Portland General Electric
2009 Integrated Resource Plan

2011 Integrated Resource Plan Update

November 23, 2011

List of Tables

List of Figures

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 Variability[y3]*:*			
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

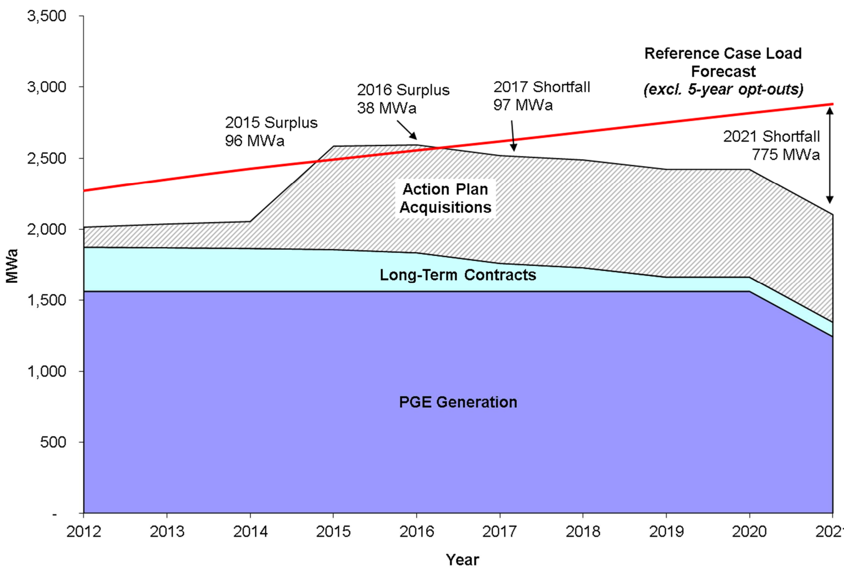


Table 1-2 shows the detail of PGE's overall load and resources in 2016. More detail about the load and resource changes since our IRP filing is found in Chapter 2.

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	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	2011 IRP Update	
	2015 MW	2015 MW	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

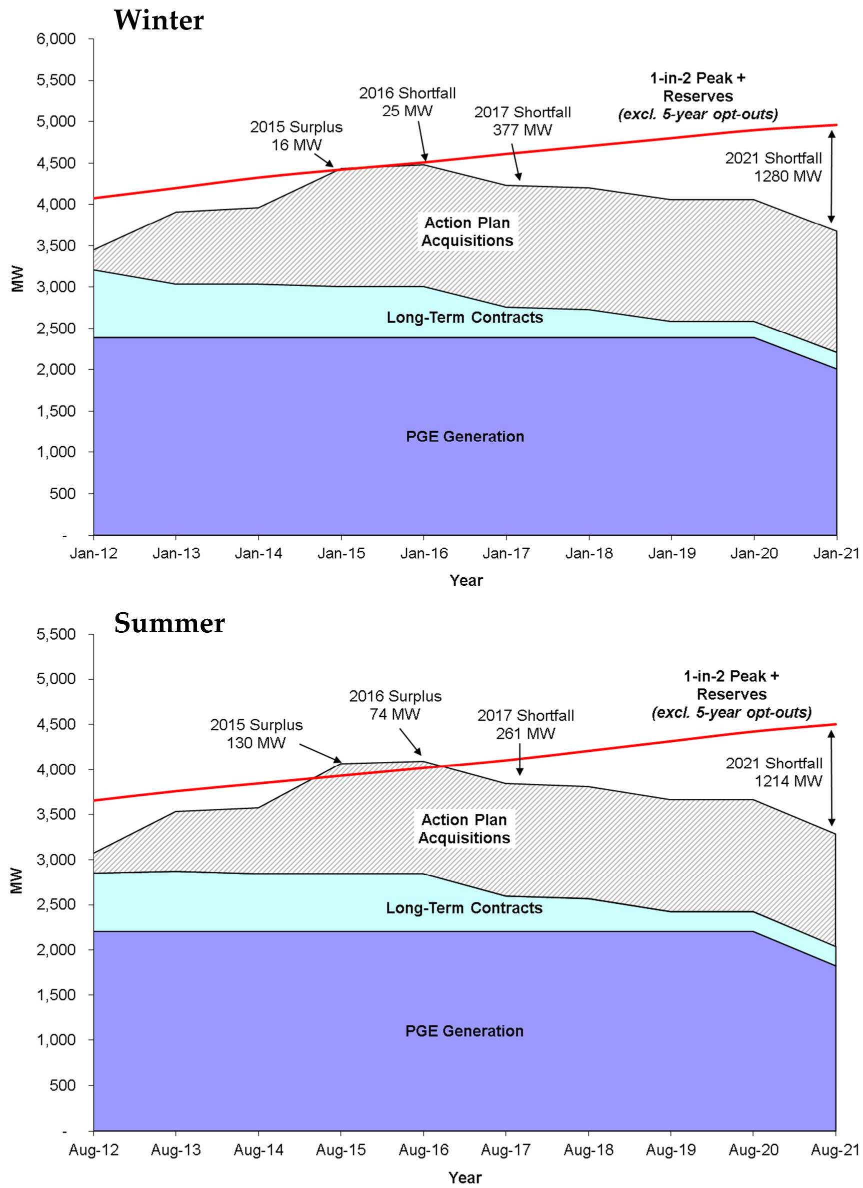
[2] Cumulative EE estimates by 2015 in the 2011 IRP Update are adjusted to include the EE projected by ETO in 2009 and 2010 for a correct comparison with the 2009 IRP. See Section 2.3 for more detail.

[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.

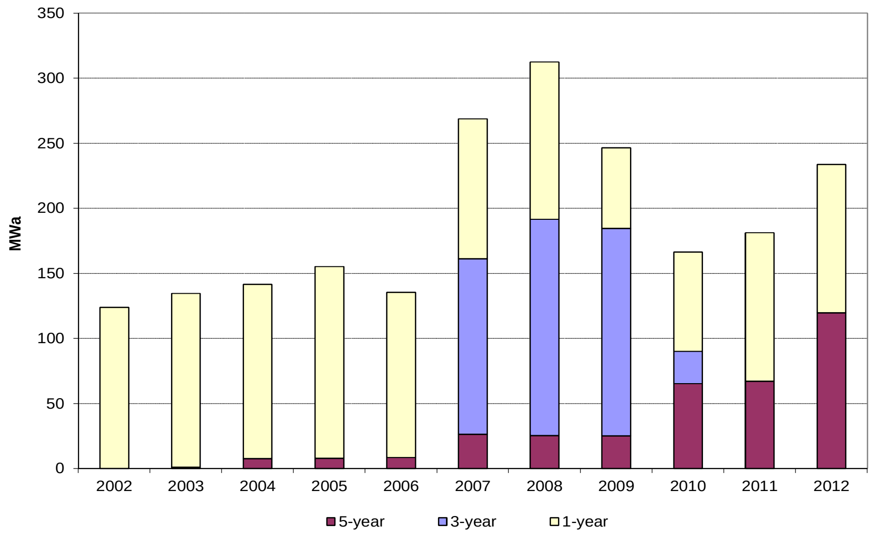
2.2 PGE's Cost-of-Service Load

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.

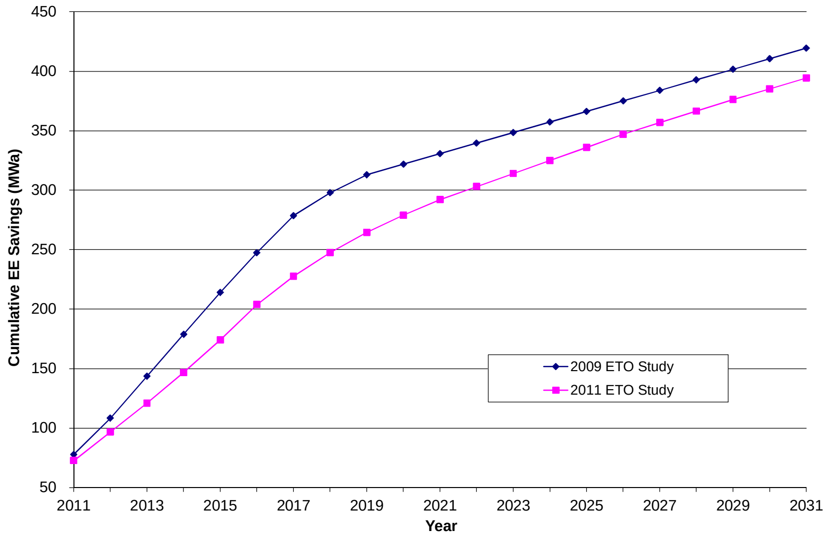
The projected cumulative shortfall (about 35 MWa) in 2015 differs from what we reported in Table 1-1 of the Action Plan (45 MWa in 2015) because of a two changes in methodology from our original IRP:

- 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

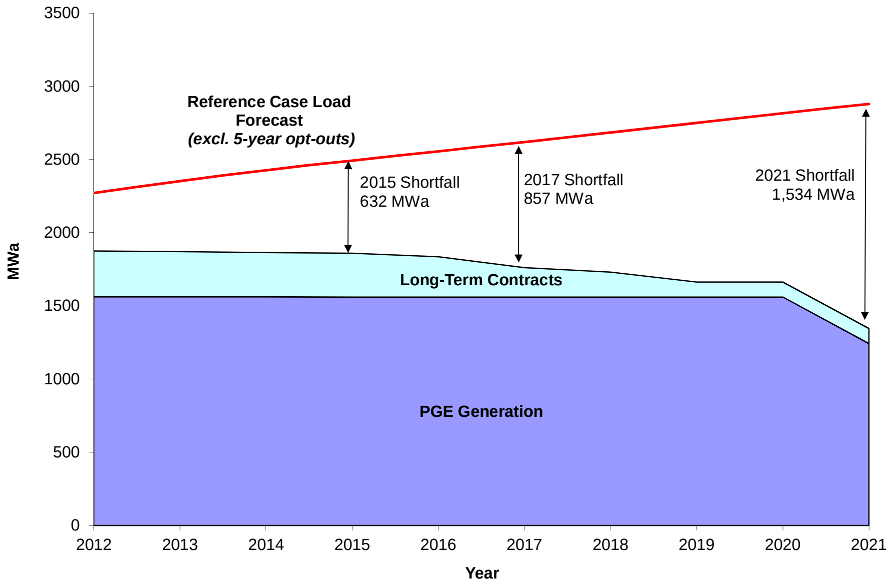


Figure 2-4 and Figure 2-5 show PGE's updated capacity needs for winter and summer, respectively. PGE remains significantly capacity deficit under the updated forecast. Our 2012 projected deficit is 859 MW in winter and 803 MW in summer. The expected capacity deficit, absent any additional capacity actions, 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

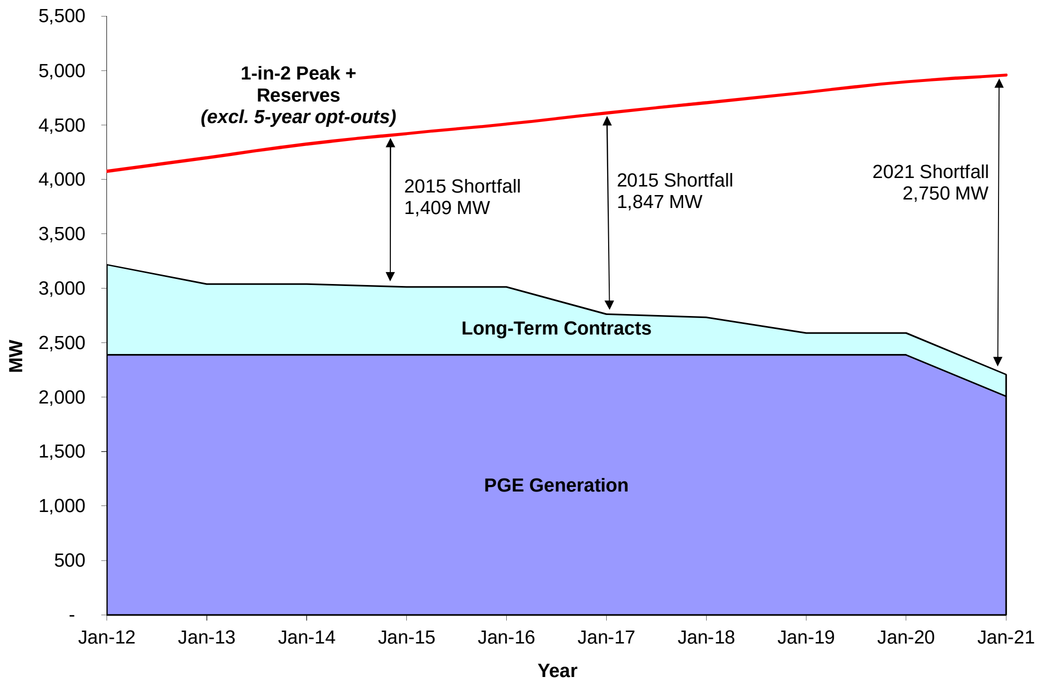
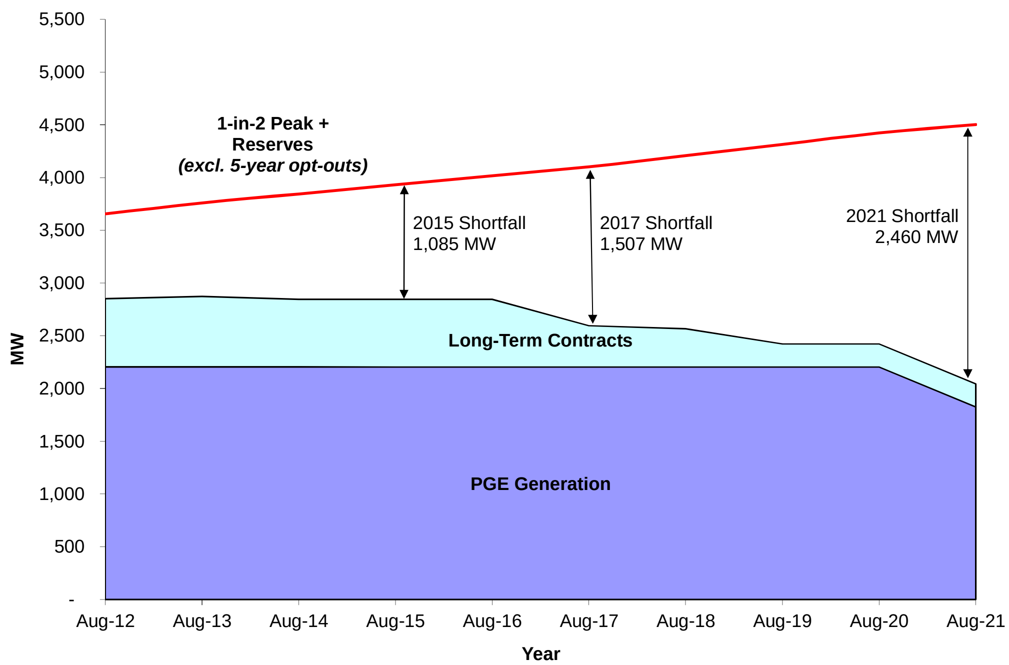


Figure 2-5: PGE Capacity Load-Resource Balance – Summer



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

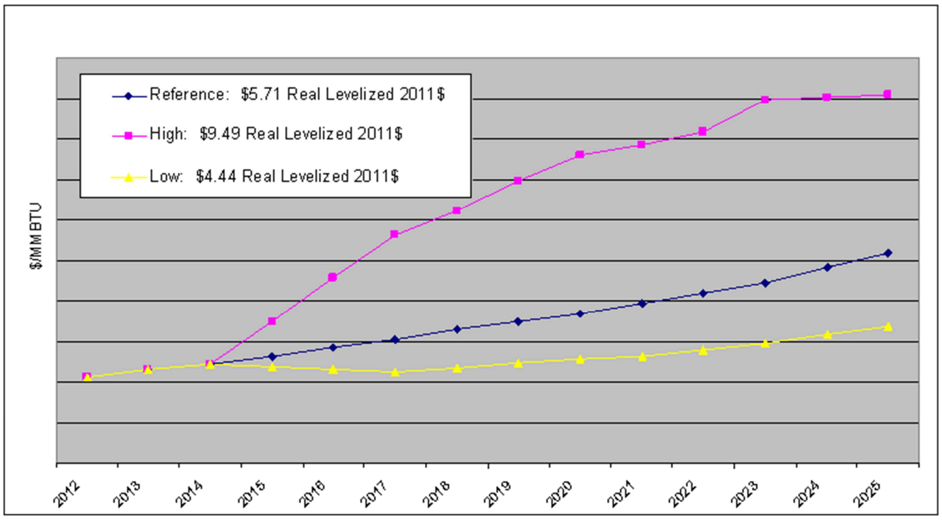
As stated in our 2009 IRP, PGE relies on independent third-party sources to project fuel prices. We updated the IRP forecasts using the most recent data available, PIRA's August 2011 forecast and the EIA's 2011 Annual Energy Outlook. To be consistent with our IRP methodology, we used the following approach:

- 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.

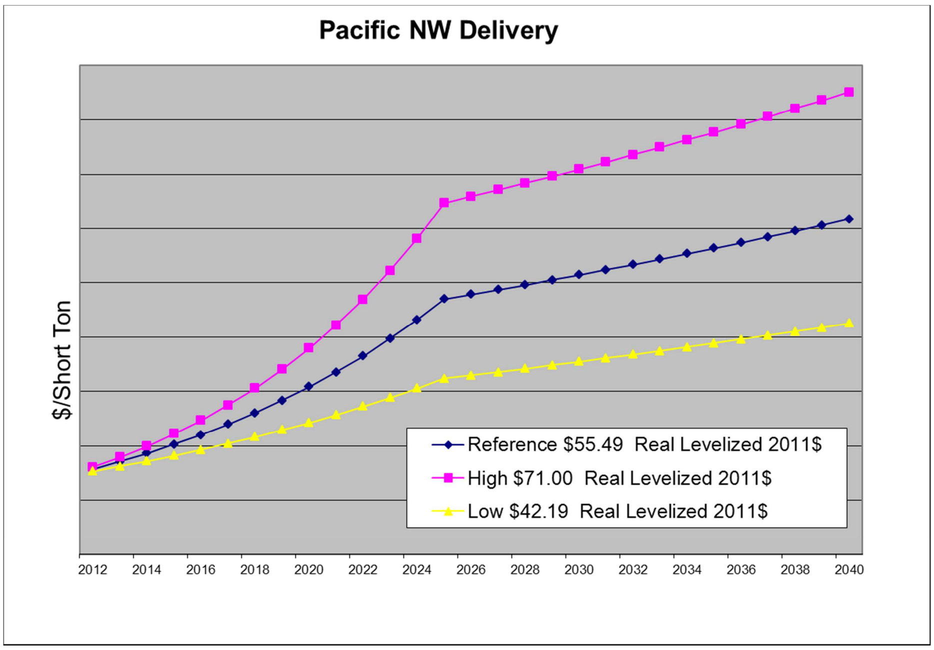
By comparison, the real levelized reference case natural gas price in the filed IRP was $7.88/MMBtu (2011$) for the same 2012-2025 period.

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

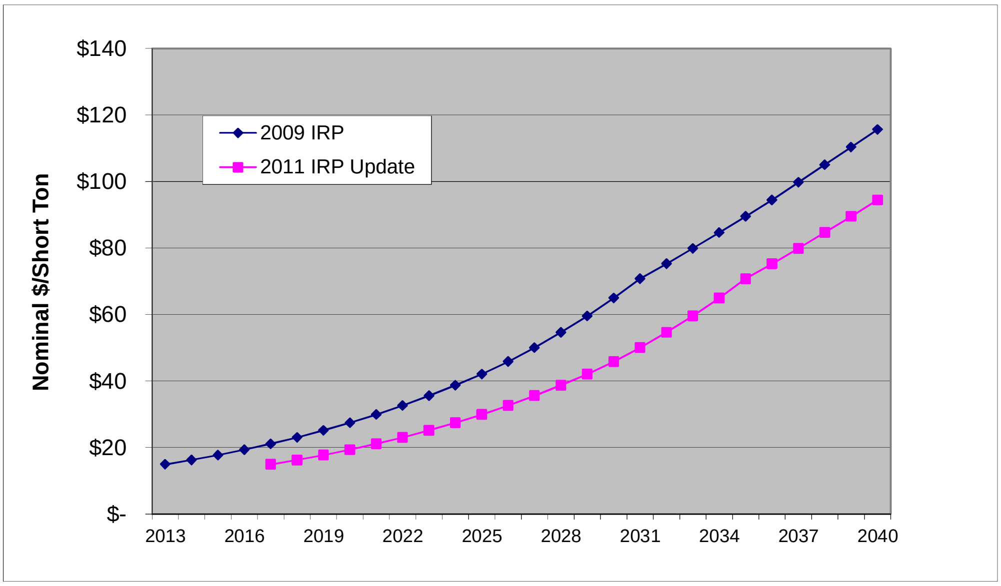


Figure 2-8 shows the effect of delayed implementation on costs. In this IRP Update, we postpone the implementation of carbon regulation and costs from 2013 to 2017.

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.

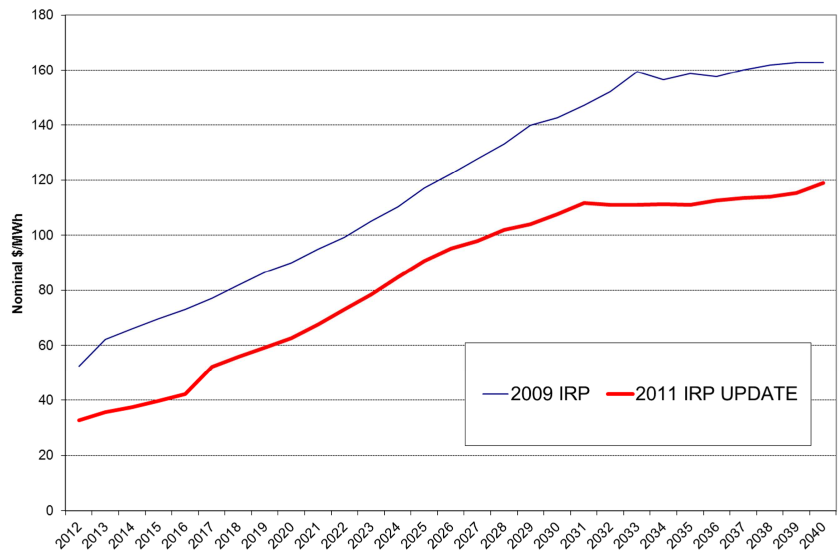
Table 2-4: Financial Assumptions

	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)

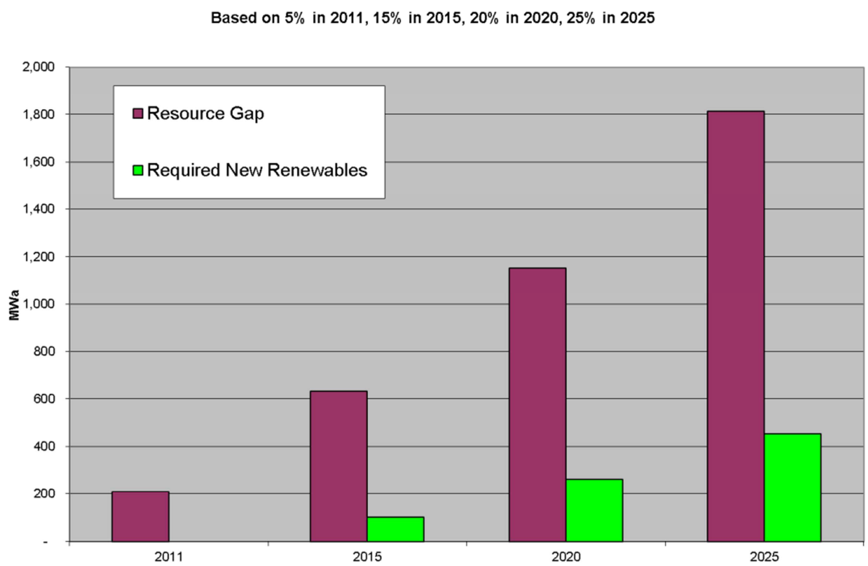
As illustrated in Table 4-1 above, our projected RPS resource deficits are significant when considered on an energy basis, and become even more challenging when converted to a nameplate generation requirement. To date, wind remains both the most available and cost-effective renewable resource. As such, 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

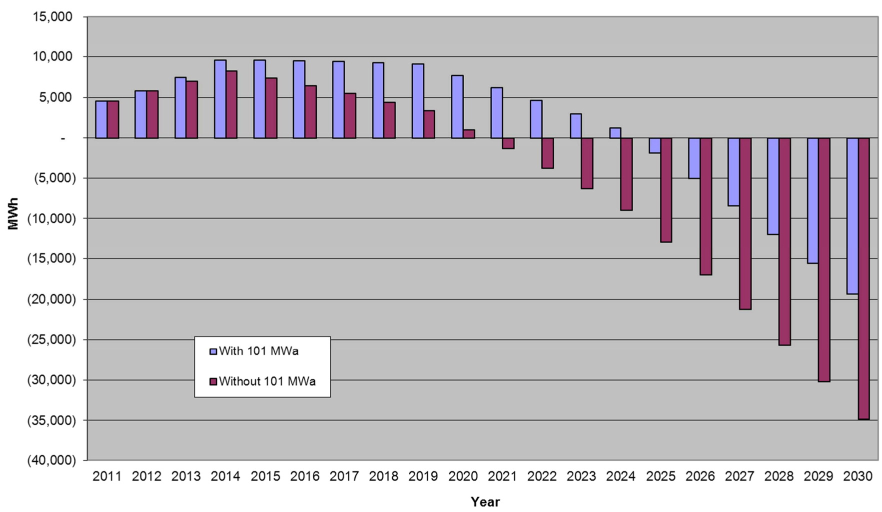
Our acknowledged Action Plan targets the procurement of additional new renewable resources to remain in physical compliance with Oregon RPS standards. More specifically, we are targeting the acquisition of additional renewable resources to be in physical compliance with, at minimum, the 15% RPS standard 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.