meet 1-in-2 peak load plus operating reserves of about 6%.
- Wind generating capacity by state in 2014 result of:
  - Existing plants as of 2008
  - Plants under construction that will be completed by 2014
  - Generic units added to the DB for RPS compliance (page 11 of IRP Addendum specifies RPS targets by State as % of demand)
  - Additional units that AURORAxmp might elect to add to meet WECC load based on economics
- Updated the following 2009 IRP assumptions: natural gas prices, wind shapes, CO2 tax, hydro shaping in WECC (see right pane)

Enernex: developed **wind hourly shapes** to apply to existing and new resources in the most relevant WECC areas (PNW, California, etc.)

Updated gas prices (Q3 2010 PIRA)

Assumed no CO2 tax by 2014

2014 Electricity Prices

Aurora^{xmp}

2014 hourly electricity prices for PNW

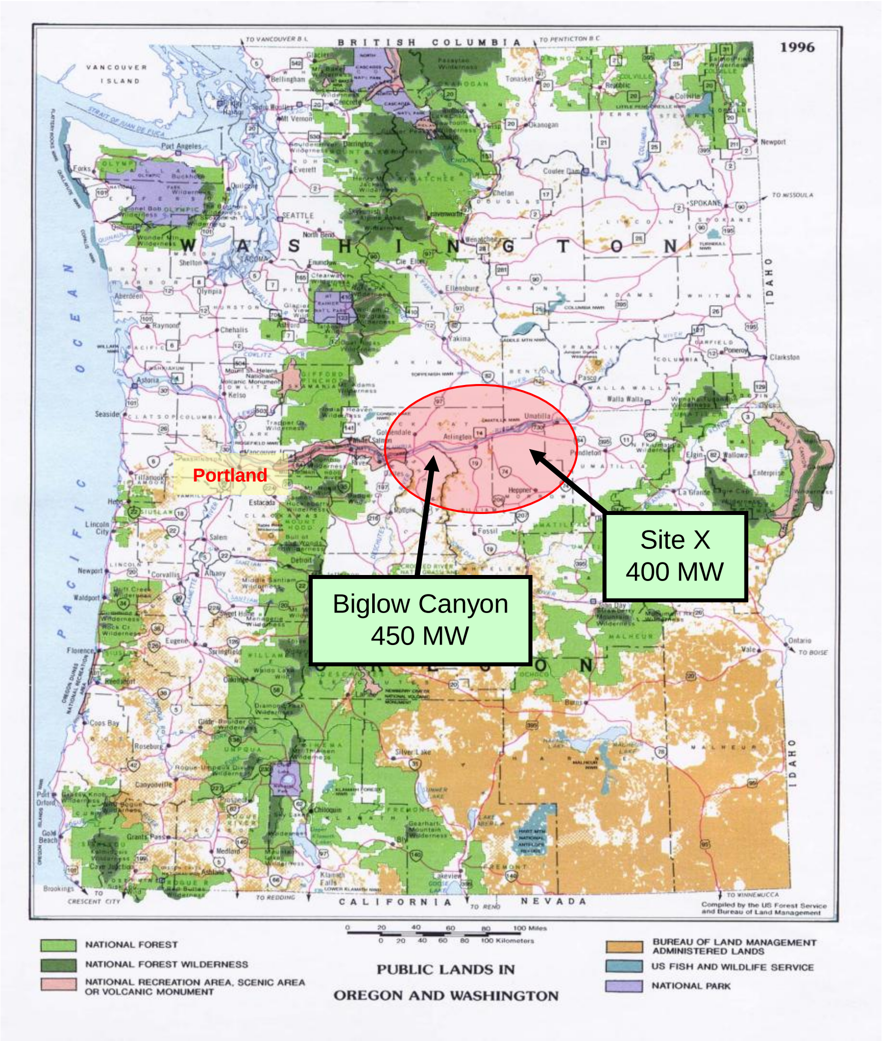
(Monthly Summary Below)

Wind Integration Model

	Average	On-Peak	Off-Peak
2014_01	$45.72	$51.42	$37.82
2014_02	$47.88	$53.71	$40.10
2014_03	$42.33	$46.99	$36.43
2014_04	$37.37	$41.55	$31.66
2014_05	$37.22	$42.56	$29.83
2014_06	$37.39	$42.78	$30.66
2014_07	$43.59	$49.64	$35.20
2014_08	$49.04	$58.10	$37.56
2014_09	$46.57	$53.04	$37.72
2014_10	$44.08	$49.74	$36.24
2014_11	$48.40	$54.30	$41.02
2014_12	$46.84	$51.99	$39.70
Average	**$43.85**	**$49.62**	**$36.15**

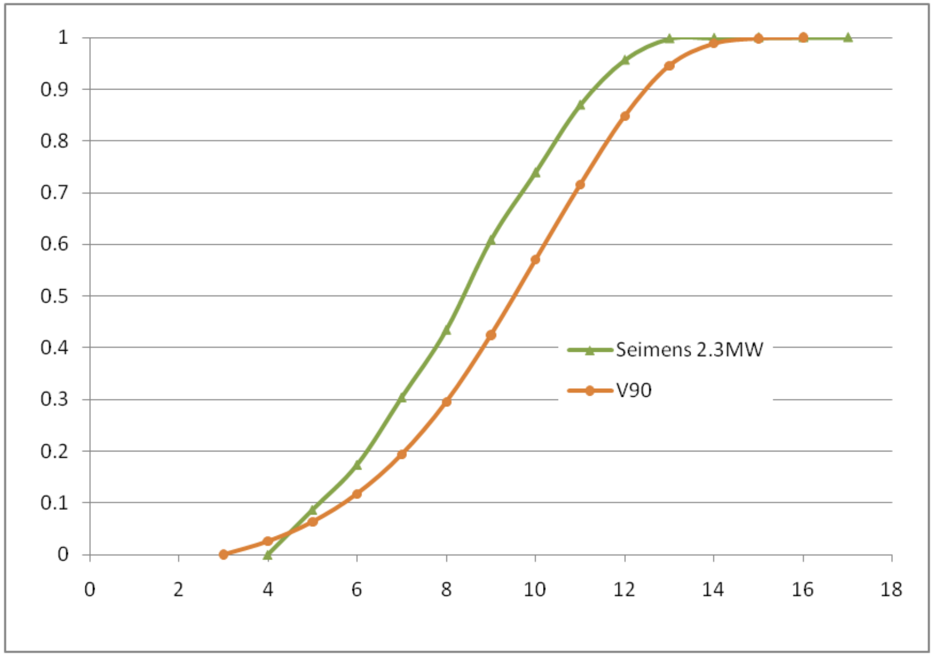
Wind Shape Development

Wind Diversity



PGE Wind Shape Development

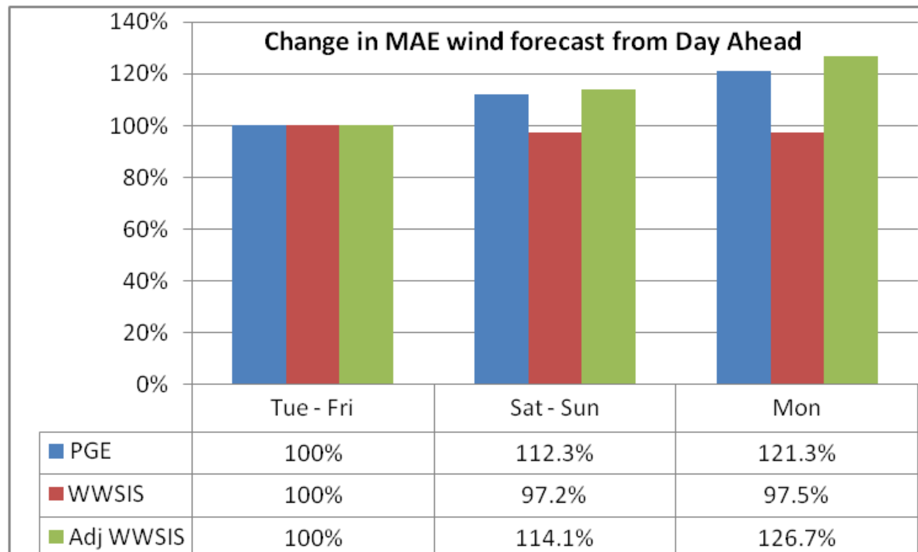
- Wind grouped inside PGE
  - 25 wind sites
  - Siemens 2.3 MW turbines
- EnerNex provided 3 years of wind data extracted from NREL WWSIS database
- Power data applied to Siemens turbine power curve 10 min intervals
- Hourly data computed from 10 minute data
- PGE used 2005 day ahead and actual power data
  - Closest to "average" hydro year



Day-Ahead Forecast Development

- Initial forecast data calculated by using ratio of WWSIS and hourly data applied to the WWSIS forecast data
- Real forecast and metered wind data from Biglow canyon was available and used to modify the inside PGE wind forecasts to better model operation forecasting techniques.
  - 1-day ahead forecast for Tuesday – Friday
  - 2-day ahead forecast for Saturday and Sunday
  - 3-day ahead forecast for Monday
- Statistical change in MAE for forecast error derived for each forecast
- Forecast profiles for 2 and 3 day forecasts where adjusted to increase/decrease forecast such that the resulting forecast error more closely represented actual forecasts

5 Day vs. 7 Day Scheduling



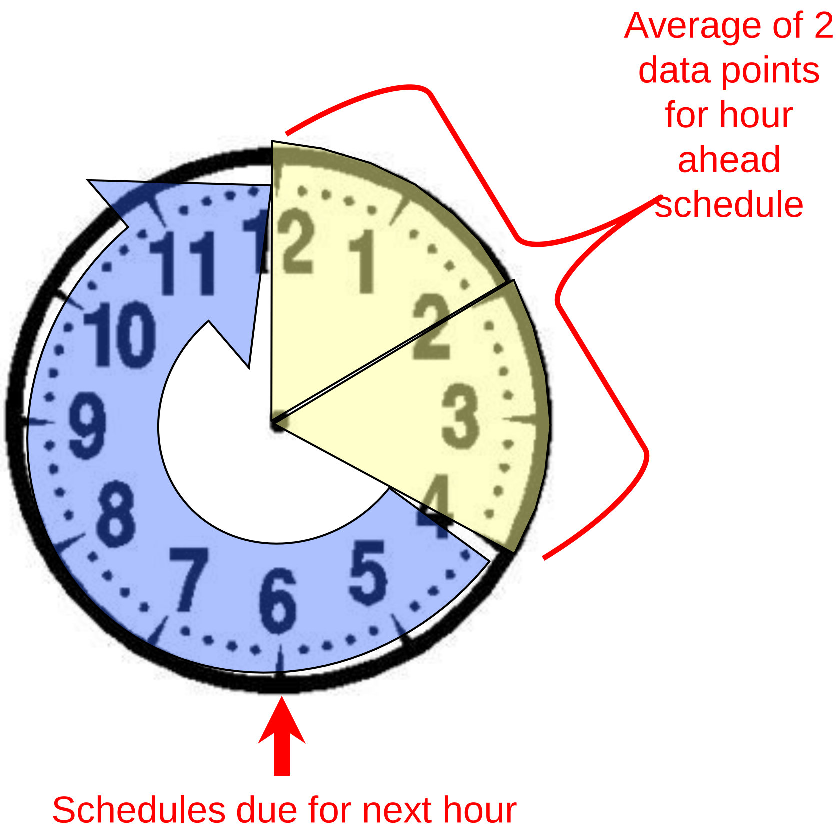
Hour-Ahead and Within-Hour Forecast Development

Hour Ahead Forecast

- NREL WWD Actual generation estimate composed of 10 minute data
- Used average of the two data points at 00:10 and 00:20 to determine HA Forecast for hour 1:00
- Simulates realistic Operations for 30 minute scheduling window
  - Does not simulate 30 minute persistence

Within-Hour Forecast

- Computed from NREL WWD Actual Forecast 10 minute data



Load Forecast Development

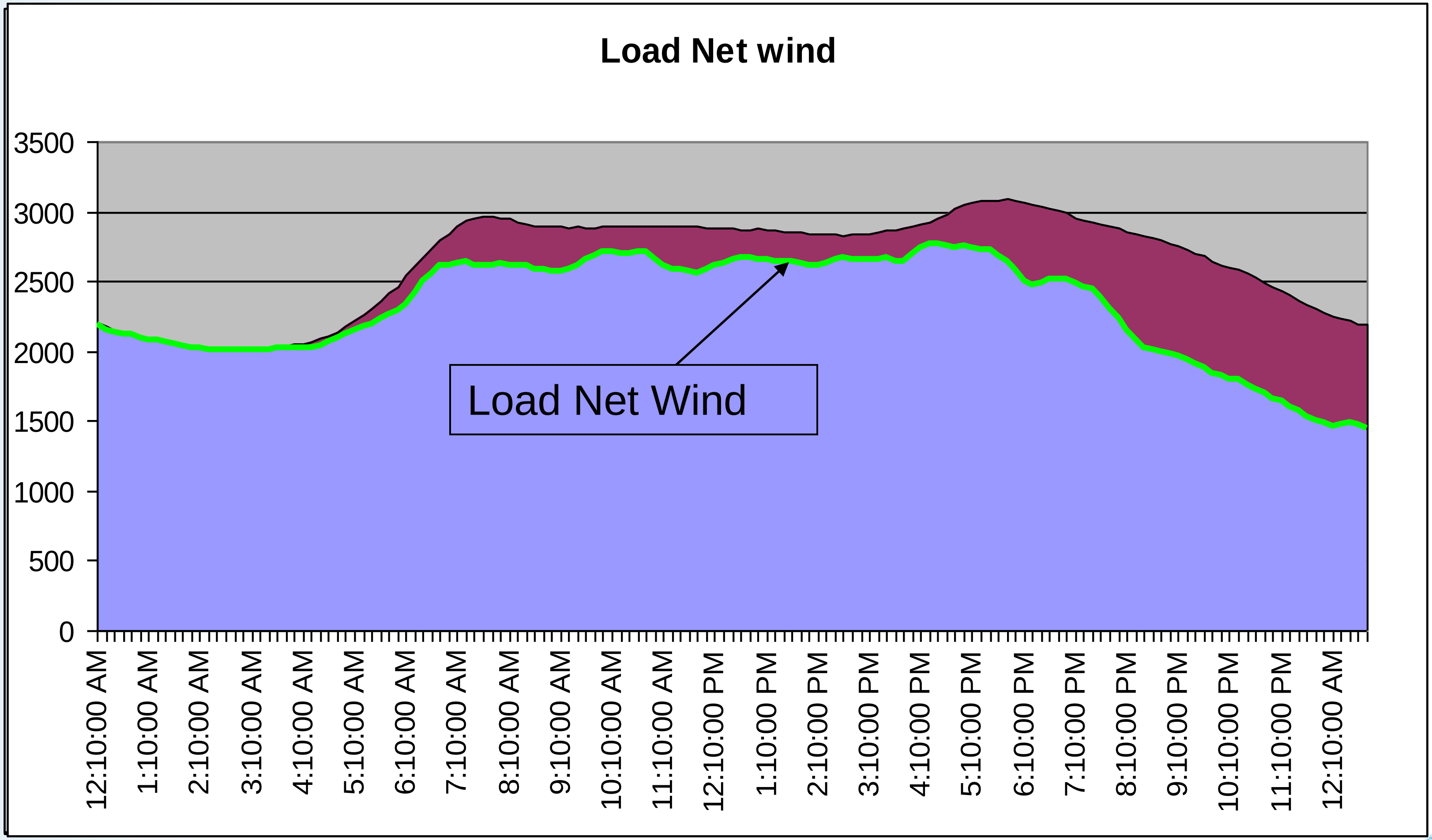
- PGE's 2014 projected Load will be used for this study
- Day Ahead Forecast Error is the difference between Actual Load and Day Ahead Load Forecast.
  - $Load_{DAFE2005}=Load_{2005}-Load_{DA2005}$
- Hour Ahead Forecast Error is the difference between Actual Load and Hour Ahead Load Forecast.
  - $Load_{HAFE2005}=Load_{2005}-Load_{HA2005}$
- Like the water year and wind year, 2005 Day Ahead forecast error will be used to augment 2014 projected load, to create Day Ahead forecast error.
  - $Load_{DA2014}=Load_{2014}*Load_{DAFE2005}/Load_{2005}$
- Similarly, 2005 Hour Ahead forecast error will be used to augment 2014 projected load, to create Hour Ahead forecast error.
  - $Load_{HA2014}=Load_{2014}*Load_{HAFE2005}/Load_{2005}$

Where:

$Load_{2005}$: 2005 Actual Load
$Load_{DA2005}$: 2005 Day Ahead Load
$Load_{DAFE2005}$: 2005 Day Ahead Load forecast error
$Load_{HAFE2005}$: 2005 Hour Ahead Load forecast error

$Load_{DA2014}$: 2014 Day Ahead Load
$Load_{HA2014}$: 2014 Hour Ahead Load
$Load_{2014}$: 2014 Projected Load

Load Net Wind

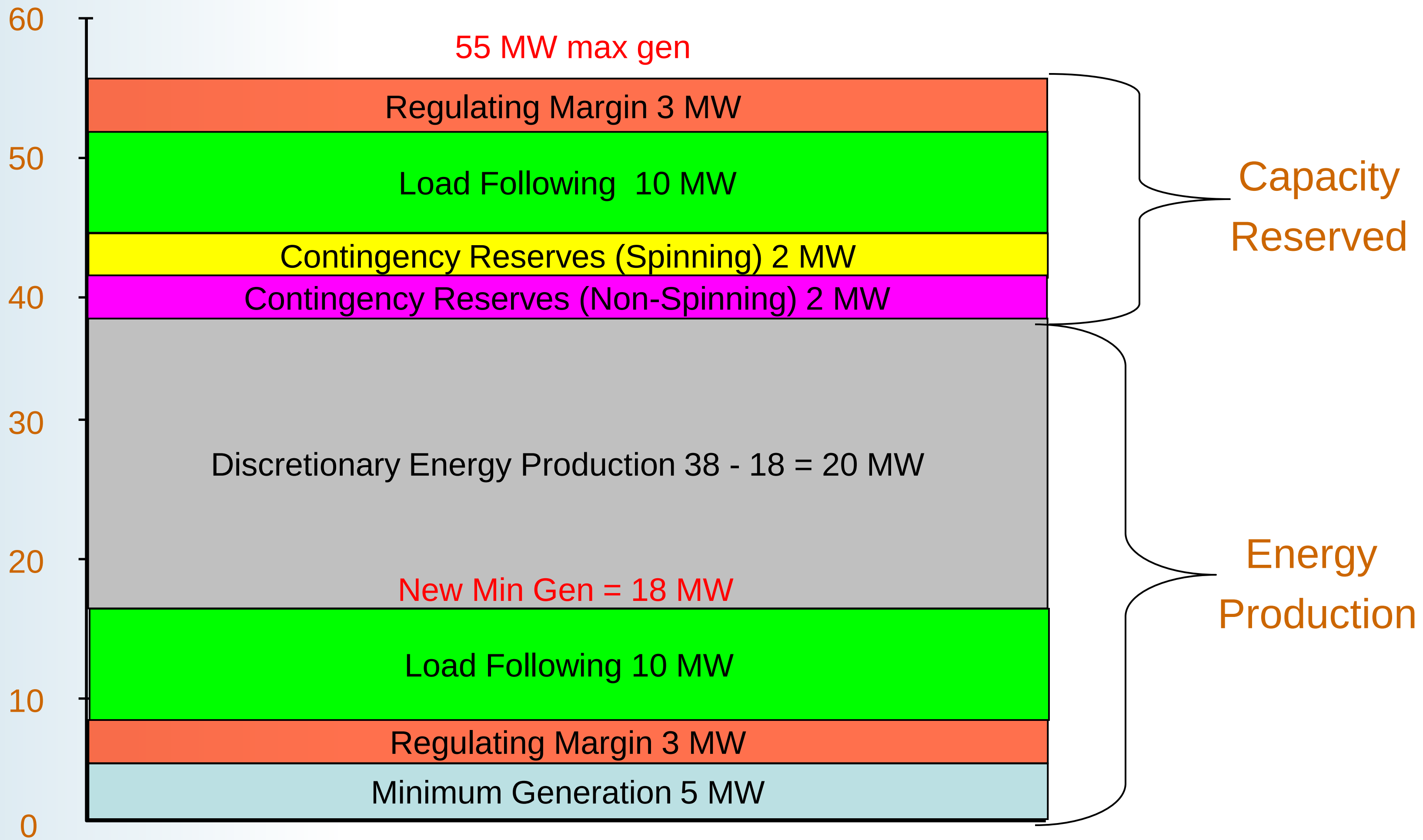


Wind Integration Cost Components

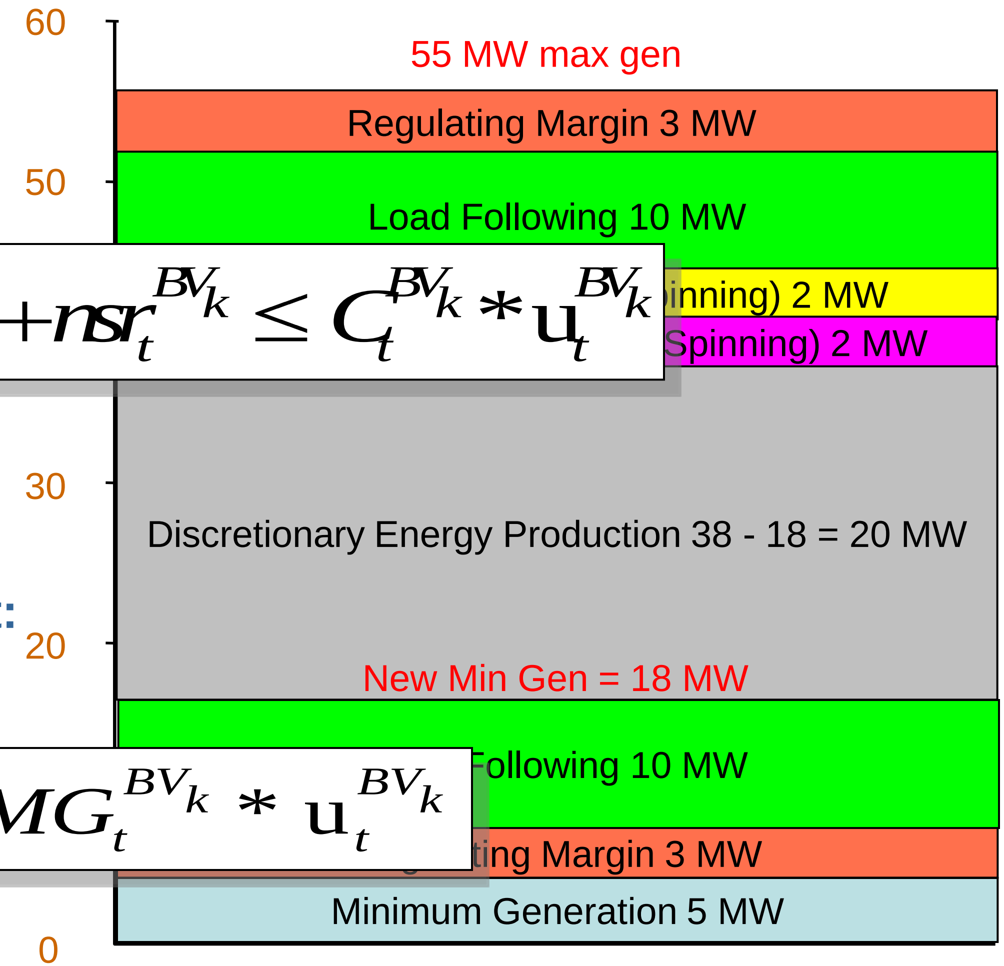
- Regulation / Regulating Margin (R/RM for Wind): Costs associated with providing reserve capacity to account for short-term variations in wind that are statistically independent of variations in load. Resources providing R/RM are assumed to be AGC equipped. (NREL paper*)
- Load Net Wind Following (LNWF): Costs associated with incremental reserves (relative to no-wind case) used to track predictable within-hour movement of load net of wind.
- Hour-Ahead Uncertainty (Wind): Costs associated with incremental reserves (relative to no forecast error) required to account for the effect of hour-ahead wind forecast errors on load net of wind.
- Day-Ahead Uncertainty (Wind): Incremental costs associated with system re-optimization resulting from DA wind forecast errors.

* M. Milligan, B. Kirby, P. Dohonoo, D. Lew, E. Ela (NREL) "Operating Reserves and Wind Power Integration: An International Comparison" (2010)

Example of Generator Supplying Dynamic Capacity



Example: Simple Cycle modeling



3.1) Maximum Capacity Constraint:

$$g_t^{BV_k} + rm_t^{BV_k} + lf_t^{BV_k} + sr_t^{BV_k} + nsr_t^{BV_k} \leq C_t^{BV_k} * u_t^{BV_k}$$

3.2) Minimum Generation Constraint:

$$g_t^{BV_k} - rm_t^{BV_k} - lf_t^{BV_k} \geq MG_t^{BV_k} * u_t^{BV_k}$$

Derivation of Regulation and Load Following Equations

PGE has contracted with EnerNex to develop the reserve requirements necessary to integrate wind resources into the PGE system.

Overview

- Reserved capacity/energy constraints in PGE dispatch model
  - Regulation
  - Load Following
- Load Following constraint is broken into two components
  - Reserves required for intra-hourly movement (perfect forecast of load net wind)
  - Reserves required to account for short-term (Hour-Ahead) forecast errors

Approach

- Load and wind "decomposition"
  - Real-time variations are covered by regulation
  - Load following tracks short-term estimates of net load trend
  - Existing PGE practice establishes benchmarks for "load only" case (1% regulation, LF allocation)

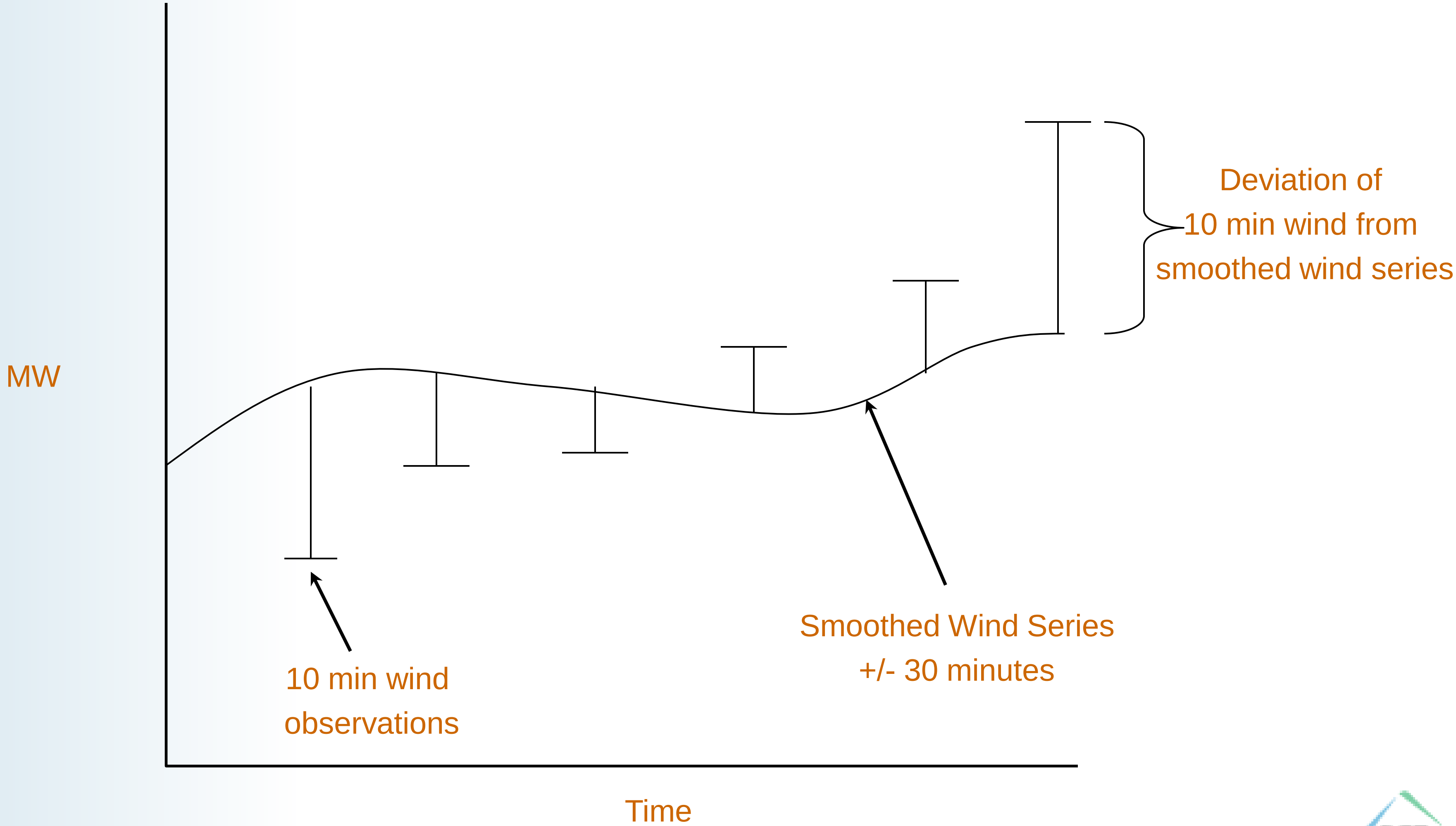
Regulation vs. Load Following

- Regulation for wind must cover fast variations and other deviations from wind trend
- LF resources will follow deviations of load net wind from hourly avg. of load net wind

Regulation

- How is the "trend" for wind uncovered?
  - Smoothing: +/-30 min rolling average of 10-minute values
  - Smoothed values correspond to "perfect" ST forecasts of the underlying wind trend
- Regulation deviations
  - 10-minute value minus wind trend (smoothed series)
  - Standard Deviation - Function of wind production level ("quadratic" approximations)

Regulation Wind



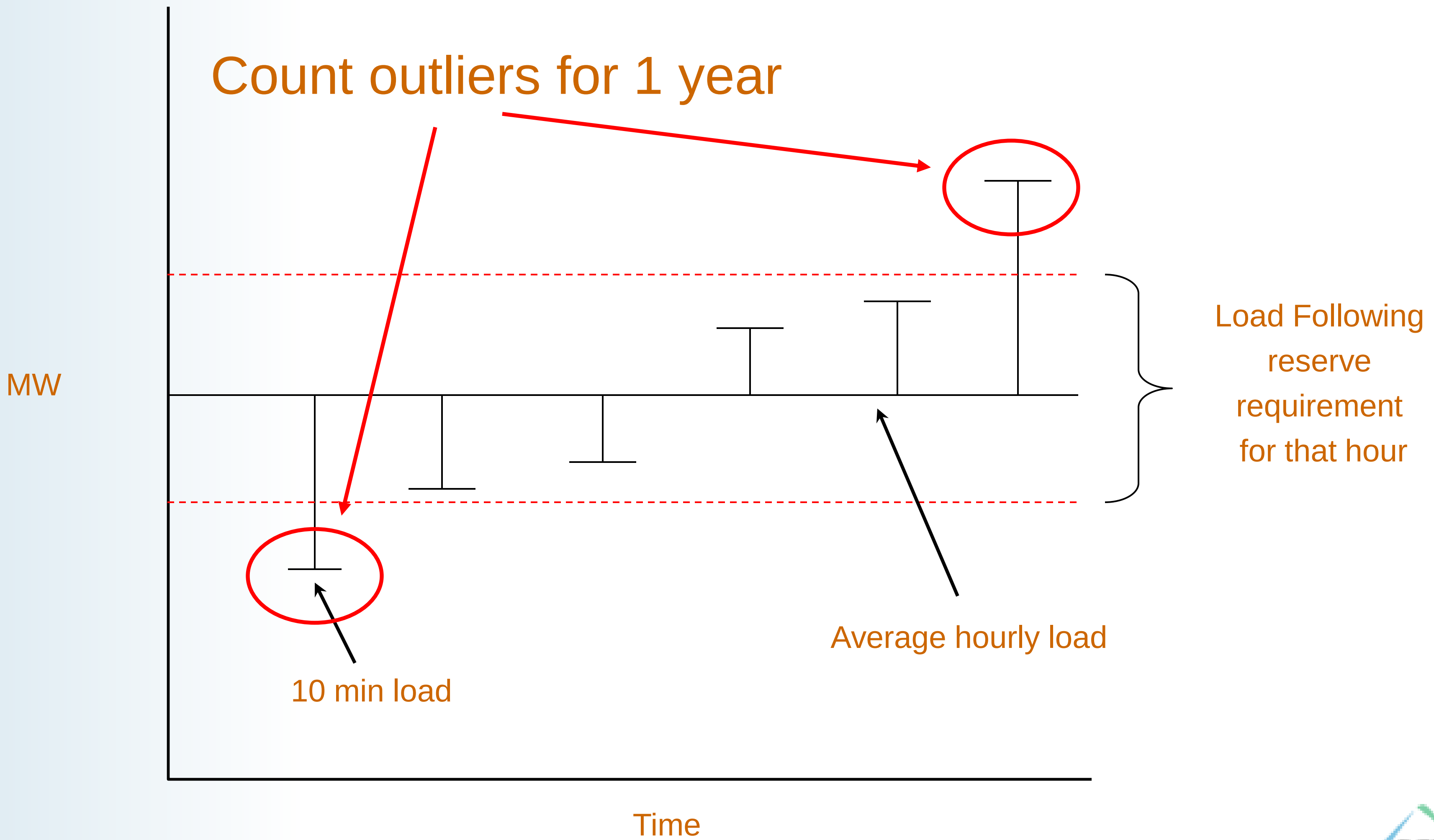
Combining Regulation Reserves for Load and Wind

$$\text{Regulation}_{\text{load and wind}} \approx Z_{\alpha} \text{ x } \sqrt{\left(\frac{1\%\text{Hourly Load}}{Z_{\alpha}}\right)^2 + \text{sigma}_{\text{wind}}{}^2}$$

Load Following "Load Only"

- Test "Load Only" case for calibration (Load Following)
  - Basic data is 10-minute average load data
  - Count number of intervals where the magnitude deviation of 10-minute load (10 min load minus hourly avg.) exceeds LF Reserves allocated for hour
  - Full year of data

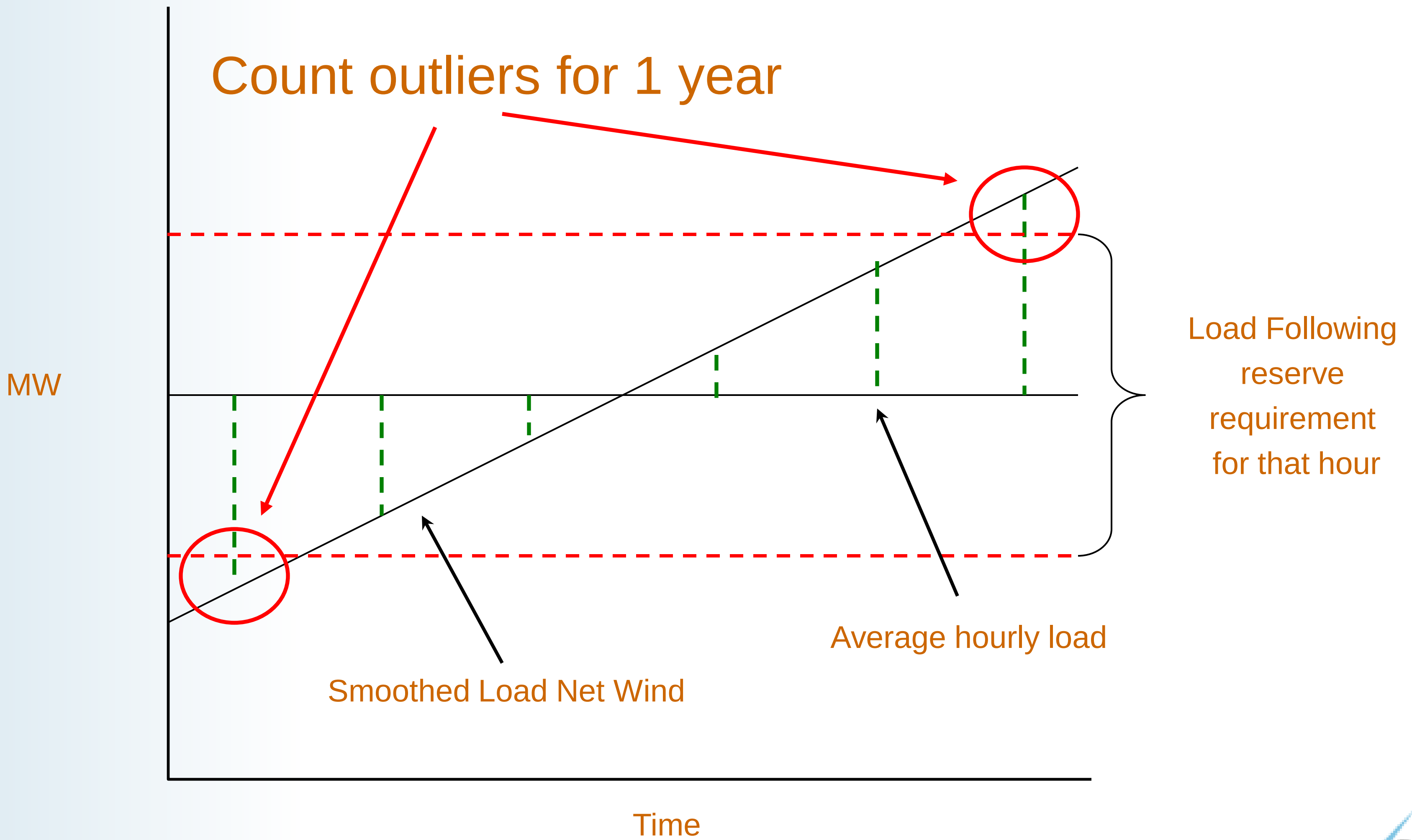
Load Following Baseline



Load Following with Wind (Short-term variability removed)

- LF must cover intra-hour movement of net load relative to hourly average
  - Load net wind = 10 min. average load (smoothed) minus 10-min. wind value (smoothed)
  - LF requirement defined as difference between net load trend (smoothed values) and hourly average (with over-hour ramp assumed)
  - Variation of wind will increase LF requirement
- Expected 10-min. wind deviation from wind trend is a function of production level
  - "Expected" defined as std. deviations
  - Calculated directly from data
  - Quadratic approximation

Load Net Wind Following: Step 1



Augmenting LF Reserve Requirements to Account for Wind

- First step: Assume no additional LF reserve
  - Count intervals where 10-min. net load deviations (from hourly average) exceed hourly LF reserve
  - If count greater than load-only case, more LF reserve needed
- Second step: Augment hourly LF
  - Use quadratic approximation for wind trend deviations (as a function of wind generation)
  - Add additional reserves (by adjusting multiplier on quadratic equation for wind trend deviations) until # of violations for "perfect in-hour forecast" case equals load only case

LF with Wind, Hour-Ahead Forecast Error

- Calculate the expected hour-ahead forecast error per PGE specified approach
  - Average of defined intervals from previous hour
  - Again, expected error a function of production level (another quadratic approximation)
- Adjust the wind each hour by the amount of the forecast error; recalculate load net wind
  - Count # of violations (load net wind minus hourly average) and compare to # of violations for perfect forecast case
  - If greater, more LF reserve needed
- Augment LF reserves for HA uncertainty
  - use quadratic approximation for wind forecast error
  - Add reserves (by adjusting multiplier on quadratic equation for HA forecast error) until # of violations = load only = perfect wind forecast

Equation Components

- Load following load only
- Load following with perfect short term wind forecast
- Load following with HA uncertainty

Three-Stage Model Runs

Day Ahead
- Pre-schedule Wind
- Pre-Schedule Load
- Pre-Schedule Regulating Margin
- Pre-Schedule Load Following for Load & Wind
- Pre-Schedule Bid-Ask Spread
- Resources: Market, Generation

Result
- Day Ahead
- Sales/Purchases in MWa
- Sales/Purchases Cost in $

Hour Ahead
- Hour Ahead Wind
- Hour Ahead Load
- Hour Ahead Regulating Margin
- Hour Ahead Load Following for Load & Wind
- Hour Ahead Uncertainty
- Real-Time Bid-Ask Spread
- Resources: Market (power, gas), Generation

Result
- Hour Ahead
- Sales/Purchases in MWa
- Sales/Purchases Cost in $

Within Hour
- Actual Wind
- Actual Load
- Actual Regulating Margin
- Actual Load Following for Load and Wind
- No Uncertainty
- Resources only: Generation, Limited Power Market, Unconstrained Gas Market

Output
- Total System Costs

Wind Integration Cost Break-Out

Model Stage / Scenarios	Day Ahead	Hour Ahead	Within Hour	Included Costs
RUN 1	**PGE Integrates All**			
Reserves	LF(W,L), RM(W,L)	LF(W,L), RM(W,L), UN(W,L)	LF(W,L), RM(W,L)	RM(L,W), LF(L,W), DA-UN(L,W), HA-UN(L,W)
Input	Pre-schedule Load and Wind Forecast	Hour Ahead Load and Wind Forecast	"Actual" load and wind	

Wind Integration Cost Break-Out

Model Stage / Scenarios	Day Ahead	Hour Ahead	Within Hour	Included Costs
RUN 4	**PGE Doesn't Integrate LF(W)**			
Reserves	LF(L), RM(L,W),	LF(L), RM(W,L), UN(W,L)	LF(L), RM(W,L)	RM(L,W), LF(L), DA-UN(L,W), HA-UN(L,W)
Input	Pre-schedule Load and Wind	Hour Ahead Load and Wind	Actual Load and Wind	

Wind Integration
Cost Break-Out

The result on row A below may not equal B+C+D

Identifier	Cost Saving For PGE	Run Delta Measures:
A	RUN 2 – RUN 1	Cost savings for HA-UN, LF, RM
B	RUN 3 – RUN 1	Cost savings for HA-UN
C	RUN 4 – RUN 1	Cost savings for LF
D	RUN 5 – RUN 1	Cost savings for RM
E	RUN 6 – RUN 1	Cost saving for DA-UN
F	RUN 7 – RUN 1	Cost saving for DA-UN, HA-UN, LF and RM (Cost of wind integration)

Next Steps

- Stakeholder comment period based upon today's presentation
  - Comments due by COB March 7, 2011
  - Send comments to Brian Kuehne (brian.kuehne@pgn.com)
- Next public Stakeholder meeting April 2011
  - Review of preliminary study results (if available)
  - Responses to stakeholder comments
- Second round of stakeholder comments based upon April meeting
  - Comments due approximately 2 weeks after stakeholder meeting
- Final stakeholder meeting (date TBD)
  - Produce final results
  - Supply written report
  - Possible comment period to follow

Questions

Wind Integration Study
External Stakeholder Meeting

May 18, 2011

Introduction

- Evolution of PGE Wind Integration Study
  - Phase 1 to Phase 2
- Currently, PGE receives integration services from third parties for Klondike II (PPA), Vancycle Ridge (PPA), and PGE's Biglow Canyon Wind Farm.
  - We do not currently self-integrate.
- As demand increases for a finite supply of BPA's hydro capacity, BPA prices are expected to rise sharply.
- Our objective is to determine PGE's costs to self-integrate wind energy.
- Preliminary results will be provided in today's meeting.

Technical Review Committee

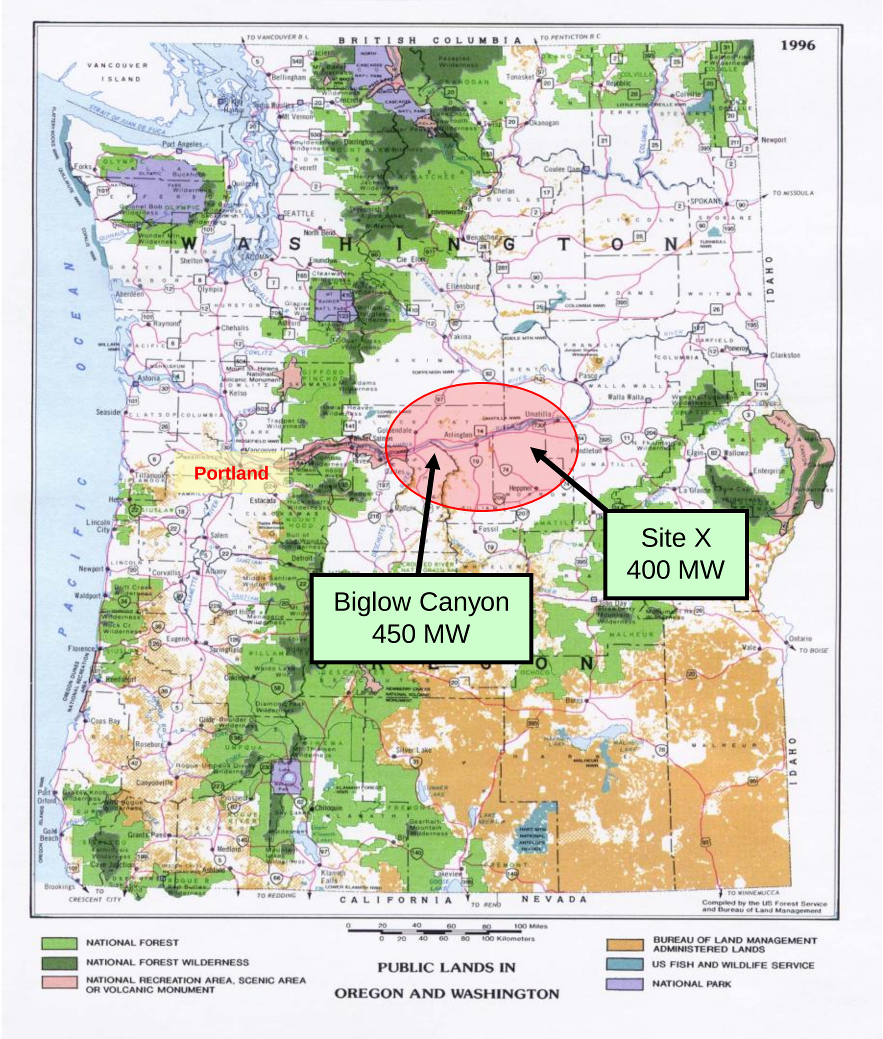
- J. Charles Smith, Executive Director
    - Utility Wind Integration Group (UWIG)
- Michael Milligan, Ph.D.
    - National Renewable Energy Laboratory (NREL)
- Brendan Kirby, P.E.
    - Consultant with NREL
- Michael Goggin, Manager of Transmission Policy
    - American Wind Energy Association (AWEA)

External Consultants

- Bob Zavadil, E.E., Executive VP of Power Systems Consulting
  - EnerNex Corporation
- Tom Mousseau, M.Ed., Principal Consultant
  - EnerNex Corporation
- Jennifer A. Hodgdon, Ph.D.
  - Poplar ProductivityWare
- Jeffrey T. Linderoth, Ph.D, Associate Professor
  - Department of Industrial & Systems Engineering
  - College of Engineering, University of Wisconsin-Madison

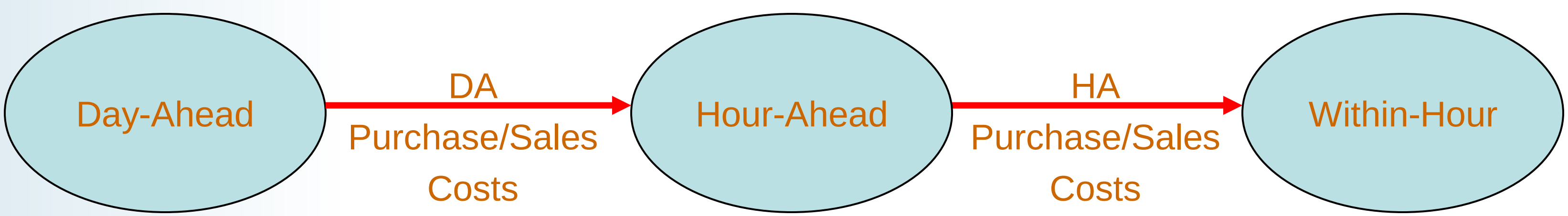
Phase 2 Project Scope and Timeline

- Determine costs of integrating wind generation into PGE system
  - Uses only current PGE generating resources (no future balancing resources)
  - Diminished Hydro Generation Capacity
  - Physical and Administrative constraints placed on balancing resources
  - Target year: 2014
  - Assumes 850 MW of wind integrated into PGE system
  - Used 2005 as the year for hydro flows, wind data, and load forecast errors
- Projected completion of Wind Study
  - Mid-Year 2011
  - Produce written report with help of EnerNex



Wind Integration Model: Stages

- One-year analysis consists of 52 one-week runs.
- Model is currently defined at a one-hour scheduling interval level.
- The model is run in three stages corresponding to:
  - Day-Ahead (DA)
  - Hour-Ahead (HA)
  - Within Hour (WH)
- Total system operating costs at the third stage are used in assessing the costs of wind integration.



Resource Assumptions

- Plants Providing Ancillary Services:
  - PGE's 2014 Share of the Mid-C.
  - Two-Thirds of Pelton and Round Butte
  - Beaver: Combined Cycle and Simple Cycle.
- Plants Not Providing Ancillary Services
  - Port Westward*
  - Coyote**
  - Boardman**
  - Colstrip**
- PGE resources are used to integrate 850 MW of wind in 2014
  - Includes self-integration of 450 MW of Biglow Canyon instead of integrating through BPA, as is current practice

*   Not designed to provide Dynamic Capacity

** Due to PGEM interpretation of BPA Dynamic Transfer Business Practice limitations

PGE's Plant Portfolio

- 850 MW in Wind Generation

	Operational Reserve	Mid-C	Round Butte **	Pelton **	Boardman	Colstrip	Port Westward	Duct Burner	Coyote	BV-SC	BV-CC	DSG
Energy		√ X	√ X	√ X	√ X	√ X	√ X	√	√ X	√ X	√	
Capacity	Load Following	√ X	√ X	√ X	X	X	X	√	X	√ X	√	
	Regulation	√ X	√ X	√ X						√ X		
	Spinning Reserve	√ X	√ X	√ X	X	X	X	√	X	√ X	√	
	Non-Spinning Reserve	√ X	√ X	√ X	X	X	X	√	X	√ X*	√	√ X

Hydro	Coal	Natural Gas	Diesel

X **2008 Study** √ 2011 Study

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

** Pelton/Round Butte dispatched at 100% in Phase 1 WIS

Reserve Components

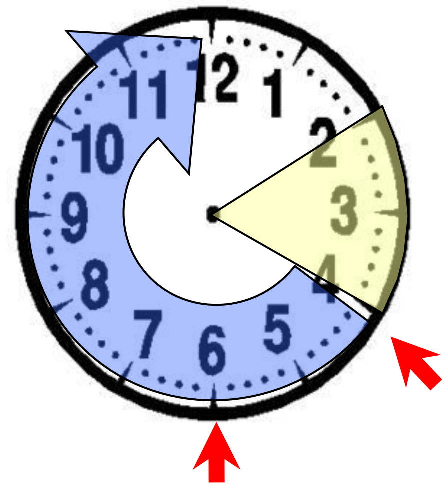
- Regulation
  - Regulation of Load and Regulation of wind are not correlated.

$$\text{Regulation}_{\text{load and wind}} \approx 3\times\sqrt{\left(\frac{1\%\text{Hourly Load}}{3}\right)^2+\text{sigma}_{\text{wind}}^2}$$

- Load following load only
  - Baseline for Load
- Load following with perfect short term wind forecast
  - Assess the incremental load following for wind.
- Load following with persistence uncertainty
  - Assess the incremental load following for persistence forecast.
  - No explicit reserves held out for Day-Ahead Uncertainty (Load or Wind)

Pre-Model Run: TRC Input

- Hour-Ahead Forecast



Schedules due for next hour

- Within-Hour Reserves
  - For Within-Hour execution, no regulation or load following is used for wind generation of 5 MWa or less; or for wind generation of 845 MWa or greater

Wind Integration Cost Break-Out

Identification	Description
RUN 1	PGE integrates Regulation, Load Following, Hour Ahead and Day Ahead Uncertainty
RUN 3	PGE doesn’t Integrate Hour Ahead- Uncertainty
RUN 4	PGE doesn’t Integrate Load Following
RUN 5	PGE doesn’t Integrate Regulation
RUN 6	PGE doesn't Integrate Day Ahead Uncertainty
RUN 7	PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty

Wind Integration Cost Break-Out (Preliminary)

The result on row A below may not equal B+C+D+E

Identifier	Cost Saving For PGE	Run Delta Measures:	Cost
A	RUN 7 – RUN 1	**Cost of Wind Integration** Cost for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation	$14.46
B	RUN 6 – RUN 1	Cost for Day-Ahead Uncertainty	$3.25
C	RUN 3 – RUN 1	Cost for Hour-Ahead Uncertainty	$5.60
D	RUN 4 – RUN 1	Cost for Load Following	$1.79
E	RUN 5 – RUN 1	Cost for Regulation	$5.30

Validating Results

- Cost Drivers
  - PGE Portfolio and Unit Dispatch
    - Limited Balancing Resources
    - High Penetration of Wind on PGE System
  - Lack of Geographic Diversity (Not quantified)
  - Bilateral vs. Organized Market
- Collaborative Discussion with TRC
  - Regulation Due to Wind

PGE's Plant Portfolio 2011 Study

- 850 MW in Wind Generation

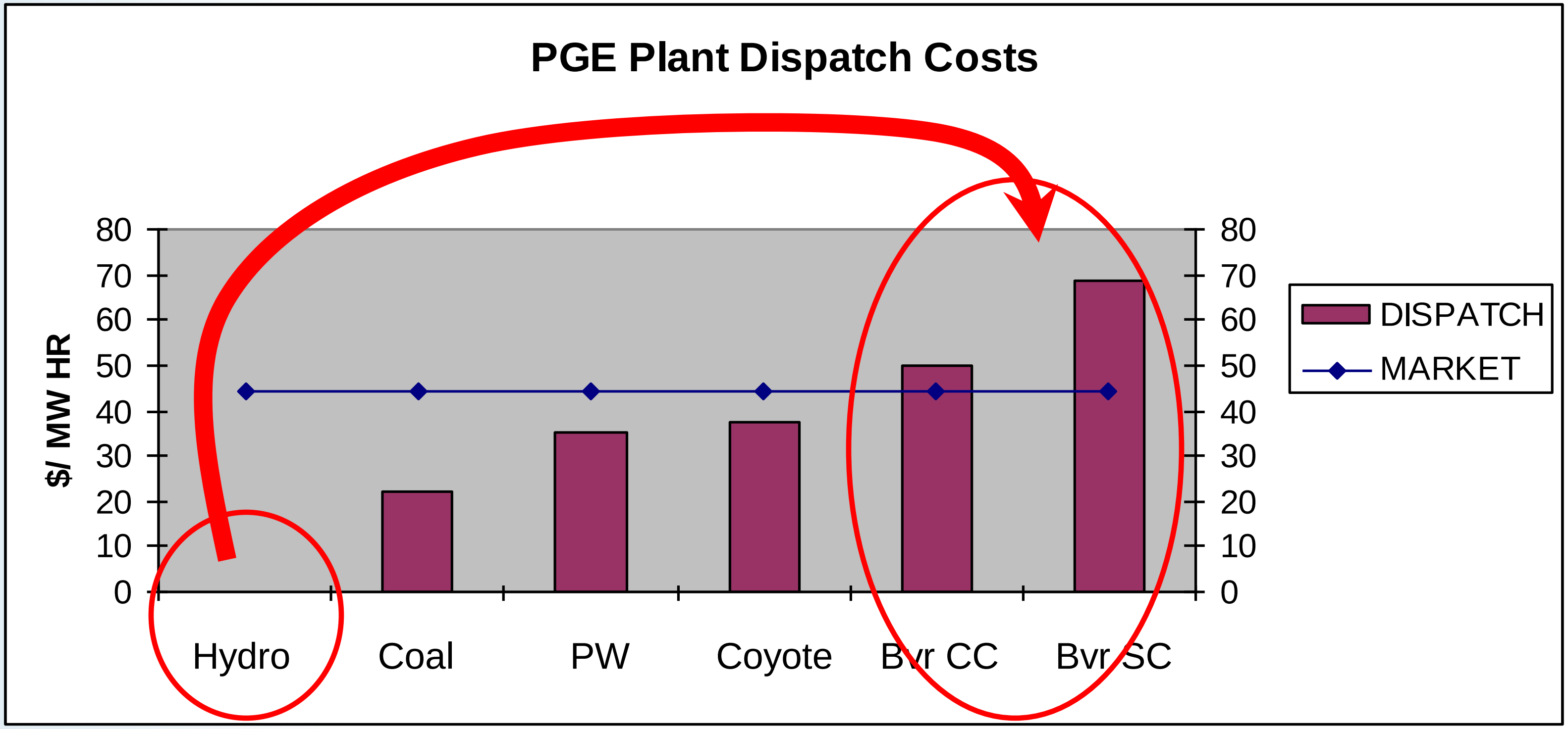
	Operational Reserve	Mid-C	Round Butte	Pelton	Boardman	Colstrip	Port Westward	Duct Burner	Coyote	BV-SC	BV-CC	DSG
Energy		√	√	√	√	√	√	√	√	√	√	
Capacity	Load Following	√	√	√				√		√	√	
	Regulation	√	√	√						√		
	Spinning Reserve	√	√	√				√		√	√	
	Non-Spinning Reserve	√	√	√				√		√ *	√	√

Hydro	Coal	Natural Gas	Diesel

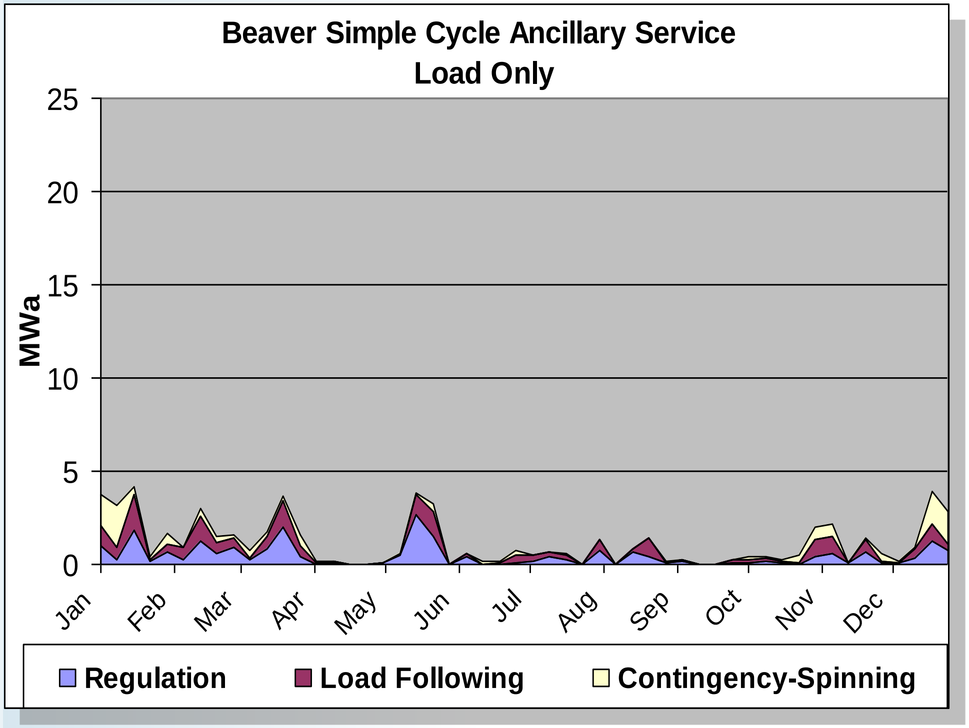
* Beaver has to be spinning to provide both spinning and non-spinning contingency reserve

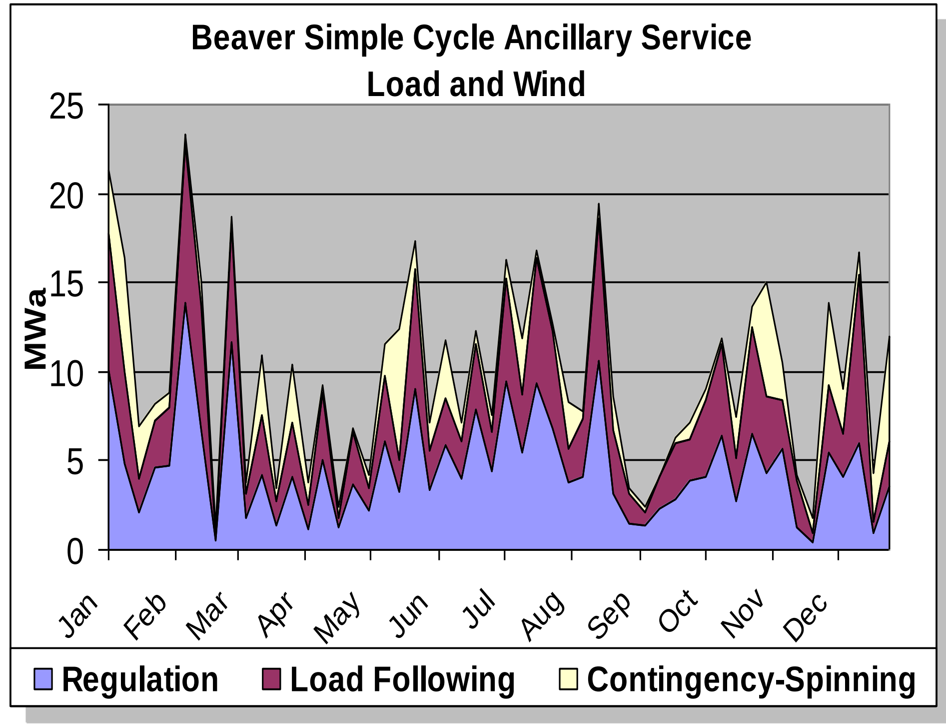
PGE Plant Dispatch

PGE Plant Dispatch at
Feb 2011 PIRA Gas Price



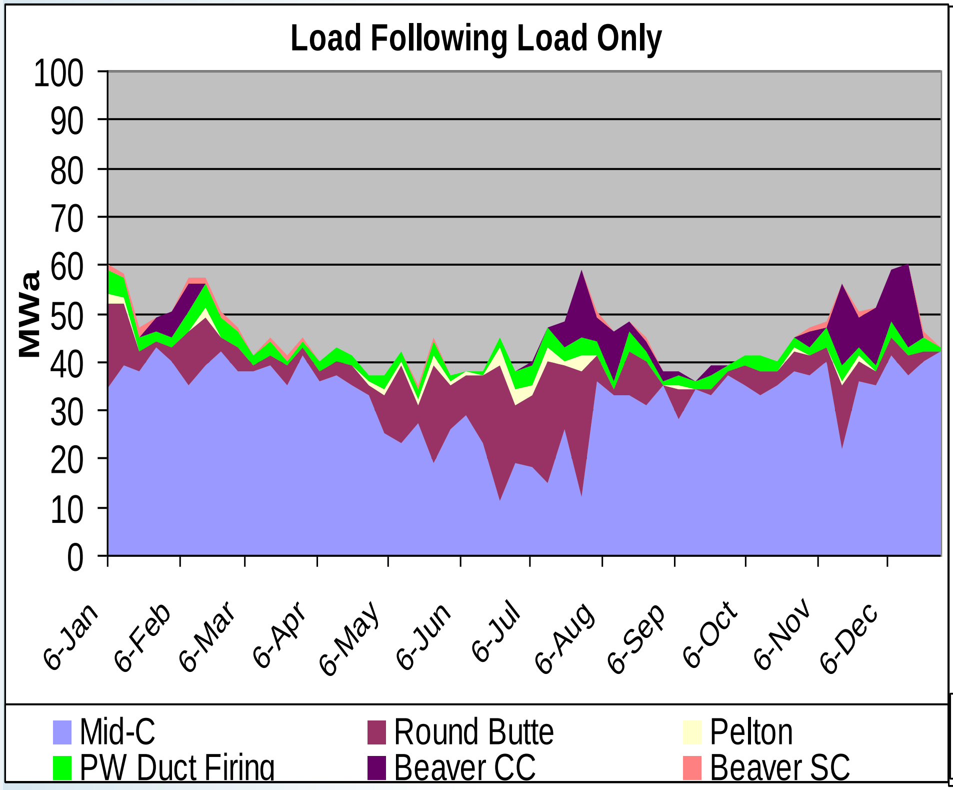
Beaver Simple Cycle Dispatch

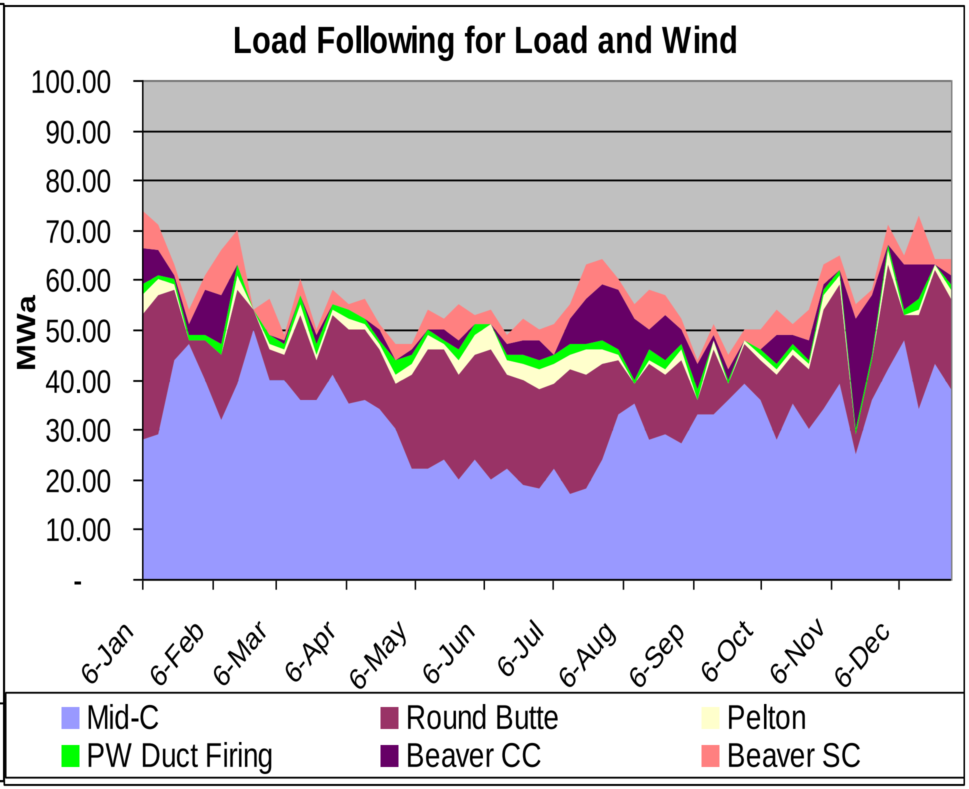




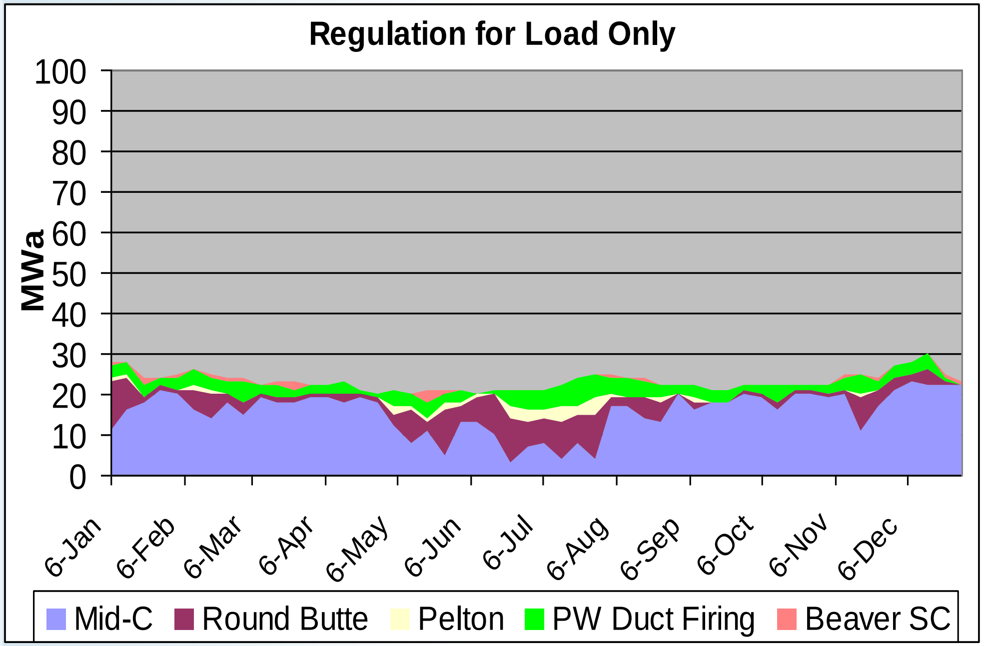
Projected 2014 Beaver dispatch for Capacity prior to new capacity actions

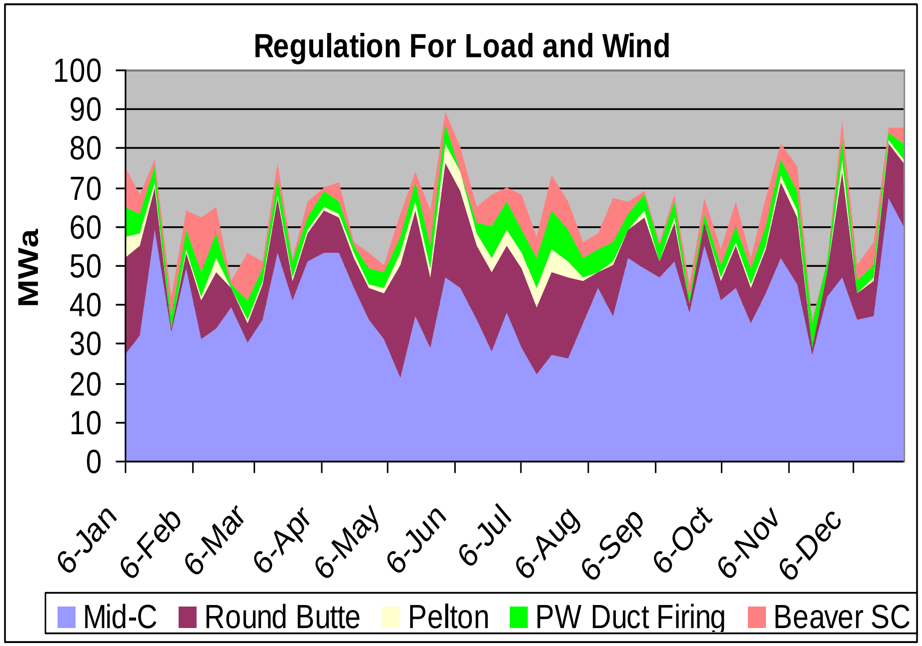
Load Following



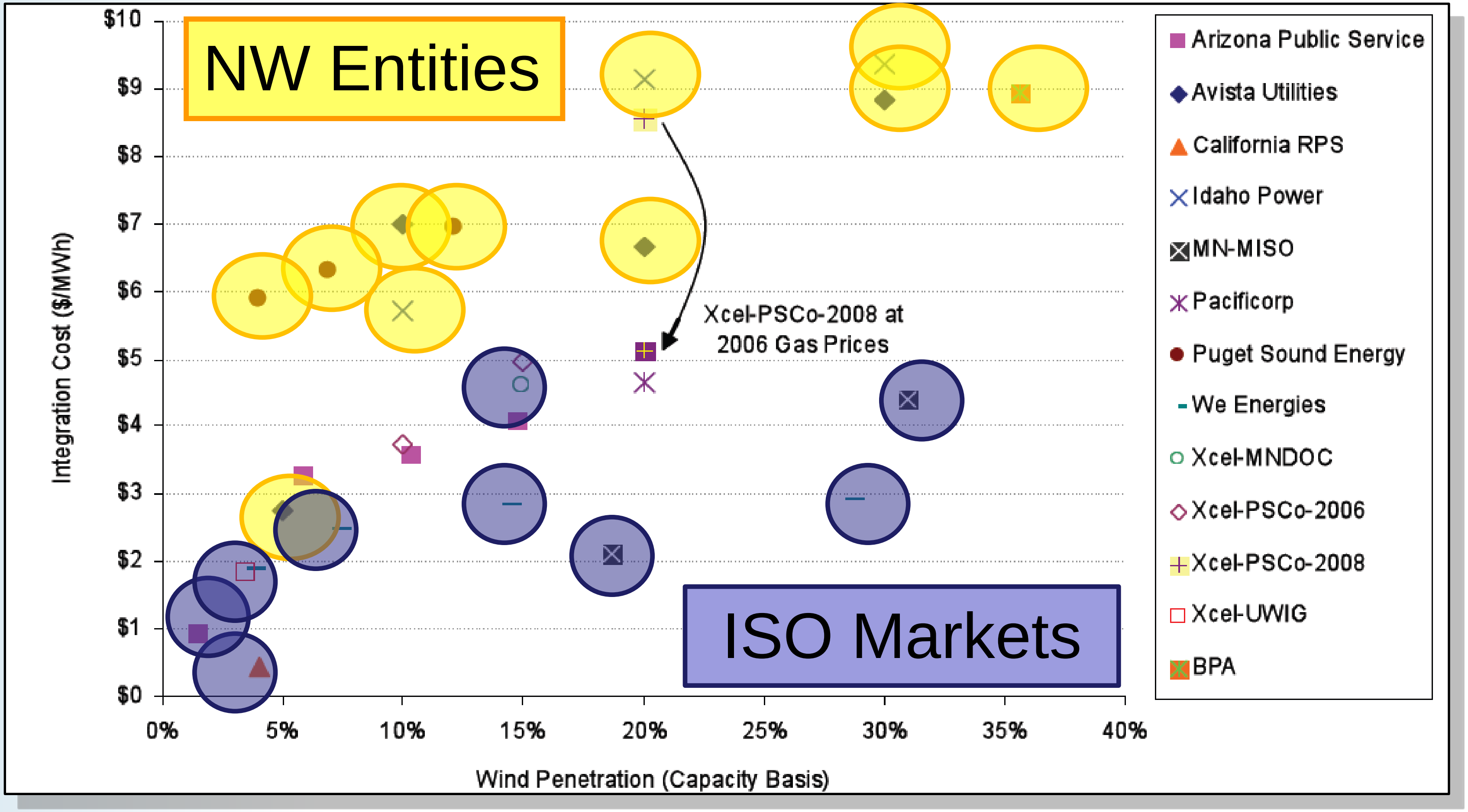


Regulation


Regulation for Load Only
MWa
100
90
80
70
60
50
40
30
20
10
0
6-Jan
6-Feb
6-Mar
6-Apr
6-May
6-Jun
6-Jul
6-Aug
6-Sep
6-Oct
6-Nov
6-Dec
Mid-C
Round Butte
Pelton
PW Duct Firing
Beaver SC


Regulation For Load and Wind
MWa
100
90
80
70
60
50
40
30
20
10
0
6-Jan
6-Feb
6-Mar
6-Apr
6-May
6-Jun
6-Jul
6-Aug
6-Sep
6-Oct
6-Nov
6-Dec
Mid-C
Round Butte
Pelton
PW Duct Firing
Beaver SC

Bilateral vs. Organized Markets



Validating Results

- Cost Drivers
  - PGE Portfolio and Unit Dispatch
    - Limited Balancing Resources
    - High Penetration of Wind on PGE System
  - Lack of Geographic Diversity (Not quantified)
  - Bilateral vs. Organized Market
- Collaborative Discussion with TRC
  - Regulation Due to Wind

Post-Model Run: TRC Input

Incremental Regulation due to Wind Generation

- TRC concerned about cost of Regulation
- Asked to review PGE's Regulation calculation and wind data
- Two Major Observations:
  - NREL Data Mesoscale (Known 3-Day seams anomaly)
  - Variability of wind data
    - Standard deviations of the deviations between the 10 minute average reading and the trend
- EnerNex is reviewing NREL wind data post power curve conversion
- TRC members researching 3Tier wind modeling methodology

Next Steps for PGE Variable Energy Resources (VER) Integration Study

- Close the loop with TRC on Regulation
- Re-run model (if necessary)
- Prepare Phase 2 Final Report
- Final Phase 2 presentation in June or July
  - Respond to Stakeholder Comments
  - Review/Discuss Phase 2 Final Report
- Begin internal discussions for future phases of VER Integration Study
  - Addition of flexible resources
  - Future Renewable Energy Standard (RES) Requirements
  - Additional sensitivity analyses
    - Natural gas prices and constraints
    - Estimate cost of transmission constraints and if necessary, model transmission constraints
    - Short-term market impact
    - Intra-hour scheduling impact
    - Water years

Questions?

Appendix

Overview

- Reserved capacity/energy constraints in PGE dispatch model
  - Regulation
  - Load Following
- Load Following constraint is broken into two components
  - Reserves required for intra-hourly movement (perfect forecast of load net wind)
  - Reserves required to account for short-term (Hour-Ahead) forecast errors

Approach

- Load and wind "decomposition"
  - Real-time variations are covered by regulation
  - Load following tracks short-term estimates of net load trend
  - Existing PGE practice establishes benchmarks for "load only" case (1% regulation, LF allocation)

Regulation vs. Load Following

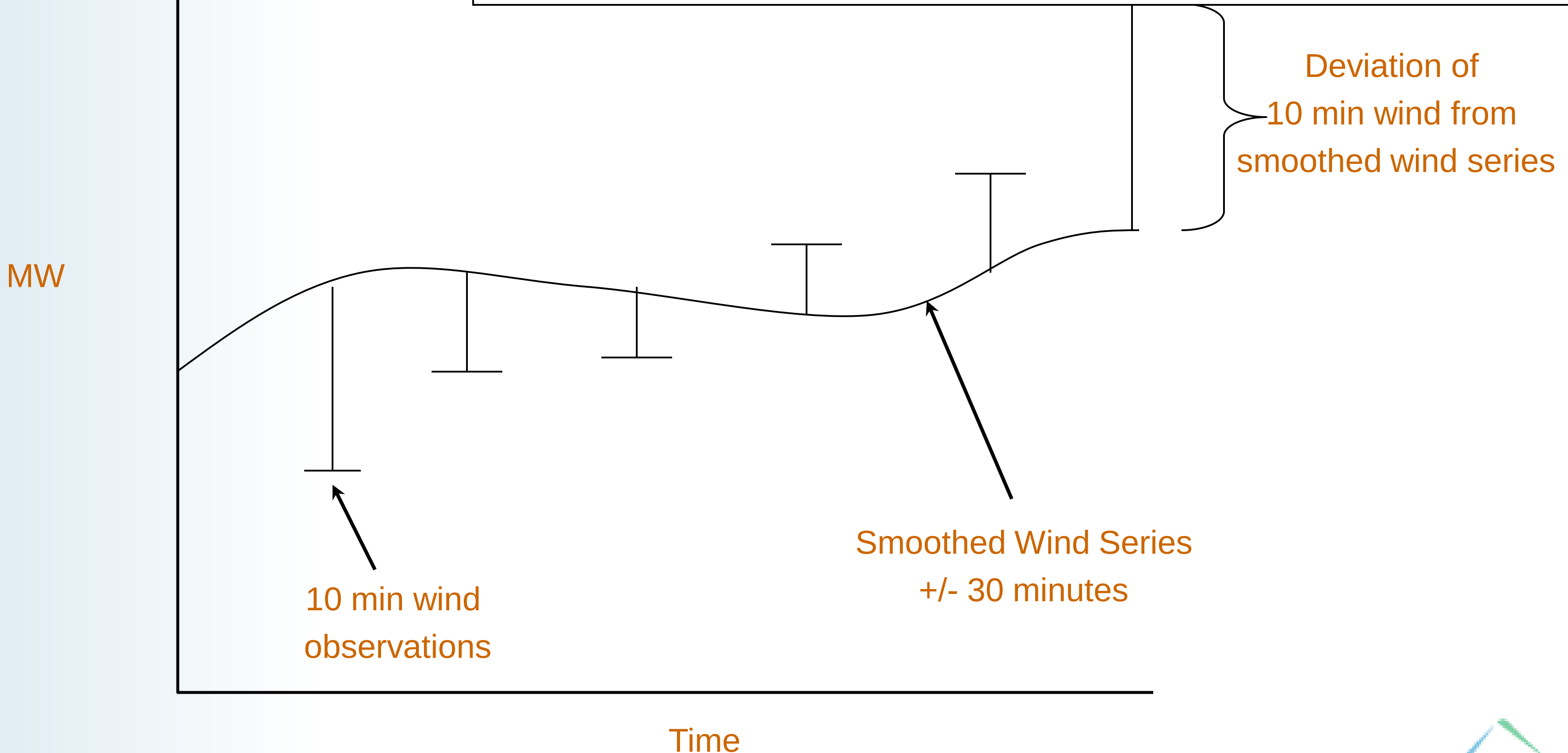
- Regulation for wind must cover fast variations and other deviations from wind trend
- LF resources will follow deviations of load net wind from hourly avg. of load net wind

Regulation

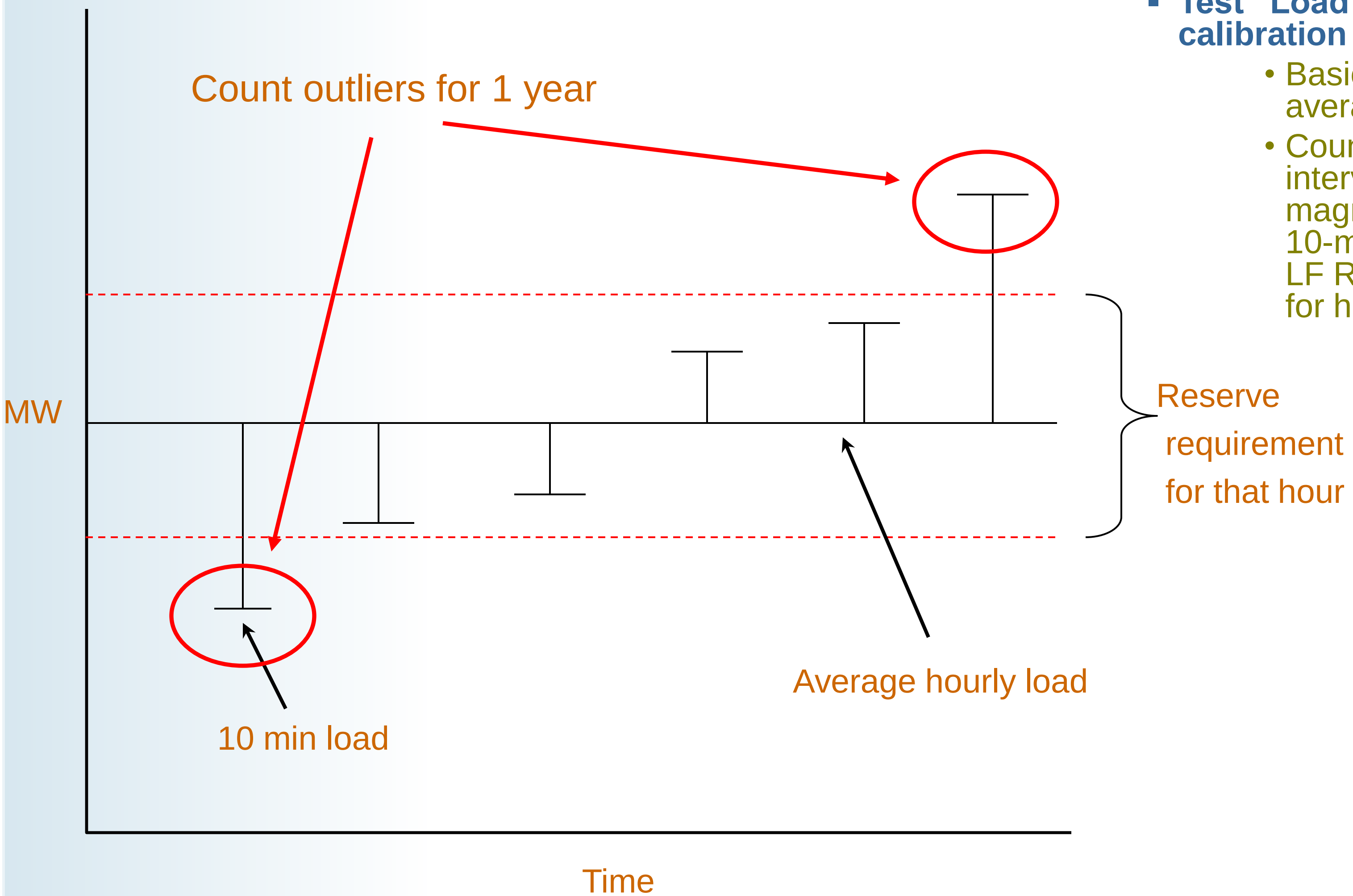
- How is the “trend” for wind uncovered?
  - Smoothing: +/-30 min rolling average of 10-minute values
  - Smoothed values correspond to “perfect” ST forecasts of the underlying wind trend
- Regulation deviations
  - 10-minute value minus wind trend (smoothed series)
  - Standard Deviation - Function of wind production level (“quadratic” approximations)

Regulation Wind

$$\text{Regulation}_{\text{load and wind}} \approx 3 \times \sqrt{\left(\frac{1\%\,\text{Hourly Load}}{3}\right)^2 + \text{sigma}_{\text{wind}}^{2}}$$

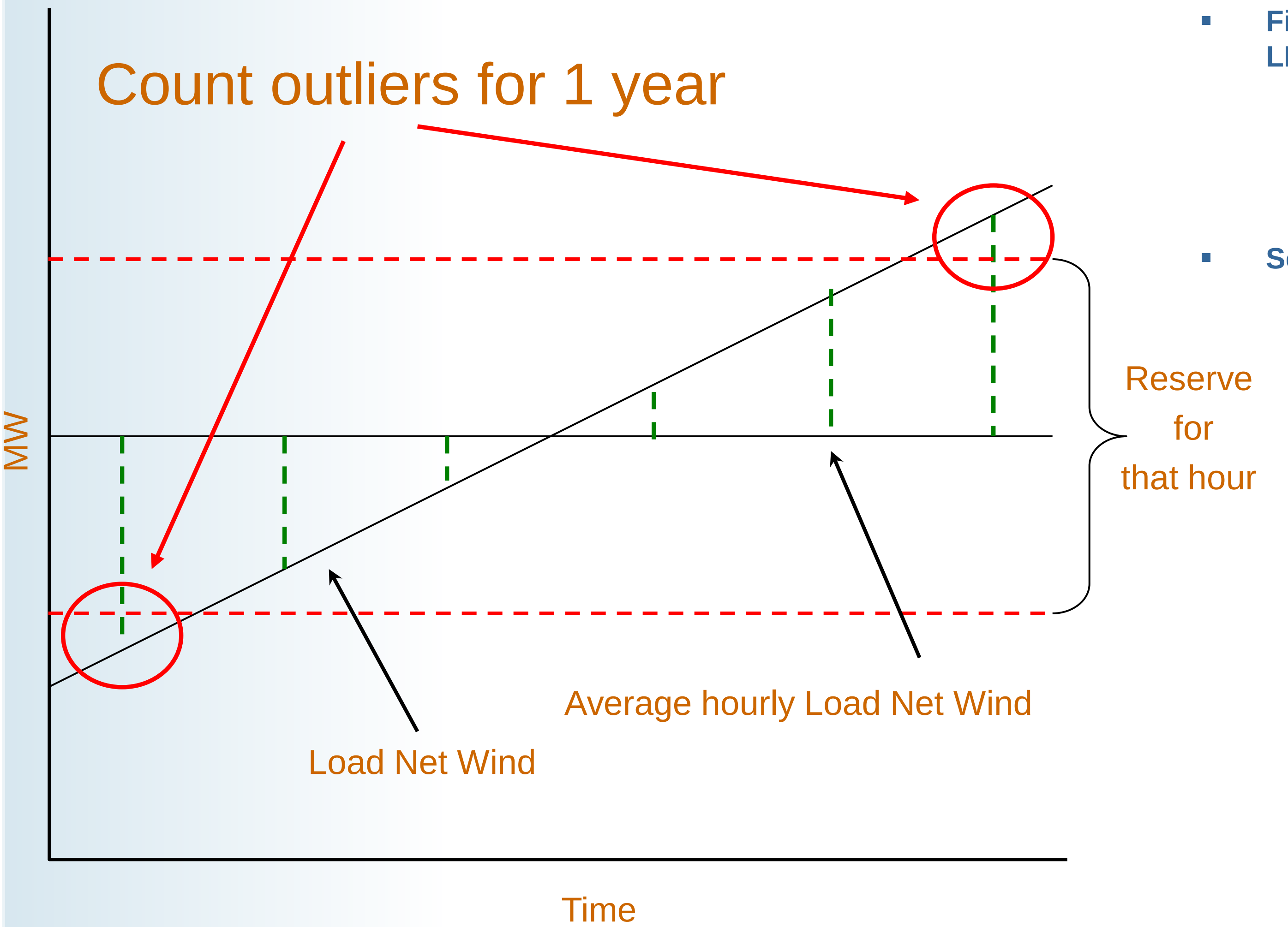


Load Following Baseline



- **Test "Load Only" case for calibration (Load Following)**
  - Basic data is 10-minute average load data
  - Count number of intervals where the magnitude deviation of 10-minute load exceeds LF Reserves allocated for hour

Load Net Wind Following: Step 1



- **First step: Assume no additional LF reserve**
  - Count intervals where 10-min. net load deviations (from hourly average) exceed hourly LF reserve
- **Second step: Augment hourly LF**
  - Use quadratic approximation for wind trend deviations (as a function of wind generation)
  - Add additional reserves (by adjusting multiplier on quadratic equation for wind trend deviations) until # of violations for "perfect in-hour forecast" case equals load only case

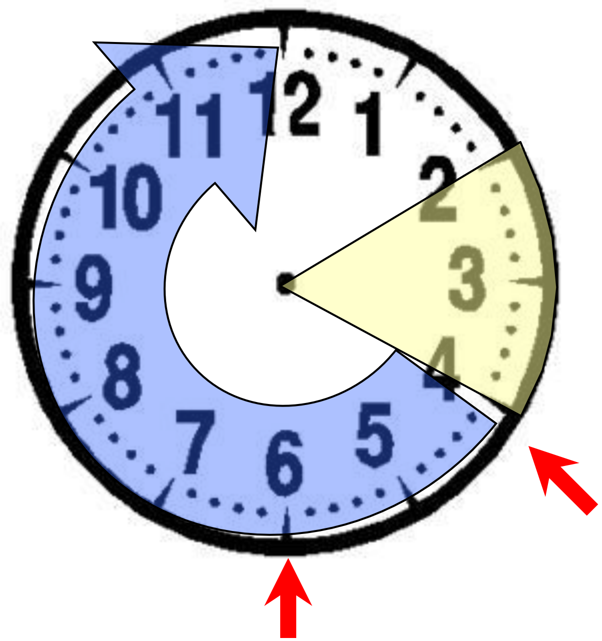
Hour-Ahead and Within-Hour Forecast Development

Hour Ahead Forecast

- NREL WWD Actual generation estimate composed of 10 minute data
- Used single data point at 00:20 to determine HA Forecast for hour 1:00
- Simulates realistic Operations for 30 minute scheduling window
  - Does not simulate 30 minute persistence

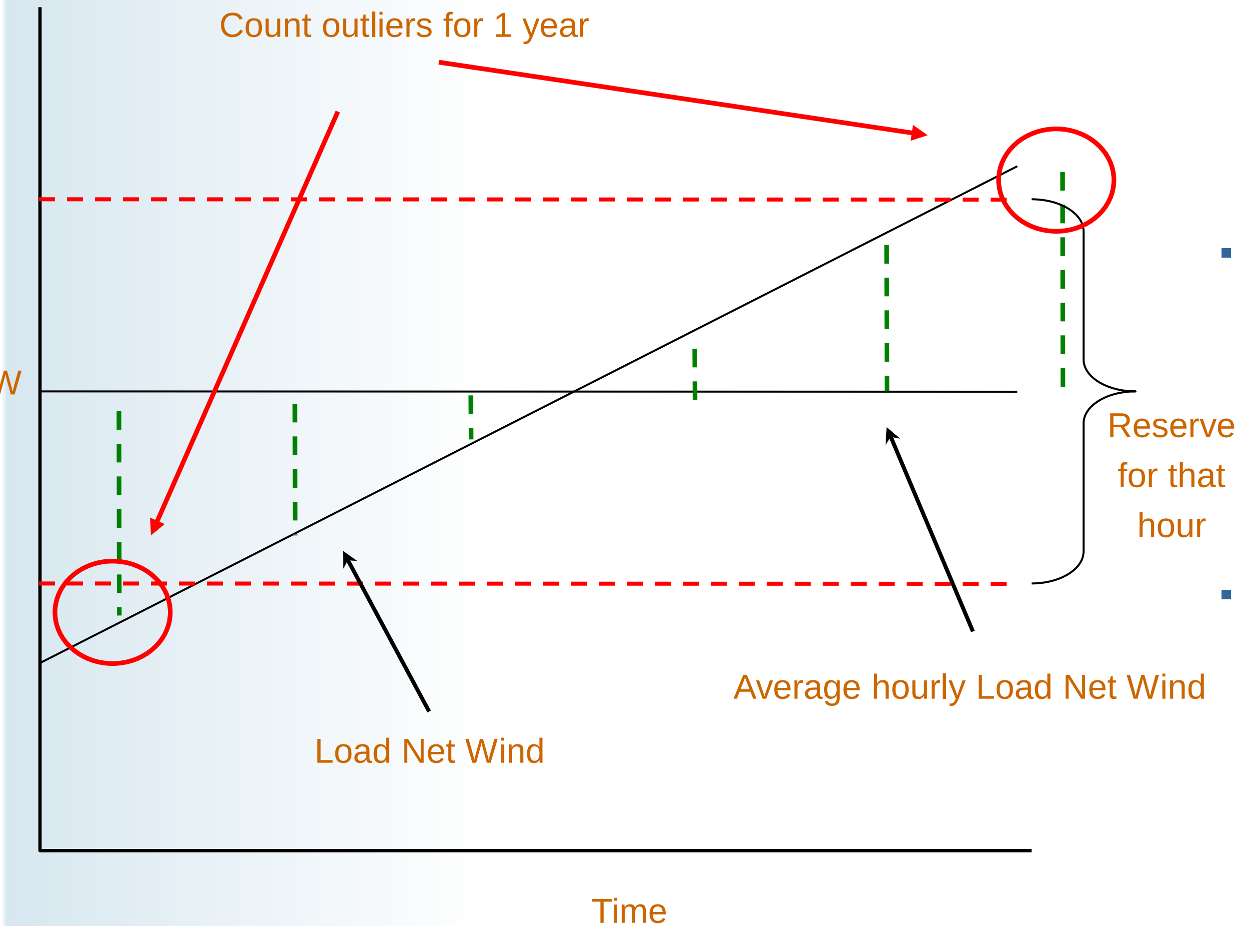
Within-Hour Forecast

- Computed from NREL WWD Actual Forecast 10 minute data



Schedules due for next hour

Load Following for Wind forecast error: Step 2



- **Calculate the expected hour-ahead forecast error per PGE specified approach**
  - Average of defined intervals from previous hour
  - Again, expected error a function of production level (another quadratic approximation)
- **Adjust the wind each hour by the amount of the forecast error; recalculate load net wind**
  - Count # of violations (load net wind minus hourly average) and compare to # of violations for perfect forecast case
  - If greater, more LF reserve needed
- **Augment LF reserves for HA uncertainty**
  - use quadratic approximation for wind forecast error
  - Add reserves (by adjusting multiplier on quadratic equation for HA forecast error) until # of violations = load only = perfect wind forecast

Wind Integration Cost Break-Out

Model Stage / Scenarios	Day Ahead	Hour Ahead	Within Hour	Included Costs
RUN 1	**PGE Integrates All**			
Reserves	LF(W,L), RM(W,L)	LF(W,L), RM(W,L), UN(W,L)	LF(W,L), RM(W,L)	RM(L,W), LF(L,W), DA-UN(L,W), HA-UN(L,W)
Input	Pre-schedule Load and Wind Forecast	Hour Ahead Load and Wind Forecast	"Actual" load and wind	
RUN 2	**PGE Integrates DA-UN (No Reserves for LF(W),RM(W),HA-UN(W))**			
Reserves	LF(L), RM(L)	LF(L), RM(L), UN(L)	LF(L), RM(L)	RM(L), LF(L), DA-UN(L,W)
Input	Pre-schedule Load and Wind	Hour Ahead Load and Wind	Actual Load and **Hour-Ahead wind**	
RUN 3	**PGE Doesn't Integrate HA-UN(W)**			
Reserves	LF(W,L), RM(W,L)	LF(W,L), RM(W,L), UN(L)	LF(W,L), RM(W,L)	RM(L,W), LF(L,W),DA-UN(L,W), HA-UN(L)
Input	Pre-schedule Load and Wind	Hour Ahead Load and Wind	Actual Load and **Hour-Ahead wind**	

Wind Integration Cost Break-Out

Model Stage / Scenarios	Day Ahead	Hour Ahead	Within Hour	Included Costs
RUN 4	**PGE Doesn't Integrate LF(W)**			
Reserves	LF(L), RM(L,W),	LF(L), RM(W,L), UN(W,L)	LF(L), RM(W,L)	RM(L,W), LF(L), DA-UN(L,W), HA-UN(L,W)
Input	Pre-schedule Load and Wind	Hour Ahead Load and Wind	Actual Load and Wind	
RUN 5	**PGE Doesn't Integrate RM(W)**			
Reserves	LF(L,W), RM(L)	LF(W,L), RM(L), UN(W,L)	LF(W,L), RM(L)	RM(L), LF(L,W), DA-UN(L,W), HA-UN(L,W)
Input	Pre-schedule Load and Wind	Hour Ahead Load and Wind	Actual Load and Wind	
RUN 6	**PGE Does Not Integrate DA-UN(W)**			
Reserves	LF(L,W), RM(L,W)	LF(L,W), RM(L,W), UN(L,W)	LF(L,W), RM(L,W)	RM(L,W), LF(L,W), HA-UN(L,W)
Input	Pre-Schedule Load and Hour-Ahead Wind	Hour-Ahead Load and Wind	Actual Load and Wind	
RUN 7	**PGE Does Not Integrate LF(W),RM(W),HA-UN(W) and DA-UN(W)**			
Reserves	LF(L), RM(L)	LF(L), RM(L), UN(L)	LF(L), RM(L)	RM(L), LF(L), DA-UN(L),HA-UN(L)
Input	Pre-Schedule Load and Actual-Wind	Hour-Ahead Load and Actual Wind	Actual Load and Wind	

Wind Integration Final Report

Report Submitted By:

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Submitted To:

Portland General Electric
Wind Integration Team

June 2011

LUNDQUIST
COLLEGE OF
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Portland General Electric

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Executive Summary

To satisfy its Renewable Energy Standard (RES) goals, Portland General Electric (PGE) must meet increasing levels of load with Variable Energy Resources, which will primarily come from wind power production. Integrating large amounts of wind power into a utility's system operations, due to wind's variability and uncertainty, presents a number of significant challenges to PGE. For this reason, a thorough study of wind integration should be conducted, including detailed cost breakdowns and system modeling with added wind generation. An in-depth wind integration study will allow PGE to mitigate its risks by understanding integration costs and employing modeling strategies to minimize such costs. A wind integration model should be dynamic, flexible, and capable of reacting to market and technological changes. Additionally, this process will help PGE drive strategic decision making processes regarding long-term generation and transmission planning.

The University of Oregon MBA team researched all prominent utility and ISO-scale Wind Integration Studies (WIS) to date, focusing primarily on those studies most relevant to PGE's unique operating environment. The goals of this effort were to synthesize existing methodologies, to identify emerging trends in modeling techniques, and to highlight general best practices. The outcome of this research was presented in March of 2011 as the team's "Wind Integration Interim Report."

The overall goals of the team's project were to research existing wind integration practices, to validate the efforts of PGE's internal wind team, led by Ty Bettis, and to offer suggestions to this team for future modeling phases. Additionally, the MBA team analyzed long-term, externally-driven market and technological shifts that could dramatically impact a utility's wind integration initiatives. This final report will break the MBA team's efforts down into the following sections:

- **Wind Integration Overview and Best Practices**
  - Within-Hour Variability: Regulation and Load Following
  - Hour-Ahead and Day-Ahead Forecast Error
- **Future Phases**
  - Access: Transmission and BA Coordination
  - Flexibility: Flexible Generation and Market Flexibility
- **Long Term Considerations Impacting Wind Integration**
  - Demand Response
  - Energy Storage
  - Solar Generation

Through its research and analysis efforts, the MBA team recommends that PGE's future study phases include greater sensitivity analyses, specifically around natural gas pricing, the addition of flexible resources and access to both transmission and more dynamic market structures. Additionally, extensive cost/benefit analyses will need to be conducted as long-term solutions become viable options.

As a whole, the process of integrating large penetrations of wind power into a utility structure is continually evolving. PGE must ensure that its operational model remains highly flexible (a living model), and the utility must continually strive to learn from evolving best practices to meet its long-term integration goals.

Introduction

Purpose

Under the Oregon Renewable Energy Standard (RES), Portland General Electric (PGE) has been charged with the task of increasing its Variable Energy Resources (VER). The RES requires 15% of PGE's load to be served by qualifying VERs by 2015, 20% by 2020, and 25% by 2025. The primary VER that PGE is incorporating into its system is wind energy. Due to the variability and uncertainty of wind's generation capabilities, the integration of wind can cost more than traditional, dispatchable generation.

For ratemaking purposes, utilities must determine an annual generation forecast for their VER generation. While this forecast may initially be based upon estimates derived from on-site meteorological towers, PGE would like to augment and refine its annual forecasts by identifying and implementing best practices used in other WIS.

Task

This report represents the culmination of the University of Oregon MBA team's efforts while working for PGE's internal wind team. It has been compiled to provide PGE with a thorough understanding of the evolution of WIS to date (a reiteration of the team's Interim Report) as well as to provide PGE with strategic recommendations regarding future study phases and long-term market trends. Specifically, this analysis will recap the various methodologies and best practices that have emerged from a review of all prominent WIS, address PGE's unique operating environment, and offer recommendations around access and flexibility modeling in future study phases and assess externally-driven market and technological shifts that will greatly affect utility wind integration.

Report Contents and Roadmap

The MBA team presented its "Interim Report" in March of 2011, which was a general synthesis of all prominent utility and ISO-scale WIS conducted to date. This report highlighted common methodologies, best practices, and specific takeaways for PGE's own study methodologies going forward. This final report will provide a condensed version of this report, only highlighting specific areas of importance, as well as focus on recommendations for future study phases and long-term considerations. As such, the order of this report will appear as follows:

1) **Wind Integration Overview and Best Practices**
    a. Within-Hour Variability: Regulation and Load Following
    b. Hour-Ahead and Day-Ahead Forecast Error
2) **Future Phases**
    a. Access: Transmission and BA Coordination
    b. Flexibility: Flexible Generation and Market Flexibility
3) **Long Term Considerations Impacting Wind Integration**
    a. Demand Response
    b. Energy Storage
    c. Solar Generation
4) **Conclusion: Elements of an Ideal Wind Integration Study**

Within-Hour Variability: Regulation and Load Following

Introduction

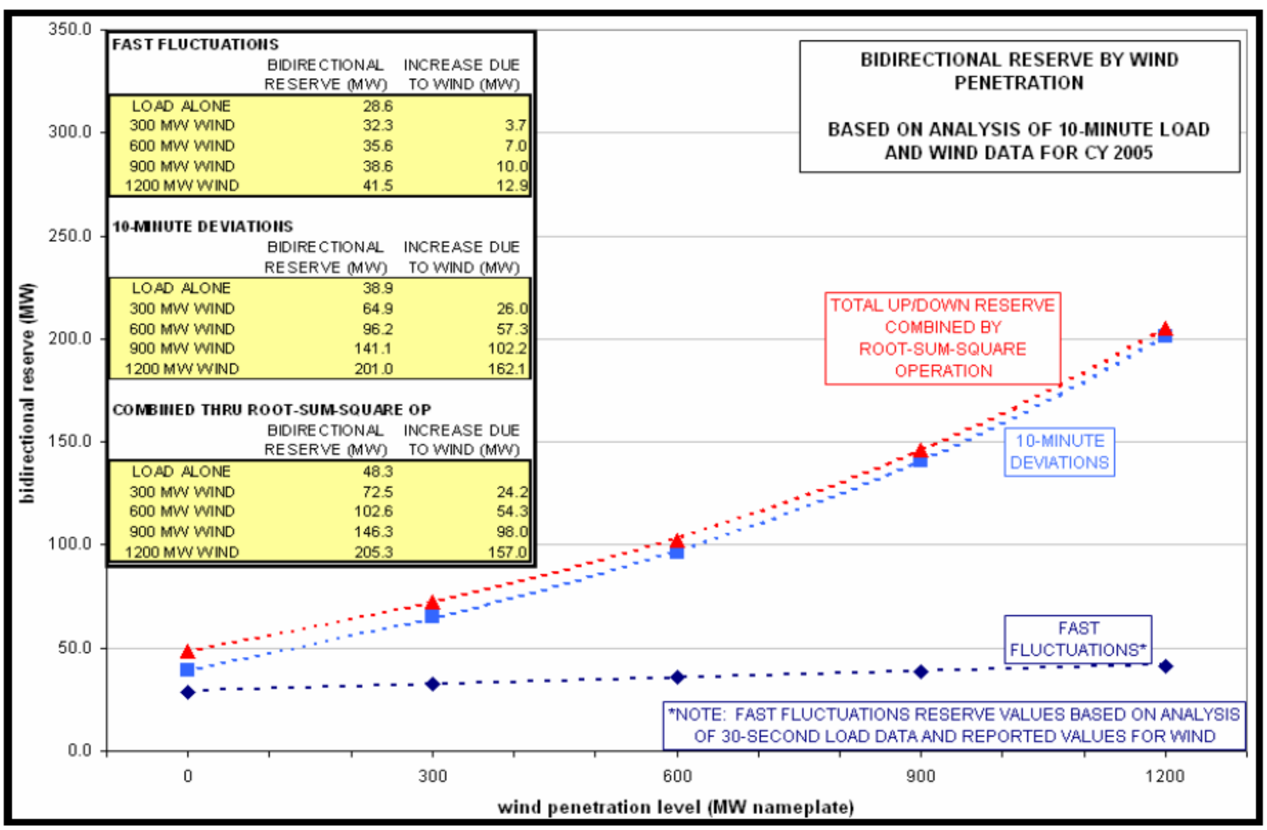
A significant portion of the total wind integration cost stems from variability within the hour, which can be further broken down into a regulation requirement and a load following requirement. These ancillary services are required to match the short and longer-term variability of load (i.e., instantaneous fluctuations in load as well as the overall trend). Wind generation exhibits similar variability characteristic—although uncorrelated—to load in this timeframe. For this reason, these ancillary services can be employed to regulate wind as well as load.

Separating regulation and load following into separate silos can be misleading. As shown in **Figure 1**, regulation and load following tend to overlap, meaning that the reserve requirement for regulation summed with the reserve requirement for load following will be more than the actual requirement for both services combined.

The combined requirement is determined using the root-sum square formula: [1]

$$RSRV_{tot}^{2} = (RSRV_{ff}^{2} + RSRV_{10min}^{2})^{0.5}$$

Figure 1: Required bi-directional reserve versus wind penetration - based on 2005 Idaho Power's system load and wind data



[1] Idaho WIS, p. 42-43

For all cases ranging from load alone to 1200 MW of installed wind, the fast fluctuations (regulation) and the 10-minute deviations (load following) sum to more than the reserve amount for the combined thru root-sum square op.

Regulation and load following are frequently provided by the same reserve generator. In the Northwest, the reserve generation is typically hydropower, given the wide range of ramping capability and relative operational efficiency at low generation levels. For this reason, regulation and load following may not be separated in some studies. Even in cases where hydro does not provide the reserve capacity, such as in the Arizona Study, regulation and load following may still be aggregated.

Because in practice regulation and load following are sometimes indistinguishable from one another (which will be discussed further in the following sections), some WIS authors decide that modeling the two as distinct is arbitrary or inaccurate. However, for the purposes of this report, regulation and load following will be assessed individually because the majority of prominent wind studies also assess the two services separately (recognizing that the two services have considerable overlap with one another).

The following sections will address within-hour variability in greater detail. Specifically, definitions for regulation and load following will be provided (as defined by both NERC and various utilities). Additionally, common WIS practices to calculate both regulation and load-following components with the introduction of wind power, as well as costs for these services, will be analyzed. Finally, this section of the report will conclude with a broad overview of best practices employed by utilities when calculating these components.

Regulation

Introduction and Definition

According to the NERC glossary of terms, regulating reserve is defined as “an amount of reserve that is responsive to AGC, which is sufficient to provide normal regulating margin.”[2] In general, this ancillary service is intended to be responsive to the fastest fluctuations in load—i.e. minute-to-minute “noise” in the overall load versus an underlying trend that is typically covered by the load-following service. The units on AGC assigned to regulation will adjust generation to cover these quick fluctuations and hold system frequency in balance.

Every WIS takes the regulating reserve component into consideration. With the addition of wind power into a control area, an increased amount of variability is introduced into the system. It is therefore critical for system operators to set aside additional reserve capacity to compensate for this variability. Utilities are required to meet NERC control standards and cover the majority of these fluctuations with capacity assigned to regulation, which will add greater operating costs to utilities as their wind penetration levels increase over time.

As stated in the Minnesota WIS, “the temporal boundary between load variations that require regulation service for compensation and those that would be considered as actual load trends is subjective.”[3] Therefore, it is important for utilities to specify a boundary where fluctuations in load are roughly

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[2] EWITS/www.nerc.com/files/Glossary

[3] Minnesota WIS, pp. 78-79

symmetrical around the underlying trend to accurately identify the fastest fluctuations. This defines regulation, where the net energy delivered over a certain period is zero and only capacity is affected.

The specific resource used to provide regulation service varies from region to region. For example, in the Pacific Northwest regulation is provided primarily by flexible hydro resources,[4] whereas in other parts of the country coal-fired units provide most regulation.[5] The use of differing resources to provide this service plays a key role in calculating the overall effects wind generation will have on regulation—production costs and market prices fluctuate considerably from year-to-year, and some sensitivity must be considered to account for these changes.

Objective

The primary goal of the regulating reserve component of nearly all Wind Integration Studies is to analyze the effect(s) that increased levels of wind penetration will have on regulating margin. As the Idaho Power WIS states, regulation's objective is "to estimate the additional flexibility needed to integrate wind integration without experiencing a decline in system reliability and regulatory compliance."[6] This is broadly done via a two-step process:

1. Calculating the additional amount of reserve requirements at each wind penetration level (MW of capacity) through a statistical process and

2. Assigning a cost to the increased regulation component that will be a component of the overall "wind integration cost."

The cost associated with an increased regulating requirement due to wind is often calculated as an opportunity cost that represents the need to hold capacity for regulation versus producing useful energy that could be sold on the open market. In making this calculation, a utility must carefully consider the production cost and selling price of this held capacity as well as the capacity factor of the wind plants when calculating the cost of incremental regulation due to wind.

Results

For lower penetration levels, the amount of incremental regulation requirement due to wind is almost negligible—3.7 MW for 300MW additional wind in Idaho, 2.46 MW for 500MW additional wind in Colorado.[7] As wind penetration levels increase in all cases, so do incremental requirements, but these increases are still quite modest under current assumptions. For example, in the Idaho WIS, for the largest wind scenario of 1200 MW, the increase in regulation due to wind came to 12.9MW.[8] In the Minnesota study, an additional 1500 MW of wind resulted in an additional 7.8 MW of regulating reserve capacity.[9] However, when regulation is added with other within-hour variability components, such as load following and forecast error, the capacity requirements increase more drastically. Thus, it is important to avoid viewing regulation in isolation.

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[4] Idaho WIS
[5] Minnesota WIS
[6] Idaho WIS, p. 47
[7] Idaho WIS, p. 40, Colorado WIS p. 59
[8] Idaho WIS, p. 40
[9] Minnesota WIS, p. 89

Regulation Cost Calculations

Some WIS explicitly assign a cost to the incremental regulation piece alone, while others treat the required capacity as an input into the model used by the utility to optimize its system and calculate a total wind integration cost. For example, Minnesota calculates its incremental regulation cost as an opportunity cost, which is the amount of incremental reserve (depending on the penetration level) multiplied by a market-driven profit margin assigned to that held capacity. Similarly, Colorado calculates it using a "marginal capacity" cost of $63.62/kW-year multiplied by the amount of capacity held for regulation.[10] Idaho, on the other hand, calculates the reserve capacity but uses this as an input into its overall integration cost model.

Because there are numerous moving parts in calculating a cost for one particular piece of wind integration, the final number calculated by a utility is not as important as the process by which this amount is obtained.

Challenges

The primary challenges in synthesizing an accurate incremental regulation requirement due to wind relate to the accuracy of data, how the utility defines regulation, how it separates this component from load following, and what assumptions are made regarding costs. The resolution of data used to construct the wind penetration levels is a critical component in calculating the standard deviation of wind variability fluctuations. However, current practice is limited to the data available; as wind integration studies progress, historic data resolution will inevitably improve. Additionally, many studies are criticized in the technical review process (i.e. PacifiCorp by Michael Milligan) due to the fact that regulation and load following overlap and double counting of cost components results. Thus, it is imperative that if these two components are to be separated that they are accurately separated.

However, in the Northwest, it is common for utilities to combine regulation and load following in their WIS. The logic behind this tactic, as sumarized in Idaho's WIS,can be attributed to "the prevalence in hydroelectric generation in supply portfolios" and the fact that regulation and load following reserves are "generally provided by the same hydroelectric units."[11] As such, Idaho separates its "regulation" piece into 2 parts: analysis of high resolution load and wind data (the process described earlier) and analysis of 10-minute load and wind data to estimate additional reserves needed to accommodate wind on the 10-minute step. This second component considers fluctuations on a longer time-scale than most regulation studies, and the distinction between regulation—as it is commonly defined—and load following is not as well defined.

As for cost assumptions, the way in which a utility accounts for costs, especially market energy prices, heavily influences the overarching goal of a WIS, which is to calculate the total cost to integrate wind. Especially in the Northwest, where energy prices and thus wind integration costs are heavily dependent on hydro conditions, the way in which a utility forecasts energy prices when looking to implement more wind resources is critical. To again use the Idaho WIS as an example (and this is also true for other wind integration studies), it is not assumed that adding additional wind would influence market prices. Idaho even acknowledges that as utilities in the same balancing areas add greater amounts of wind power, market prices will almost certainly be affected. The same can be said for load forecasts, especially when

[10] Colorado WIS, p. 77
[11] Idaho WIS, p. 58

forecasting over long time horizons. Greater ramp rates with increased load, and lower seasonal hydro capacity, could have large influence over wind integration costs that are difficult to predict.

Load Following

Introduction and Definition

The longer-term component of within hour variability is commonly referred to as load following. Traditionally, load following is an ancillary service which tracks the demand trend as it rises during the morning, levels out in the middle of the day, rises again in the evening, and drops off at night. This daily load pattern is quite predictable and can be forecasted accurately. When wind is added to the generation system, the load following service is used to track the load net wind trend. The wind trend is less predictable than the load trend, adding significant complexity to a utility's or balancing authority's load following requirement.

Load following is not formally defined in the NERC Glossary.[12] However, there appears to be general consensus in the industry that load following refers to the adjustment of generation to compensate for the trend of load over time periods ranging from a few minutes to several hours.

This section will identify and discuss the methodologies used in various WIS to determine the reserve requirements and costs for integrating variable wind power on the time scale of several minutes to an hour or more.

The definition of load following also varies between studies. The Idaho Study defines load following broadly as "the increasing or decreasing of generation using AGC, non-AGC units, and units identified as contingency reserves in response to system load".[13] BPA delineates between load following and "wind following," or the incremental following requirement attributable to wind's variability. Following reserve is generally defined as the spinning and non-spinning reserve capacity needed to meet within-hour differences between actual load and generation and forecast load and generation. The wind component of the following reserve is defined as "the difference minute-by-minute between the 10-minute clock average of the load net wind dataset and the associated perfect schedule".[14]

The consensus seems to be that load following reserves dispatch in response to changes in load trend, in contrast to regulating reserves, which respond to random fluctuations in load. Load following is also distinct from regulation in terms of timescale. Whereas load following operates generally in 5-10 minute increments, regulation responds to fluctuations that occur in the span of seconds. Some wind studies tend to focus on the type of generation control used to meet the load following requirement (i.e. AGC, spinning/non-spinning, etc) while others place greater emphasis on the timescale (usually a few minutes up to an hour).

Objective

WIS generally attempt to identify the incremental reserve requirement and cost associated with adding wind generation to a utility's generation portfolio. This additional requirement becomes part of the

[12] North American Electric Reliability Corporation
[13] Idaho Power WIS
[14] 2010 BPA Rate Case. Generation Inputs Study. July 2009. P. 7

ratemaking case before the regulator. Selecting the appropriate methodology for accurately estimating the wind component of load following, or “wind following,” is important when presenting an effective rate case and in understanding the interaction of wind power with the power system as a whole.

Although the same generation units frequently provide both regulation and load following, the two services are distinct. Differentiation between these two services permits the integrator to understand what portion of the reserve requirement is attributable to random, short-term variability in wind output as opposed to longer-term trends.

The ultimate objective of studying wind is not only to identify, but also to determine ways to minimize the cost of wind’s integration. A thorough understanding of the cost drivers of wind following service will inform more effective wind power integration in the future.

Results

Depending on the study, the requirements for load following range from the smallest to the largest of wind integration’s four cost components.

Since the definition of load following differs significantly between studies, results are largely incomparable. Inconsistency is found in:

- Operating Reserve Resource: Most utilities in the Northwest use hydro power plants to provide load following service. Other utilities use natural gas or coal-fired plants.
- Time Period: While load following tends to mean the 10-minute timescale, the actual definition used in WIS varies from one minute to more than one hour.
- Simulation Methodology: Some utilities use the 10-minute delta method while others use the hour-ahead persistence to derive a distribution of variability about the mean. It is unclear to what extent the vector allocation method has been employed to isolate the incremental impact of wind on load following.
- Measurement Units: Many wind studies describe reserve requirement and cost in terms of MW and $/MW of nameplate wind capacity. However, other measurement units are employed, as discussed in the “Challenges” section below.

Challenges

The practice of identifying load following presents a number of challenges, not least of which is the definition of load following. Most studies appear to associate load following with a 10-minute time period, although its impact spills over into regulation on the shorter end of the timescale and into hour-ahead forecast error on the longer end. The lack of a practical delineation between these three wind integration cost components means that the methodology used to model load following varies from study to study. In the absence of a clear industry standard for identifying load following requirement and cost, comparability is approximate at best.

Where load following requirement and cost for wind has been defined and analyzed, there is also a lack of consensus as to the appropriate units by which to measure that requirement. The most common unit appears to be MW (requirement) and $/MW (cost) of nameplate wind capacity. However, some studies deviate from this methodology. The BPA Study measures load following cost in $/kw/month.

Within-Hour Variability: Conclusion and Best Practices

For the majority of utility-scale WIS, the additional capacity required solely for regulation due to wind integration is manageable in the near-term. As penetration levels increase, regulation requirements will also increase and incrementally add to the overall cost of integration. However, as stated in the regulation section of this report, this is dependent on the assumptions made in synthesizing a regulation cost.

The wind integration studies conducted by Idaho and Avista successfully address the potential danger in making convenient assumptions and therefore perform more sensitivity analyses than other studies do. For example, each study deliberately analyzes historic load years based on hydro conditions (low, average, high), which is a strategic approach given the fact that hydro resources are most commonly used for regulation in the Northwest; Avista even calculates a specific integration cost estimate based on these three water condition scenarios. This method is beneficial, especially for Northwest utilities, and does not analyze load years simply based on convenience. Moreover, hydro conditions affect market prices for energy greatly, and it is wise to plan for multiple hydro scenarios over long time horizons since these costs assumptions greatly impact the opportunity cost of holding capacity for regulation and load following.

Over time, utilities will have access to higher-resolution wind data and industry best practices, which will help them to make more accurate and informed decisions regarding wind's integration. Additionally, as stated in the Avista study, wind power advocates are encouraging a transition to sub-hourly energy markets so that utilities in the West are not overly reliant upon hour-ahead forecasts. The EWITS study even acknowledges that "functional sub-hourly markets are the most economic means to compensate for short-term changes in load and wind generation that can be forecast."[15] Given the potential presence of these markets, less capacity will need to be committed to cover short-term fluctuations, and thus the cost to provide regulation will decrease. However, according to Avista, there is a general consensus to date that the costs to implement a sub-hourly market outweigh the benefits.

The load following required to accommodate the within-hour variability of wind depends primarily on the way in which regulation and load following are defined. These ancillary services are typically provided by the same AGC unit and are therefore difficult to distinguish from one another. Nonetheless, the two services are fundamentally different in that regulation responds to random fluctuations while load following adjusts to underlying trend.

It may be appropriate for the industry to adopt the term "wind following" in order to clearly distinguish the variability requirement of load from that of wind. Establishing a separate term for the component of following requirement that is attributable to wind may be arbitrary (i.e., the actual effect of adding wind generation is to change from load following only to load net wind following). However, for the purpose of making rate cases, clear distinction between load variability and wind variability is helpful in communicating the actual incremental impact of wind generation.

[15] EWITS WIS, p. 155

Forecast Error: Hour-Ahead and Day-Ahead

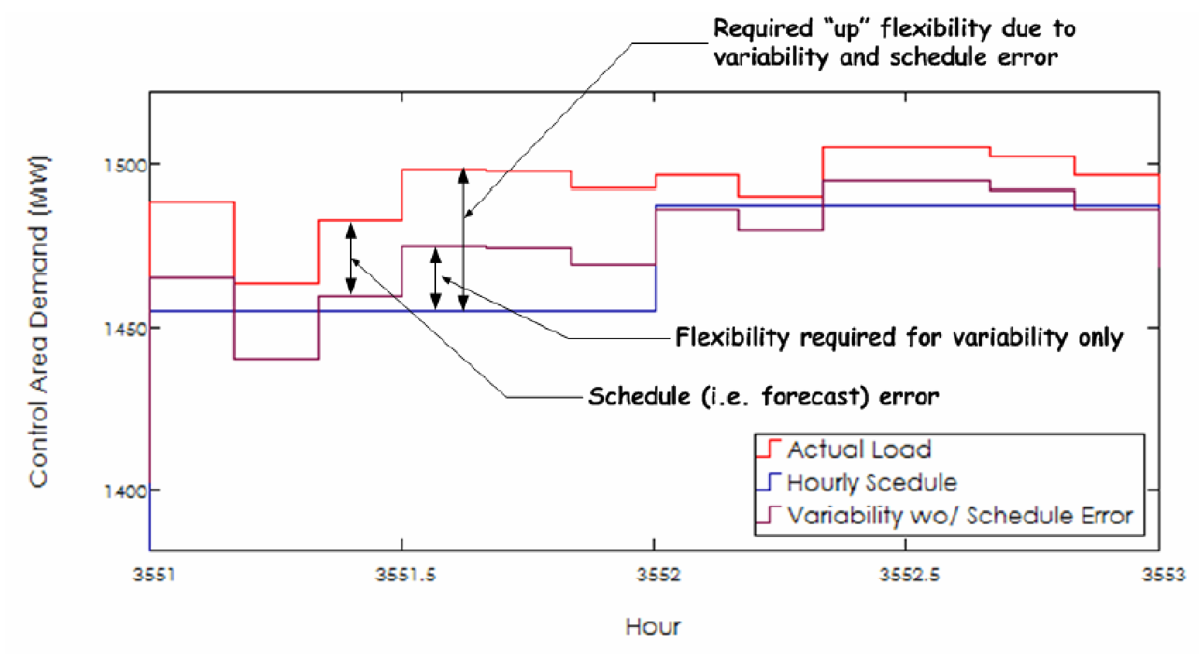
Introduction

As with load following, NERC does not provide a concrete definition for either hour-ahead or day-ahead forecast error. However, both concepts are interrelated and share the same generalized approach.

Utilities are charged with the task of ensuring that they can meet expected load. As part of this process, system operators must submit the manner in which they plan to meet these demands at least 24 hours in advance. However, because operators inevitably make errors in their forecasts, they do not utilize the utility's resources in an optimal manner; the extent to which forecasts differ from actual load constitutes day-ahead forecast error. Likewise, in the hour-ahead period, operators again make adjustments to ensure that they meet actual load; the amount by which operators deviate from optimal unit commitment levels is defined as hour-ahead forecast error.

Over time, system operators have become quite adept in their ability to anticipate load at different times of the day. However, due to wind's uncertainty, schedulers must allocate additional operating reserves in both the day-ahead and hour-ahead periods. As such, for purposes of this report, day-ahead and hour-ahead forecast error is defined as the "additional capacity that must be reserved to cover deviations in actual wind energy delivery from the forecast."[16] **Figure 2** below provides an illustration of the effects of additional reserve requirements on a utility's operations:

Figure 2: Additional intra-hour flexibility requirements due to schedule error bias[17]



As illustrated in the diagram, "schedule error" (which captures both day-ahead and hour-ahead forecast error) compels a utility to carry additional operating reserves to ensure that it is capable of meeting load.

[16] Avista WIS, p. 58
[17] Avista WIS, Figure 29

The following section will provide an in-depth analysis of both hour-ahead and day-ahead forecast error, the ways in which each are calculated, the challenges associated with their computation, and the best practices that we recommend PGE consider when conducting its own WIS.

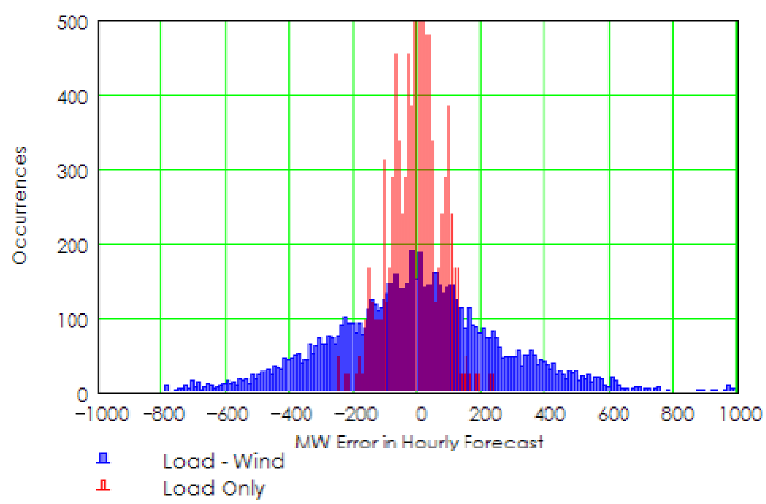
Hour-Ahead Forecast Error

Introduction and Definition

This section will focus on the portion of integration costs related to sub-optimal hour-ahead unit commitment that accompanies higher levels of wind penetration. Many studies do not attempt to break out the hour-ahead system optimization costs from other estimates of regulation and non-spinning reserves. These studies may have either been constrained by certain modeling techniques (the Couger model used by XCEL Energy in Colorado) or had greater flexibility due to the presence of 5-minute markets.

In the absence of wind, hour-ahead commitment plans are dependent on load forecasts. While not perfectly predictable, load follows regular patterns and can therefore be estimated with some degree of accuracy. As traditional generation is replaced with variable wind generation, wind's impact becomes significant. In the hour-ahead scheduling phase, wind's volatility forces system operators to carry additional spinning and non-spinning reserves. The cost of additional reserves that can be attributed to hour-ahead forecast errors (causing sub-optimal unit commitment) is the hour-ahead commitment cost described in this section. **Figure 3** below demonstrates the increased variability in forecast error attributable to wind.

Figure 3: Hourly forecast error distribution for load only and load with wind[18]



As wind penetration levels rise to 15% or 20%, there are periods when actual generation will approach double the penetration level as a percentage of total generation for an hour period. Combined with poor forecast abilities, the cost of sub-optimal unit commitment can be a significant portion of total integration

[18] Minnesota WIS, Figure 71

costs. Compounding this challenge is the fact that high generation levels are temporary and must therefore be supported by quick replacements if the wind generation falls off.

Objective

There are several benefits of breaking down integration costs into hour-ahead optimization costs. First, breaking out hour-ahead costs allows a utility to better measure sensitivities of its model to certain inputs and better mimics actual operations. In markets where energy is traded on an hour-ahead basis, system operators are continuously reacting to load requirements by committing resources to meet load or act as reserves.

Second, increased wind penetration will alter system operators' roles. Wind is unique in that it has the potential to fundamentally alter the balancing role that system operators play throughout the day by increasing the prevalence of previously unfamiliar patterns. For example, wind generation ramping up quickly in the morning would turn a "ramp-up" period around.[19] From the perspective of a system operator, a morning ramp-up is a daily occurrence and experienced operators are experts at handling such events. If wind generation increases rapidly during a morning ramp-up, operators will be forced to scramble to ramp down other generation resources, an unfamiliar event during a morning ramp-up.[20] Modeling these characteristics provides not only a cost estimate but also highlights unique circumstances that system operators will face and should provide insights into effective reactions by system operators.

Third, understanding the cost of forecast error on hour-ahead operations allows a utility to better focus resources by either adapting to forecast errors or enhancing forecast accuracy.[21] Forecasting large-scale wind generation in short-periods is a nascent practice and one that will improve over time. That said, utilities should weigh wind forecasting against the cost of greater hour-ahead forecast errors.

Results

Only one study, Avista, explicitly measured the proportion of total integration cost that can be attributed to hour-ahead uncertainty. The APS study combined hour-ahead and day-ahead results into one measure of forecast error cost. The results from each of those studies are listed in Tables 1 and 2 below.[22] The small sample size and unique methodology and scenarios does not allow for a robust comparison of the results across studies.

Table 1: APS Integration Cost, Hour and Day-Ahead Uncertainty

APS – Incorporates both hour-ahead and day-ahead uncertainty

	Incremental Cost	% of Integration Cost
4%	$ 1.88	58%
7%	$ 2.32	65%
10%	$ 2.65	65%

[19] Minnesota WIS, p. 103

[20] Readings suggested that operators "cheat" in that they don't carry downward reserve during normal ramp-up periods and vice versa. This was never explicitly said but seems to be inferred.

[21] Avista WIS, p. 43

[22] Figures taken from Arizona WIS

Table 2: Avista Integration Cost, Hour-Ahead Uncertainty

Avista – Only hour ahead uncertainty				
	Incremental Reserve (MW)	% of total Incremental Reserve	Incremental Cost	% of Total Integration Cost
5%	0	0%	$ 0.30	11%
10%	5	34%	$ 1.70	24%
20%	15	39%	$ 2.69	40%
30%	30	44%	$ 3.00	34%

Challenges

Modeling the costs of hour-ahead forecast error is not without challenges. The linear programming models often used for unit commitment do not have the same ability as system operators to make qualitative judgments in real-time. For example, trend errors tend to be higher at the beginning and end of each hour due to the fact that load is ramping up or down. Human system operators are able to recognize these patterns and adjust unit commitment accordingly.

Persistence forecasts are applied in a non-standard manner between studies. This inconsistency is further magnified by the fact that system operators do not necessarily use persistence forecasts when making unit commitment decisions. An ideal model would better capture the actual forecasts used, not simply estimate using the persistence forecast. However, the human dimension of unit commitments makes modeling these decisions almost impossible.

Day-Ahead Forecast Error

Introduction and Definition

The following section will discuss the methodology that various WIS employ to calculate the costs associated with day-ahead forecast errors. A survey of these studies reveals that calculating day-ahead forecast error is not a straightforward task; some studies do not delineate day-ahead forecast error from either hour-ahead forecast error or incremental load following and regulation costs, while others do not even discuss day-ahead forecast error. Thus to better understand the potentially significant role that day-ahead forecast error can play in these studies, it is necessary to more closely scrutinize what is meant by day-ahead forecast error, grasp its significance when performing a WIS, and determine whether there is a methodology that is most effective.

When attempting to ensure that they generate/purchase enough electricity to meet load requirements, utilities must submit day-ahead forecasts whereby different units are committed for various purposes (i.e. regulation, load following, etc.). Under normal circumstances, any error in operators' forecast is primarily attributable to deviations between forecasted and actual load values. Such deviations result in increased costs, as reserves committed for a specific purpose are unable to be utilized in the most efficient manner possible. While system schedulers have become adept at forecasting load, the fact that forecasts must be made more than 24 hours in advance results in increased errors (compared with forecasts made 20 minutes ahead, which are of course much more accurate).

The introduction of wind, however, creates significant challenges for operators scheduling a utility's resources. Due to wind's uncertainty, utilities must allocate more reserves. Therefore, WIS focus upon the role that day-ahead forecast error plays in total wind integration costs. Day-ahead forecast error is generally divided into two parts: 1) "The additional capacity that must be reserved to cover deviations in actual wind energy delivery from the short-term forecast[23] and 2) the role that day-ahead markets play in a utility's scheduling system.

Objective

WIS seek to determine the extent to which day-ahead forecast errors contribute to a utility's total wind integration costs. By performing these calculations, utilities can more accurately cite the impact that additional wind integration has on their total operations and achieve the following objectives:

First, utilities are able to assign quantitative costs to forecast errors. By determining the incremental impact of day-ahead forecast error, decision-makers are able to understand the extent to which forecast error hinders a utility's ability to optimize its resources. After performing calculations in the manner described below, operators can then qualify how improvements in forecasts can ultimately reduce their overall costs.

A second benefit associated with calculating day-ahead forecast error involves quantifying the discrepancy between purchases/sales in the day-ahead and short-term energy markets. Day-ahead forecast errors encapsulate such costs, and can therefore provide decision-makers with a better understanding of the advantages of short-term energy markets, particularly as utilities are mandated with the task of integrating more variable energy into their portfolios.

By undergoing a detailed assessment of the costs borne by a utility as a result of day-ahead forecast error, a utility can 1) ensure that its system is set up in a manner that optimizes resources under current operating practices and 2) make long-term plans that improve operational efficiencies based upon forecast errors. Armed with such an understanding, utilities will be provided with the information necessary to integrate wind into their systems in the most cost-efficient manner possible.

Results

There are several challenges in comparing studies' calculations for day-ahead forecast error. As has been well documented, variances in studies' inputs and methodologies make a comparison of these costs impractical; therefore, the results reported below serve only to report each study's findings.

Idaho uses the "spread-based" approach to calculate day-ahead costs; it determines the spread between day-ahead and real-time prices and applies that difference to various wind penetration scenarios. One such figure at the 300 MW penetration level estimates day-ahead forecasts to be 53 cents, as shown in Table 3:

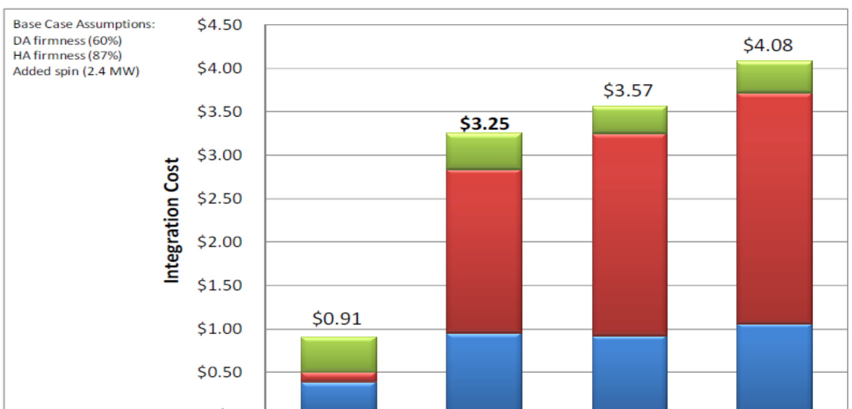
[23] Avista WIS, p. 58

Table 3: Applying transaction to the total forecast error for the 300 MW penetration level[24]

Month	DA Buy RT Sell HL	DA Buy RT Sell LL	DA Sell RT Buy HL	DA Sell RT Buy LL	Total Market (loss)gain
Jan	-5,815.79	893.63			($4,922)
Feb			19,094	1,839	$20,933
Mar			9,122	-1,496	$7,626
April			-2,328	1,635	($693)
May			76,892	-896	$75,996
Jun			69,436	-30,839	$38,597
July			422,262	-30,837	$391,425
Aug			120,059	-78,797	$41,263
Sep			295,867	-35,157	$260,710
Oct			135,741	-13,561	$122,180
Nov			-51,291	-48,743	($100,034)
Dec			-459,868	-21,596	($481,465)
	($5,816)	894	634,986	-258,448	**$371,616**
				Wind MWh	**702,507**
Value of Forecast Trade error					**$0.53**

Finally, the Arizona study calculates the costs associated with day-ahead uncertainty at varying penetration levels as shown in **Figure 4**:

Figure 4: Sensitivity of integration cost to percent penetration of wind energy[25]



Wind Energy Penetration	1%	4%	7%	10%
Within-hour Regulating	$0.40	$0.41	$0.31	$0.37
Hour-ahead Uncertainty	$0.11	$1.88	$2.32	$2.65
Day-ahead Uncertainty	$0.39	$0.95	$0.93	$1.06

24 Idaho WIS, Table 20
25 Arizona WIS, Figure 32

Challenges

There are several inherent challenges when computing day-ahead forecast error costs. Foremost among these is the difficulty in separating day-ahead forecast errors from other affected cost components, including hour-ahead uncertainty, load following, and regulation. Given such difficulties, utilities may either 1) compute day-ahead errors differently or 2) neglect day-ahead forecast error altogether, instead incorporating forecast errors into these other components. As a result of such inconsistency, a cross-study comparison of day-ahead forecast errors becomes problematic.

A second challenge arising in the computation of day-ahead forecast error is the large impact that differences in market types can have on the stated costs of forecast errors. For example, because New England has five-minute markets, the magnitude of day-ahead forecast errors is not as great as it is on the West Coast, which is forced to operate with hour-ahead markets. In a similar vein, a model's inability to accurately gauge actual market prices can create discrepancies between the predicted and actual costs of wind integration (for example, spreads may tend to be either larger or smaller than predicted).

The third challenge presented by day-ahead forecast error comes in the various assumptions made by each model. Factors such as discrepancies in persistence forecasts reflect the gap between the models used in these studies and the real-time data that system operators utilize. Until models are better able to simulate the various factors that decision-makers use when assimilating their forecasts, integration studies will not fully capture the complexity that goes into operators' decision.

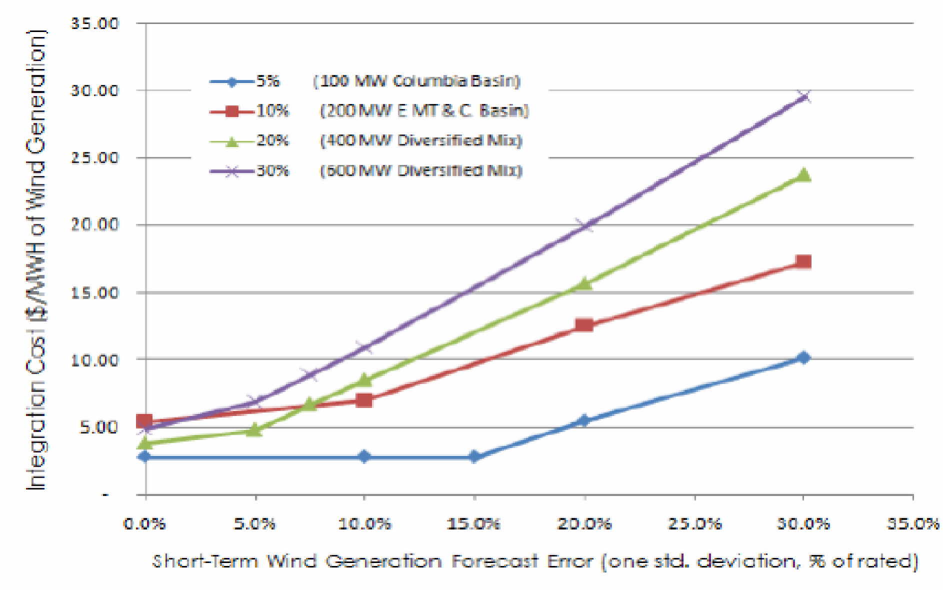
Forecast Error: Conclusion and Best Practices

As is now evident, various methods are used to calculate the costs associated with hour-ahead and day-ahead forecast errors. However, several studies distinguish themselves by taking the following approaches:

Sensitivity Analyses

Studies such as Arizona and Avista perform sensitivity analyses on some of the key assumptions that impact their findings. For instance, while many studies assessed forecast errors at varying wind penetration levels, not all of them determined the extent to which changes in forecast errors impact overall integration costs. Forecast sensitivity analysis is especially important given the nascence of short-term forecasting methods and the aforementioned shortcomings of using persistence forecasts. Running sensitivities for several levels of forecast error highlights an important conclusion: as **Figure 5** below demonstrates, short-term forecast error begins to rise rapidly when forecast errors rise above 5%:

Figure 5: Short-term wind generation forecast error[26]



Studies that perform sensitivity analyses thus better grasp how variations in their modeling approaches/assumptions will affect projected costs.

Market "Spread" Analysis

Reports differed in their proclivities to determine the "spread" between day-ahead prices and real-time market prices. Given the potentially large disparity between these two numbers, it is important that future WIS take two steps: 1) Determine the spread with as much accuracy as possible to improve forecast estimates 2) Use associated costs to determine whether, as penetration levels increase, it will be useful for PGE to partner with other utilities to create a short-term market to combat the additional forecast errors created by wind.

Finally, it is important to note that the above list is by no means comprehensive; each of the studies analyzed for this report contained facets that may prove useful. However, the incorporation of sensitivity and market analyses represent practices most useful when determining the costs associated with forecast error.

[26] Avista WIS

Future Phases Overview

The reliability requirement of variable and uncertain wind power presents unique challenges for utilities in the Northwest. This next section will explore the implications of significant wind penetration on PGE's power operations. Specifically, it will address key considerations for PGE regarding access to transmission facilities as well as flexibility in the power generation fleet and power market.

Figure 6 illustrates the high cost of wind integration in the Pacific Northwest relative to other parts of the country. The yellow circles identify wind integration cost estimates for utilities and other integrating entities in the Northwest. This trend of high wind integration cost in a region rich in "cheap" hydro power seems counter to conventional wisdom. However, because hydro power is generally maximized at peak hours of the day, its use for wind integration must be valued at the foregone market value of that power.

Figure 6: Wind Integration Cost by Penetration Level – Northwest Entities

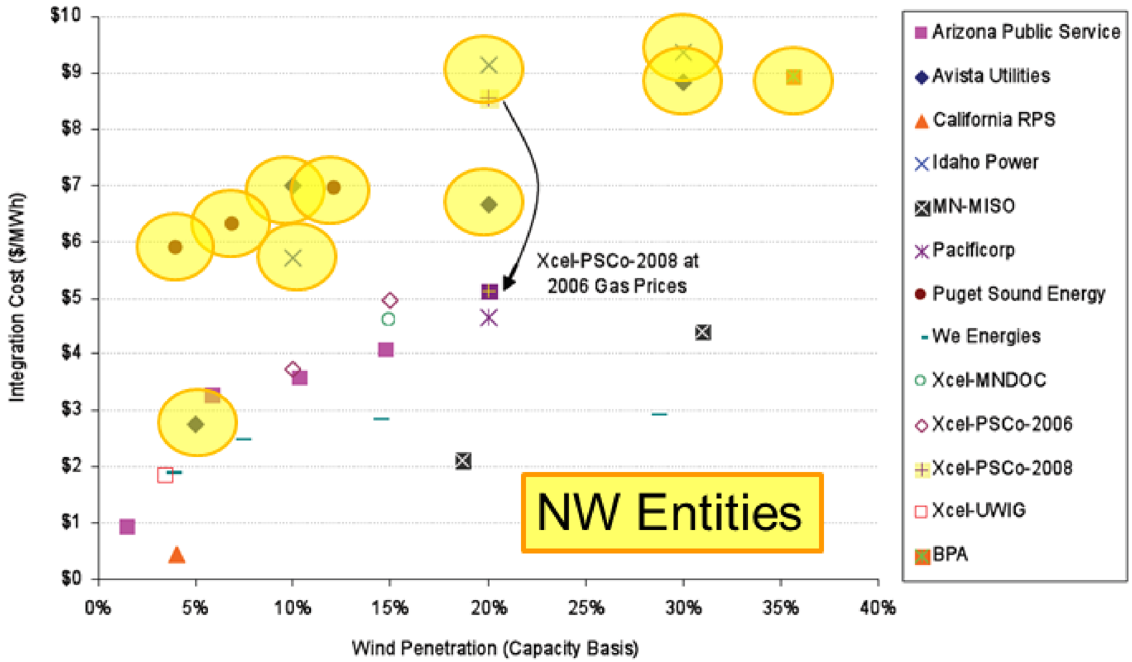


Figure 6 further suggests that there may be some characteristics of the Northwest power system which are resulting in high integration cost, perhaps due to constrained access to transmission facilities and lack of market and generation flexibility.

Access: PGE is one of the region's many small balancing authorities. As such, it is subject to constraints that may not affect wind integrators in other parts of the country. The Northwest does not have a region-wide transmission operator and, with some exception, it is limited to transmission scheduling on an hourly basis. Furthermore, significant portions of Northwest's power system are managed by Bonneville Power Administration, which is assessing its role as the primary integrator of regional wind power.

Flexibility: A flexible power system facilitates the balancing of large quantities of wind power. Generation resources that can ramp rapidly and cost-effectively over a wide capacity range can bring down integration costs. Robust markets for capacity and reliability resources also play a role in optimizing the value of variable resources.

By highlighting relevant limitations of the regional power system and analyzing existing research, this section seeks to provide guidance for incorporating new sensitivities into future phases of PGE's WIS. Future phases of PGE's Wind Integration Study should determine how the unique context of the Northwest affects wind integration and to identify opportunities for optimizing and improving the regional power system to accommodate variable generation resources. PGE should evaluate the costs associated with specific transmission constraints to which the utility is subject and study the feasibility of investing in generation and market flexibility.

Access

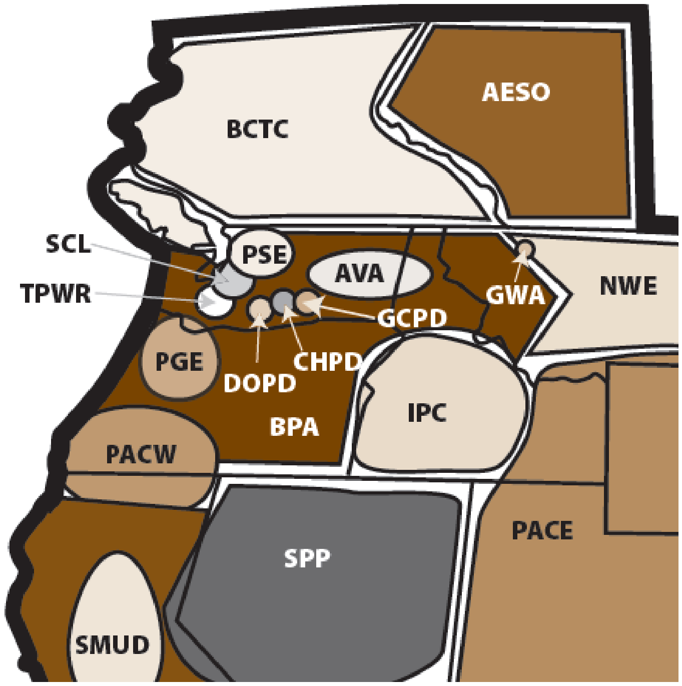
Optimal locations for wind power tend to be far from load. Power from PGE's wind resources in the Columbia Basin must be transmitted to PGE's service territory. Accessing transmission capacity to bring variable wind energy from where it is generated to where it is used means that PGE must move power across a network of transmission lines. These lines largely are operated by other parties, especially the Bonneville Power Administration, and are constrained in their ability to accommodate large quantities of wind power. This section is composed of four subsections:

> **Northwest Transmission Characteristics:** Many small balancing authorities and the absence of a regional transmission operator result in a patchwork transmission system that constricts access to regional generation and load diversity. New transmission construction takes time and is costly.
>
> **Best Practices in Wind Transmission Assessment:** The EWITS has developed methodology for modeling transmission constraints. However, assessing the cost of transmission constraints is generally outside the scope of WIS.
>
> **Transmission Constraints:** Since transmission interties and other components are managed manually, fluctuations in intra-hourly power flows are subject to limitations.
>
> **Regional Coordination:** WECC is studying transmission constraints in the West. Efforts are underway to standardize, optimize, and enhance transmission, thereby improving PGE's access to balancing resources.

Northwest Transmission Characteristics

The Pacific Northwest power system is characterized by a number of small balancing authorities, shown in **Figure 7**. Moving power around the region is complicated by autonomously operated transmission systems and the additive transmission costs, or "pancake" rates, that must be paid. While attempts have been made in the past, there is currently no regional transmission operator (RTO) or independent system operator (ISO) providing standardized scheduling procedures or overseeing sub-hourly markets that would permit easier access to diverse balancing resources. The transmission system was not designed to accommodate the dynamic nature of variable generation resources and system components such as capacitors and buses are exposed to accelerated wear and tear. Furthermore, existing transmission facilities are reaching their capacity limits.

Figure 7: Pacific Northwest Balancing Authorities[27]



The many small balancing areas in the Northwest make wind's integration more difficult and costly because there are few reserve resources within those service areas with which to smooth wind generation's variability and uncertainty.

Transmission planning and construction projects have long time horizons. PGE is seeking to build the Cascade Crossing transmission project by 2015. This project will ease congestion on the existing east-to-west transmission lines, allowing PGE to connect its thermal generation resources in Boardman and various new wind projects in Eastern Oregon with its service territory in the mid-Willamette Valley.

Between now and 2014, new transmission projects will not be available. This means that PGE must meet its 2015 RPS requirements with the existing transmission resources, most of which are operated by BPA. In addition, BPA is currently revising its business practices in ways that will place greater integration responsibility on wind generators, which may impact the cost of wind's integration. The PGE Wind Team should consider how best to model the costs associated with limited transmission capacity.

Best Practices in Wind Transmission Assessment

Existing WIS do not, in general, consider the integration costs associated with transmission of wind energy. Transmission considerations are explicitly beyond the scope of most wind studies. One noteworthy exception is the Eastern Wind Integration and Transmission Study (EWITS), which has modeled the costs of a constrained transmission system using the "copper sheet" method. **Figure 8** displays estimated wind energy losses due to transmission constraints in the Eastern Interconnection.

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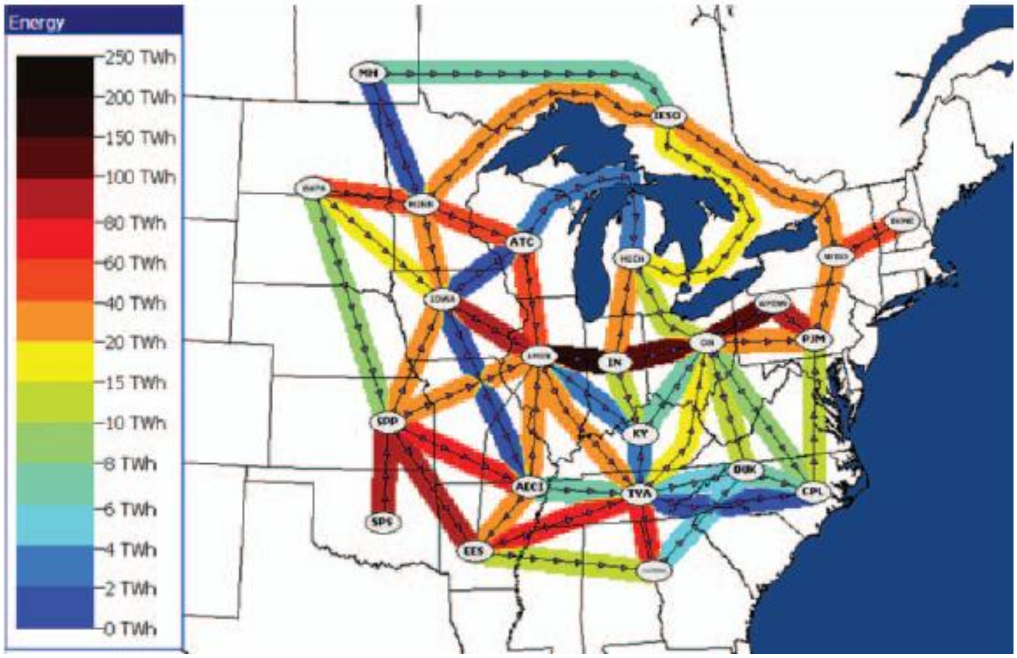
[27] Source: WECC. http://www.wecc.biz/library/WECC%20Documents/Publications/Balancing%20Authorities.pdf. Accessed April 19, 2011.

Total annual losses are measured in terawatt-hours, suggesting the magnitude of energy that would be lost assuming 20% wind penetration.[28]

Figure 8: Eastern Interconnection – Annual wind energy lost to transmission constraints



The EWITS assessed the cost of transmission constraints by modeling two regional transmission scenarios. In the first scenario, the energy system was modeled in the absence of any transmission constraints. Energy flowed from source to load as though the energy system were built on a copper sheet. Generation units, therefore, dispatched based entirely on economic factors in a way that minimized total system costs.

This "copper sheet" scenario was then compared to a second scenario where existing transmission constraints were incorporated into the model; generation was now dispatched based on economic and transmission limit factors. By subtracting the total system cost found for the "copper sheet" scenario from the constrained scenario, transmission constraint costs were assessed for each of the top 24 transmission interfaces in the Eastern Interconnection.

In addition to assessing transmission constraint costs, the EWITS also evaluated the benefit-cost ratio for construction of new transmission facilities. The study found the benefit of new transmission to exceed cost in two of the four scenarios studied.[29]

The New England ISO has proposed conducting a transmission constraint study similar to the EWITS. Other regional bodies, including the WECC, are in various phases of transmission constraint assessments.

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[28] EnerNex and National Renewable Energy Laboratory. "Eastern Wind Integration and Transmission Study." 2010. P. 107.

[29] EnerNex and National Renewable Energy Laboratory. "Eastern Wind Integration and Transmission Study." 2010. P. 115. Benefit-cost ratio for Scenario 1 (20% penetration, high capacity factor, onshore): 1.22. For Scenario 2 (20% penetration, hybrid and offshore): 1.09.

As a stakeholder in the Northwest regional transmission system, PGE should monitor and participate in WECC efforts to assess transmission constraint costs as they relate to wind power.

Transmission Constraints

As of May 2011, the Bonneville Power Administration integrates 3522 MW of nameplate wind capacity, roughly 10% of the total installed capacity in the United States. The output variability from this amount of wind generation strains the transmission system. BPA is formulating new business practices designed to limit its operational exposure to wind. These policies push wind generators, such as PGE, to bear a greater portion of the integration responsibility for regional wind power. Three such policies, dynamic transfer, environmental redispatch, and wind limiting and curtailment, may impact wind integration costs for PGE.

Dynamic Transfer

Increases in real-time variation of power on BPA's transmission system require greater enhanced operational flexibility. Regional interties and other transmission components within BPA's balancing authority are controlled manually by transmission operators. To accommodate the need for flexibility, transmission operators may have to take multiple actions within an hour to maintain system reliability. Additional workload accentuates the possibility of human error. For this reason BPA has indicated that no more than three manual actions may be taken within an hour.

Furthermore, BPA limits the size of within hour power swings. These limits were assessed in the BPA Dynamic Transfer Limits Study, as illustrated in **Table 4**. Increasing levels of wind power and the ancillary resources needed to balance wind on BPA's system have the potential to trigger manual clamp-downs. The risk of such an event may contribute to wind integration cost for PGE.

Table 4: Dynamic transfer limits for Northwest transmission paths[30]

Name	Studied Dynamic Transfer Limit (may be reduced by system conditions)
COI	500
NORTHWEST - CANADA	300
MONTANA - NORTHWEST	110
IDAHO-NW	200
NORTH OF HANFORD	320
NORTH OF JOHN DAY	350
SOUTH OF ALLSTON	300
WEST OF CASCADES - NORTH	320
WEST OF CASCADES - SOUTH	280
WEST OF MCNARY	150
WEST OF SLATT	150

The constraints imposed by dynamic transfer limits pose operational challenges for PGE. Within hour variations in wind output are subject to the limits imposed by BPA. If dynamic transfer limit is exceeded, either by fluctuation size or by number of actions per hour, BPA may intervene with a clampdown. Currently, wind power is not exceeding dynamic transfer limits. However, as additional wind power is added to the regional grid, these limits may impact wind integration costs.[31]

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[30] BPA. Dynamic Transfer Limits Study Methodology. Draft Report February 2010. P. 2.
[31] McManus, Bart. BPA Tranmission Technical Operations. Interview, April 28, 2011.

PGE should assess the probability of wind output exceeding dynamic transfer limits. The constraint imposed by dynamic transfer limits may need to be included in PGE's wind integration model in order to determine the associated costs. More generally, PGE should advocate for transmission system automations and improvements that will better accommodate variable energy resources.

Environmental Redispatch

The Endanger Species Act restricts the amount of hydro spillage allowed over BPA-controlled dams. BPA's "Statement on Environmental Redispatch and Negative Pricing" states that the agency will not pay negative prices for federal hydro energy.[32] Instead, regional thermal and wind plants are subject to redispatch under certain conditions. While this policy is advantageous to thermal plants, wind generators are adversely impacted by the loss of federal production tax credits and renewable energy credits. These credits combined represent roughly $40 per MWh of lost revenue to wind generators.

PGE should assess the likelihood of wind generation redispatch under the environmental redispatch policy. To the extent that lost wind generation credits due to this policy can be classified as wind integration cost, PGE should incorporate the impact of environmental redispatch and the associated costs into its WIS. For example, modeling for environmental redispatch sensitivity during high hydro, high wind, and low market price scenarios could provide some indication of the impact this policy will have on the value of wind power.

Wind Limiting and Curtailment

In 2009, BPA Transmission put into effect an operating procedure for limiting within hour wind variability. Known as Dispatcher Standing Order (DSO) 216, this policy authorizes dispatchers to limit wind over-generation above schedule (DEC reserve) and curtail wind schedules during under-generation (INC reserve). DSO 216 reduces BPA's exposure to wind forecast error.

For PGE, this policy presents two challenges. First, such events result in lost federal production tax credits and renewable energy credits. Second, the risk of curtailment events means PGE must hold additional contingency reserves to meet the wind power's reliability requirement.

PGE should evaluate the impact of DSO 216 events on its wind generation output. Model simulation of BPA's DEC and INC balancing reserve allocations and the resulting impact on PGE's wind power revenue and contingency reserve requirement would reveal the extent to which this policy will result in additional wind integration costs.

Regional Coordination Facilitates Flexibility

Efforts to evaluate and improve transmission capacity in the Northwest and across the Western Interconnect are underway. The WECC's Variable Generation Subcommittee (VGS) has begun a study to evaluate regional transmission constraints with respect to increasing penetration levels of variable generation. Using a "copper sheet" methodology similar to that of the EWITS, the study is identifying both the cost of regional transmission congestion and the potential savings of consolidating balancing authorities.

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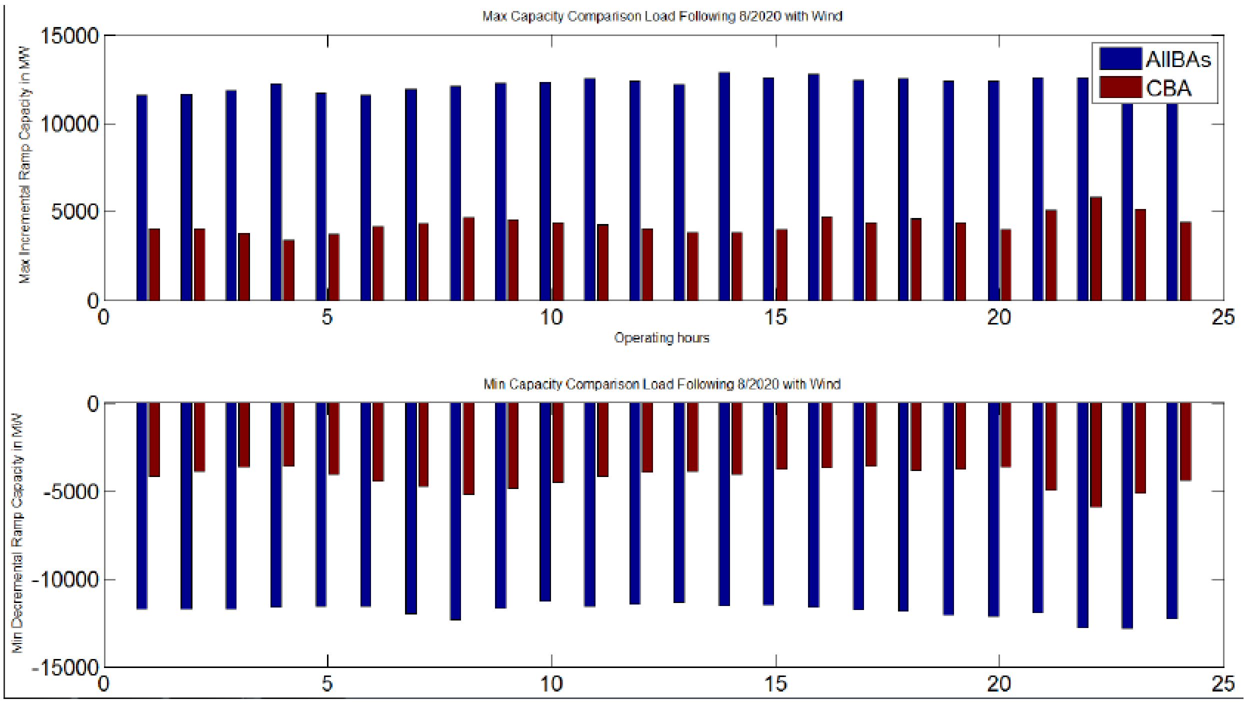
[32] Bonneville Power Administration. "Statement on Environmental Redispatch and Negative Pricing." December 2010.

Figure 9: Preliminary maximum and minimum load following capacity savings from consolidated balancing authorities (CBA)[33]



Load following capacity requirement declines significantly under the consolidated balancing authorities relative to similar requirements for all balancing authorities operating independently, as shown in **Figure 10**. WECC maximum and minimum load following ramp capacity, shown on the vertical axis, decreases by approximately 8 GW for the 2020 study year. Preliminary study results also show approximately $250 million in thermal production savings, 20 GW of hour-ahead schedule capacity savings, and 1 GW of regulating reserve capacity savings.[34]

Other regional initiatives are targeting greater transmission scheduling flexibility. The Intra-hour Transaction Accelerator Platform (I-TAP) is a key market transformation effort designed to facilitate intra-hour energy and capacity exchanges among utilities and other power entities across the Western Interconnect. I-TAP is the outcome of collaboration between three regional transmission planning organizations: Columbia Grid, West Connect, and Northern Tier Transmission Group. This platform represents a key opportunity for PGE to overcome real-time balancing challenges with real-time market transactions.[35]

The Efficient Dispatch Toolkit (EDT) provides PGE with yet another opportunity to increase access to system flexibility. One EDT tool, the Energy Imbalance Market, could allow PGE to purchase ancillary services such as load following, thereby reducing within hour wind integration costs. The Southwest

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[33] Samaan, Nader. Pacific Northwest National Laboratory. "Benefits of Balancing Authorities Cooperation Across the Western Interconnection." Presented at UWIG Spring Workshop. Kansas City, MO. April 14, 2011.
[34] Ibid.
[35] Columbia Grid. "Joint Initiative – I-TAP." www.columbiagrid.org. Accessed April 30, 2011.

Power Pool is currently demonstrating the efficacy of this tool and its ability to achieve efficiencies similar to those found in ISO control areas.[36]

Transmission constraints are a likely driver of high Northwest wind integration costs. PGE could derive significant cost reductions from intra-hour scheduling tools such as I-TAP and EDT. The reductions in balancing requirements shown by the preliminary results of the VGS study indicate the degree to which regional coordination could reduce integration costs both in the hour-ahead and within-hour time scales. Achieving these potential savings will require systematic changes on the part of regional balancing authorities such as PGE and on the part of public utility commissions and other regulating bodies.

Clear benefits for PGE could be realized from the utility's active participation in initiatives to standardize, optimize, and enhance the operation of regional transmission infrastructure. Such initiatives have the potential to reduce wind integration costs by facilitating flexible markets and improving access to the regional capacity and load diversity.

Flexibility

The resilience and reliability of an electrical grid is dependent on the flexibility of either load or generation in order to constantly balance supply and demand. Electrical utilities focus on the generation (supply) side of the equation because influencing demand is seen as both more difficult and more expensive in most contexts.[37] In the Pacific Northwest much of the system flexibility is in hydroelectric facilities. However, increasing variable resources on the grid promises to max out the capacity of hydro resources and require greater system flexibility be achieved through other resources.

This section will focus on three important components for system flexibility for PGE:

> **Flexible Generation**: The addition of new flexible generation resources on the system, specifically the addition of new natural gas plants with the capability of rapid ramp up and down. The focus on natural gas generation is driven by both technological advancements and a greater need for regulation and load following services.
>
> **Market Flexibility**: PGE operates in a unique context without and ISO and without a short-term market for electricity or ancillary services. Therefore, a discussion of the benefits of a short-term market will be explored.
>
> **Hydro Level Sensitivity**: The importance of hydro resources as balancing resources warrants greater study into system sensitivities to hydro levels.

Exploring the impacts of new flexible generation, the role of short-term markets and the role of hydro levels on system resilience will provide greater clarity on solutions to PGE's future flexibility challenges.

Flexible Generation

PGE's need for flexibility mimics the national trend towards resources that provide power with lower up-front costs but higher variable costs. In the past, new resources tended to require high up-front capital costs followed by low variable costs which operated at a set level providing baseload power (nuclear and

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[36] Dragoon, Ken. Northwest Power and Conservation Council. Interview: April 29, 2011.

[37] The final section of this paper will briefly discuss how the dynamics of demand side management is changing with new technologies and new programs.

large coal both fit this description). This trend has shifted to favor plants that provide greater flexibility with less operational and wear and tear costs from flexing output; technologies like single-cycle natural gas turbines fit this description.

An interesting way to consider the addition of a new flexible resource is the role that resource could play in "unlocking" a zero variable cost resource. For example, the addition of a natural gas plant with higher variable costs than a baseload plant could actually unlock the potential of wind resources that have a zero or even negative variable cost (with production tax credits) to create a system that can meet load at the lowest possible cost. It is this "unlocking" role that natural gas plants provide that should be modeled by PGE to understand total system cost with alternative flexible resources.

Xcel Energy in Colorado studied the impact of adding a new flexible resource (in the form of a 500 MW natural gas plant) to their system in their WIS.[38] The results showed only a modest decrease in wind integration costs as a result of the new flexibility. The explanation is that the Xcel Colorado system is not flexibility constrained and therefore the linear programming model did not call on the new resource to a large extent. Xcel Colorado has a high percentage of their total generation from flexible natural gas plants so the addition of another plant did little to lower integration costs. For PGE, it is reasonable to estimate a much larger impact on integration costs as PGE faces real capacity and flexibility constraints that would benefit from new flexible generation.

PGE should model the impact of a 200 MW flexible resource on their system (consistent with RFP process).

The addition of a new natural gas resource does raise new risks, specifically around supply and price. In order to benefit from the flexibility of the new resource, fuel supplies must also contain flexibility through either flexible supply contracts or storage capacity. Xcel Colorado again provides an example of a WIS that modeled the impact of natural gas storage with the conclusion that storage had a significant (>20%) impact on integration costs[39].

PGE should model the impact of gas storage facilities on integration costs.

Fuel prices for natural gas also have shown high variability and using the integration model to understand the impact of fuel prices on integration costs provides an opportunity for PGE to model risk from price variability. Again, Xcel Colorado serves as an example, with results from their integration study showing approximately a two to one ratio between increase in prices per MMBTU and integration costs per MWh. So, a $1 increase in natural gas prices (per MMBTU) will increase integration costs by $0.50 (per MWh). This range of values is specific to Xcel Colorado's unique operating environment and therefore will not necessarily match the results of a PGE specific study.

PGE should provide sensitivity analysis of natural gas prices to wind integration costs.

To truly understand the impact of new natural gas resources PGE should weigh the benefits of the new flexibility against the costs of the resource *and* the costs of providing storage or flexible purchase

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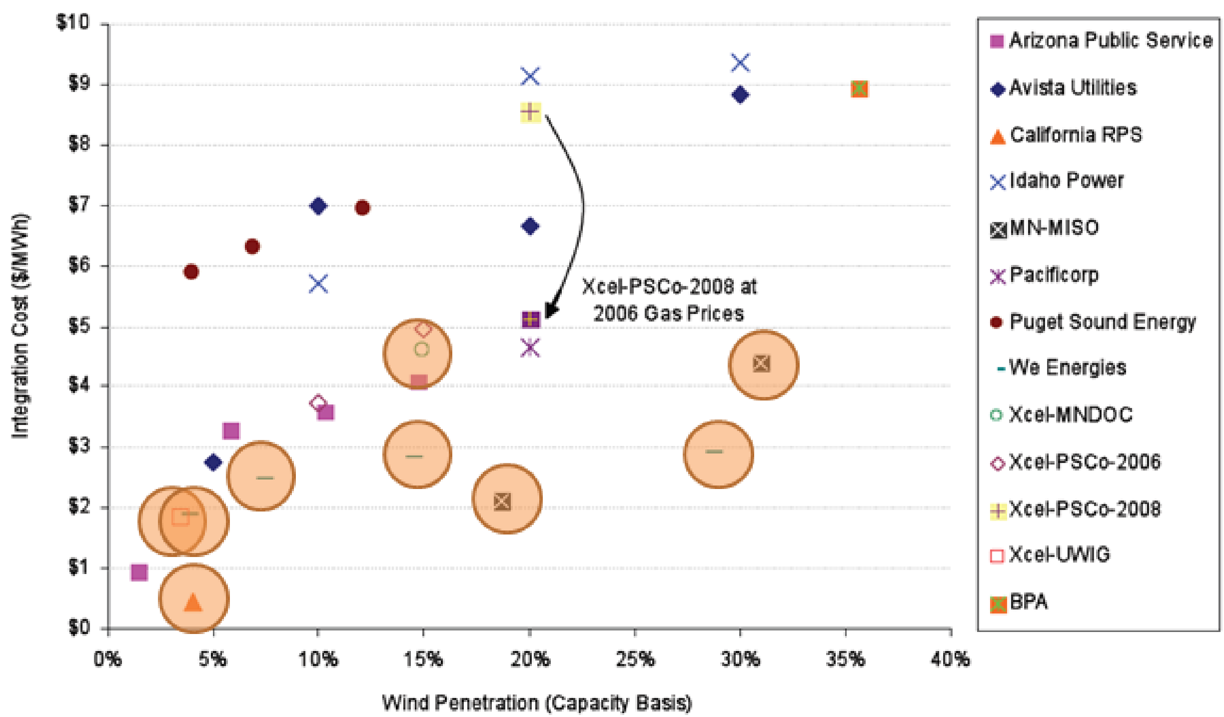
[38] Excel Colorado WIS
[39] Excel Colorado WIS

agreements. Additionally, the impact of natural gas prices should be modeled to understand risk exposure.

Market Flexibility

The Pacific Northwest is unique for its many balancing authorities and lack of an ISO. This results in no true short-term market for electricity. This section will discuss the presumed negative impacts of the lack of market access on integration costs for NW utilities. **Figure 11** below highlights the integration study results from utilities that operate in ISO markets with access to 5-minute markets for electricity. Clearly, the results demonstrate a trend towards lower costs resulting from access to short-term markets.

Figure 10: Integration Costs with ISO markets highlighted



Graph modified from Porter et al.[40]

Understanding the benefits of a short-term market. Avista modeled the expected benefit from a short-term market and found that integration costs would fall by 40-60% depending on penetration level.[41] These results obviously ignore the additional costs of running a short-term market that would be shared between all participants in some manner. Still, the results serve as proof of the value of flexible market structures and if replicated by more NW utilities will begin to build a case for greater cooperation.

PGE should model the potential impacts of a short-term market and compare those benefits to PGE's expected share of the costs of operating a short-term market.

[40] Porter K, Mudd C, Fink S, DeCesaro J, Wiser R, 2009. "A Review of Large-Scale Wind Grid Integration Studies in the United States" prepared for The Energy Foundation by Exeter Associates, Inc.
[41] Avista Wind Integration Study

Current efforts at creating increased cooperation in the NW are progressing with initiatives such as I-TAP, described as a bilateral bulletin board. I-Tap will also build the infrastructure for greater future coordination. PGE should understand the value of a short-term market through modeling and then use those results to encourage efforts in the NW, if appropriate.

Hydro Sensitivity

Hydro resources play a huge role in balancing load in the NW. Additionally, hydro drives market prices by creating a baseline of power that pushes the marginal unit of production from low cost hydro through high cost natural gas depending on the overall hydro output in the region. These two roles, balancing and price setting, make hydro sensitivity an important component of overall wind integration costs. External pressures are also changing the role of hydro with climate change impacting hydro capacity and variability and environmental concerns driving the decrease of hydro capacity throughout the region.

Idaho Power modeled hydro level on integration costs with the expectation that as hydro levels were at high and low levels balancing ability would be constrained and integration costs would rise. The results of that study were flawed because input data was inappropriately chosen. Idaho Power used year 2000 data as regular hydro level baseline data. Unfortunately, market prices in the year 2000 were extremely variable and significantly higher than normal years. Therefore, actual integration costs from varying hydro levels were skewed. Despite, or perhaps as a result of, the error in using year 2000 data uncovered an interesting conclusion – market price correlation trumps reduced balancing ability as a driver of integration costs. Specifically, hydro's impact on market prices had a much larger impact on overall integration costs than did the reduced ability of hydro resources to provide balancing services. The results of Idaho Power's integration study highlight a need to understand market price sensitivity that result from hydro level variability.

PGE should model the impacts of high, low and regular hydro years on integration costs.

Additionally, PGE could separate hydro years from market prices in an attempt to tease out the influence of market prices on integration costs versus the impacts of hydro balancing capacity on integration costs. This could be achieved by keeping hydro levels consistent while using market prices form varying years.

By better understanding the impact of flexible resources, market flexibility, and hydro levels on integration costs, PGE can take appropriate steps towards increasing system reliability and resilience as greater levels of variable resources are added. Using the existing model to run sensitivity analyses will allow PGE to understand costs and benefits of alternative strategies. Understanding current system conditions also creates a baseline that can be altered over time as new technologies or market-driven changes take place. These long-term considerations will be discussed in the next section.

Long-Term Considerations Overview

The previous two sections have identified current areas that PGE should consider in the next phases of its WIS. However, because studies must constantly evolve to match market and technological shifts, PGE should also identify those long-term issues that may impact PGE's future wind integration efforts. As such, the final section of our report assumes a forward-looking approach that assesses the following long-term considerations:

- **Demand Response**
- **Energy Storage**
- **Solar Energy**

While not demanding PGE's immediate attention, each of these components represent externally driven factors that have the potential to significantly impact PGE's future wind integration initiatives. The following section will explore the potential impact of each of these factors, identify the challenges associated with each, and conclude with a series of next steps for PGE's to consider for future phases of its WIS.

Demand Response

Opportunities

Demand response is one external factor that may enhance a utility's ability to integrate wind into its portfolio. Demand response (DR) is defined as the ability of end users of electricity to reduce load in response to price signals or other grid management incentives and regulations. Indeed, demand response has already proven its ability to provide both reliability and regulation response services. For example, PJM uses demand response to provide regulation reserves.[42] Similarly, ERCOT has a market in which DR can bid in to provide four different day-ahead ancillary services.[43] By utilizing demand response in such a manner, utilities can better optimize their power generation resources to provide other services, such as load following, which will in turn lower the opportunity cost of wind's integration.

PJM and ERCOT both highlight the opportunities that demand response provides at relatively low wind penetration levels. However, PGE should also turn its attention to regions with higher wind penetration levels to better grasp the significant role that DR can play in combating wind's variability and uncertainty. For example, Denmark, a global leader in its use of renewable energy, states that approximately half of its energy will be generated from renewable power, most of which is wind. In planning for such a goal, Denmark has made significant investments in DR, recognizing that DR can play a significant role in offsetting wind's variability. Thus, as it prepares to model wind integration scenarios with higher penetration levels, it may be prudent for PGE to explore DR in greater detail.

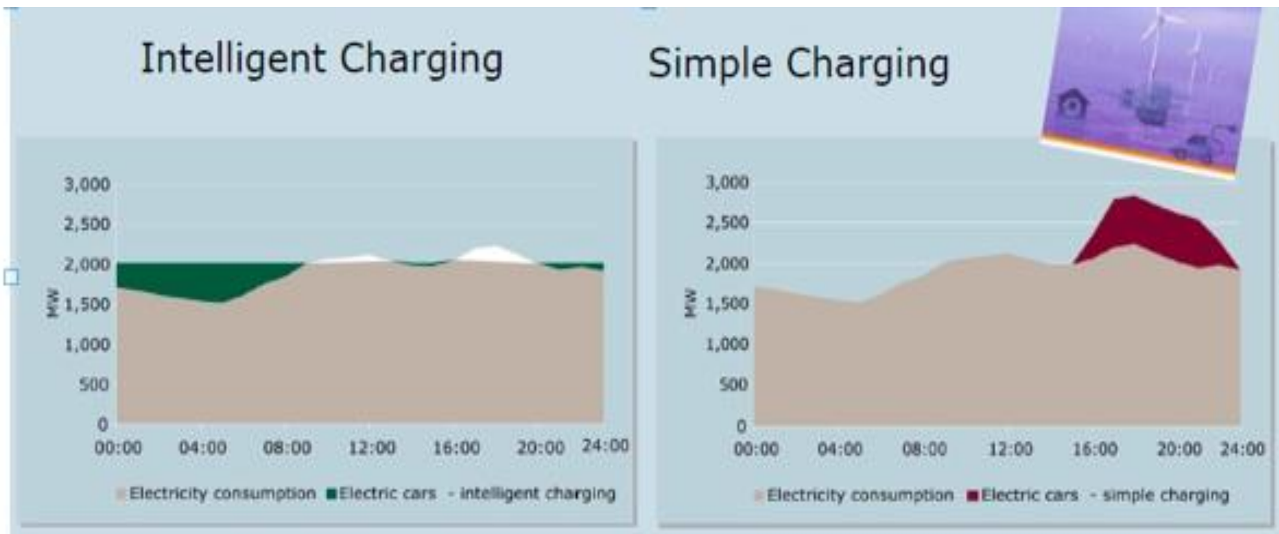
[42] "Demand Response." (2011). Retrieved from http://pjm.com/markets-and-operations/demand-response.aspx.
[43] GE Energy. (2008). Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements. Retrieved from http://www.nrel.gov

Challenges

Despite its promise, demand response still poses significant challenges for PGE at this juncture. First, demand response is reliant upon both technological and consumer changes. For example, EVs (electric vehicles) are often cited as a resource that will enable DR's increased viability. However, at present EVs' batteries are not equipped to handle the cycling required by DR. Similarly, DR is reliant upon customers' willingness to adopt new technology and participate in DR programs. Thus if consumers are either unable or unwilling to purchase such technology, it is questionable whether PGE can pursue these programs on a large scale.

Second, despite its promise, demand response **by itself** may not provide PGE with an adequate tool to help integrate wind into its power portfolio. Rather, the manner in which DR is implemented may determine its success. As Figure 12 demonstrates, there is a significant difference between a program that uses "simple" charging and one that uses "complex" charging mechanisms. Thus if PGE hopes to maximize DR's full potential, it must ensure that DR programs are implemented in a manner that allows for both consumers and utilities to fully reap its benefits.

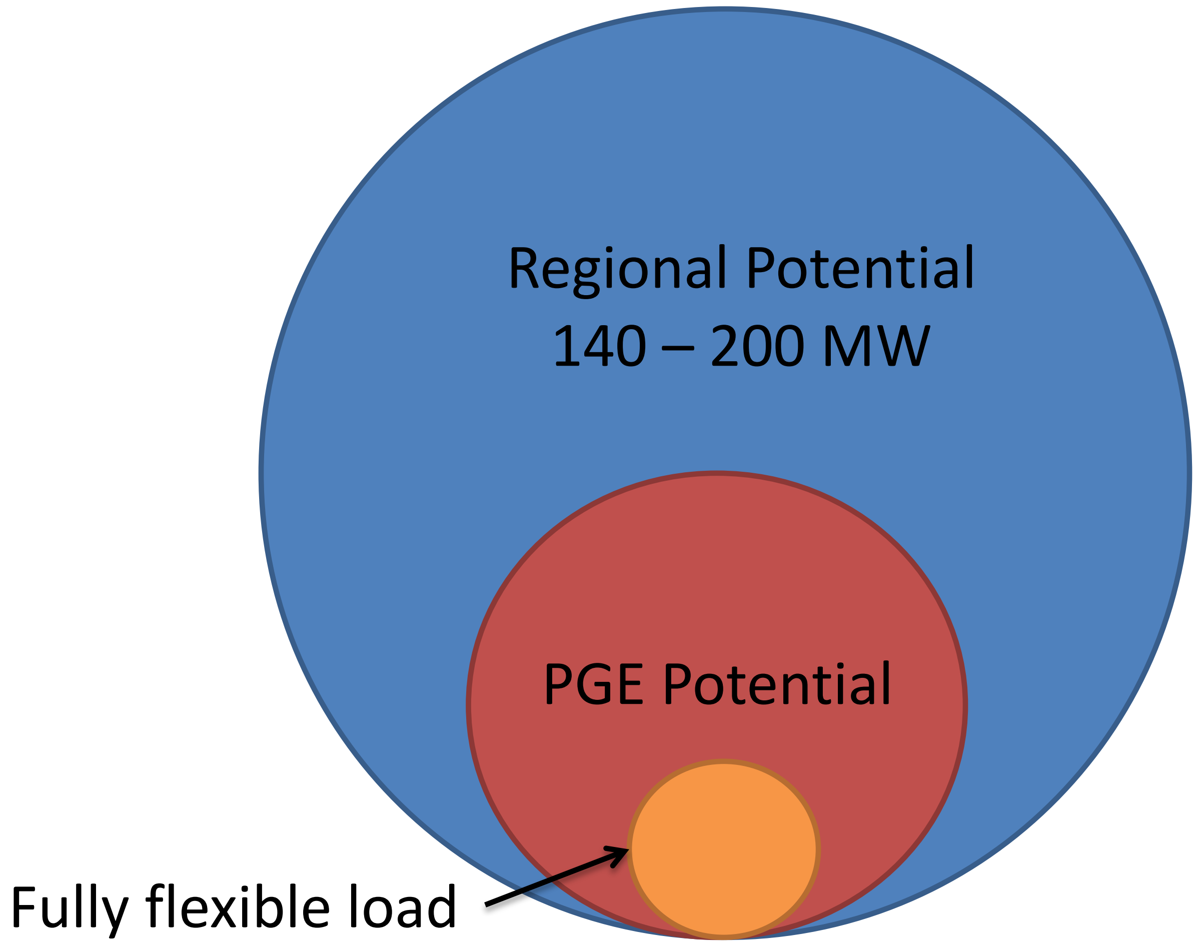
Figure 11: Intelligent and Simple Charging Mechanisms for Demand Response



Third, successful demand response initiatives will best function through the use of variable, or real-time, pricing. With real-time prices, if available wind generation is less than forecast, the cost of deploying ancillary services to cover the generation shortfall will be passed on to consumers, thereby reducing electricity demand and the cost of serving the load. However, current technology and infrastructure may inhibit PGE's ability to implement real-time prices at this juncture; it will therefore be critical for the organization to continue to invest resources in this area as it moves forward.

Finally, and perhaps most relevant to PGE, is determining whether demand response can provide load following. The recent partnership between BPA and EnerNOC, may provide a new paradigm for the way in which demand response is utilized. Specifically, this partnership may provide PGE with a better grasp of the ways in which DR can be implemented on a commercial, rather than industrial scale. Thus unlike programs that use DR on an industrial scale to provide contingency reserves, this new partnership may prove DR's ability to provide load following; such a program would in turn provide customers with greater load flexibility. However, our analysis reveals that PGE's opportunities are limited at this juncture. As Figure 13 reveals, while cold storage's regional potential ranges from 140-200 MW, only a small fraction of this, from 1-5 MW, can be easily accessed by PGE

Figure 12: Regional Demand Response Potential



Compounding the challenge of using DR for load following are its uncertain economics. Our estimates reveal that DR could compete at $100-$200/KW annually. However, the complexity of determining its cost curve, in terms of both its fixed and variable cost components, makes it difficult to ascertain its practicality. As such, its unknown price structure makes DR's use for load following problematic at this point in time.

Moving Forward

Given the uncertainties highlighted above, PGE must take several steps to identify the most optimal way to use demand response when integrating wind into its power portfolio. First, PGE must continue to lead smart grid deployment efforts. Indeed, the company recognizes the significant impact that demand response can have on its operations, stating that it "has actively supported market transformation of peak load reduction through development of smart appliance technology. We also are working with consortia of utilities, appliance manufactures and stakeholder groups to advance market acceptance, technology standardization and the development of pilots to advance the opportunities for significant DR in the smart appliance arena."[44] It will be imperative for PGE to continue to pursue advancements in this area, as such technology and infrastructure are crucial components to successful DR programs.

Likewise, while PGE's opportunity to use DR for load following appears low at this time, the organization should focus on the recent partnership between BPA and EnerNOC.[45] Such a partnership may lend insight into the ways in which demand response will affect consumer behavior and pricing, both of which are key facets of successful DR programs. By taking these measures, PGE will be better positioned to use DR as a wind integration tool as it increases its wind penetration levels.

Energy Storage

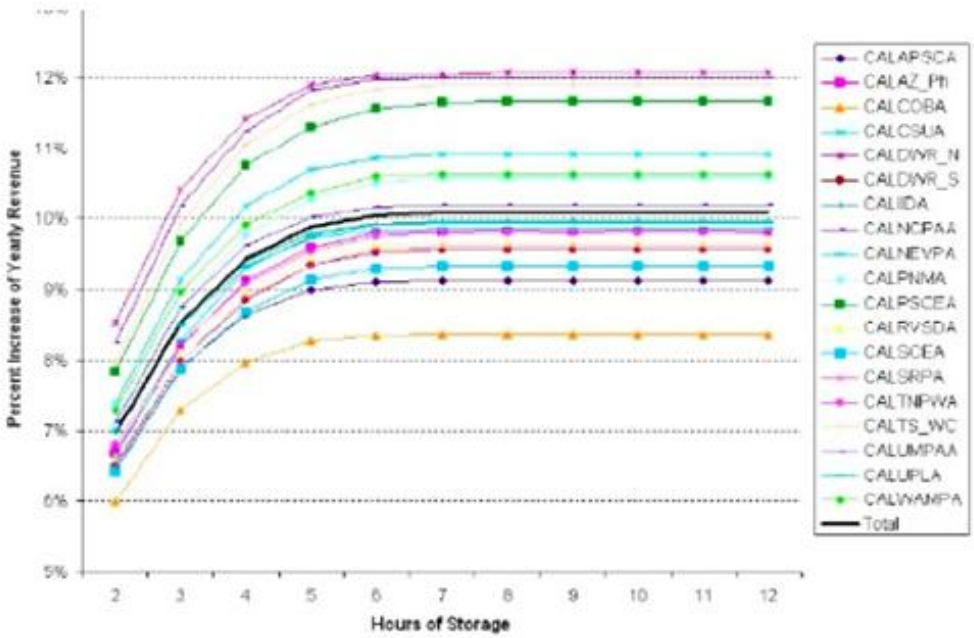
Opportunities

Energy storage is often cited as the "Holy Grail" for integrating wind into a utility's power portfolio. As should be evident at this point, one of the primary challenges accompanying wind's integration is the fact that a utility's load often peaks during the day, while wind normally peaks nocturnally (when load demand is lowest). Thus system operators currently struggle to identify ways to maximize wind's potential. Energy storage offers one such solution to this daunting challenge, as it allows system operators to store the wind generated at night and use that energy when demand (and consequently prices) is at its highest. As shown in **Figure 14** below, which displays annual Concentrated Solar Power revenue increases relative to hours of storage, energy storage offers utilities the opportunity to address such a challenge:

[44] PGE IRP, p. 85

[45] "BPA Partners with EnerNOC." (2011). Retrieved from http://www.sustainablebusinessoregon.com/articles/2011/02/bpa-partners-with-enernoc-ecofys-on.html

Figure 13: Concentrated Solar Power Revenue Relative to Hours of Storage



Aside from increases in revenues, energy storage expands the ways in which wind power can be utilized. For example, "energy storage technologies decouple the production and consumption of electricity, and can provide regulation, sub-hourly load-following, hour-to-hour storage and shaping, firm capacity, and other ancillary services."[46] Using energy storage in such a manner will lower a utility's overall integration costs, as the wind itself can be harnessed to account for those excess reserves that would otherwise be needed to account for wind's variability.

Finally, and perhaps most importantly, there have been numerous studies that have focused on the ways in which energy storage projects can be used to create price arbitrage opportunities. For example, the Colorado WIS estimated that energy storage created a summer/winter price arbitrage of $.75/Dth; by storing gas during the summer (when prices are lower) and then selling excess gas during the winter when prices are higher, the utility was able to offset many of the costs associated with wind's integration. Given the numerous benefits afforded by energy storage, PGE should explore its own energy storage options in greater detail.

Challenges

While energy storage projects offer numerous benefits, there are still significant obstacles preventing their full implementation. Perhaps most challenging are the high up-front capital costs that accompany such projects. For example, when exploring the possibility of various energy storage projects, Colorado found that one project required a 100-year payback period. Indeed, while Colorado may offer an extreme example, most energy storage projects, including pumped storage hydro, compressed air, and batteries, all require significant up-front investments. Similarly, unless utilities have high levels of wind penetration (and therefore disproportionately high levels of uncertainty and variability), it is uneconomical to consider

[46] *Sixth Power Plan*, p. 40

energy storage. As such, many organizations do not explore energy storage projects in great detail.

A second challenge associated with energy storage is the fact that available options are either unproven or possess characteristics that limit their adoption. Thus while pumped storage hydro and compressed air are both proven technologies, they require specific geographical and topographical features that are often unavailable to utilities. Conversely, while battery technologies can be located at nearly any site, most batteries are either uneconomical or unproven on a large scale. Due to the combination of these challenges, many experts do not believe that it is appropriate to examine energy storage projects, dismissing them as “distracting topics”[47] that detract from utilities’ ability to focus on plausible ways to lower their wind integration costs.

Moving Forward

As should be clear, energy storage is a polarizing topic among those looking for ways to optimize wind’s integration. However, while some may continue to debate its relevance, recent events indicate that it will be prudent for PGE to explore energy storage options in greater detail. Recent legislation in California, *California AB 2514*, “requires CPUC to initiate a proceeding no later than March 1, 2012, to determine if procurement targets for energy systems are appropriate[48].” If such legislation passes, the question of energy storage’s possibility becomes moot, as utilities in California will have to determine not if, but how to incorporate energy storage into their systems. As such, it may be only a matter of time before Oregon mandates similar measures.

A second event that may change the energy storage landscape is Duke Energy’s 36 MW battery storage project in Texas, the world’s largest storage project at a wind farm. As mentioned above, one of the barriers that energy storage must overcome is the fact that battery technology is sometimes unproven at a large scale. If the project is successful, it may provide other utilities with the confidence necessary to proceed with their own storage projects.

Given the above proceedings, PGE should begin to explore its energy storage options in greater detail. Specifically, it should first confirm its most promising storage options. Unlike many other regions, PGE is geographically situated in a location that makes pumped storage hydro projects feasible. Similarly, given the benefits associated with gas storage, particularly the opportunities for price arbitrage, PGE should consider modeling the potential benefits of such projects. Finally, the organization may benefit from exploring the potential benefits of using EVs for future storage projects, as they make storage a more economical option. Regardless of which projects it chooses, PGE should ensure that it comprehends the ways in which energy storage enable the organization to enhance the effectiveness of its wind integration efforts.

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[47] Charlie Smith, PGE TRC Member. Interview: April 26, 2011.

[48] Kanellos, Michael. (2011). Will New Bill Cause Storage to Boom in California? Retrieved from http://www.greentechmedia.com/articles/read/will-new-bill-cause-storage-to-boom-in-california/

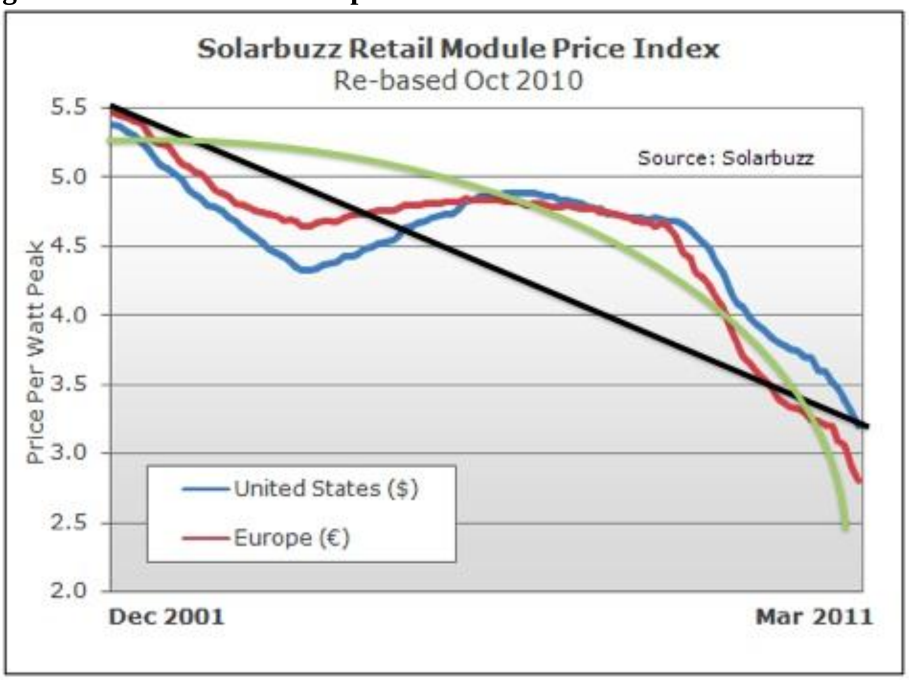
Solar Generation

Opportunities

Few studies have examined the potential benefits of including solar power in WIS. However, solar's characteristics, particularly as they relate to wind, make its future inclusion enticing. Perhaps most promising is the fact that solar and wind's generation are negatively correlated; while wind tends to peak at night (when load is at its lowest), solar peaks during the day. Given this relationship, combining wind and solar will help to reduce their overall variability, thereby decreasing the amount of additional reserves, resulting in lower wind integration costs.

Solar is also attractive in that it is rapidly becoming more economical. As **Figure 15** demonstrates, over the past ten years solar power's costs have fallen by more than 50%.

Figure 14: Solar Power Costs per Watt Peak



Further declines in solar's costs make its inclusion particularly attractive for PGE as it seeks to advance the amount of renewable resources in its power portfolio given solar's potential in PGE's territory. As stated in its IRP, PGE already ranks in the top 10 nationally in its solar penetration levels. This, coupled with PGE's stated interest in solar's distributed generation potential, makes solar energy an attractive complement to wind as the organization increases its portfolio of renewable resources.

Challenges

Despite the opportunities highlighted above, solar nonetheless presents a number of challenges. Foremost among these is the fact that solar possesses many of the same obstacles as wind. Like wind, solar power is both variable and uncertain; factors such as latitude, season, time of day, and cloud cover all affect the amount of power generated by solar energy. As such, if PGE includes solar in future WIS, it will be confronted with the challenge of modeling solar's forecast errors. Likewise, studies such as Western

Wind and Solar (WWSIS) question the effectiveness of solar power in the absence of storage capabilities. As WWSIS demonstrates, if solar power is unable to be stored and used for peak evening loads, it is questionable whether a utility can effectively combine solar and wind resources in an economical fashion.

Moving Forward

Given the number of challenges that solar energy presents, it is not appropriate to include solar in PGE's near-term WIS. Despite solar's negative correlation with wind, such benefits do not offset the new costs introduced by solar's integration. Indeed, at this point in time solar may only increase the amount of studies' uncertainty and may therefore muddle their results. However, studies such as WWSIS illustrate that under certain conditions, adding solar power to future WIS may prove to be beneficial. As such, PGE should closely monitor whether solar's costs per kWh continue to decline, and, just as importantly, determine at what point it becomes cost effective to combine solar and wind into a single comprehensive study.

Long-Term Conclusions

The three long-term considerations identified above all possess the potential to improve the quality of PGE's future WIS. However, given the uncertainty surrounding each consideration, PGE must address the following questions in order to better understand how these factors may impact future studies:

Demand Response

- Can DR provide load following?
- Will grid improvements enable market transformation?

Energy Storage

- Will the potential of energy storage be realized?
- Should PGE consider energy storage as a wind integration resource?

Solar Generation

- Will per kWh cots continue to rapidly decrease?
- Does solar belong in a wind integration study?

By using the information above as a starting point, PGE can begin to identify possible answers to each of these questions. Through such an effort, the organization can position itself to conduct innovative wind integration studies that not only address current operational challenges, but also consider long-term factors that may significantly impact PGE's future wind integration initiatives.

Conclusion

Through the research conducted over the course of this project, it is important for PGE to grasp several key points as it proceeds with future phases of its WIS. First, PGE has rightfully identified that four components serve as crucial foundations to any successful WIS:

- **Regulation**
- **Load Following**
- **Hour-Ahead Forecast Error**
- **Day-Ahead Forecast Error**

As has been demonstrated, entities differ in the exact manner in which these components' costs are calculated. However, a thorough analysis of both domestic and international WIS reports reveals that there are emerging best practices on the basic ways to calculate each of these components. PGE should therefore compare its own methodologies with those of the best practices contained in this report, as these four components will serve as key pillars upon which an accurate study can be built.

However, while these four components are necessary parts to a successful WIS, they alone do not sufficiently inform PGE of wind's comprehensive effects on its operations. As such, the organization should consider two additional features when compiling its future reports:

- **Access**
- **Flexibility**

By estimating the costs of transmission constraints on PGE's system imposed by wind's integration, modeling those constraints, and considering the ways in which both flexible generation and markets may impact PGE's future wind integration efforts, the company will be better situated to conduct a thorough analysis that more precisely measures the impact of wind's impact.

Finally, this report has identified three externally driven considerations that have the ability to significantly impact PGE's future wind integration efforts:

- **Demand Response**
- **Energy Storage**
- **Solar Generation**

By closely monitoring present and future developments in these areas, PGE will have the potential to both reduce its wind integration costs and to advance to the forefront of innovative WIS.

As this report's findings demonstrate, successful WIS are not stagnant, but rather living models that can incorporate new information as it becomes available. As such, PGE should follow the guidelines identified in this report to ensure that its model remains highly flexible. By doing so, PGE will create a model that will allow the organization to fulfill its wind integration requirements in a cost-effective and strategic manner.

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Appendix G
Detailed Reserve Calculations

I. Preliminary Variable Definitions

Notation: Let $A_{i,-10} = A_{i-1,50}$ by convention.

(A) Let $L_{i,j}$ indicate the 2014 ten minute load data in hour beginning *i* (0-8759) and ten-minute increment *j* (start time 00, 10, 20, 30, 40, and 50 minutes after the hour). Currently using 2014 projected PGE load data (developed from 2005 actual load and load forecast data). Note that the ten-minute load data is used only in the derivation of the reserve requirements, NOT the model dispatch.

(B) Let L_i indicate the 2014 hourly load data in hour beginning *i* (0-8759). Currently using 2014 projected PGE load data (developed from 2005 actual load and load forecast data). This load data IS used in the dispatch of the model, not the derivation of the reserve requirements. Note that the hourly load data used affects only the regulation piece of the reserve calculations.

(C) Let $L^{2005}{}_{i,j}$ indicate the 2005 ten-minute control area load data in hour beginning *i* (0-8759) and ten-minute increment j (start time 00, 10, 20, 30, 40, and 50 minutes after the hour).

(D) Let $W_{i,j}$ indicate the ten-minute generation data in hour beginning *i* (0-8759), and ten-minute increment j (start time 00, 10, 20, 30, 40, and 50 minutes after the hour). Currently, derived from 2004-2006 ten-minute wind data (Enernex low diversity wind scenario). This data is used in the derivation of the quadratic functions used to capture the relationship between the amount of penetration of wind in the system and the corresponding amounts of regulation, variability due to wind, and forecast error due to wind is the full ten-minute 2004-2006 data set provided by Enernex.

(E) Let W_i indicate the hourly generation data in hour beginning *i* (0-8759). Currently, derived from 2005 ten-minute wind data (Enernex low diversity wind scenario).

(i) Similar to the 2014 load, there are three different corresponding 2014 hourly wind forecasts: Day-Ahead, Hour-Ahead, and Real-Time. All of the 2014 hourly wind forecasts are developed from a 2005 forecast (a subset of a 2004-2006 low diversity wind data set developed by Enernex) that has been realigned as follows (by Enernex):

1/5/2005 8:00 GMT is a proxy for the first Wednesday in 2014, 1/1/2014 0:00 PST.
1/6/2005 8:00 GMT is a proxy for the first Thursday in 2014, 1/2/2014 0:00 PST.
1/7/2005 8:00 GMT is a proxy for the first Friday in 2014, 1/3/2014 0:00 PST.

1/1/2005 8:00 GMT is a proxy for the first Saturday in 2014, 1/4/2014 0:00 PST.
1/2/2005 8:00 GMT is a proxy for the first Sunday in 2014, 1/5/2014 0:00 PST.

And so on through

12/28/2005 8:00 GMT is a proxy for the first Wednesday in 2014, 12/31/2014 0:00 PST.

(ii) The W_i data, as it will be referred to in the appendix, is used primarily as an input into the quadratic functions *f*, *g*, and *h*. The W_i data used will depend on the time horizon of the model and the model scenario run.

(iii) However, it should be noted that the hourly wind data used as a proxy for hour-ahead wind, $W_i = W_{i-1,10}$ is utilized (will be discussed below) in the derivation of the hour-ahead forecast error.

(F) Let $LF^{LoadOnly}{}_i$ indicate the actual 2005 PGE control area hourly load following data in hour beginning *i* (0-8759).

$$LF^{LoadOnly}{}_i = \max\left(LF^{2005}{}_{x,j}\right)\Big|_{x=i} - \min\left(LF^{2005}{}_{x,j}\right)\Big|_{x=i}$$

(G) Let $\overline{l_{i,j}}$ (hourly average load with ramp) be the average of ten-minute load data for hour *i*, except for in the first and final ten-minutes of an hour. In the first and final ten-minutes of an hour *i*, let $\overline{l_{i,j}}$ be as defined below. The calculation of loads the first and final ten minute periods in the hour represents the system ramp that occurs operationally due to the net effect on load of the net market purchases and sales in the last ten minutes of one hour and the first ten minutes of the next hour.

$$\overline{l_{i,j}} = \left\{ \begin{array}{ll} average(l_i) - \dfrac{average(l_i) - average(l_{i-1})}{3} & , j = 00 \\ average(l_i) & , j = 10, 20, 30, 40 \\ average(l_i) + \dfrac{average(l_{i+1}) - average(l_i)}{3} & , j = 50 \end{array} \right\}$$

(H) Let $\overline{w_{i,j}}$ be the average of ten-minute wind generation data for hour *i*, except for in the first and final ten-minutes of an hour. In the first and final ten-minutes of an hour *i*, let $\overline{w_{i,j}}$ be as defined below. The calculation of wind generation the first and final ten minute periods in the hour represents the system ramp that occurs operationally due to the net effect on generation of the net market purchases and sales in the last ten minutes of one hour and the first ten minutes of the next hour.

$$\overline{w_{i,j}} = \left\{ \begin{array}{ll} average(w_i) - \dfrac{average(w_i) - average(w_{i-1})}{3} & , j = 00 \\ average(w_i) & , j = 10, 20, 30, 40 \\ average(w_i) + \dfrac{average(w_{i+1}) - average(w_i)}{3} & , j = 50 \end{array} \right\}$$

(I) Let $\widehat{W_{i,j}}$ be the wind generation trend in hour *i* about the ten-minute period *j*. Recall that $W_{i,j}$ represents the average of the wind generation data in a ten-minute time period proceeding time *j*.

$$\widehat{W_{i,j}} = \frac{\sum_{j-30}^{j+20} W_{i,t}}{6}$$

(G) Let LF_i be the amount of reserves held out for the load following requirement in hour *i* (for **load** only, perfect forecast).

(H) Let WF_i be the amount of reserves held out for the load following requirement in hour *i* (for **wind** only, perfect forecast).

(I) Let $FELF_i$ be the amount of reserves held out for the forecast error requirement in hour *i*.

(J) Let $\sigma^{wind}{}_i$ be a function in terms of wind production level used in defining the regulation requirement in hour *i* due to wind.

(K) Let $R^{LoadOnly}{}_i$ be the amount of reserves held out for regulation for load-only.

(L) Let $R^{LoadWind}{}_i$ be the amount of reserves held out for regulation for load and wind.

II. **<u>Develop Regulation Requirement</u>**

(A) <u>Regulation for Load-Only</u>

Per the NREL paper "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 following equation represents three times the standard deviation of the total load.

$$R^{LoadOnly}{}_i = (.01)\, L_{i,j}$$

Thus, ONE standard deviation of the total load can be represented as follows:

$$\frac{R^{LoadOnly}_{i}}{3} = \frac{(.01)\,L_{i,j}}{3}$$

(B) Additional Regulation for Wind

To determine the additional reserve requirement for regulation needed due to the advent of wind, we must first determine the short-term variation of wind at a particular wind production level in an hour. In other words, derive the following function:

$$\sigma^{wind}_{i} = f(W_i).$$

(i) To find the appropriate $f(W_i)$, compare ten-minute trend wind values with actual ten-minute wind values within an hour. Define the short-term deviations of wind in hour *i* for a ten minute data period *j* as follows:

$$WD_{i,j} = \left|W_{i,j} - \widehat{W_{i,j}}\right|$$

(ii) Sort all the deviations by wind production levels in ten equal sized subsets (bins) of $(0MW, 850MW)$.

$\widehat{W_{i,j}} \in [0MW, 85MW)$, $\widehat{W_{i,j}} \in [85MW, 170MW)$, ... ,
$\widehat{W_{i,j}} \in [765MW, 850MW]$.

(iii) To establish the variability in each wind production bin, take the standard deviation of the short-term wind deviation data points $WD_{i,j}$ in that wind production bin.

(iv) Using the standard deviation of the short-term-wind deviation data points for each bin, and the average wind production value of each bin, generate a least squares fit to a quadratic polynomial $f(W_i)$.

(v) Since $\sigma^{wind}_{i} = f(W_i)$ represents an indicator of short term wind variation at a particular wind production level in an hour, we can now use the sigma function to determine how much additional regulation is required due to wind.

(C) Regulation for Load and Wind

Per the October 2010 NREL paper[1], "since load and all wind variability on this timeframe were also considered to be the variability on this timeframe were

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

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." Assuming that 3 times the standard deviation of load and wind variability will be held back, analogous to the load-only regulation calculation, the following equation would apply to the regulation requirement for load and wind.

$$R^{LoadWind}{}_{i} = 3\sqrt{\left(\frac{R^{LoadOnly}{}_{i}}{3}\right)^{2} + \left(\sigma^{wind}{}_{i}\right)^{2}}$$

III. **<u>Develop Load Following and Hour-Ahead Forecast Error Requirements</u>**

(A) <u>Summary:</u>

The decomposition of the load following requirement into what PGE considers as load following and hour-ahead forecast error could be done in two ways. Both of these ways use a similar methodology and we have split them into two "paths".

The first methodology "path" is as follows: (1) determine the Load Following requirement for load only with no forecast error, (2) then determine how much incremental reserve is required when wind generation is introduced into the system, and (3) then how much additional reserve is required when forecast error is introduced into the system.

The second methodology path is the same as the first except steps (2) and (3) are done in the reverse order. NOTE: While theoretically the second methodology path might make sense in general, it has been determined that it will not work for current PGE modeling.

(1) <u>Establish a PGE Baseline from Actual 2005 Data</u>

(a) Using actual 2005 control area load data ($L^{2005}{}_{i,j}$) and 2005 load following data ($LF^{LoadOnly}{}_{i}$), a historical PGE Baseline representing the percentage of hours that all load following needs for the hour are met (hereafter referred to as $PGE_{Baseline}$) is established.

(b) The 2005 load following data ($LF^{LoadOnly}{}_{i}$) is determined by looking actual ten-minute load data from 2005 and determining half of the range of the load within in a particular hour *i*. This can be achieved by taking the difference of the maximum and minimum load value within an hour and dividing by two.

$$LF^{LoadOnly}{}_{i} = \frac{\max\left(L^{2005}{}_{x,j}\right)\Big|_{x=i} - \min\left(L^{2005}{}_{x,j}\right)\Big|_{x=i}}{2}$$

(c) Define the ten-minute deviations from hourly average load (for load only) as follows:

$$\Delta^{L_{2005}}{}_{i,j} = \left| L^{2005}{}_{i,j} - \overline{L^{2005}{}_{i,j}} \right|$$

See "Preliminary Variable Definition (e)" for a more precise definition to $\overline{L^{2005}{}_{i,j}}$.

(d) Let the percentage of the ten-minute deviations from the hourly load exceeding the magnitude of half of the actual load following range $\left|LF^{LoadOnly}{}_{i}\right|$ equal PGE Baseline (a percentage of outliers allowed per hours of load served).

$$\frac{count\left(\Delta^{L2005}{}_{i,j} > \left|LF^{LoadOnly}{}_{i}\right|\right)}{6n} = PGE_{Baseline},$$

where 6n represents the number of hours in the study multiplied by the 6 ten minute data points in an hour.

(e) This $PGE_{Baseline}$, established from the relationship between 2005 load and load following, will be used to calibrate the calculations of how much load following reserve is needed in the study.

(2) <u>Load Following for Load Only, No Forecast Error</u>

(a) Recall the load-following range from actual 2005 data, $2\left(LF^{LoadOnly}{}_{i}\right)$, represents the range of load movement within an hour of actual 2005 load data. In the study, 2005 load data has been scaled up to a 2014 load forecast (using the percent increase of the 2005 annual average load to 2014 annual average forecasted load). So for consistency, half of that range of load movement 2005 data, $\left|LF^{LoadOnly}{}_{i}\right|$ will be used as a test requirement and scaled up (or down) as needed to meet the requirements of the $PGE_{Baseline}$.

(b) Define the ten-minute deviations from hourly average load (for load only) as follows:

$$\Delta^{L}{}_{i,j} = \left| L_{i,j} - \overline{L_{i,j}} \right|$$

(c) If the percentage of the ten-minute deviations from the hourly load exceeding the magnitude of the actual load following $\left|LF^{LoadOnly}{}_{i}\right|$ is not equal to the previously established PGE Baseline then $\left|LF^{LoadOnly}{}_i\right|$ must be scaled to calibrate the reserve calculation.

More formally, let there be a k_1 such that

$$\frac{count\left(\Delta^{L}{}_{i,j} > k_1\left|LF^{LoadOnly}{}_i\right|\right)}{6n} = PGE_{Baseline},$$

where 6n represents the number of hours in the study multiplied by the 6 ten minute data points in an hour.

(3) <u>Additional Load Following for Wind, Perfect Forecast</u>

(a) Note that in a system with wind, there may be an additional load following requirement in some hours to account for the hour to hour movement of wind generation, and vice versa. To account for this interaction between load and wind we consider "load net wind".

(b) Define "load net wind" as the magnitude of the difference between actual load and wind trend at a particular time.

$$\widehat{LNW}_{i,j} = L_{i,j} - \widehat{W}_{i,j}$$

(c) Define the 10 minute deviations from hourly average load net wind as follows:

$$\Delta^{LNW}{}_{i,j} = \left|\widehat{LNW}_{i,j} - \overline{LNW}_i\right|$$

(d) If $\Delta^{LNW}{}_{i,j} > k_1\left|LF^{LoadOnly}{}_i\right|$, then count $\Delta^{LNW}{}_{i,j}$ as an outlier (in other words it is outside of the load following band for hour i).

(e) If the percent of outliers is more than the PGE Baseline (a percentage of outliers allowed), then more reserve is needed. More formally, if

$$\frac{count\left(\Delta^{LNW}{}_{i,j} > k_1\left|LF^{LoadOnly}{}_i\right|\right)}{6n} > PGE_{Baseline},$$

where 6n represents the number of hours in the study (n) multiplied by the 6 ten-minute data points in an hour, then more reserve is needed.

(f) To determine the additional reserve requirement needed due to the advent of wind, we must determine how much load following due to wind is necessary per wind production level in an hour. In other words, derive the following function:

$$WF_i = g(W_i).$$

(i) To find $g(W_i)$ that is appropriate, compare hourly average wind values with wind variability within an hour. Define wind variability in hour *i* for a ten minute data period *j* as follows:

$$WV_{i,j} = \widehat{W_{i,j}} - \overline{W_i}$$

(ii) Sort all the deviations by wind production levels into ten equal sized subsets (bins) of $(0MW, 850MW)$.

$\overline{W_i} \in [0MW, 85MW)$, $\overline{W_i} \in [85MW, 170MW)$, ... ,
$\overline{W_i} \in [765MW, 850MW]$.

(iii)To establish the variability of each wind production bin, take the standard deviation of the wind variability data points $WV_{i,j}$ in the wind production bin.

(iv)Using the standard deviation of the wind variability for each bin, and the average wind production value of each bin, generate a least squares fit to a quadratic polynomial $g(W_i)$.

(v) Since $WF_i = g(W_i)$ represents the wind variability per hour at a particular wind production level in an hour, we can now use the wind variability function to determine how much additional reserve is required due to wind, with perfect forecast.

(g) Let k_2 be a multiplier to WF_i that will make

$$\frac{count\left(\Delta^{LNW}{}_{i,j} > k_1\left|LF^{LoadOnly}{}_i\right| + k_2 WF_i\right)}{6n} = PGE_{Baseline}$$

Test different values of k_2 until true. Fix k_2.

(h) Then, $k_1\left|LF^{LoadOnly}{}_i\right| + k_2 WF_i$ is half of the reserve requirement for load following, when considering load and wind with a perfect forecast.

(4) Additional Load Following for Wind Forecast Error (Hour-Ahead)

(a) Note that in a system with wind, there may be an additional reserve requirement in some hours to account for the errors in the hour-ahead wind generation forecast. To account for this forecast error a new stream of wind generation data is needed that will represent the forecasted wind, then we will need to revisit the concept of "load net wind", and then we will need to generate a new function that estimates the forecast error of wind depending on the production level of wind generation in an hour.

(i) Calculate a forecast error for wind (hour-ahead) by taking the the actual wind generation at twenty minutes (after the hour) in the hour previous to the one being forecasted and the hourly average wind in an hour. Recall that forecasted ten minute value $W_{i-1,10}$ is the value that represents the ten-minute average (forecast) value for the time period between ten minutes after the hour and twenty minutes after the hour.
More formally, if FE_i^{HA} is the forecast error for wind in the hour *i*, then

$$FE_i^{HA} = W_{i-1,10} - \overline{W_i}$$

(ii) To determine the additional reserve requirement needed due to forecast error, we must determine how much reserve is necessary to hold back due to forecast error per wind production level in an hour. In other words, derive a forecast error function:

$$FELF_i = h(W_i).$$

(iii) To find an appropriate $h(W_i)$, compare hourly average wind values with wind forecast error within an hour.

(iv) Sort all the forecast errors by wind production levels into ten equal sized subsets (bins) of $(0MW, 850MW)$.

$\overline{W_i} \in [0MW, 85MW)$, $\overline{W_i} \in [85MW, 170MW)$, ... ,
$\overline{W_i} \in [765MW, 850MW]$.

(v) To establish the standard deviation of the forecast error of each wind production bin, take the standard deviation of the data points FE_i^{HA} in that wind production bin.

(vi) Using the standard deviation of the wind forecast error for each bin, and the average wind production value of each bin, generate a least squares fit to a quadratic polynomial $h(W_i)$.

(vii) Since $FELF_i = h(W_i)$ represents the wind forecast error per hour at a particular wind production level in an hour, we can now use the wind variability function to determine how much additional reserve is required due to wind forecast error.

(b) Develop a new "forecasted" wind series $W_{i,j}{}^{*}$ that takes the forecast error calculated in step (i), and adds it to the actual ten-minute wind generation data.

$$W_{i,j}{}^{*} = W_{i,j} + FE_i^{HA}$$

(c) Define a new "load net wind" as the magnitude of the difference between actual load and wind forecast trend at a particular time:

$$\widehat{LNW_{i,j}}^{*} = L_{i,j} - \widehat{W_{i,j}}^{*}, \text{ where } \widehat{W_{i,j}}^{*} = \frac{\sum_{j-30}^{j+20} W_{i,t}{}^{*}}{6}$$

(d) Define the 10 minute deviations from hourly average load net wind as follows:

$$\Delta_{i,j}{}^{LNW^*} = \left| \widehat{LNW_{i,j}}^{*} - \overline{LNW_i} \right|$$

(e) If $\Delta_{i,j}{}^{LNW^*} > k_1 \left| LF^{LoadOnly}{}_i \right| + k_2 WF_i$, then count $\Delta_{i,j}{}^{LNW^*}$ as a outlier (in other words it is outside of the load following band for hour i).

(f) If the percent of outliers is more than the PGE Baseline (a percentage of outliers allowed), then more reserve is needed. More formally, if

$$\frac{count\left(\Delta_{i,j}{}^{LNW^*} > k_1 \left| LF^{LoadOnly}{}_i \right| + k_2 WF_i\right)}{6n} > PGE_{Baseline},$$

where 6n represents the number of hours in the study (n) multiplied by the 6 ten minute data points in an hour, then more reserve is needed.

(g) Let k_3 be a multiplier to $FELF_i$ that will make

$$\frac{count\left(\Delta^{LNW^*}{}_{i,j} > k_1 \left| LF^{LoadOnly}{}_i \right| + k_2 WF_i + k_3 FELF_i\right)}{6n} = PGE_{Baseline}$$

Test different values of k_3 until true. Fix k_3.

(h) Then, $k_1 \left| LF^{LoadOnly}{}_i \right| + k_2 WF_i + k_3 FELF_i$ represents half of the total reserves to be held back for load following and forecast error.