Portland General Electric Company
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November 5, 2009

Via E-filing and US Mail

Public Utility Commission of Oregon
Attn: Vikie Bailey-Goggins
550 Capitol Street, N.E., Ste 215
Salem, OR 97301-2551

Re: PGE 2009 Integrated Resource Plan

In accordance with Commission Orders 08-246 and 07-002, PGE hereby files an original and ten copies of its 2009 Integrated Resource Plan (IRP). Also included is PGE's motion for a Protective Order.

Our plan is the result of a diligent public process in which we conducted seven public workshops, actively solicited input from Staff and stakeholders, and participated in a number of regional forums that helped inform our planning process.

On September 4, 2009, we issued a draft IRP for public review and comment. We received ten sets of comments from stakeholders on our proposed plan.[1] We have considered the comments and have revised the draft IRP to address suggestions raised by our stakeholders. Specifically, we provide additional information on the cost of wind integration; discuss the effect of wind integration costs on our Cascade Crossing transmission line; provide additional information on our reference case assumptions; add a description of high and low wholesale electricity prices; add an appendix to show our detailed portfolio costs; and, add a graph showing the projected annual CO_2 emissions (before assumed federal cap and trade allowances) for each portfolio through 2030. We also provide updates to our stochastic analysis, coal and gas prices, assumed CO_2 mitigation costs, and to our discussion of EPA regulations. We have also made two technical corrections within our modeling.

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[1] The Pacific Environmental Advocacy Center attached comments from Synapse Energy Economics, Inc. – a Massachusetts-based consulting firm and incorporated approximately 1500 form letters submitted to PGE encouraging us to phase out the Boardman plant by 2016. In addition, we also received about 220 e-mails regarding the Boardman plant, most of which are organized closely around suggested message points from Onward Oregon's Web site.

Throughout our public process, parties have expressed concerns with our proposal to continue operating the Boardman plant through 2040. We recognize that our role as an electricity provider affects the environment. We are endeavoring to find ways to limit our environmental impact while meeting our obligation to provide reliable energy to our customers at a reasonable cost. We are proud of the fact that we rank among the top ten utilities for wind generation as a percent of load. We also were among the first IOUs in the U.S. to call for and signal support to federal legislation for national, economy-wide CO_2 emissions regulation. Our IRP also includes costs and sensitivities related to potential greenhouse gas legislation based on recent proposals and negotiations in Congress. These legislative proposals, which are the basis for our IRP CO_2 cost analysis, envision a substantial reduction in greenhouse gas emissions over time. The IRP therefore accounts for our participation in a future national CO_2 reduction plan.

We will continue to be pro-active at the federal and state levels on issues related to climate change. Our proposal to continue the operation of Boardman was made after careful analysis of a number factors including reliability, cost and cost stability for our customers and compliance with current and potential future regulations. The analysis specifically included a series of scenarios regarding the potential cost of carbon emissions. Even when considering a range of such costs, the fact is that Boardman remains a key part of a diverse energy portfolio. It allows us to provide 15% of our customers' energy needs with a reliable, stable and low-cost source of power. We believe that operating Boardman through 2040 continues to be the best choice for our customers given the alternatives available in accordance with the Oregon DEQ's Regional Haze Rule.

Some parties have encouraged us to look closely at a 2014 closure of the Boardman plant because it will result in lower local CO_2 emissions. We have carefully considered the implications of closing the Boardman plant in 2014 and have concluded that, among other concerns, we cannot realistically or responsibly close the plant in 2014 and continue to ensure reliable delivery of power to our customers. Our energy load-resource balance before acquiring 214 MWa of cost effective energy efficiency and 122 MWa of renewables necessary shows a resource gap of 873 MWa in 2015 with Boardman remaining in the portfolio. Closing Boardman in 2014 would increase the gap to 1,191 MWa. This gap would equate to approximately 43% of the average electricity demand for PGE's entire customer base. We believe that it would not be prudent for us to assume that such a large of amount of generation could be built or acquired from the wholesale energy markets in time to reliably satisfy the gap, especially in a time when there is pressure to close more fossil-fuel facilities. Even if we could obtain the energy from the market, we do not think it is prudent to subject our customers to the cost variability and reliability risks attendant on obtaining roughly one-half of our electricity from market purchases.

Several parties have encouraged us to seek clarification from DEQ as to whether there are any options for closing Boardman beyond those discussed in the EQC's June 19, 2009 order. We are attempting to obtain such clarification from DEQ. We will amend the IRP to include an analysis of any new options which are legally viable if they appear to be reasonable from a cost/risk basis.

We believe it is important that the Public Utility Commission and our stakeholders understand that the current IRP process must include a comprehensive decision on our proposal to install controls in 2011, 2014 and 2017. This is because the commitments for the 2011 and 2014 controls must be made before the next IRP will be acknowledged and investments in the 2014 and 2017 emissions controls are mutually dependent.

We look forward to continuing work with our stakeholders and the Commission on issues related to Boardman as well as other issues affecting our IRP.

Please direct communications, formal correspondence, and Commission Staff Requests regarding this filing to

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Sincerely,

Randy Dahlgren,
Director, Regulatory Affairs & Policy

Encl.

RD/jb

Integrated Resource Plan 2009



Portland General Electric

2009 Integrated Resource Plan

Portland General Electric Co.

November 5, 2009

This 2009 Integrated Resource Plan (the "IRP") represents the views of Portland General Electric Company at the time of preparation, based on information available at such time. The IRP includes forward-looking information that is based on our current expectations, estimates and assumptions concerning the future. This information is subject to uncertainties that are difficult to predict. As a result, the IRP is not a guarantee of future performance. We intend to revisit the plans and strategies set forth in the IRP on an ongoing basis and, as new information becomes available or as circumstances change, to make such changes as we deem advisable.

For more information, contact:

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List of Acronyms and Abbreviations

ACP	Alternative Compliance Payment
AEO	Energy Information Agency's Annual Energy Outlook
AGC	Automated Generation Control
AMI	Advanced Metering Infrastructure
ARRA	American Recovery and Reinvestment Act
ATC	Available transmission capacity
AWEA	American Wind Energy Association
BA	Balancing Authority
BACT	Best available control technology
BAL	Bank of America Leasing
BIPV	Building Integrated Photovoltaic
BPA	Bonneville Power Administration
B&V	Black and Veatch
CAA	Clean Air Act
CAES	Compressed air energy storage
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCCT	Combined-cycle combustion turbine
CHP	Combined heat and power
COS	Cost of Service
CO_2e	Carbon dioxide equivalent
CPP	Critical peak pricing
CSP	Concentrating solar power
CT	Combustion turbine
CUB	Citizens' Utility Board
DBB	Demand buy-back
DEQ	Oregon Department of Environmental Quality
DLC	Direct load control
DR	Demand Response
DSG	Dispatchable Standby Generation
EE	Energy efficiency
EGS	Engineered Geothermal System
EIA	U.S. Energy Information Agency
EIS	Energy Information Services
EPA	U.S. Environmental Protection Agency
EQC	Environmental Quality Commission
EPRI	Electric Power Research Institute
ESS	Energy Services Supplier
ETO	Energy Trust of Oregon
EUE	Expected unserved energy
FERC	Federal Energy Regulatory Commission

FGD	Flue gas desulfurization
FOR	Forced outage rate
FTE	Full time employee
GADS	Generating Availability Data System
GECC	General Electric Capital Corporation
GHG	Greenhouse gas
HHI	Herfindahl-Hirschman Index
HHV	Higher Heating Value
HRSG	Heat recovery steam generator
ICNU	Industrial Customers of Northwest Utilities
IDES	Information-Driven Energy Savings
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utility
IPC	Idaho Power Company
IPP	Independent power producer
IR	Integration of Resources transmission agreement
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
LGIA	Large Generator Interconnection Agreement
LNB	Low NOx burners
LNG	Liquefied natural gas
LOLP	Loss of load probability
Mid-C	Mid-Columbia
MACRS	Modified Accelerated Cost Recovery System
MOU	Memorandum of Understanding
MTTF	Mean time to failure
MTTR	Mean time to repair
NCEP	National Commission on Energy Policy
NERC	North American Electric Reliability Corporation
NITS	Network Integration Transmission Service
NOS	Network Open Season
NPV	Net present value
NPVRR	Net present value of revenue requirements
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NTTG	Northern Tier Transmission Group
NTAC	Northwest Transmission Assessment Committee
NWEC	Northwest Energy Coalition
NWP	Northwest Pipeline
NWPCC	Northwest Power and Conservation Council
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
ODOE	Oregon Department of Energy

OEFSC	Oregon Energy Facility Siting Council
OFA	Overfire air ports
OPT	Oregon Power Technologies
OPUC	Oregon Public Utility Commission
OSU	Oregon State University
OWET	Oregon Wave Energy Trust
PC	Pulverized coal
PCC	WECC Planning Coordination Committee
PGE	Portland General Electric
PIV	Plug-In Vehicle
PPA	Power purchase agreement
PPC	Public Purpose Charge
PPM	PPM Energy, Inc.
PRB	Powder River Basin
PSD	Prevention of significant deterioration
PTC	Production Tax Credit
PTP	Point-to-Point transmission agreement
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
REC	Renewable energy credit
RFP	Request for proposals
RH BART	Regional Haze Best Available Retrofit Technology
RISEC	River In-Stream Energy Conversion
RPS	Renewable Portfolio Standard
RNP	Renewable Northwest Project
RTO	Regional transmission organization
RVI	Rate Variability Index
R/W	Rights-of-way
SCCT	Simple-cycle combustion turbine
SCPC	Super critical pulverized coal
SCR	Selective catalytic reduction
SoA	South of Allston
SPP	State-wide pricing pilot
SRPB	Southern Powder River Basin
TailVar UE	TailVar of unserved energy
TCWG	Transmission Coordination Work Group
TEPCC	Transmission Expansion Planning Policy Subcommittee
TOU	Time of Use
TRC	Technical Review Committee
TSS	WECC Technical Studies Subcommittee
TTC	Total transfer capacity
Tribes	Confederated Tribes of Warm Springs
TWG	Technical Work Group

UWIG	Utility Wind Integration Group
VPO	Variable pricing options
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WGA	Western Governor's Association
WIS	Wind Integration Study
WREGIS	Western Renewable Energy Generation Information System

Executive Summary

PGE's 2009 Integrated Resource Plan is prepared at a time when we face considerable challenges and uncertainty driven by an economic recession, global concerns over CO_2 and other greenhouse gases, an increasing need to integrate new wind resources into our portfolio, significant transmission constraints within the region, new emissions controls mandated for our Boardman coal plant, and uncertainty over the long-term price of natural gas.

In this context, we have prepared this IRP based on some fundamental principles:

- Maintain compliance with all laws and regulations governing PGE and our business activities;
- Preserve the high standard of reliability that our customers are accustomed to and expect;
- Ensure high standards of safety at PGE electric generation and transmission facilities;
- Identify sustainable demand and supply choices that are socially and environmentally responsible;
- Be responsive to the interests of PGE's primary stakeholders, including customers, investors and the communities where we operate;
- Pursue a portfolio that provides diversity of technologies and fuel sources in order to minimize exposure to significant and unexpected changes in future circumstances that could adversely impact PGE and our customers; and
- Balance these quality-of-supply objectives against the imperative of keeping electricity prices affordable and stable.

Planning Context

Traditional electric generation choices and issues are greatly different today than they were just a few years ago. The sudden emergence of wind energy in quantities unimagined even in our last IRP has created new challenges for resource planning and system operations. Innovations in other technologies such as solar power are advancing and may have a considerable impact in future resource plans. At the same time, there is unprecedented uncertainty about the timing, form and cost of potential greenhouse gas legislation; the price for natural gas; and the ultimate impact of renewable energy standards on availability, cost and quality of renewable resources.

As we examined available resource choices to meet the future needs of PGE customers, a few major considerations significantly affected our analysis:

- PGE, like other utilities in the region that have benefited from a historically robust hydro system, has traditionally had greater energy needs than capacity needs. Due to reduced access to hydro, increased reliance on non-dispatchable and intermittent wind generation, and the continued growth of summer peak loads, our capacity needs now exceed our energy requirements and occur sooner (in 2013 versus 2015).

- The Oregon Regional Haze Plan and Oregon Utility Mercury Rule requirements at the Boardman plant have caused PGE to examine the risks and benefits of making substantial investments in new emissions controls against the risks and benefits of ceasing plant operations and replacing the resource with a new source of supply. The implications are significant given the costs of both choices and the important role that the plant has in our portfolio. The Boardman plant currently serves about 15% of our customers' electricity needs and provides a reliable, low-cost source of power. From a portfolio perspective, the plant provides important fuel diversity and benefits from the relative abundance and stable pricing of coal. An early closure would trigger the need to consider a major replacement resource during a timeframe in which additional resource needs are already considerable.

- The outlook for domestic natural gas supply has dramatically improved compared to just two years ago. With the discovery of vast domestic shale gas deposits, combined with drilling innovations enabling its relatively economic extraction, domestic gas supply is expected to be sufficient through at least 2025 without heavy reliance on liquefied natural gas (LNG). However, the future supply-demand balance for natural gas remains uncertain and price volatility will likely continue.

- Passage of the Waxman-Markey legislation in the U.S. House of Representatives gives us more insights regarding a possible near-term framework for regulation of CO_2 and other greenhouse gases. While the policy goals for CO_2 reduction targets and the potential regulatory mechanisms are becoming clearer, actual compliance costs are still uncertain, and the legislation may change considerably in the Senate and over the course of our planning horizon.

- Emerging technologies (e.g., hydro-kinetic technologies other than wave, low-temperature geothermal, CO_2 capture and storage or recycling, and next-generation nuclear) were not modeled as portfolio resource options in this IRP because, as a result of high technological and/or cost hurdles, they will not be available to meet our customers' needs during this resource planning term. In many instances, substantial regulatory challenges also exist.

- With the passage of Renewable Portfolio Standards (RPS) in Oregon and across the West, the role that renewable resources such as wind are playing in the regional resource mix has increased dramatically. As a result, it has been necessary for utilities in the Northwest to more carefully consider the impact of increasing levels of intermittent resources, as well as changes to portfolio mix and operations to support higher penetration levels. At the same time, RPS standards and concerns about future greenhouse gas legislation have increased the competition for renewable resources. The increased competition adds to the uncertainty regarding both the future availability and cost of these resources. Finally, some renewable resources continue to require existing federal and state tax incentives in order to be cost-competitive. Whether these subsidies will be either necessary or available in the future is uncertain and could have a considerable impact on the cost of meeting RPS requirements.

- Resource choices, both thermal and renewable, tend to be located far away from PGE's loads, underscoring the need for upgraded and new transmission links. We are encouraged by the apparent success of BPA's new approach to transmission expansion via its Network Open Season process. In addition, PGE has been proactive in examining our own options for developing new transmission to meet our current and future needs. These options are presented in detail in this IRP and, where appropriate, included in our recommended resource action plan.

In general, the historic trend toward increasing electrification appears to be continuing. Just as wind energy and compact fluorescent light bulbs were not under consideration as resource options 20 years ago, many opportunities for new supply and end uses with the potential to change how we do business are on the horizon. These include plug-in vehicles (PIV); smart metering and smart grid advancements; biogenic capture and recycling of CO_2 and biomass co-firing at coal plants; thermal and PV solar applications that are closer to cost parity with more traditional supply alternatives; ocean energy and other hydrokinetic forms of generation; next-generation nuclear plants; and various end uses such as LED lighting and hot-water heat pumps.

For now, however, there are limited resource alternatives available to meet our action plan requirements. Traditional utility generation technologies (hydro, coal, nuclear) face environmental and statutory concerns that hinder their development at this time. For all practical purposes, our current, large-scale renewable energy options are largely limited to wind. Non-wind renewables are constrained by economics, physical availability of the resource, geographic limitations, or a combination of these.

Compared with most utilities in the U.S., PGE is in a good position in that we currently have a diverse resource mix, a comparatively small environmental footprint and relatively competitive power prices. However, we anticipate that the general historical trend of stable or declining real costs for electricity may reverse as our portfolio evolves to meet the future requirements of growing customer demand, new legislation, and changes in technology and fuel availability.

Resource Needs

By 2015, we will need more than 870 MWa of new supply and demand resources to meet our annual average energy gap, as shown in the chart below. This shortfall is driven, in part, by ongoing load growth and by resource expirations. See Figure ES-0-1 below.

Figure ES-0-1: PGE Energy Load-Resource Balance to 2020

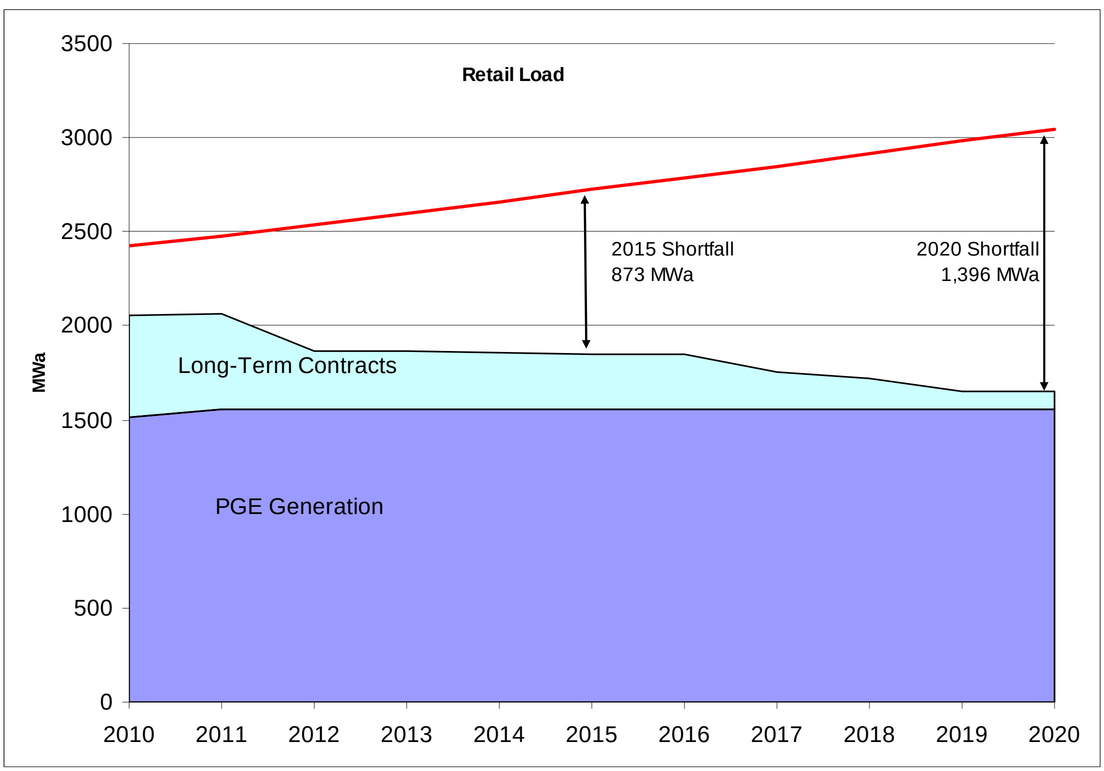
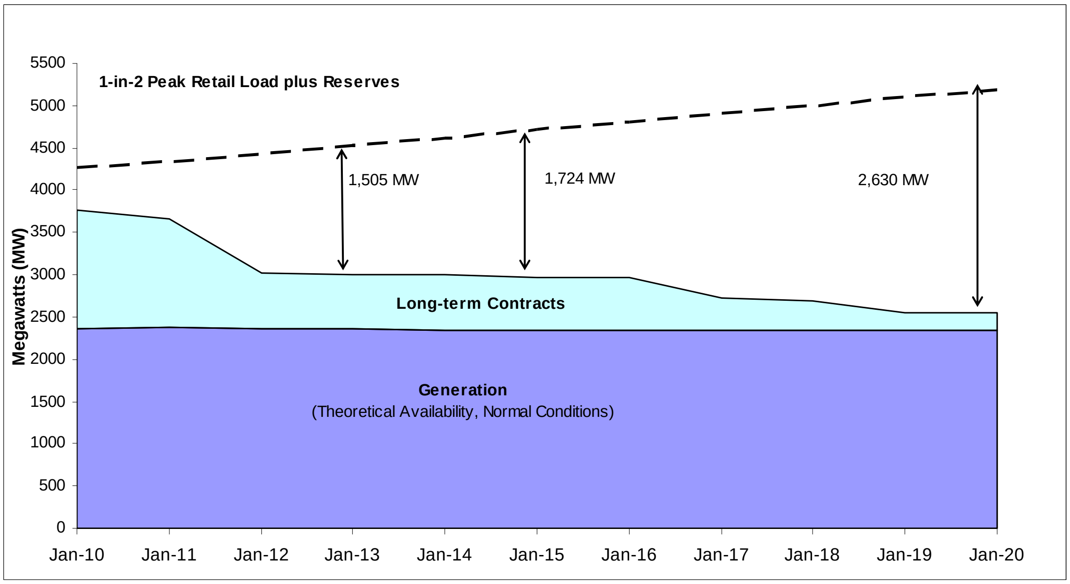


Figure ES-0-2: PGE Capacity Load-Resource Balance - Winter



In that same timeframe, we will need to acquire over 1,700 MW of capacity[1] to meet the needs of the highest hour of the year under normal (1-in-2) weather conditions, inclusive of required operating and planning reserves.

As with energy, our capacity shortfall is driven in part by continued growth in peak load requirements, but the greater driver is the loss of expiring hydro and capacity contracts. In addition, due to rapid growth in central air-conditioning, PGE is transitioning from being a winter-peaking utility to being a dual-season peaking utility.

Our Planning Approach

We have made every effort in this IRP to account for both the letter and spirit of the OPUC's IRP Guidelines. Over the course of a year, we conducted seven day-long public stakeholder meetings, presenting our assumptions, analytics and results, while also seeking – and greatly benefiting from – stakeholder feedback.

To arrive at a portfolio of new supply and demand resources that provides the best combination of expected cost and associated risk and uncertainties, we evaluated 15 candidate portfolios with major resource additions out to the year 2020 under 21 futures[2], with hourly economic dispatch through 2040, inclusive of end effects[3]

[1] Before accounting for the capacity contribution of energy actions to fill our 800+ MWa energy need

[2] Futures are a set of input assumptions for the behavior of a set of variables over the planning horizon; see Chapter 10 – Modeling Methodology for more detail.

thereafter. In our analysis, we used a combination of expected cost under reference case conditions in conjunction with scenario (deterministic) and stochastic risk metrics to assess cost uncertainty. In addition, we evaluated portfolios for reliability, as well as fuel and technology diversity. We then took the performance of our portfolios based on expected cost and the risk metrics described above and applied weighting factors to arrive at a composite portfolio score.

Most of the foregoing metrics are specifically called for in the OPUC IRP Guidelines. A few others provide additional insights not contemplated in the Guidelines. The IRP Guidelines provide a detailed framework for examining the strengths and weaknesses of resource plans and underscore the inherent and increasing complexity of Integrated Resource Planning. Although we have performed a rigorous evaluation of portfolio cost performance while considering a wide range of risks and uncertainties, such an analysis cannot account for or quantify every consideration. We must also emphasize that a portfolio scoring approach does not replace prudent utility judgment or the necessity to consider qualitative factors and the viability of implementing a preferred resource action plan.

We also have included a detailed analysis of our transmission needs, along with proposed actions, recognizing that the region's current transmission infrastructure is not capable of bringing diverse new resources, such as wind energy from remote areas east of the Cascades, to load centers without significant new investments to improve both reliability and capacity of the bulk transmission system.

The Boardman Decision

In Chapter 12 we present a careful analysis of the considerations and tradeoffs of continued operations of the Boardman plant with full Oregon Regional Haze Plan and Oregon Utility Mercury Rule compliance versus cessation of plant operations and replacement supply options. PGE recommends proceeding with the Phase 1 and 2 emissions control upgrades and retaining Boardman in our resource portfolio. This recommendation is based on the results of our portfolio analysis, which indicate similar expected cost results between the top-performing portfolio that retains Boardman through 2040 and the top-performing early closure case that ceases Boardman operations in 2014. In addition, the preferred portfolio with Boardman through 2040 performs considerably better across most risk metrics, including scenario and stochastic price risk, and supply reliability measures. The preferred portfolio also provides for increased fuel and technology diversity when compared to the early shutdown cases.

[3] End effects are calculated for generation projects that have a book life beyond 2040 and reflect the value of these plants which would otherwise not be captured in our modeling planning horizon, which extends to 2040; see Chapter 10 – Modeling Methodology for more detail.

Further details regarding the results of our portfolio analysis for Boardman can be found in Chapter 12.

Proposed Action Plan

Our proposed Action Plan is a subset of our preferred portfolio (see Chapter 11, Preferred Portfolio Recommendation) and includes actions that we would undertake in the next two to four years with the goal of new supply being in place by no later than 2015. The Action Plan calls for a mix of new energy efficiency (EE), renewable resources and efficient natural gas generation for both energy and capacity needs.

Specifically, the Action Plan features the following elements:

1. Acquire all cost-effective EE (215 MWa), which offsets almost 60% of PGE's load growth through 2015. This EE acquisition exceeds the implied amount targeted for PGE in the draft Northwest Power and Conservation Council's 6th Plan. Because EE delivers nearly 1.5 times more energy savings during winter peaking conditions than on an annual average, it also provides a substantial reduction in PGE's capacity requirements.

2. Acquire at least 122 MWa of new renewable energy by 2015 to be in compliance with the 2015 Oregon Renewable Portfolio Standard target. This action was previously found to be reasonable in our last IRP; however, we have not yet been able to fill this target.

3. Acquire cost-effective Dispatchable Standby Generation (52 MW), resulting in 120 MW of peaking capability by 2015.

4. Acquire approximately 400 MWa of new, high-efficiency natural gas generation by 2015.

5. Renewal of expiring hydro contracts, if they can be renewed cost-effectively, in order to maintain fuel diversity.

6. Acquire up to 200 MW of new flexible natural gas generation by 2013 to meet peaking needs and future load and intermittent resource variability.

7. Implement all emission controls required under the Oregon Regional Haze Plan and the Oregon Utility Mercury Rule to continue operations at the Boardman plant in order to capture the value of its fuel diversity and reliability of supply.

8. Exercise one of our options under the Bank of America Leasing agreements to acquire an additional 15% share of the Boardman plant output, thereby adding 72 MWa of existing Boardman generation to PGE 's portfolio.

9. Acquire 100 MWa of energy supply from the mid-term market via rolling PPAs to hedge against load uncertainty.

10. Acquire up to 283 MW of limited duration peaking supply (152 MW winter, and 131 MW bi-seasonal) from the market.

11. Continue building a demand response (DR) supply portfolio targeted at 60 MW of bi-seasonal supply by 2015.

12. Conduct preliminary engineering, siting and permitting activities and, subject to achieving certain milestones and participation described in Chapter 8, construct a 500 kV double-circuit transmission line connecting the southern portion of our service territory near Salem, Oregon, to our Boardman and Coyote Springs plants near Boardman, Oregon.

13. PGE will immediately issue one or more RFPs for action items 2, 4, and 6 upon obtaining Commission acknowledgment of the plan. PGE will submit a benchmark wind resource and benchmark energy and capacity natural gas resources into the RFP(s).

Conclusion

Our basic choices to meet future load in this IRP are energy efficiency and (to a lesser degree) demand response, renewable resources (primarily wind), and natural-gas-fired generation. We plan to maximize the acquisition of EE by continuing to work closely with the Energy Trust of Oregon and our customers. While we considered out-of-state nuclear and IGCC coal options, our top-performing portfolios exclude these in favor of a mix of new renewable resources and high-efficiency natural gas generation.

In the end, while PGE has sufficient resources to meet our customers' needs in 2009 and 2010, we will require capacity and energy resource additions beginning as soon as 2013. Given the lead times for construction of new generation, as well as the timelines to meet the requirements of the Oregon Regional Haze Plan and Oregon Utility Mercury Rule, PGE feels a sense of urgency in receiving acknowledgement of the Action Plan so that we may move forward in a timely manner to prepare for and implement the resource decisions.

1. IRP Process and Stakeholder Involvement

The primary goal of the Integrated Resource Plan is to identify a resource action plan that provides the best combination of expected cost and associated risks and uncertainties for the utility and our customers. We do this by evaluating the performance of various portfolios of new and existing resources against varying potential futures over a planning horizon of at least 20 years (for this IRP from 2010 to 2040). Our planning is guided by regulatory orders issued by the Oregon Public Utility Commission (OPUC). Throughout the IRP process we also share with customers, regulators and other stakeholders the results of our research, analysis and findings with respect to anticipated resource requirements and alternatives for serving our customers' future electricity needs. The next sections briefly discuss the regulatory requirements and public dialogue that have helped shape this IRP.

Chapter Highlights

- The primary goal of the IRP, as defined in OPUC Order No. 07-002 governing utility planning, is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.
- PGE actively seeks input from customers, OPUC staff and other stakeholders throughout the IRP process.
- PGE hosted seven public workshops to discuss with stakeholders our future energy needs, assumptions, modeling methods and analytical results.
- We incorporated in our analysis several new sensitivities suggested by stakeholders during the public process.
- PGE also participates in a number of regional forums that inform and influence our planning.

1.1 Regulatory Requirements

Order 08-246: PGE's 2007 IRP

We filed our last IRP in June 2007. The 2007 IRP called for significant resource acquisitions, approximately 903 MWa of energy resources, and an additional 748 MW of incremental capacity resources in 2012. On May 6, 2008 the Commission issued Order No. 08-246, declining to acknowledge PGE's 2007 IRP but determining that the renewable resource actions in the plan were reasonable. The Commission directed PGE to submit a new IRP within 18 months of the effective date of Order No. 08-246, or by November 5, 2009, and mandated a number of conditions for PGE's next planning cycle.

Order No. 07-002: Adoption of IRP Guidelines

In January 2007, the OPUC issued Order No. 07-002 adopting updated IRP guidelines[4]. The Commission stated that the primary goal of the IRP remains the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. However, the Commission's Order clarifies and updates certain elements of the prior resource planning guidelines, and also adds some new procedural and analytical requirements. This IRP meets the requirements of Order No.07-002, while at the same time recognizing the changing power supply and policy environment that we face. Specifically, our IRP incorporates:

- Energy efficiency provided by the Energy Trust of Oregon (ETO) as well as incremental energy efficiency (EE) acquisitions.
- All system load in our load forecasts, except that of customers expected to opt out of PGE service on a long-term basis.
- An evaluation of all supply-side resource options, including distributed generation and resources not yet commercially available, but which are expected to be available in the near future.
- More extensive risk analysis, both on a stochastic (i.e., analysis incorporating random fluctuations in inputs) and scenario bases.
- Several other sensitivities beyond those required in Order No. 07-002 (see Chapter 10).

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[4] The guidelines were subsequently corrected in an errata order (Order No. 07-047) issued on February 9, 2007.

- The following cost and risk measures:
  - Net present value of revenue requirement (NPVRR) and associated risk for each candidate resource portfolio, including both variability of costs and the severity of bad outcomes.
  - Reliability measures, including loss of load probability, expected unserved energy, and the TailVar90[5] of expected unserved energy.
  - Stochastic as well as long-term scenarios.
  - A wide range of possible future CO_2 compliance costs.

We provide a detailed description of how we comply with the provisions of Order No. 07-002 in *Appendix A: Compliance with Order No. 07-002*.

Order No. 08-339 – Adopted Guideline 8: Environmental Costs

In Order No. 08-339, the Commission adopted a refined Guideline 8 of Order No. 07-002 on environmental costs. Order No. 08-339 instructs the utility to construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for CO_2, nitrogen oxides, sulfur oxides and mercury emissions. The utility must also develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.

We discuss how we comply with the provisions of Order No. 08-339 in Chapter 6 and Chapter 11.

Other OPUC Orders

The Commission has issued additional orders which provide requirements applicable to the IRP process. For example, Order 07-499 modified the IRP Guidelines to include a recommended standard for fossil fuel generation

[5] TailVAR90 is the average of the worst 10 percent of NPVRR outcomes.

efficiency and Order 07-083 directed PGE to analyze, in its IRP process, the valuation and risks associated with the disposition of tradable Renewable Energy Credits (RECs). PGE has satisfied these and any other applicable regulatory requirements in this IRP. We address the disposition of RECs in Chapter 6 and fossil fuel generation efficiency in Chapter 7.

1.2 Planning Context

The 2009 IRP is being prepared in a period of unprecedented uncertainty for PGE. The greatest of the uncertainties is the impact of federal carbon legislation that is expected to be enacted by Congress in the near future. At this time, it is not possible to predict with any certainty the level of carbon tax that may emerge or the implications of those costs on our resource options. Another major uncertainty is future natural gas prices and supply. With gas-fired generation being one of the few viable new base-load supply-side resource options available, the continued volatility in gas prices adds to the uncertainty we face. In addition, the nation and region are in the grip of the worst economic recession and financial market instability since the 1930s, which is having at least short-term impacts on our load growth. How long this recession will persist, and whether economic activity and new construction will rebound in the near term to support traditional levels of load growth, remains unclear.

These macro-economic factors are coupled with more localized issues, including pending new regulatory requirements for emissions controls at our Boardman coal-fired power plant, the need to meet our Renewable Portfolio Standard (RPS) requirements and continuing transmission constraints across the Pacific Northwest. On June 19, 2009, the state Environmental Quality Commission (EQC) acted on a state Department of Environmental Quality (DEQ) recommendation to further limit certain emissions from the Boardman plant, which supplies 15% of our customers annual energy needs. Uncertainty regarding future Boardman plant operations could create significant challenges in meeting our customers' future resource needs. At the same time, we have been actively pursuing additional wind energy and other renewable resources but are competing with other utilities in the region, many of which also have RPS standards to meet. Even if we can develop or purchase new supply-side resources successfully, we need to be able to transmit that power to our customers. Transmission congestion throughout the region, particularly along the Cross-Cascades South cutplane, if not addressed soon, will make it difficult for us to capitalize on available new resources, most of which are located east of the Cascade Mountains.

Another factor contributing to the complexity of our planning is the increasing need for capacity resources, particularly in light of rapidly increasing winter and summer peak load growth and the loss of our Mid-Columbia (Mid-C) hydro contracts. Mid-C contracts provided us with a dependable and dispatchable capacity resource. At the same time we are acquiring increasing amounts of wind generation which does not provide a reliable capacity resource for our system.

Given the challenges and uncertainties that we face with respect to supply-side resources, we have also been aggressively pursuing cost-effective demand-side resource options, working closely with the ETO and leveraging our relationship with customers to promote energy efficiency. Through these efforts, we are seeking both to reduce our energy requirements and to achieve peak-load reduction through demand-response programs. Still, the weakened economy could impact the EE market if customers choose not to invest in EE or if incentive levels have to be increased to achieve our targets.

1.3 Public Outreach

In this challenging environment, we have sought input from a variety of stakeholders as we developed our 2009 Plan. As part of the IRP process, PGE solicits input from various stakeholder groups to ensure that we understand and consider the perspectives and feedback of our external constituents, and to demonstrate that our conclusions meet the cost and risk objectives of IRP. Our public outreach takes three forms: 1) public meetings at which we review and allow stakeholders and customers the opportunity to comment on key assumptions, research and analysis; 2) direct outreach activities to PGE customers; and 3) participation in state and regional planning efforts.

Public Meetings

To help ensure that the views of our customers and other stakeholders are well-represented in this IRP, PGE hosted seven public workshops. In these workshops PGE discussed with the parties the fundamental building blocks of the IRP as well as our assumptions, modeling techniques and analytical results.

Participants in our public meetings included representatives from the following organizations:

- Citizens' Utility Board (CUB)
- City of Portland
- Energy Trust of Oregon (ETO)
- Industrial Customers of Northwest Utilities (ICNU)
- NW Energy Coalition (NWEC)

- NW Natural
- Northwest Power and Conservation Council (NWPCC)
- Oregon Department of Energy (ODOE)
- Oregon Pubic Utility Commission (OPUC)
- Pacific Environmental Advocacy Center
- Renewable Northwest Project (RNP)
- Sierra Club

Some of the fundamental building block discussions included:

- Load/resource balance (future energy and capacity requirements)
- Fuel market fundamentals and forecasts (natural gas and coal)
- Transmission and natural gas transportation considerations
- Energy and capacity resource options
- Demand-side resources
- Supply-side generation resources
- Boardman emissions controls
- Federal and state policy developments, including potential climate change legislation
- Modeling approach and IRP risk metrics

See *Appendix B* for a detailed description of topics covered throughout our public process.

To facilitate ease of communication with interested parties PGE published all the presentation materials from the public meetings on our website. These materials may be accessed at www.portlandgeneral.com/irp[6]. In addition, PGE will make available copies of the Final IRP and the accompanying technical appendices on this website, once filed with the OPUC.

Throughout our public meetings, participants were encouraged to ask questions about our analytical process, comment on our candidate resource action plans, and request additional information. The results and findings from such requests were presented at subsequent meetings. We found these meetings to be very valuable, and as a result of the stakeholder dialogue, we incorporated a number of suggested sensitivities and modifications in our research and modeling. For example:

- We incorporated the following analytical sensitivities:
    - A scenario consisting of high CO_2 and gas costs combined with low coal price forecasts;

[6] In several areas, information and assumptions presented in the workshops, which began in June 2008, were subsequently revised. The material contained in this document takes precedence over all previously published material.

    - An aggressive projection of EE;
    - Additional combined-cycle combustion turbines (CCCTs) instead of simple-cycle combustion turbines (SCCTs) in portfolios that have wind in order to provide integration capacity.
- We worked with OPUC Staff on plant end-of-life analytics.
- At ODOE's request, we analyzed solar availability and its potential for matching PGE's load.
- At OPUC Staff's suggestion, we analyzed wind capacity contribution to see if the Northwest Power and Conservation Council's 5% value was also a good proxy for PGE's wind plants.

1.4 Participation in Regional Planning

PGE also participates in a number of regional forums that inform our planning process. We believe that it is important for the Company to be aware of and help guide and shape regional initiatives and industry groups that address resource planning and utility operations. By doing so, we are better able to identify and influence emerging issues and policy developments that could either favorably or adversely impact future portfolio choices. These include:

- Northwest Power and Conservation Council
    - Generating Resources Advisory Committee (GRAC)
    - Resource Adequacy Committee
- Transmission Expansion Planning Policy Subcommittee (TEPPC)
- Transmission Issues Steering Committee
- BPA Collaborative
- WSPP (formerly the Western Systems Power Pool)
- Northern Tier Transmission Group (NTTG)
- Transmission Coordination Work Group (TCWG)
- ColumbiaGrid
- Oregon Governor's Renewable Energy Working Group
- Oregon Energy Planning Council
- Oregon Global Warming Commission
- Northwest Transmission Assessment Committee:
    - Montana-Northwest Study Group
    - Canada-Northwest-California Study Group
    - Northwest Wind Integration Study Group
- Northwest Wind Integration Action Plan
- Western Electricity Coordinating Council (WECC) Variable Generation Subcommittee
- American Wind Energy Association (AWEA) Utility Work Group
- Northwest Power Pool Temperature Related Variable Generation Subcommittee

- Utility Wind Integration Group (UWIG)
- Oregon Wave Energy Trust (OWET)

PGE also active participated in OPUC dockets which relate to our integrated resource planning process such as the AR 518 and UM 1330 dockets addressing administrative rules for the Oregon Renewable Portfolio Standard and the Renewable Adjustment Clause respectively.

2. Existing Resources

PGE's existing resources represent a diverse combination of thermal, hydro-electric, and wind generating plants, and wholesale market purchases. PGE's power supply portfolio in 2009[7] includes annual average energy availability (by fuel type) of approximately 41% from natural gas-fired generation, 25% PGE-owned hydroelectric generation and long-term contracts for Mid-Columbia hydro, 23% coal, 7% other long-term contracts, and 4% from non-hydro renewable resources.

The expiration of several energy and capacity contracts by the year 2012 is one of the major drivers of our resource need going forward.

Chapter Highlights

- PGE's current generating resources include five thermal plants, seven hydroelectric plants, and the Biglow Canyon wind facility with total combined generating availability of 1,838 MWa. In addition, we have 614 MWa of long-term contracts.
- Since the 2007 IRP, PGE has completed the Port Westward natural-gas-fired plant, Biglow Canyon wind project phases I and II and added two solar projects to our generation portfolio.
- Biglow Canyon III will come on line by 2010, and will add 61 MWa to our resource portfolio.
- The expiration of contracts totaling almost 300 MWa in energy and over 800 MW of capacity is one of the key drivers of our need for new capacity resources starting in 2013 and new energy resources in 2015.

[7] This breakdown is based on our owned and contracted resources alone; it does not include market purchases or energy efficiency.

2.1 PGE Today

PGE serves approximately 810,000 customers in 52 Oregon cities. As Oregon's largest utility, our service territory attracts major employers in diverse industries, such as high technology and health care. Our historic 2% annual load growth has been faster than the national average, although the current economic downturn will influence near-term growth. In 2008, total retail energy deliveries increased 1.05% over 2007 levels to 19,838,137 MWh or 2,264 MWa.

PGE's current power supply portfolio is a diverse mix of generating resources that includes hydropower, coal and natural gas combustion, and wind resources currently providing 1,838 MWa of energy annually. In addition, we rely on long-term contracts for another 614 MWa. Phase II of our Biglow Canyon wind plant was completed in August, 2009 and Phase III will be completed by the end of 2010. These two additional phases of Biglow Canyon are expected to produce 114 MWa[8] of energy each year. The expansion of Biglow Canyon better positions us to meet Oregon RPS requirements as well as ongoing customer needs with a relatively stable-cost renewable resource. In addition, expansion of the project provides economies of scale by utilizing common facilities constructed during the initial phase of the project.

A key factor in our future resource needs is the recent and impending loss of owned and contractual energy resources. During 2008, we completed the decommissioning of the Bull Run hydro plant, reducing our generating availability by 11 MWa. Between 2008 and 2015 we also will lose approximately 300 MWa of contractual energy resources, although we will seek to renew some portion of them, if economic and available. Over the same period approximately 870 MW of winter capacity contracts expire.

In 2009, our total power supply availability will be 2,452 MWa of physical supply, including 1,838 of owned resources, and 614 MWa of contracts additionally there are 23 MWa of energy efficiency (EE) forecasted. These figures do not include any additions that may be forthcoming from PGE's 2008 Renewables Request for Proposals (RFP).

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[8] Based on our operating experience with Biglow Canyon Phase I, we are predicting a higher output from Phases II and III than was originally reported in the 2007 IRP.

Figure 2-1 shows PGE's 2009 energy resource mix on an annual average availability basis.

Figure 2-1: PGE 2009 Annual Average Energy Resource Mix (Availability)

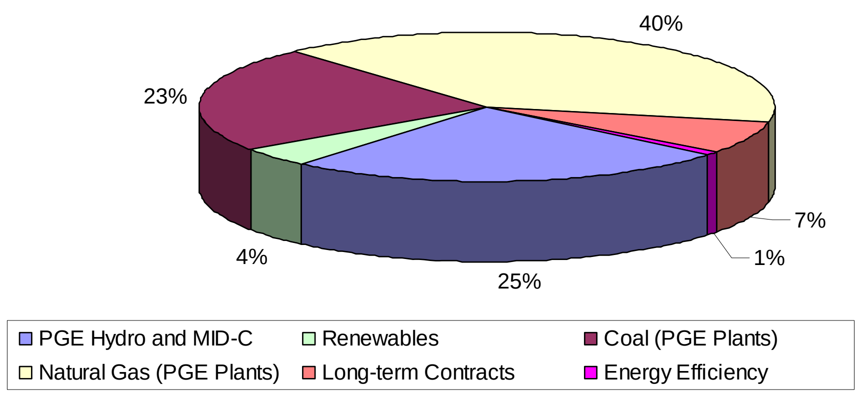
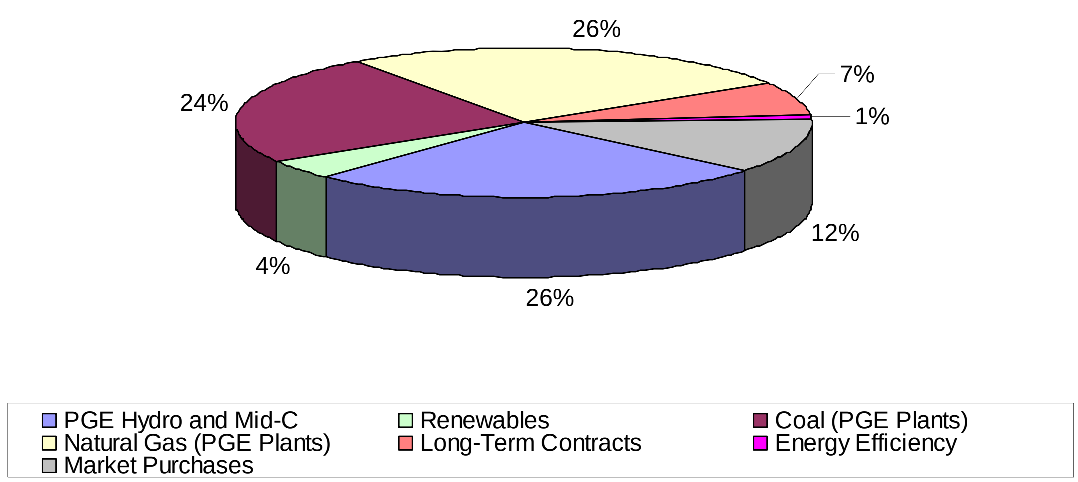


Figure 2-2 below shows our expected 2009 resource mix after economic dispatch. This is a more realistic view of how PGE meets retail load. This graph demonstrates that the flexibility of our gas generation allows us to capture economy energy opportunities through market purchases. This is largely driven by the economic displacement of Beaver, which we describe in the next chapter.

Figure 2-2: PGE 2009 Annual Average Resource Mix (After Economic Dispatch)



2.2 Actions Taken Since the 2007 IRP

In 2007, PGE completed supply-side actions pursuant to our last acknowledged IRP Action Plan (2002). The Port Westward plant became available for commercial operation on June 12, 2007 and Phases I and II of the Biglow Canyon wind project came on line in December 2007, and August 2009 respectively.

Since filing the 2007 IRP, PGE has added additional peaking resources, through the expansion of our dispatchable standby generation (DSG) program at customer sites. As of June 2009, PGE has 59 MW of DSG available.

PGE has sought additional demand response opportunities through various programs, including demand buy-back, energy information services, time-of-use pricing, load curtailment contracts, residential direct load control and real-time pricing. The implementation of advanced metering infrastructure (AMI) throughout PGE's service territory also creates the potential for a range of demand response options in the future. We discuss demand response programs in more detail in Chapter 4.

Meanwhile, PGE has decommissioned our 22-MW Bull Run Hydro facility and constructed two new solar projects, which are described later in this chapter. In early 2008, pursuant to our 2007 IRP, we issued a Renewable Resource RFP and received 38 bids. Technologies represented included wind, solar, wave, biomass and geothermal. After conducting a careful evaluation and scoring process, with ongoing involvement and oversight from an independent evaluator, we determined that we will not fulfill the 218 MWa of renewable energy resources acquisitions targeted in the RFP. This decision was made as a result of several challenges encountered during the RFP bid review and negotiations. These challenges included adverse changes in financial market conditions that impacted bidder costs and ability to execute, transmission and interconnection deficiencies, and changes to bid structures that were inconsistent with our objectives. We have addressed the need for additional renewable resources in this 2009 IRP process.

2.3 Thermal Plants

With the completion of Port Westward, PGE has an ownership interest in five thermal resources – two coal-fired and three natural-gas-fired – with combined January peaking capacities of 1,892 MW in 2009. Supply of fuel to thermal plants is discussed in Chapter 5.

Port Westward became available for commercial operation in June 2007. The combined-cycle combustion turbine (CCCT) plant, located in Clatskanie, Oregon, is the most efficient natural-gas-fired generator of its type in the Northwest. The new plant supplies approximately 425 MW of capacity in January (based on expected ambient temperature), including almost 400 MW base load plus 25 MW duct firing, with a heat rate of approximately 6,800 Btu/kWh (Higher Heating Value, or HHV). Average annual energy capability is approximately 365 MWa.

Beaver is a CCCT facility located in Clatskanie, Oregon. It has been in service since 1976, and we expect it to operate through 2024. Beaver has a peak January capacity of 521 MW and an average annual energy availability of 398 MWa[9]. The six combustion turbines are dual fuel, operating on either natural gas or No. 2 diesel fuel oil via on-site tank storage. A separate simple cycle unit (Beaver 8) added to the site in 2001 has average annual energy availability of 19 MWa and a January peaking capacity of 24 MW.

Coyote Springs I is a gas-fired CCCT facility located in Boardman, Oregon. It has been in service since 1995, and the original asset life extends to 2025. It has January capacity of 245 MW and forecasted average annual energy availability of 209 MWa, including 2 MW of duct-firing capacity.

Boardman is a pulverized coal plant located in Boardman, Oregon. It went into service in 1980. Its expected life extends through 2040. Coal for Boardman is imported by rail from Powder River Basin coal fields. PGE is the operator of the plant, and we have a 65%, or 380 MW, share of the plant output. Forecasted average annual energy availability for PGE's share is 318 MWa.

Colstrip Units 3 and 4 are coal-burning units located in Colstrip, Montana. The plants went into service in 1985. They are expected to run through at least 2024. The plants are operated and managed by PPL Montana. PGE owns 20% of the units, and our share of the capacity is 296 MW as of July 2007. Colstrip is a mine-mouth plant, with coal transported by conveyor belt directly from the on-site mine to the boiler. Forecasted average annual energy availability for PGE's share of Colstrip Units 3 and 4 is 252 MWa.

2.4 Hydro

PGE owns and operates seven hydroelectric plants[10]. They are:

- Two plants located on the Deschutes River near Madras, Oregon: Pelton (PGE share 73 MW[11]) and Round Butte (PGE share 225 MW).

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[9] Combustion turbine capacities vary inversely with temperature over the year.

[10] Since the 2007 IRP, the Company has decommissioned the Bull Run hydro facility (22 MW).

- Four plants located on the Clackamas River: Oak Grove (33 MW), North Fork (43 MW), Faraday (43 MW) and River Mill (23 MW).
- Sullivan (16 MW), located on the Willamette River at Willamette Falls.

The Pelton Round Butte project is the only PGE-owned hydro resource that provides material reservoir storage flexibility. The other projects are limited in their ability to store water and shape energy and are generally operated as run-of-the-river projects. At the usable capacity numbers listed above, these hydro resources account for approximately 15% of PGE's 2013 generation capacity. In addition to energy production, these resources (particularly Pelton and Round Butte) provide valuable peaking and load-following capabilities. A portion of PGE's hydro capacity is also used to meet spinning and supplemental (operating) reserve requirements, which are necessary for responding to system contingencies.

In March 2007, Pelton Round Butte was certified by the Low Impact Hydropower Institute, making it the second-largest hydro project in the U.S. to receive the designation. A 50-MWa portion of the project qualifies to meet PGE’s renewable resource target under the Oregon Renewable Portfolio Standard.

Hydro Relicensing

PGE's hydro plants operate under long-term (30- to 50-year) licenses issued by the Federal Energy Regulatory Commission (FERC). FERC issued a new 50-year license for Pelton and Round Butte on June 21, 2005, and a new 30-year license for Willamette Falls, which covers our Sullivan plant, on December 8, 2005. PGE is in the process of renewing its licenses on the four hydro plants located on the Clackamas River, which are covered by long-term licenses for the Oak Grove (Oak Grove plant) and North Fork (North Fork, Faraday, and River Mill plants) Projects. These licenses expired at the end of August 2006. The four plants will continue to operate under annual licenses until FERC issues a new long-term license. Relicensing is very cost-effective, as the costs of relicensing are substantially lower than procurement of other resource alternatives.[12]

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[11] The figures used in this section refer to *usable* capacity, i.e., the maximum generation maintainable for four hours.

[12] Pages 23 – 25 of PGE Exhibit 300 of Fixed Power Costs Direct Testimony in Docket UE 180 provide a detailed discussion of the relative costs of relicensing and other supply alternatives.

2.5 Non-hydro Renewable Resources

Biglow Canyon – PGE owns the development rights to the Biglow Canyon wind plant located in the lower Columbia River Gorge near Wasco, Oregon. When all phases of the plant are complete, Biglow Canyon will have a total generating capacity of up to 450 MW. The first of three phases was completed in 2007. Phase I is powered by 76 1.65-MW wind turbines with a total nameplate capacity of approximately 126 MW, and expected average energy production of 49 MWa.

The project is interconnected to a new 230 kV transmission line and substation that terminates at BPA's John Day 500 kV substation. Under the agreement between PGE and BPA for the interconnection of Phase I, BPA absorbs intra-hour fluctuations in accordance with applicable tariff terms and conditions, and PGE receives the hourly scheduled energy from BPA.

The two subsequent phases of Biglow Canyon are scheduled to be completed by 2010 and will add 114 MWa to the PGE resource portfolio.

Klondike II – Effective December 1, 2005, PGE began taking delivery of the entire output of the Klondike II Wind Farm located in Sherman County, Oregon. The expected output from this facility is 26 MWa on an annual basis. PGE's power purchase agreement (PPA) with PPM Energy, Inc.[13] provides for energy firming and shaping service from PPM.

Vansycle Ridge – PGE entered into a PPA in 1997 with ESI Vansycle Partners to purchase 25 MW (expected annual average energy of 8 MWa) of output from the Vansycle Ridge Wind Farm located north of Pendleton along the Washington/Oregon border. The PPA expires in 2027. Firming and shaping is provided by BPA.

ProLogis and ODOT Solar Projects – PGE developed two customer-sited solar projects in our service territory in late 2008 and early 2009 using a third-party LLC ownership model in partnership with U.S. Bank. The 104 kW Oregon Department of Transportation (ODOT) demonstration project (expected annual average energy of 13 kWa) uses monocrystalline photovoltaic panels and is owned by SunWay 1 LLC. Power from the project is sold by the LLC to ODOT, which has a net metering agreement with PGE. The 1.1 MW ProLogis installation uses thin film panels on three buildings and is owned by SunWay 2 LLC, with all power sold to PGE under a qualifying facility PPA. Expected annual average energy is 134 kWa. PGE receives Renewable Energy Credits (RECs) from both the ODOT and ProLogis projects. Once tax credits have been fully utilized PGE will assume majority ownership of the projects (estimated to be in 2014).

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[13] PPM Energy Inc. is now Iberdrola Renewables Inc.

2.6 Other Contracts

Hydro Output Shares – PGE has contracts for specified output shares of the hydro facilities on the Mid-Columbia identified below. We receive percentage shares of the output in exchange for paying a proportional share of the plants' costs[14].

- **Wells** – PGE has a contract with Douglas County PUD at Wells on the middle section of the Columbia River (Mid-C) for 147 MW of capacity and 85 MWa of energy under normal water conditions. This contract expires in 2018.

- **Grant County PUD Settlement Agreement** – In 2001, PGE reached a new agreement with Grant County PUD for the purchase of a share of the energy output of the Priest Rapids and, starting in 2009, Wanapum hydro projects, also on the Mid-C. PGE's share of these projects (as of 2012) provides approximately 134 MW of capacity and 69 MWa of energy under normal water conditions[15].

Pelton Round Butte Agreement – In 2001, PGE and the Confederated Tribes of Warm Springs (Tribes) reached an agreement relating to the Pelton Round Butte project. The agreement established the terms for joint ownership of the project. Under this agreement, the Tribes sell part of the energy generated by their share of the hydro plants to PGE through 2012 at a fixed price. The remainder of their share of the output of Round Butte is currently being sold to PGE at market price. The agreement also provides for PGE to purchase from the Tribes the 9 MWa expected output from the Pelton re-regulation dam.

Portland Hydro – PGE has a contract with the City of Portland to purchase the output of the Portland Hydro Project, located on the Bull Run River. The contract runs through 2017 and provides 10 MWa.

Canadian Entitlement Allocation Agreement – This agreement relates to the Columbia River hydro projects. Columbia River storage reservoirs located in Canada are operated so as to increase the overall value of the Columbia River hydro system. However, these benefits are shared with Canada. The current agreement ended in 2003, but an extension agreement is effective through most of 2024.

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[14] The term "capacity" as used in this section means usable peaking capacity and energy is measured under average water conditions.

[15] Output from this agreement varies each year until 2012, when the contract will provide 134 MW of capacity and 69 MWa of energy under normal water conditions.

Covanta Marion – We purchase the output of the Covanta Marion municipal solid waste burning facility located in Brooks, Oregon, under a Public Utility Regulatory Policies Act of 1978 (PURPA) contract that expires in the middle of 2014. This plant has a capacity rating of 16 MW, and produces about 10 MWa of energy.

Wells Settlement Agreement – Under this agreement with Douglas County PUD, which runs through August, 2018, we purchase approximately 15 MWa of non-firm energy in 2012, falling to 11 MWa by 2018.

Capacity Exchange Contracts – PGE has two long-term exchange agreements that provide daily/weekly storage and capacity. Under the agreements we receive energy and capacity during peak hours and return the energy during off-peak hours:

- Spokane Energy (formerly Washington Water Power) – 150 MW, under contract running through 2017.
- Eugene Water and Electric Board – 10 MW, under a contract that ends in the middle of 2014.

TransAlta – We executed a 10-year, 100 MW fixed price PPA with TransAlta as an action item pursuant to our 2002 IRP Final Action Plan.

Glendale Exchange – This agreement with the City of Glendale, California, provides PGE with 30 MW of capacity during the months of November, December, January, and February. We have similar obligations to Glendale during the months of June, July, August, and September, yielding zero net annual energy. This agreement runs through February 2012.

Glendale Long-Term Sale – The City of Glendale purchases 20 MW of year-round capacity with the right to purchase related energy from PGE. This contract expires in 2012.

Expiring Contracts

PGE has a number of contracts that expire, or are being adjusted, on or before 2015. These reductions in energy and capacity involve about 300 MWa of energy and are significant drivers of our need for additional resources in the 2013 – 2015 timeframe; see Chapter 3. Expiring resources are listed along with their full-year energy and capacity volume in the expiration year.

Table 2-1: Expiring or Adjusted Contracts

Contract	Expiration	Energy (MWa)	Capacity (MW)
Confederated Tribes	2012	66	167
Chelan Exchange	2011	7/-8	0/-32
Covanta Marion	2014	10	16
EWEB Capacity	2014	0	10
Flat Energy Agreement*	2011	19	25
Glendale Exchange	2012	0	30
Glendale Long-Term Sale	2012	-10	-15
Grant PUD [16]	2012	50	50
Peak Tolling Agreement*	2009	14**	25
Rocky Reach	2011	77	137
Wanapum	2009	78	166
Winter Capacity I*	2010	NA	100
Winter Capacity II*	2011	NA	300
Totals by 2015		**311/296**	**1011/979**

* *Contract names have not been disclosed due to confidentiality agreements with counterparties.*
** *Availability*

[16] PGE's contract with Grant PUD is being adjusted downward as of 2012 from 119 MWa to 69 MWa and 185 MW to 134 MW.

Table 2-2 summarizes the total contracts and resources remaining in our portfolio in 2015.

Table 2-2: Existing PGE Resources in 2015 – Before New Actions

		In-Service Date	Annual Energy (MWa) *	January Capacity (MW)
Type	**Plants**			
Coal	Boardman	1980	314	375
Coal	Colstrip	1985	252	296
Gas	Beaver	1976	398	521
Gas	Beaver 8	2001	19	24
Gas	Port Westward	2007	365	425
Gas	Coyote	1995	209	247
Wind	Biglow Canyon Wind Project	2008	48	6
Wind	Biglow Canyon Wind Project II	2010	52	7
Wind	Biglow Canyon Wind Project III	2011	62	9
Hydro	Oak Grove	1924	25	33
Hydro	North Fork	1958	27	43
Hydro	Faraday	1907	24	43
Hydro	River Mill	1911	13	23
Hydro	Sullivan	1895	14	16
Hydro	Round Butte	1964	75	225
Hydro	Pelton	1957	34	73
	Total PGE Plants		**1,931**	**2,366**
Type	**Contracts**			
Hydro	Wells		85	147
Hydro	Grant PUD Deal		69	134
Hydro	Portland Hydro		10	36
Wind	Iberdrola's Klondike II		26	19
Wind	Vansycle Ridge		8	1
Solar	ProLogis/ SunWay 2 LLC		.013	0
Capacity	Spokane Energy Capacity		0	150
Hydro	Canadian Entitlement Ext.		-10	-18
Hydro	Wells Settlement Agreement		14	0
Other	TransAlta		93	100
Capacity	Dispatchable Standby Generation (DSG)		0	53
	Total Longer-term Contracts		295	622
	Total Resources		**2,226**	**2,988**

** Theoretical Annual Average Availability Using Average Hydro.*

Figure 2-3 and Figure 2-4 display PGE's owned and contracted energy availability from energy resources for 2015, before any new actions recommended in this IRP Action Plan. We also show expected economic generation, as opposed to physical availability, which results in a material increase in short-term market purchases[17], if no new resources are acquired.

Figure 2-3: PGE Projected 2015 Energy Resource Mix (Availability)

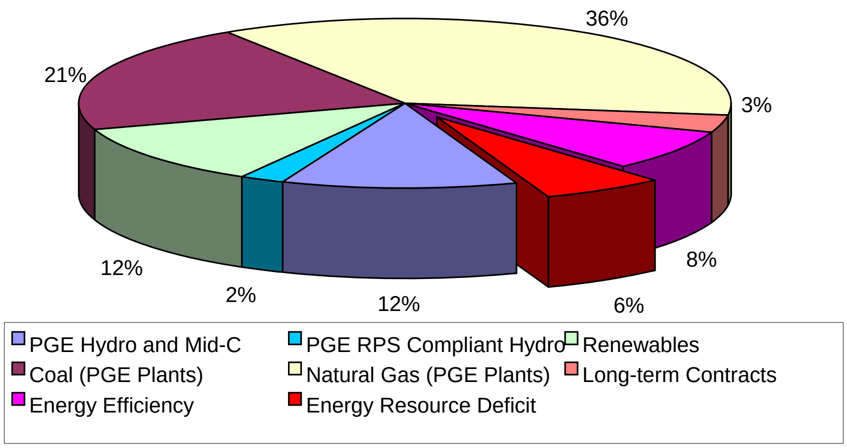
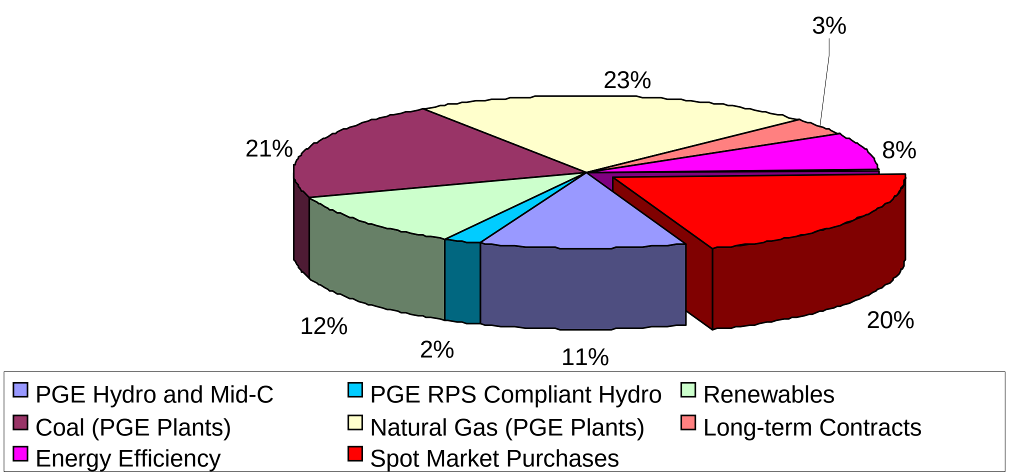


Figure 2-4: PGE Projected 2015 Energy Resource Mix (After Economic Dispatch)



[17] Total renewable percentage does not equal 15% due to inclusion of EE. Renewables as a percentage of load adjusted for EE will be 15%.

With the loss of the Mid-C contracts and Bull Run hydroelectric project – offset by our anticipated increase in renewables from Biglow Phase II and III the renewables RFP – we expect the percentage of non-emitting resources to be about 26% of our total resource pool in 2012 compared with 29% in 2009.

3. Resource Requirements

PGE's existing resources are not sufficient to meet our customers' expected future energy and capacity requirements. Due to a combination of load growth, new renewable resource characteristics, and existing resource expirations, the deficit becomes considerable over time. As a result, we forecast a need for significant new resource additions.

We discussed our resource expirations in the previous chapter. In this chapter we describe our reference case load growth forecast which indicates a long-term load growth, with embedded EE removed, of 2.2% for the period 2010-2030.

Based on our changing demand and supply situation, we are forecasting a capacity need of 1,505 MW in 2013 and an average energy need of 751 MWa in 2015, based on normal weather conditions and normal hydro conditions. On a forecast basis, our maximum annual demand requirements are in the winter (January). As a result, our winter capacity deficit continues to drive our overall capacity need. However, our summer demand is growing faster than winter demand – due to increasing commercial cooling load and residential air-conditioning saturation. Our summer peak demand is expected to overtake our winter requirements around the end of the next decade. This evolution may require us to seek a larger proportion of capacity resources that are able to serve peaking requirements for multiple months.

Consistent with past IRPs, we evaluate peaking needs by calculating the difference between our forecast annual 1-hour maximum load, based on normal (1-in-2) weather conditions[18], inclusive of approximately 6% operating and 6% contingency reserves, and the energy production capability of our resources.

In addition to evaluating our future load-resource balance and resulting resource requirements, this chapter also provides an assessment of regional resource adequacy and its impact on PGE.

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[18] Meaning that there is a 1-in-2 or 50% probability that the actual peak load will exceed the forecasted peak load during the stated time frame.

Chapter Highlights

- Our reference case load forecast shows long-term energy demand growth rates of 2.2% annually with peak demand growing 2.0% in winter, 2.4% in summer.
- Our load-resource balance projects an energy need of 751 MWa in 2015 and a winter peak capacity need of 1,505 MW in 2013.
- We do not plan long-term energy resources for five-year opt-out customers (about 30 MWa at the time of analysis).
- We propose to retain a minimum peak reserve margin of 12%, which includes a 6% contingency reserve margin and the required approximately 6% operating reserve.
- The 2013 critical hydro adjustment for PGE is about 85 MWa; however, we do not propose any adjustments to our supply targets for critical hydro conditions.
- With the uncertainty around future timing and penetration of plug-in electric vehicles (PIV), as well as the relatively small load increase of the medium case scenario (25 MWa), we have determined that a higher load growth future is a reasonable proxy to evaluate the impact of PIVs on future resource needs and performance in this IRP.

3.1 Demand

PGE updated its long-term system load forecast in March 2009[19]. For IRP purposes, we identify annual energy needs under our reference case (i.e., expected or most likely) and high-load and low-load forecasts, assuming normal weather conditions. We report annual peak demand using 1-in-2, or expected (normal) weather conditions, meaning that there is a 1-in-2 or 50% probability that the actual peak load will exceed the forecasted peak load during the stated time frame.

Figure 3-1 displays annual load and peak demand under our reference case forecast from 2010 to 2030. Here load growth varies between 1.6% and 2.6% in the mid-term (2010-2015) and is 2.1% from 2015 forward. Peak demand for 2013 through 2030 is growing at a rate of 2.0% in winter and 2.4% in summer. We do not include historical embedded EE in our reference case forecast because the EE actions identified in our action plan are based on an expected level of future EE, as forecast by the Energy Trust of Oregon (ETO), and include continuation of historical embedded EE.

For comparative purposes, PGE shows its non-EE adjusted forecast in Figure 3-2. This forecast is prepared by our load forecasting group and includes historic embedded EE from past actions. Here load growth is between 0.7% and 1.2% in the mid-term, and 2.0% from 2015 through 2030. Long-term peak demand is growing at 1.8% in the winter and 2.3% in the summer. PGE's current forecast shows a decrease in the rate of load growth from the 2007 forecast primarily due to the current global recession. We do not expect aggregate demand to return to pre-recession levels until 2010. Similarly, our current forecast shows peak load demand lower than the prior IRP forecast. Peak demand is not projected to exceed 2008's actual peak (4,031 MW) until 2013-2014.[20]

PGE and the Pacific Northwest have historically been winter peaking, but summer demand has been growing and is projected to increase at a faster rate than winter demand. This is a result of the residential and commercial sectors' faster summer growth driven by cooling demand and the residential sector's slower winter growth due to declining electric space and water heat penetration. This trend, if continued, will likely transform PGE's system from winter-peaking

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[19] PGE based its reference case load forecast on the Oregon Office of Economic Analysis March 2009 economic forecast and Global Insight's February 2009 U.S. forecast. The load forecast therefore incorporates the impact of the 2009 recession.

[20] It is important to recognize that load forecasts can be influenced, especially in the near-term years, by the position of the base year (2009 in the case of this IRP) with respect to the current economic cycle. The discrepancy between historic load growth and a forecast using a base year during a recession could give rise to a 50-100 MWa band of uncertainty in a single year.

to summer-peaking in 15 to 20 years. From an energy perspective, a shift to higher overall consumption in the summer will not occur as quickly, as forecasts continue to reflect an expectation for more heating days than cooling days in a year in the Pacific Northwest.

Figure 3-1: PGE Reference Case Load Forecast 2010 - 2030

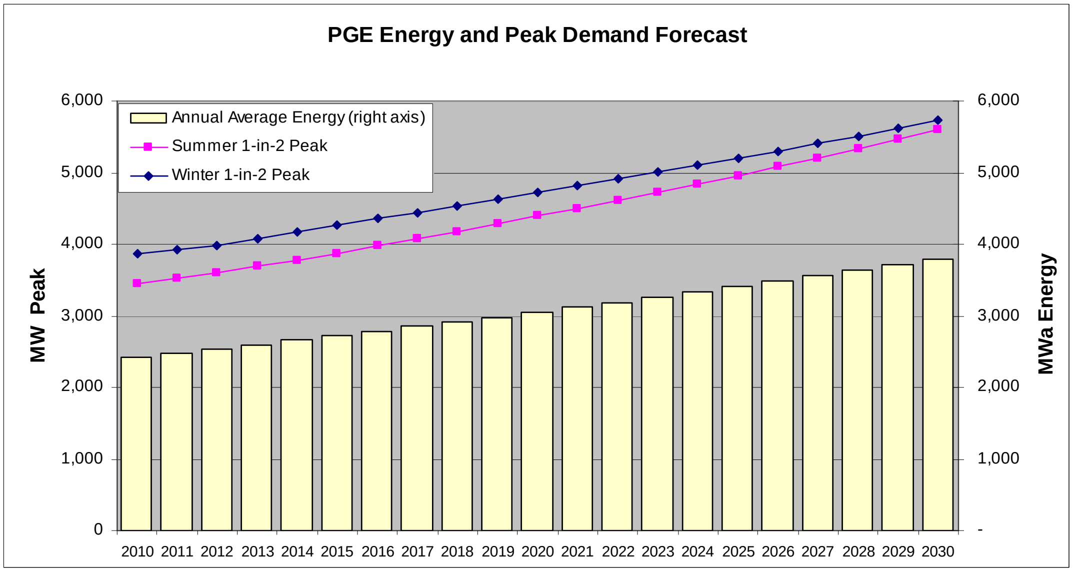
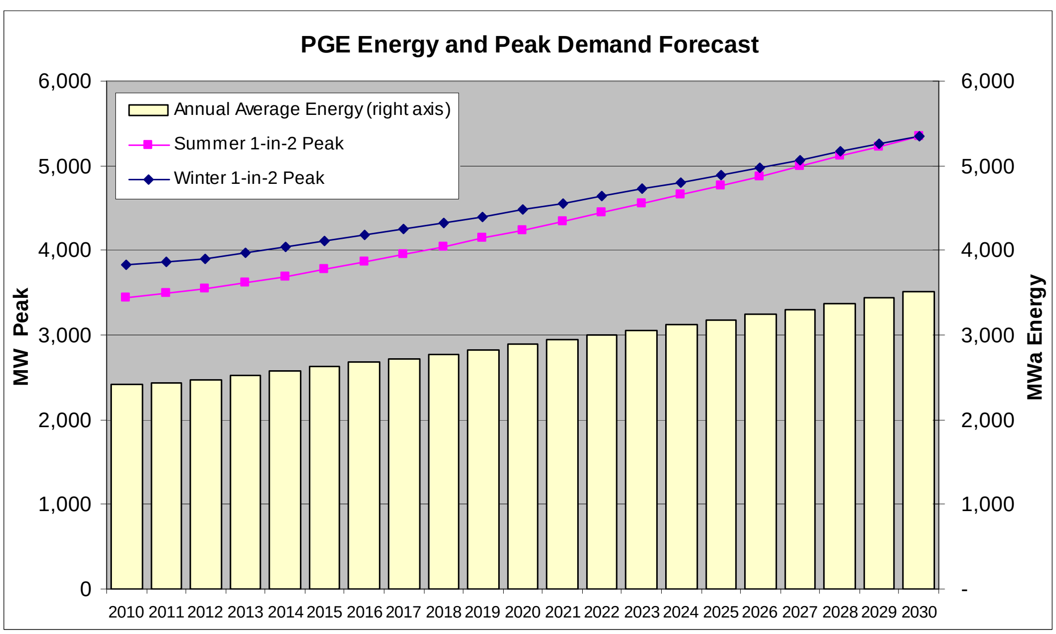


Figure 3-2: PGE Non-EE Adjusted Load Forecast 2010 - 2030



Historically, there were brief periods (anywhere from one to five years) during which demand for electricity in PGE-served areas declined due to boundary changes, business cycles, departures of large customers from the system or significant economic shocks. However, overall demand has always rebounded to grow over time based on macroeconomic and fundamental drivers. PGE expects this trend to continue in the future. The following factors are fundamental drivers of PGE's reference or base-case demand forecast:

- Through the next few years demand for energy will be affected by the recession, the deepest since the Great Depression, as the recovery for both the economy and energy demand starts from below-trend base, essentially under-estimating upside strength. Oregon economic activity historically tends to falter faster during a downturn, but also accelerate faster during an upturn.

- The economy, demographic trends such as in-migration and life expectancy, and a business environment that favor future growth.

- Oregon's position as a magnet state, the presence of prominent industry leaders, continued gains in productivity, and emerging sectors sustaining and creating new growth.

- The high-technology sector, which continues to be a strong force in the local economy, led by solar cell manufacturing.

PGE expects that the following trends will continue and will, over time, alter the composition and characteristics of various customer sectors:

- Faster growth in the commercial sector, which is dominated by cooling load, will continue in the forecast period. This sector's share of load grew from 34% to 40% between 1985 and 2008.

- Slower growth in the residential sector (in part due to declining space and water heat penetration) will continue. This sector's share of load fell from 43% to 39% between 1985 and 2008. Higher air conditioning penetration combined with declining heating penetration will alter diurnal and seasonal load shapes.

- Industrial load volatility and uncertainty will increase as industrial customers react more quickly to changing market conditions and business cycles. Our 20 largest industrial customers account for two-thirds of industrial load. Their business decisions can cause load to deviate significantly from our long-term forecast.

Guideline 4b of Order No. 07-002 requires an analysis of high- and low-load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions. We address stochastic load risk analysis in Chapter 10. We address high and low load growth scenarios below.

In addition to a reference case forecast, PGE projects high and low long-term growth cases. These demand cases are constructed from historical parameters[21]. They do not reflect specific changes to assumptions for customer usage patterns or consumption rates or shifts in aggregate demand due to fundamental pattern changes (e.g., sustained out-migration, rebound in space heat penetration or renaissance of certain key industries). These high and low cases essentially serve as demand boundaries, or jaws, and are sufficiently large to incorporate a mid-term departure from the reference forecast caused by business cycle and/or macroeconomic fluctuations. However, brief excursions outside the boundaries could occur in the short run due to large shocks to the economy or departures from normal weather conditions.

PGE currently uses a 15-year moving average of historic data for the weather variables in our load forecast. Prior to UE 180, PGE used a 30-year moving average[22]. Annual average temperatures have trended upward since the 1960s, thus the change to a shorter historic time frame.

Table 3-1: Reference Case, High and Low Load Growth Rates

	Energy		Winter Capacity		Summer Capacity	
	2015 MWa	2010-30 growth	2013 MW	2010-30 growth	2013 MW	2010-30 growth
Reference Forecast (Removes Embedded EE)						
Medium	2,752	2.22%	4,115	2.00%	3,720	2.44%
High	2,884	2.98%	4,279	2.77%	3,868	3.22%
Low	2,664	1.57%	4,055	1.38%	3,680	1.88%
Non-EE adjusted Forecast						
Medium	2,624	1.91%	3,964	1.70%	3,619	2.24%
High	2,756	2.72%	4,128	2.53%	3,767	3.05%
Low	2,536	1.21%	3,904	1.03%	3,579	1.65%

[21] Monthly sector energy demands are individually projected to grow at the mean (average) rates plus one standard error for the high case and minus one standard error for the low case.

[22] Please see Page 8, Lines 5 to 8, of PGE Exhibit 1200 from March 15, 2006 Testimony and Exhibits in OPUC Docket UE 180 for further details.

Table 3-1 displays projected 2013 and 2015 (the target years in our Action Plan) loads and annual load growth through 2030. We show the reference forecast, as well as the non-EE adjusted for comparative purposes.

PGE's energy growth forecasts are consistent with the Northwest Power and Conservation Council's (NWPCC) Draft Sixth Plan forecasts, particularly in the earlier years. Our load forecast is slightly higher than the NPWCC's in the long term, primarily because the NPWCC does not differentiate in their forecast between rural and urban areas. Urban growth is traditionally higher than that of rural areas. Therefore, PGE's forecast would be expected to be higher than the NWPCC's, as we serve primarily urban areas. Table 3-2 below shows the comparisons.

Table 3-2: PGE vs. NWPCC Forecasts

	PGE		Council	
Forecast Period	With Embedded EE	Without Embedded EE	Northwest Base	Oregon Base
Full Forecast (2010-2030)	1.91%	2.22%	1.26%	1.24%
Immediate-years (2010-2015)	1.72%	2.37%	1.96%	1.96%
Out-years (2015-2030)	1.97%	2.24%	1.02%	1.00%

As seen in the table PGE's forecasts are lower than the NWPCC's in the beginning years, 2010-2015, although still comparable. This is the period covered by our Action Plan.

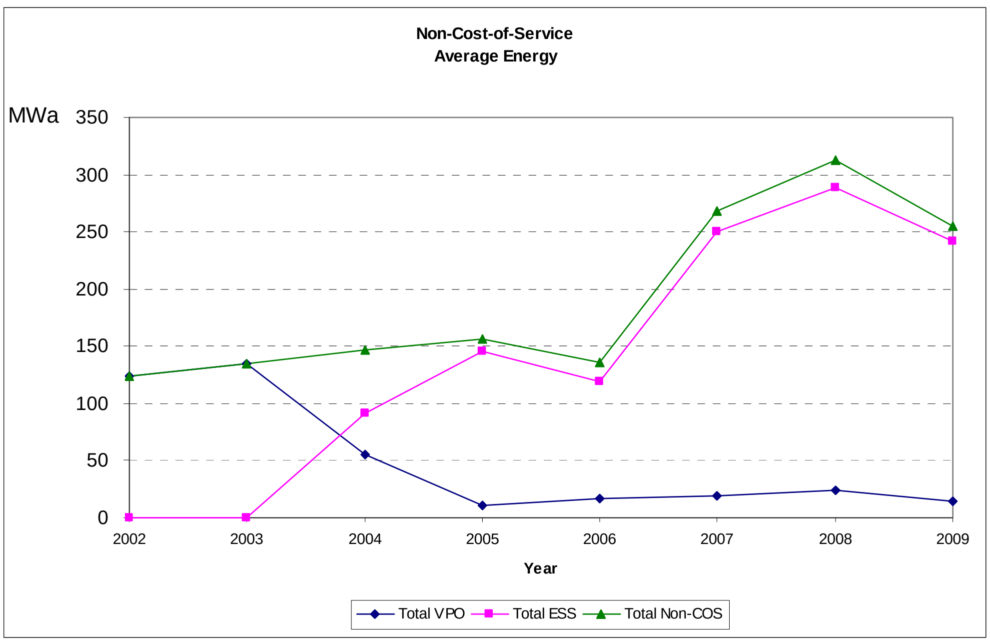
3.2 PGE's Cost-of-Service Load

Under Oregon law, PGE must offer our cost-of-service (COS) rates to all customers. COS rates are PGE's regulated, cost-based tariffs, which are based on the cost forecasts approved by the OPUC in either PGE's general rate case or annual update tariff filings. Our COS rates are available to all customers within PGE's service territory based on applicable customer class tariffs. We must offer to all non-residential customers the choice of leaving COS rates and electing either 1) PGE's daily or monthly index rates (i.e., variable price options or VPO), or 2) a registered Energy Services Supplier (ESS) as a supplier for one, three or five years. However, according to Oregon law and related OPUC rules, PGE also remains the provider of last resort for all customers in our system.

Customer load eligible for the three- and five-year ESS options is limited to an aggregate cap of 300 MWa per Schedule 483 and 489 of PGE's electric tariff. Past experience suggests that some of the one-year and three-year opt-out customers may default back to PGE's rates over time. However, we assume that the five-year opt-out customers will not return because these customers must complete the five-year opt-out election before becoming eligible to elect COS rates and must also provide a two-year notice to PGE before returning. Based on the extended term and reduced return flexibility of the five-year opt-out program, we assume that these customers have made a longer-term decision to leave PGE's COS rate plans and, consequently, we do not plan for their long-term power supply needs. Guideline 9 of Order 07-002 confirms that our load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

In 2009, PGE has about 255 MWa of load on non-COS tariffs (roughly 12% of retail load). Between 2002 and 2006 an average of approximately 140 MWa of load was on non-COS tariffs. Non-COS levels increased in the following two years, topping out at just over 310 MWa in 2008 before declining in 2009. Figure 3-3 below summarizes this recent historical trend.

Figure 3-3: Non-Cost-of-Service Load

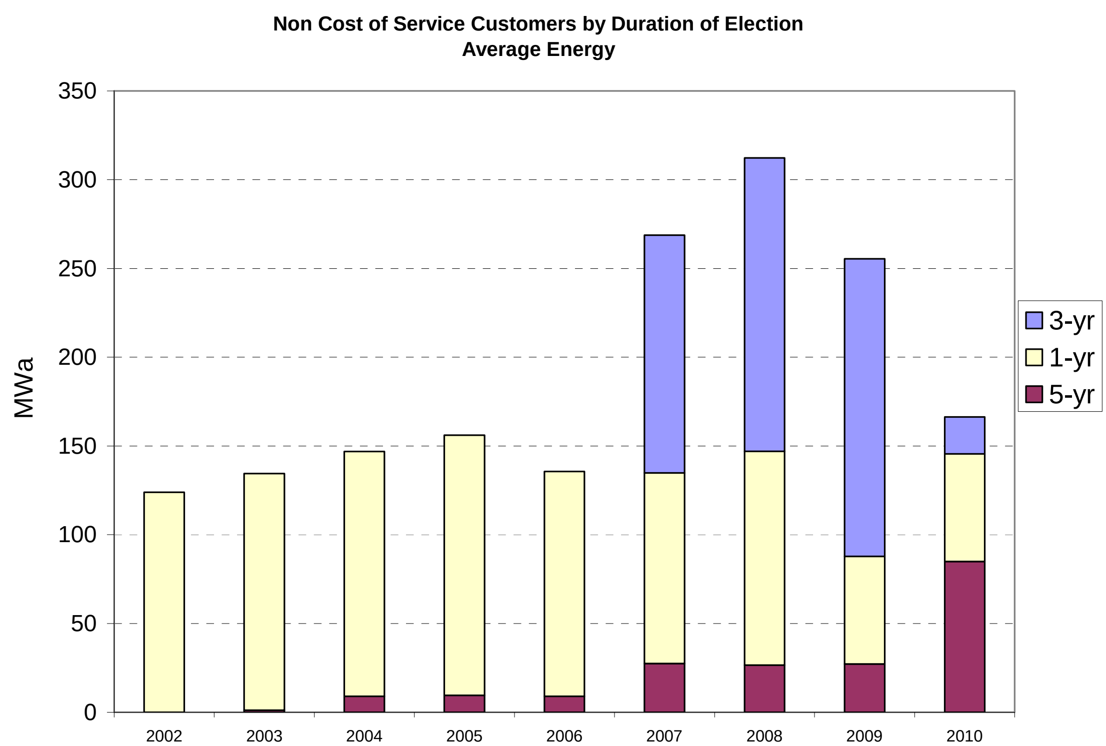


The three- and five-year opt-out load reached 160 MWa in 2007 and just over 190 MWa in 2008 and 2009 compared to average historical elections of 10 MWa. The increase in longer-term opt-out load can be attributed primarily to arbitrage opportunities during opt-out election windows. From a long-term planning perspective, we do not know from one year to the next exactly how much of the eligible load may choose to opt out from COS rates. Figure 3-4 shows a detailed break-out of non-COS customers by duration of election. We have updated the figure including the results of the September enrollment window for 3- and 5-

year opt outs. The 1-year opt-out window occurs in November, so for 2010 we have assumed the same amount of 1-year opt out customers as in 2009.

Opt-out/opt-in election decisions magnify future load uncertainties and the related risk of having to procure or sell electricity in an adverse market. To address the uncertainties related to opt-out-eligible load, PGE proposes the following planning approach. In accordance with the guidance of Order 07-002, PGE will not plan energy resources for five-year opt-out customers (about 30 MWa at the time of our analysis). For the shorter-term opt-out eligible load we suggest a balanced approach that will avoid being overly short during times when more customers choose utility COS tariff offerings or being overly long during times of increased opt-out elections by our customers.

Figure 3-4: Non Cost-of-Service Customer Load by Duration of Election



For capacity purposes, we have an obligation to serve as provider of last resort for all jurisdictional customers. Given the guidance in Order 07-002 regarding our five-year opt-out customers, we propose to meet their capacity needs in the short-term market. We do not propose to acquire long-term capacity resources to meet this potential energy demand, which was about 32 MW at the time of our analysis. As a result, we make an adjustment to our capacity load-resource balance to remove this load.

PGE Cost of Service Opt-out Election

PGE's 2009 Cost of Service opt-out election window closed on September 30, 2009. During the election window customers may choose to opt-out of cost-of-service rates for either three or five years. When the window closed there was an incremental increase of 5-year opt-out load of approximately 60 MWa. The associated demand is approximately 65 MW. However, these results will not alter our Action Plan with regard to major resource acquisitions, as we have built in flexibility through market purchases of energy and demand to respond to load fluctuations. Moreover, this reduction to PGE cost-of-service load requirements corresponds roughly to a year of load growth and must be considered in the context of a 2015 need of over 500 MWa.

3.3 Load-Resource Balance

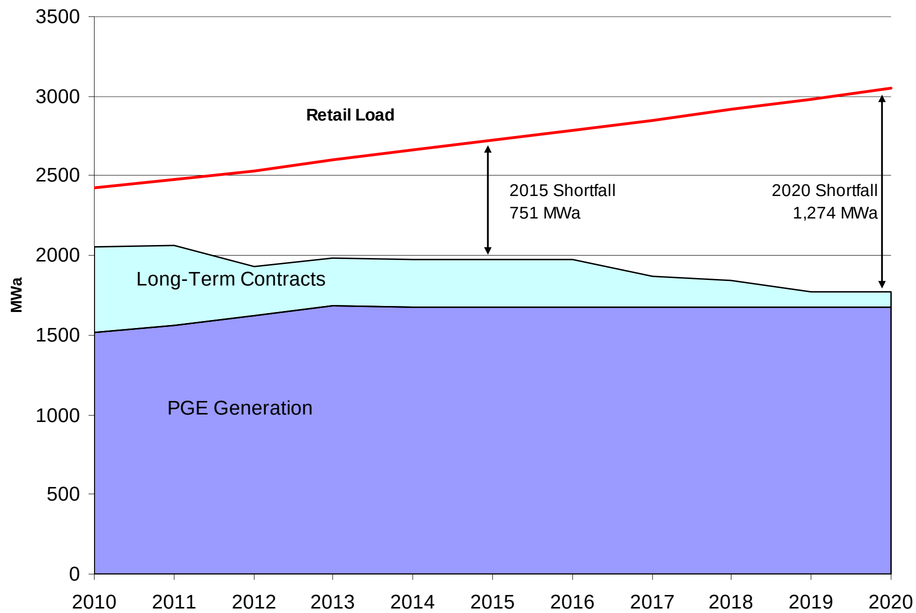
PGE's Energy Load-Resource Balance

Energy balance in this IRP refers to the average amount of electricity PGE will need over a year under normal hydro and weather conditions. It is computed as the difference between the expected energy capability of PGE's resources (plants, contracts and purchases) and the expected annual average load. Using this approach suggests that when we are in supply/demand balance on an annual average basis, we would be short for about half the hours of the year and long for the remaining hours. Unfortunately the long hours and short hours also vary across the year. As a result, we generally find that when our energy supply and demand are balanced on an average annual basis for planning purposes, we are short during the high-demand, high-price periods and long during times of low prices and reduced demand for PGE and the region. A primary function of PGE's Power Operations group is to make purchases and sales to balance resources to meet loads for all hours.

Figure 3-5 shows a projection of PGE's load and resources. It reveals resource gaps increasing to 537 MWa in 2015 including ETO EE projections (751 MWa without EE). The forecast deficits are attributed to the expiration of existing long-term resources, the economic treatment of Beaver and load growth of approximately 50 MWa per year at our reference case annual long-term load growth forecast of 1.9%. This annual load growth is net of an assumed average of 18 MWa per year (through the end of the forecast period) of total EE savings as forecasted by the ETO.

By 2025, PGE will face the potential economic obsolescence and full depreciation of our Colstrip, Beaver and Coyote plants. These plants will likely require either upgrades for ongoing operation or decommissioning and replacement. However, for modeling purposes only, we assume in this IRP that the Coyote, Beaver, Boardman, Beaver 8 and Colstrip plants all continue operation throughout the planning horizon (2040).

Figure 3-5: PGE Energy Load-Resource Balance to 2020



* *PGE Generation includes 122 MWa of renewable energy for2015 physical compliance with Oregon RPS*

PGE's Capacity Load-Resource Balance

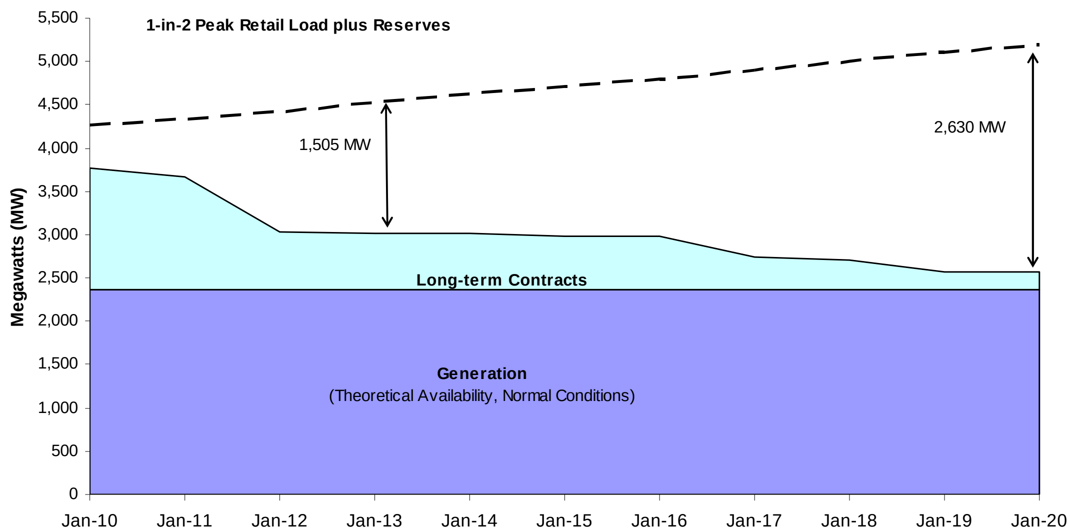
Capacity is the amount of electricity a utility needs at the times when customers place maximum demand on the system (i.e., during a hot or cold weather event). A given resource's capacity value is the amount of electricity the facility is capable of producing in a given hour on demand (i.e., when called for).

Consistent with past IRPs, we evaluate peaking needs by comparing the annual one-hour maximum load inclusive of 12% reserves[23], calculated on a 1-in-2 or average basis, to the capability of our energy-producing resources. The capabilities of our resources are reported at their August and January peak operating capacities, with the exception of hydro resources, for which we use a more prudent sustained four-hour generating capability measure. We are reporting both the winter and the summer peak loads because summer peak needs are growing faster and could exceed the winter peak in the future.

[23] Inclusive of approximately 6% operating and 6% contingency reserves.

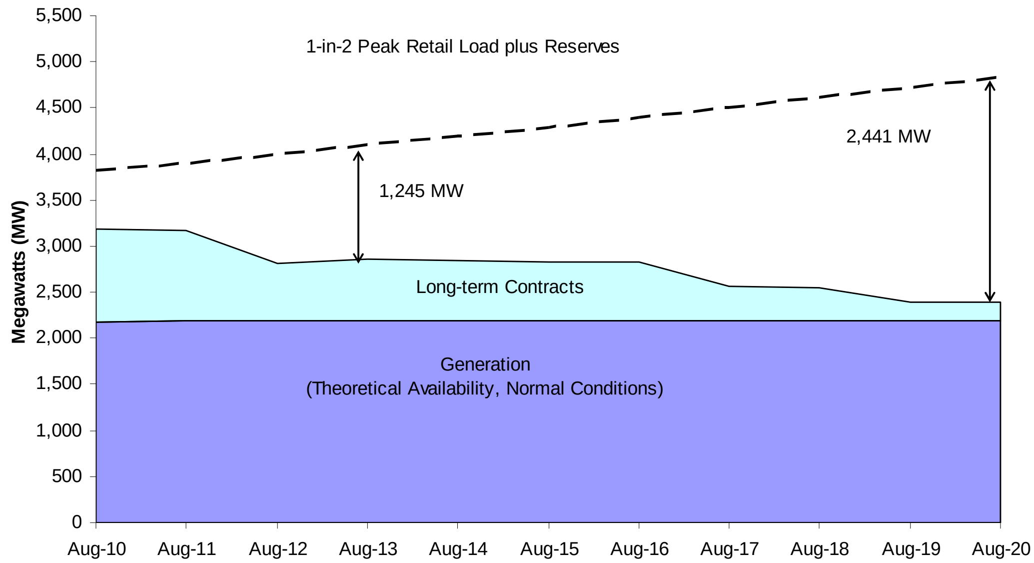
Figure 3-6 and Figure 3-7 show PGE's projected capacity needs for winter and summer, respectively. They show a gap (after removing embedded EE) that starts at approximately 500 MW in winter, 640 MW in summer when including both operating and planning reserves. The gap is lowered to 270 MW and 430 MW for winter and summer respectively when including only operating reserves. The expected capacity deficit, absent any baseload energy actions, will grow to approximately 1,505 MW in winter and 1,245 MW in summer by 2013, 1,269 and 1,030 respectively without planning reserves.

Figure 3-6: PGE Capacity Load-Resource Balance - Winter



* *Generation includes 18 MW of renewable capacity associated with energy needed for 2015 physical compliance with Oregon RPS*

Figure 3-7: PGE Capacity Load-Resource Balance - Summer



* *Generation includes 18 MW of renewable capacity associated with energy needed for 2015 physical compliance with Oregon RPS*

PGE's Proposed Planning Reserve

The level of reserves that we include in resource planning is an important component of PGE's capacity need. We propose to keep the same reserve levels as in the 2002 and 2007 IRPs - a minimum of 12%, which includes an approximate 6% contingency reserve margin[24] and approximately 6% operating reserve[25]. The operating reserve is required by regional reliability standards and is meant to maintain supply stability and power quality during unexpected real-time disruptions that occur within the operating hour and must be corrected for within one hour's time, such as a sudden plant trip or unanticipated increase in load. A contingency reserve primarily covers two types of events: 1) extreme weather events and resulting load excursions (beyond a 1-in-2 event); and 2) generator and transmission unplanned outages (or partial outages) that extend for longer periods of time than an operating reserve is meant to cover. Our combined planning reserve is generally sufficient for either of these events alone, but not for both should they happen simultaneously.

[24] In accordance with current WECC standards we have calculated operating reserves as 7% of capacity for thermal resources, and 5% for hydro and wind resources.

[25] See 2002 IRP Final Action Plan, March 2004, Pages 34 and 35.

To provide perspective, a 12% reserve for our peak winter load at normal weather in 2013 is approximately 440 MW. Moving from normal winter weather in 2013 to 1-in-5 weather conditions increases PGE's forecast one-hour peak load by about 260 MW (see Figure 3-8). Our largest single shaft risk is Port Westward at 425 MW (inclusive of duct firing). Given that 205 MW of that 440 MW reserve is required operating reserve, our proposed contingency reserve alone covers about 80% of a 1-in-5 weather event and about 50% of our Port Westward shaft risk. Figure 3-8 shows the impact for PGE in 2013, for both winter and summer peaks, of moving from normal weather to 1-in-3, 1-in-5, and 1-in-10 weather. Beyond 1-in-10 weather, incremental load increases diminish rapidly because most weather-sensitive electricity consuming devices are already operating.

Figure 3-8: Impact of Temperature on PGE Peak Load

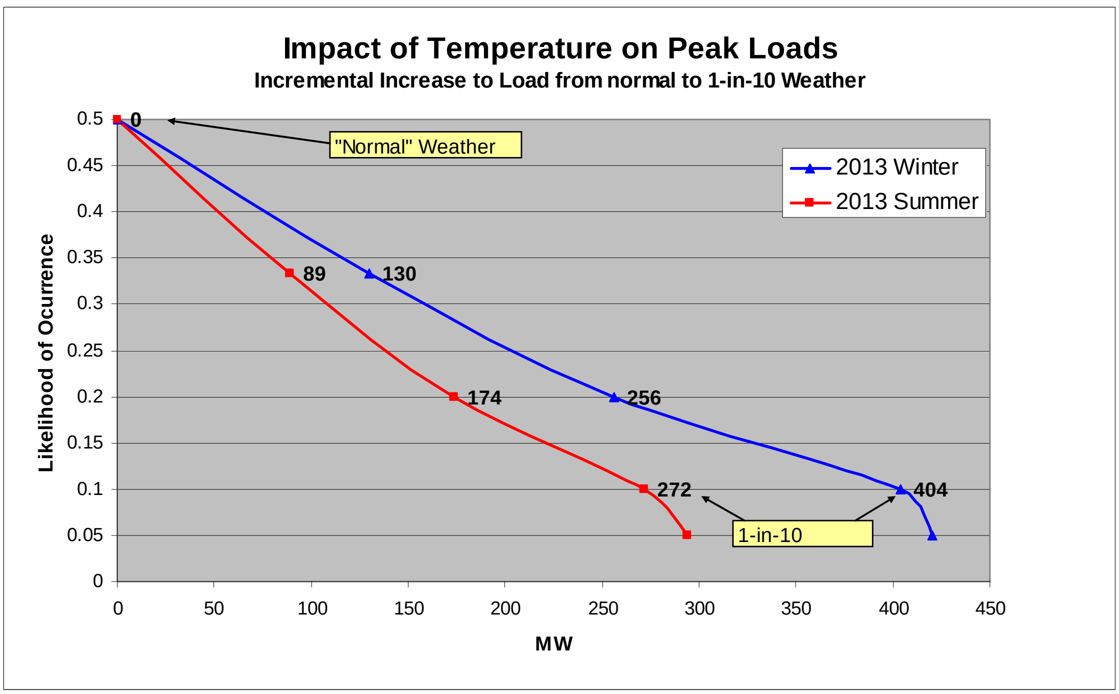
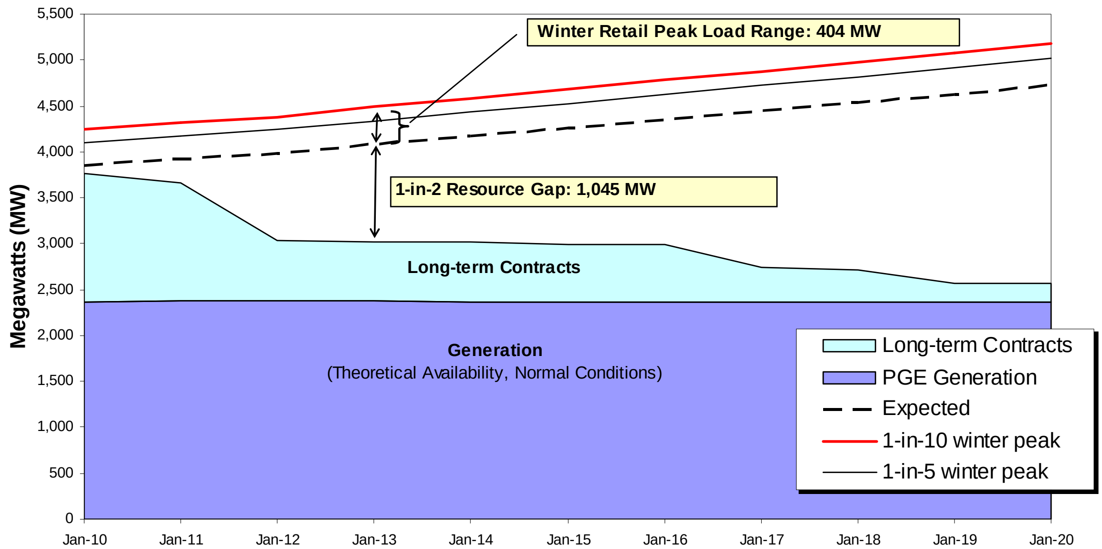


Figure 3-9 shows the impact of temperature excursions on the expected capacity gap. It shows that the proposed 12% reserve margin on the 1-in-2 peak (about 440 MW) load allows PGE to meet a 1-in-10 load excursion, which is 404 MW higher than the 1-in-2 peak.

The WECC region does not have mandatory resource adequacy standards, with the exception of an operating reserve margin of 5% for hydro and renewable plants and 7% for thermal plants. Historically, utilities sought reserves that would equal at least the largest generating shaft risk in their portfolio. OPUC Order No. 07-002 generally does not impose prescriptive planning standards.

Rather, it requires utilities to identify resources needed to bridge the gap between expected load and resources. It also requires utilities to analyze reliability standards, recognizing that higher reliability typically carries a higher cost.

Figure 3-9: Expected Capacity Gap across Peak Events



Given stakeholder concerns about increased reserve margins expressed in our last IRP process, and in view of developing regional efforts to evaluate common utility reliability standards, we are not recommending a change in our reserve margin requirements for this IRP. However, we also consider 12% to be the minimum acceptable peak reserve margin to use for planning purposes and have retained these levels for the current IRP. As stated above, a 12% reserve margin is not adequate to insulate PGE customers from exposure to supply disruptions in all circumstances. Large plant outages, adverse regional hydro conditions and extreme weather events could individually or collectively exceed the capability of our portfolio to meet 100% of our customers' power supply requirements.

Ultimately, during times when contingency events exceed our reserve margins, we will need to rely on voluntary demand reductions and market sources of supply (if available) to maintain system reliability. To mitigate our supply and reliability risk, we are proposing in this IRP to become less reliant upon the short-term markets to provide for our planned (1-in-2) peak needs. Specifically, we believe that in the future with the regional load-resource balance becoming tighter and the transmission system increasingly constrained, it will no longer be prudent to satisfy as much of our capacity need through the short-term markets as we targeted in our last IRP. In our last IRP, we targeted filling 500 MW of our capacity needs through the short-term wholesale electric market. For this IRP we propose filling 300 MW of our capacity needs with market purchases.

Impact of Critical Hydro Conditions

Critical hydro is defined as the monthly energy-generating capability of Northwest system hydro plants during a critical energy period. The critical energy period is the historical time period of stream flows during which the least amount of load can be served from regional firm resources. Critical hydro for PGE is the year 1944, which was the worst annual hydro generation in the period from 1929 to 1997 for PGE-owned and contract hydro resources. For the Pacific Northwest, the critical hydro year is 1937. The 2015 critical hydro energy adjustment for PGE is about 85 MWa (assuming continued access to the entire output of Pelton and Round Butte).

Risks associated with hydro plants differ from the risks associated with thermal plants in the following ways:

- Reduced water flow, as opposed to forced outages of generating equipment, is the primary risk. However, as our access to existing hydro is reduced over the next 10 years, our exposure to low water flows declines from about 115 MWa to 61 MWa (if none of the long-term hydro contracts expiring by 2012 are renewed).

- While our plants encompass more than one river drainage system, we remain at risk for region-wide hydro impacts. This risk is relatively high since the climate factors that influence snow pack and precipitation for PGE hydro resources are common to the larger regional system. Unlike individual thermal plant risk, and because of the size of the regional hydro system, region-wide low hydro has a very direct and potentially significant effect on Pacific Northwest supply availability and Western wholesale electricity prices. Perhaps surprisingly, the inability to regulate down during high hydro conditions can also adversely affect the region by limiting the ability to access generator capacity and therefore, the ability to integrate the region's significant amount of intermittent resources.

Hydro risk can affect PGE in two fundamental ways:

- First, hydro risk affects our average cost of production. To the extent that PGE-owned and contracted hydro output is below normal, we may replace hydro generation, which has a very low variable cost, with thermal generation, which has a substantially higher variable cost. Conversely, above-normal hydro conditions allow us to displace more expensive thermal plants with less expensive hydro resources.

- Second, hydro risk affects PGE's total power costs, because hydro conditions directly affect wholesale market prices. Abundant hydro production tends to depress wholesale prices. Low hydro production tends to increase wholesale prices when the region turns to higher-cost generating units. Therefore, we expect the cost of replacement power in adverse hydro years to be greater than the value of surplus output in above-normal hydro years. Poor hydro conditions can also increase the demand for and cost of natural gas, thereby increasing our overall thermal generation costs. In addition, poor hydro conditions can also contribute to real supply scarcity and reliability problems, as were seen in 2000 and 2001 across the West.

While we recognize the unique benefits and risks of hydro in this IRP, we do not propose any adjustments to our supply targets for critical hydro conditions because, for reliability purposes, the reduction in supply for PGE resulting from poor hydro conditions is less than the change in supply or demand that can occur from weather and forced outage events.

3.4 Regional Reliability Standards

Adequacy Planning in the Context of the Regional Load/Resource Balance

The Northwest Power and Conservation Council sponsors a Pacific Northwest Resource Adequacy Forum led by NWPCC Staff with representation from BPA, regional investor-owned utilities, municipal utility districts, public utility districts and other stakeholder parties. The purpose of the Forum was to develop a standard for gauging regional resource adequacy for both energy and capacity and to provide forecast estimates of regional adequacy as a sort of early warning system should the region as a whole need to add new resources to maintain reliability. This material can be accessed at: www.nwcouncil.org/energy/resource. PGE participates in the Resource Adequacy technical committee.

The most current NWPCC adequacy assessment was completed in 2008 and looks at adequacy for the years 2011 and 2013. The NWPCC is in the process of updating the study and is focusing on the years 2012 and 2014.

While the regional resource adequacy outlook is helpful context for PGE's planning, the NWPCC concurs that their resource sufficiency standards and outlook are not meant to displace the need for utility planning and supply acquisition. In *A Resource Adequacy Standard for the Northwest* dated April 18, 2008, the NWPCC says:

> "The prudent amount of resource acquisition should be derived from an integrated resource planning process. For the region, the NWPCC's power plan serves as a blueprint for the types and amounts of resources the Northwest should acquire. Individual utilities must assess their own needs and risk factors and determine their own planning targets, which are screened by public utility commissions or by their boards of directors."

They also add that:

> "It would be a misapplication of the adequacy standard to infer that utilities should slow down their resource acquisition activity because the adequacy standard is already being met."

Regional Energy Outlook

The NWPCC targets to have sufficient resources on an annual average basis to meet load, based on critical hydro. PGE uses the same approach except that PGE uses normal hydro. When in balance on an annual basis (that is, where annual resources equal annual load), this generally results in being long in shoulder months, and short in peak winter and summer months.

The NWPCC includes 1,300 MWa of resources in 2013 for out-of-region spot market and hydro flexibility. When looking strictly within the region, inclusive of nearly 2,200 MWa of uncommitted merchant generation[26], 2013 shows an annual surplus of about 580 MWa against load requirements of about 23,600 MWa. Note that the NWPCC treats the entire region as a whole and assumes that all generation will be made available to the market. This is a simplifying assumption and does not reflect the fact that generation owners are driven by factors besides economics when making decisions to commit or dispatch their plants to sell electricity. These factors could include concerns over unforeseen increases in load and ability to meet demand (for load serving entities), concerns regarding plant and transmission contingencies and availability and cost of fuel. The regional load/resource balance is also impacted by sales and commitments of Pacific Northwest generation units to purchasers outside the region. Should

[26] PGE's assessment of the Northwest market indicates that the amount of uncommitted merchant generation is far lower than the NWPCC's 2,200 MWa.

some of the merchant generation become committed outside the region, the surplus number will fall correspondingly. In short, the region, as viewed currently, looks to be in approximate balance in 2013, but there also is no dependable surplus and the Northwest is vulnerable to supply deficits resulting from market inefficiencies and the commitment or sale of merchant generation to demand outside the region. The NWPCC also assumes that there are no transmission constraints within the region, such that power can move to wherever it is needed. This supply vulnerability is heightened when considering the relatively small number of merchant generating plants (10 plants[27]) that comprise the 2,200 MWa of available capacity cited by the NWPCC.

Regional Capacity Outlook

Whereas the energy view tends to focus more on how to supply the region cost-effectively, the capacity view is a more exacting standard which is designed to maintain a high level of supply reliability. The NWPCC considers whether there is sufficient sustainable peaking capability to meet the average load of the highest six demand hours in a day over a consecutive three-day period, where it tests both the annual winter and summer peaks.

Even without the contributions from uncommitted merchant generation, the 2013 look indicates sufficient reserve margins (>12%) in all months. Again, it should be noted that this is a regional evaluation and does not consider the load-resource balances of individual utilities, where reserve capacity is held or the commercial availability of generation to meet local imbalances when they occur.

Implications for PGE – Energy

The NWPCC projection for energy in 2013 indicates that PGE should work toward achieving its own balance. During fairly tight markets, wholesale prices tend to become more volatile and a strategy that is overly reliant on market purchases is risky both from a cost and supply perspective. In this regional context, we conclude that PGE needs to acquire its own year-round baseload energy rather than rely on market supply which may not be available or economic when needed. This conclusion takes on more urgency after 2013 as loads continue to grow.

Implications for PGE – Capacity

As shown in Section 3.3 above, PGE is more constrained by capacity (as well as the need for dispatch flexibility) than it is by energy alone. While the regional

[27] See the NWPCC 2008 Assessment Data at http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%2070908.xls

capacity outlook seems robust for 2013, we note that the region has twice in the last three years faced unexpected events that stressed PGE's ability to maintain reliable supply to meet customer demand.

In the regional context, we conclude that the most prudent course for PGE will be a hybrid strategy to improve our capacity position by acquiring more year-round resources that also provide flexibility to rapidly respond to both changes in load and fluctuations in supply attributed to increased levels of intermittent resources such as wind. The seasonal nature of our peak customer demand also suggests a need for more targeted capacity products such as seasonal exchanges and winter / summer capacity contracts. Whether these targeted seasonal capacity resources can be cost-effectively secured will be dependent on market conditions at the time of procurement.

3.5 Plug-in Electric Vehicles

Plug-in Electric Vehicles (PIVs) have been attracting the interest of customers, regulators, and other state and local officials. PGE expects to play a leadership role in a number of areas related to PIV technology. PGE is participating in a nationally publicized pilot project to facilitate the development and deployment of charging stations, with metering and monitoring technology, throughout our service territory. In addition, Nissan has partnered with PGE and the State of Oregon to introduce zero-emission vehicles in the State in 2010.

Market drivers for adoption of PIVs include:

- Cost and availability of lithium batteries
- Lifecycle cost of the vehicle
- The price of gasoline and concerns about oil independence
- Intensified climate concerns
- Availability of subsidies

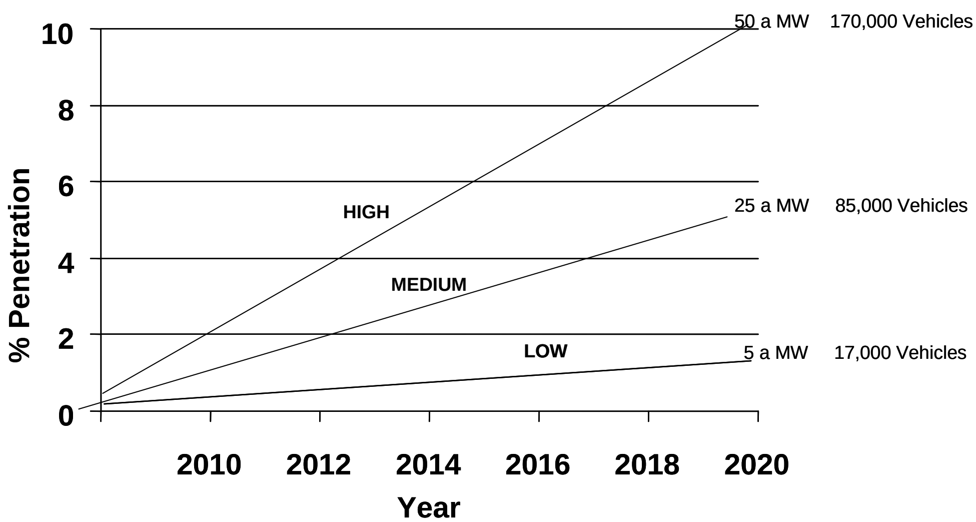
PGE estimates that 90% of charging would be done at customers' homes, with the remaining 10%[28] at public stations, representing a potential new off-peak load. Research has indicated that the existing electric grid in the Northwest could

[28] This estimate could be low if federal, state and/or local government commit to the deployment of a charging infrastructure.

handle a nearly 75% penetration rate of PIVs[29]. However, upgrades to infrastructure may be required in areas of PGE's service territory with particularly high PIV adoption rates.

Mass deployment of PIVs in PGE's service territory may occur in the next 5-10 years. The range of possible penetration rates for PIVs in Oregon over the next decade continues to be quite wide. In their first decade of availability, hybrids achieved a penetration rate of just over 1%. Optimistic projections for PIVs range as high as 10%. For purposes of analysis, low (1%), medium (5%), and high (10%) estimates have been used. See Figure 3-10 below.

Figure 3-10: Penetration Levels of PIVs



Under the high market adoption rate scenario, PGE could see 50 MWa of load growth by 2020. This does not include new load associated with economic development opportunities that may accompany the emergence of electric vehicles (e.g., battery or charging station manufacturing).

Vehicle mix (plug-in hybrids, range-extended, or electric) is also unknown. The analysis in Figure 3-10 assumes that pure electric vehicles prevail and are driven an average of 10,000 miles a year. If plug-in hybrids or range-extended vehicles prevail, miles driven under electric power would be reduced, potentially by as much as 50%. With the uncertainty around the type of vehicle that will ultimately prevail in the marketplace, as well as the relatively small impact of the medium case scenario (25 MWa), we have determined that a higher load growth

[29] Hadley, Stanton W. and Tsvetkova, Alexandra. Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation. Oak Ridge National Laboratory, January 2008, p. 55.

future is a reasonable proxy to model the impact of PIVs on future resource needs in this IRP (see Chapter 10). As such, we have not included any additional loads from PIVs in the load resource balance presented in this chapter.

PIVs providing electricity to the grid ("vehicle-to-grid") is an intriguing opportunity but is not likely to be an option for the first generation of electric vehicles. Vehicle manufacturers are reluctant to pursue vehicle-to-grid models, although advancements in batteries and the emergence of the "Smart Grid" could change that. Under any scenario, vehicle-to-grid appears to be at least a decade away.

PGE will continue to closely monitor the development of PIVs and establish a leadership role in the encouragement and advancement of electric vehicles.

4. Demand-Side Options

We consider customer-based solutions, both energy efficiency (EE) and demand response (DR) actions, to be an effective way to meet some of our energy and capacity requirements. Given the costs and uncertainty associated with many future supply-side resources, demand-side resources not only can be a cost-effective solution, they also can provide substantial risk mitigation against price volatility and supply availability. In addition, our research has indicated that our customers have a preference for demand-side solutions to meet our growing energy and capacity needs.

With the exception of EE, most of the potential demand-side resources available to PGE are capacity resources. Historically, PGE has had sufficient capacity. However, we will begin to experience a significant deficit due to several factors. Among them are the shift over time from long-term hydro contracts to wind generation, the expiration of current capacity contracts, and our peak demand growing in both winter and summer months.

Given these factors, we are increasing our focus on demand-side resources by pursuing several new ideas and initiatives to acquire, expand or enable future customer-based solutions. In this chapter, we outline PGE's assessment of demand-side alternatives and a variety of specific measures, programs and initiatives that we believe offer potential for increased energy savings and capacity opportunities for this IRP cycle.

In describing our options, we distinguish between demand-side solutions that primarily bring energy reductions (e.g., EE savings expressed in MWa) and customer-based capacity solutions which primarily reduce or shift peaks with little aggregate reduction in energy consumption (e.g., demand response, such as air-conditioning cycling, and critical peak pricing, expressed in MW).

Chapter Highlights

- The Energy Trust of Oregon (ETO) estimates that there is approximately 453 MWa of technical potential and 358 MWa of achievable potential for energy efficiency (EE) within PGE's service area between 2008 and 2027.
- Our support of ETO programs includes using a portion of SB 838 dollars for educational and promotional activities, especially directed at under-served markets.
- Demand response (DR) programs could help us fill our winter and summer peak demand gaps.
  - We issued a request for proposals for 50 MW of DR and are currently evaluating various bids for firm capacity from vendors who work with larger business and residential/small business customers.
  - We expect to obtain 10 MW of DR capacity in 2010 from large non-residential customers through a Firm Load Reduction Pilot.
  - In March 2009, we filed a residential critical peak pricing (CPP) tariff for a pilot program to be implemented in 2010.

4.1 Demand-Side Energy Resources

PGE Approach

Energy efficiency is a preferred option for meeting our growing energy needs. EE is a low risk, cost-effective resource. In addition, our customers expect PGE to be proactive in helping them become more efficient in their energy use. Therefore, we want to ensure that we are able to capture as much cost-effective energy efficiency as our customers are willing to pursue.

In 2002, SB 1149 consolidated funding for EE at the state level by directing funds collected from utility customers through a 3% public purpose charge to several agencies charged with responsibility for running EE programs, primarily the Energy Trust of Oregon (ETO). For the past six years, the ETO has successfully worked with utility customers to implement EE measures, resulting in savings via costs that are lower than the equivalent amount of generation. We continue to work closely with the ETO to direct our customers to the ETO to access its EE programs.

PGE played a lead role in seeking legislative action to expand EE opportunities. In the 2007 IRP, it was noted that some ETO programs were oversubscribed and that there was more cost-effective energy efficiency available than was being captured. Oregon's Renewables Energy Act (SB 838), ratified in 2007, provides an alternative compliance payment (ACP) mechanism for PGE to set aside funds to invest in conservation when doing so is more cost effective for customers. Through SB 838, PGE began collecting an additional 1.25% in public purpose charges in June 2008 to help achieve additional EE[30].

Since the 2007 IRP, PGE has been actively working with the ETO to leverage PGE's relationships with customers to promote EE, particularly in underserved market segments such as small to mid-sized businesses. Our unique access to the market and ability to assist customers in determining which ETO programs can best benefit them helps increase the penetration rate of ETO programs. We also help to overcome market barriers, test emerging new EE markets and pre-qualify customers for existing ETO programs. Later in this chapter we describe our promotional and educational activities in greater detail.

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[30] In 2008, $40 million of PGE ratepayer dollars were directed to ETO through the public purpose charge (PPC). In addition, some PPC funds flow to schools and organizations involved with low-income weatherization.

ETO Targets

To arrive at the technical potential for future energy efficiency acquisition, we relied upon an assessment prepared by the ETO[31]. The ETO report details the amount and cost of potential energy efficiency measures over a 20-year period, 2008 to 2027. Table 4-1 summarizes the ETO's assessment of technical potential within PGE's service area.

Table 4-1: ETO Forecast for EE Technical Potential in PGE's Service Area

Sector	ETO Forecast Technical Potential 2008-2027 (MWa)
Residential	32
Commercial	179
Industrial	223
Conservation Voltage Reduction	19
Total	**453**

PGE worked closely with ETO planners, revising and updating assumptions for the ETO's model specific to PGE's service territory and customers. We provided our load growth assumptions based on PGE's load forecast as of September 2009. PGE's EE specialists then worked with ETO staff to fine-tune assumptions of customer acceptance rates by sector.

The ETO estimates that the technical potential[32] for PGE's customers is to acquire about 453 MWa from 2008 through 2027 through programmatic EE measures at current funding levels. The ETO's consultants evaluated the costs of individual measures and packages of measures based on measure life, equipment and installation costs, annual O&M expenses, and a real discount rate of 5.2% to arrive at levelized costs and a benefit-cost ratio[33].

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[31] *Energy Efficiency and Conservation Measure Resource Assessment for the Years 2008-2027*, prepared for the Energy Trust of Oregon by Stellar Processes and Ecotope, February 26, 2009.

[32] The technical potential assumes 100% adoption, i.e., all customers participate. All of the 453 MWa of EE is deemed to be economic.

[33] The ETO report states: "It is important to note that program-related costs are not included . . . [and] . . . it is equally important to note that the levelized costs shown in this study are the entire societal cost of efficient measures for situations where existing, working equipment is retrofit, and the incremental cost of efficiency when considering new purchases of efficiency versus standard equipment." *Energy Efficiency and Conservation Measure Resource Assessment for the Years 2008-2027*, page 2.

Based on the ETO's projections, our reference case includes 357 MWa of incremental achievable EE[34], which includes self-directed customers[35], as shown in Table 4-2. It is important to note that in the ETO assessment, programs sunset over time and changing technology is not included in the forecast. Historically, technologies have emerged that have allowed EE to continue to grow beyond the projected saturation rate for current technology. Consequently, we believe that there is potentially more opportunity for EE in the later years than shown in the ETO forecast.

Table 4-2: ETO Forecast for EE Achievable Potential in PGE's Service Area

DSM Program	Achievable Savings Potential 2008-2027 (MWa)
Existing Buildings	103
New Buildings	84
Production Efficiency	130
Existing Homes	30
New Homes and Products	9
Total	**357**

According to the ETO, these EE targets are consistent with, and in fact exceed, EE projections in the Northwest Power and Conservation Council's Draft Sixth Plan, at least in the near term. Table 4-3 below compares the near-term EE targets for PGE provided by the ETO vs. those in the Council's plan. ETO forecasts higher amounts of EE through 2017 as compared to the NWPCC. The NWPCC's forecast is higher for the period from 2010-2029, but this is due to inclusion of emerging technologies after 2017 that the ETO did not have in their forecast. These back end differences will not have a material impact on PGE's IRP Action Plan, which focuses more on the near-to-mid-term for resource additions. Note that the ETO and NWPCC values include free-riders[36], while the values used in our IRP do not.

[34] Achievable EE takes into account actual customer behavior (not all customers will participate in EE programs even when offered incentives).

[35] Self-directed customers control their energy efficiency dollars. They can use their funds for on-site or approved EE projects.

[36] Free-riders do not have to take any new actions in order to benefit from the ETO incentives.

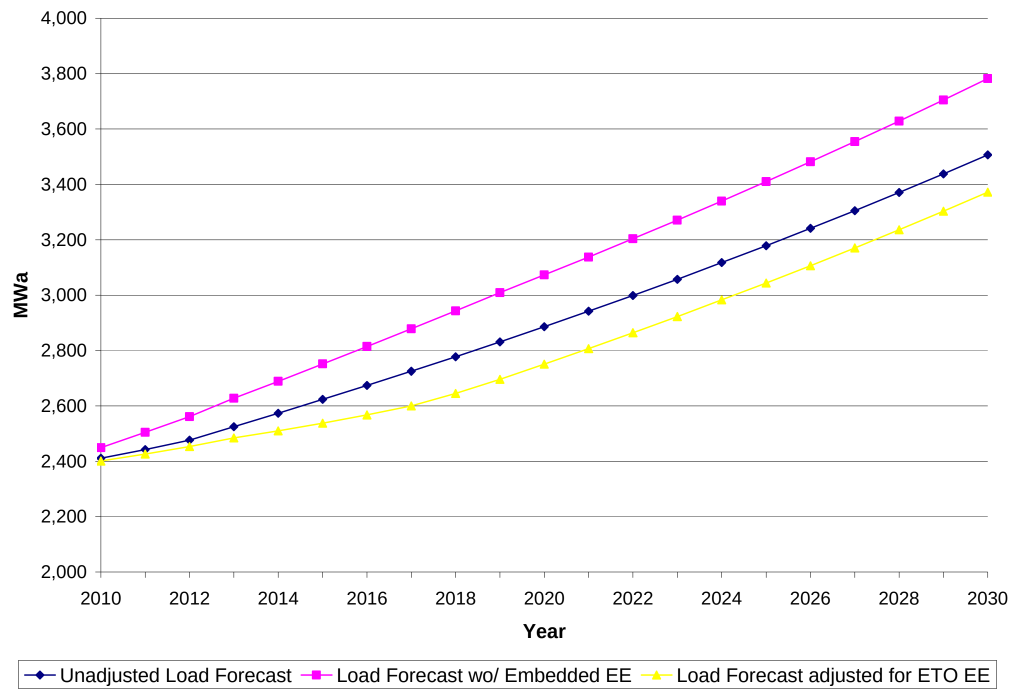
Table 4-3: Comparison of ETO and Council EE Forecasts

Year	ETO Planned EE Acquisition-Base Case	ETO Planned EE Acquisition Aggressive Case	PGE's share of 6th Plan Targets
2010	30.7	30.7	22.0
2011	36.0	46.9	24.2
2012	37.2	48.4	26.4
2013	42.7	55.5	28.6
2014	42.7	55.5	30.8
2015	42.7	55.5	31.9
2016	40.7	52.9	35.2
2017	38.0	49.4	37.4
2018	24.4	31.7	38.5
2019	19.5	25.4	39.6
2020	12.4	16.1	40.1
Total 2010-2020	367.2	468.1	354.6
Total 2010-2029	478.8	613.2	642.6

Energy Efficiency in the IRP Portfolios

The following section explains how we applied EE in our portfolio modeling and sensitivity analyses. As discussed in Chapter 3, PGE relies on the ETO for estimates of EE for our study period. These EE values will act as load reduction measures. To determine the overall impact of the ETO-forecasted EE, we must also consider the level of embedded EE that is in PGE's initial load forecast that we previously described in Chapter 3 as our "non-EE adjusted forecast". This is the level that our load forecast would be if historical EE measures were not continued. Figure 4-1 below presents PGE's energy load forecast along with the associated EE comparisons.

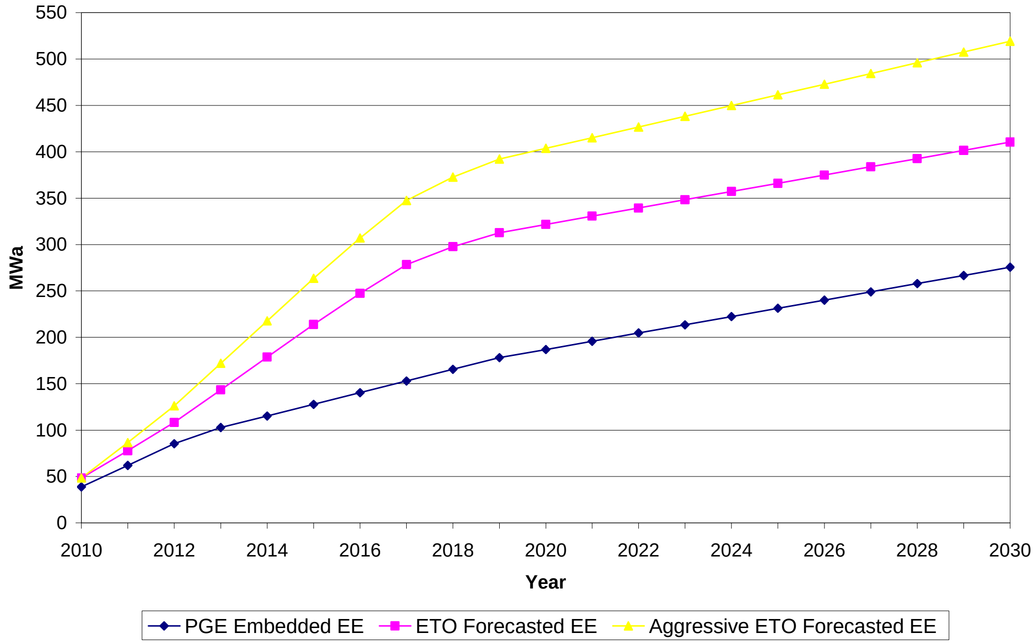
Figure 4-1: PGE's Load Forecast and Energy Efficiency Comparisons



PGE's non-EE adjusted load forecast is shown in Figure 4-1 above in blue (the middle line). This forecast includes a level of embedded (historical) EE. We have based our expectations of the embedded EE on historical levels of EE obtained within PGE's service area as reported by the ETO, and our internal calculations for periods prior to when ETO was established. Once the embedded EE is removed, the forecast increases, as shown in Figure 4-1 with the pink line (the upper line). The yellow line (lower line) is the load we expect to serve inclusive of the incremental EE from the ETO's forecasts. This includes new EE identified by the ETO as well as continuation of historical EE.

Figure 4-2 below shows a more detailed view of the cumulative amounts of embedded EE in our load forecasts (the bottom line in blue), along with the ETO forecasts (the middle line in pink). For our analysis, we examined an aggressive EE future, and requested such from the ETO. The aggressive case for EE as forecasted by the ETO is also shown in the Figure 4-2 below (the top line in yellow). It assumes that historical EE actions continue. We use the aggressive case as a future in our analysis as described in Chapter 10.

Figure 4-2: Energy Efficiency Forecasts for PGE's Service Area



From Figure 4-2 above, it is apparent that EE can be a valuable resource for reducing PGE's energy needs. The expiration of certain EE programs (without replacement) leads to a lower rate of growth in the EE forecasts around 2017. Thus, EE has a larger effect on demand in the near term as opposed to the long term. Table 4-4 below shows the impact of EE on load growth both on an annual basis and a cumulative basis (using 2010 as the base year). For 2010, EE will meet 65% of PGE's load growth. By 2015, EE accounts for 56% of load growth both for the specific year and, generally, for the period 2010-2015. By 2030, EE meets only 14% of annual load growth, but has covered 28% of the prior 20-year load growth. Our current assumptions reflect a decline in growth over time. These values would need to be adjusted if the programs are replaced.

Table 4-4: Energy Efficiency as a Percent of Load Growth

Year	Annual Value	Cumulative Value (2010 start year)
2010	65%	65%
2013	53%	55%
2015	56%	56%
2017	49%	55%
2020	14%	45%
2030	11%	28%

Energy Efficiency and Capacity Effects

While the discussion above focuses on the effect EE has on energy requirements, there are similar results for EE on a capacity basis. PGE worked with ETO's consultant, Stellar Process, in developing load shapes for EE. The results show that every annual MWa of EE contributes to a 1.47-MW reduction of peak winter demand and .98 MW of summer demand. Figure 4-3 and Figure 4-4 break out PGE's initial winter and summer highest 1 hour demand forecasts (blue line, middle), our forecast without embedded EE (pink line, top), and forecast after accounting for ETO's EE forecast (yellow line, bottom).

Figure 4-3: PGE's Winter Capacity Forecast and Energy Efficiency Comparisons

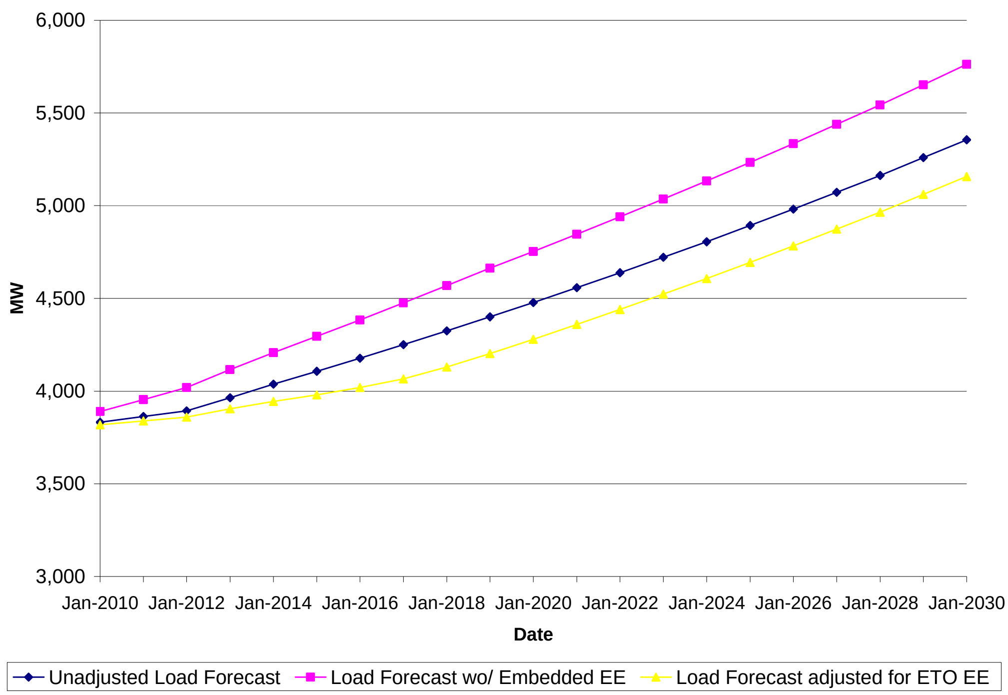


Figure 4-4: PGE's Summer Capacity Forecast and Energy Efficiency Comparisons

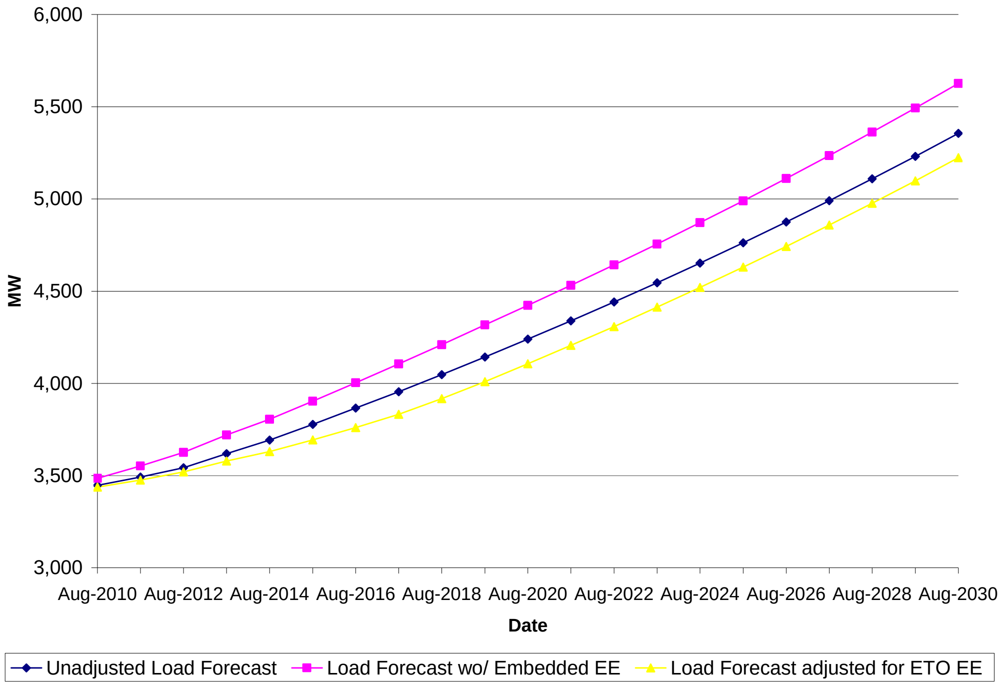


Table 4-5 below shows the overall contribution of EE to meeting peak load growth in both summer and winter. While EE has a large impact for winter peaking needs (1.5 to 1 on a MW to MWa basis), the overall reduction in peak load growth is somewhat more modest as compared to the reduction in energy growth. This is because peak energy growth (especially summer) is growing at a faster rate than energy needs.

Table 4-5: Energy Efficiency as a Percent of Peak Load Growth

	Winter		Summer	
Year	Annual	Cumulative	Annual	Cumulative
2011	14%	14%	31%	27%
2013	11%	30%	13%	32%
2015	8%	37%	8%	34%
2017	5%	41%	5%	34%
2020	1%	36%	1%	30%
2030	1%	25%	0%	17%

Strategies for Achieving More EE

In 2007, PGE collaborated with interested parties to advance legislation that removes impediments to utilities' involvement in and funding of EE. That effort culminated in the passage of SB 838, which enacts the Oregon Renewables Portfolio Standard (RPS). The legislation also contained a provision in which the

OPUC may authorize an electric utility to include in its rates the costs of funding or implementing cost-effective energy conservation measures (measures for customers greater than 1 MW are excluded).

To achieve the additional EE savings made possible by SB 838, PGE is working cooperatively with the ETO to achieve additional EE, primarily by leveraging PGE's marketing capabilities and customer contacts and relationships with those of the ETO to increase participation in existing programs. We are supporting ETO programs and program managers with additional PGE staff expertise, and providing funding to the ETO to implement additional cost-effective programs.

PGE's objective is to further develop the EE markets and to drive customers to the appropriate ETO programs. We retain 10% of the SB 838 funding for advertising and promotion activities. Most of our focus has been on residential customers, but we are increasingly engaging our business customers by offering free EE consultations and implementing an annual "Save More, Matter More" EE awareness campaign. With these activities and the programs offered by the ETO, our goal is for ETO to achieve 25 MWa of EE annually from within our customer base. In 2008, ETO achieved 19 MWa of EE among our customers.

One of the ways we approach this is to target specific market segments and promote an integrated set of programs, or product bundles. For the residential sector, we build our quarterly marketing activities around specific themes and promotions with highly targeted and segmented marketing. Typically, we work with vendors to create incentives or promotional offers that build customer awareness of and participation in ETO programs. For business customers, we offer free consultations as a means of encouraging participation. This is particularly necessary with the small and medium-sized business sectors where there are significant barriers to entry. However, there are considerable opportunities to achieve EE savings once we are able to engage the customer.

Our current support activities include:

- Save More, Matter More™: In September 2008, we launched our first Save More, Matter More campaign. By year's end, we had worked with 262 individual businesses to introduce them to EE opportunities. In this campaign, businesses are encouraged to make a pledge to save energy and post that pledge on PGE's website. Where appropriate, we perform facility "walk-throughs" with customers and direct referrals to ETO programs or ETO trade allies. Pledges range from small behavior changes to large investments. About one-third of these companies have pledged to implement a capital improvement project to improve EE in their businesses in 2008-2009. Many of these projects will qualify for ETO incentives. In addition, participating customers will implement identified

EE projects in years to come. Our goal is to double the number of participating pledging businesses in 2009. These activities will increase the awareness for EE opportunities as well as ETO programs and incentives for all of our business customers.

- Residential Heat Pump Program: PGE has developed an effective heat pump program that promotes the advantages of heat pump technology over electric baseboard or electric furnace heating. This program does not market to customers with gas or oil space heating. We have assembled a contractor network aimed at both residential retrofit and new construction. Typically, we are seeing 40% more efficiency from heat pumps over the other electric options. A new initiative for our program is in the area of ductless mini-split heat pumps, which are now gaining increasing market acceptance, although still with relatively low market penetration. These devices are essentially zonal heat pumps that can produce 2.25 to 4 times the efficiency of electric baseboard heating systems. Another advantage of ductless mini-split systems is that they allow for conversion of baseboard units without the expense and challenge of installing ducting in homes with this infrastructure.

- Ongoing Marketing and Promotion: Throughout each year, we use our direct marketing and customer contact channels to engage in seasonally adjusted information campaigns and offers of free consultation for business customers. In summer months, for instance, we focus on new construction or pumps/motors/drives in industry-specific outreach activities. In the fall, our Save More, Matter More campaign kicks off across all of our business segments. Similar seasonally oriented informational campaigns are carried out and directed toward residential customers as well.

- Information-driven Energy Savings (IDES): With PGE's smart metering project implementation well underway, we will soon be able to offer all of our customers online access to their daily electricity usage data. We believe, as does the electric utility industry in general, that customers will better understand their energy consumption patterns and reduce their overall energy use with access to their hourly and, in some cases, 15-minute usage data. With this information, they can make informed choices on how – and even when – to use electricity. In focus groups and other interactions with our customers, we have found that they quickly grasp the advantage of having this data readily available. In early 2010, we expect to launch the first phase of IDES for those customers that are on the smart metering network. Over time, we plan to expand the service to provide stronger analytical tools to enable customers to assess the impacts of behavioral changes and programmatic choices available to them. Our IDES project is discussed more fully below as a component of our demand response strategy.

- Future Opportunities: We also see important opportunities in the future working more closely with manufactured housing, particularly in demonstrating the energy efficiency of very high efficiency traditional heat pumps, and also in the area of heat pump water heaters. On the latter, we will be working on a pilot in 2009 with a manufacturer (Rheem/Marathon) of the currently best available technology. We believe heat pump water heaters have the potential for reducing electricity consumption by half compared to current electric water heater technology.

- EE Market Transformation: Another focus for PGE is transforming markets through new codes, education and promotion of efficient technologies with wide applicability, multi-family retrofit, and commercial lighting. We are currently working with the ETO and the City of Portland on a 500-home pilot to encourage EE by offering a home assessment and package of insulation/sealing/new HVAC or water heater upgrades. We will provide on-bill repayment for EE upgrades that homeowners make through the program.

4.2 Customer-based Capacity Resources

Demand response (DR), as the name suggests, is generally responsive to peak loads via direct control or pricing signals. In this respect, it differs from EE which tends to yield fixed load reductions that do not vary based on external controls or price signals.

In addition to promoting EE for both energy and demand reduction, PGE is working to enable and implement cost-effective customer-based capacity resources (i.e., demand response) programs. Demand-side capacity options offer improved reliability, resource diversity and lower environmental impact than many supply-side capacity options.

We treat customer-based capacity resources in two categories: firm resources such as non-discretionary direct load control programs, and non-firm resources such as non-technology-enabled pricing options and programs or products that are elective and behaviorally driven (instead of requiring a firm commitment). When demand response resources are considered, they are evaluated against the supply-side capacity resource alternatives, such as a simple-cycle CT.

For IRP planning, we primarily assume acquisition of firm DR resources because of their expected reliability. Such resources may also be dispatchable. We believe we can reliably achieve, by 2012, up to 50 MW on a day-of or day-ahead notice from direct load control, with up to 10 MW additional from the introduction of a non-firm curtailment tariff. These amounts are included in the portfolios described in Chapter 10. Such demand response capacity reductions allow us to reduce generation supply costs while offering customers more options to control their monthly electricity bills.

The following factors influence the role that demand response will play at PGE:

- Availability of Capacity – the Pacific Northwest historically has had spare generating capacity due to the regional hydro system which can deliver, when needed, about twice as much power as normally generated. However, PGE access to regional hydro is decreasing and peak demand is growing. By 2012, PGE will be in need of more capacity than can reliably be obtained from the region, as shown in Chapter 3.

- Low Prices – Utilities in the Northwest are still relatively low-cost providers compared to other regions in the West and throughout the country. Until now, customers have had little incentive to practice DR because of the minimal difference in their bills for their efforts. Longer payback periods on the DR investments have also been an economic impediment.

- Winter Peaking Programs – Nationally and in the West, the most successful DR programs to date are for irrigation, air conditioning, and pool pump control – all programs for summer peaking. PGE continues to be winter peaking and must instead look to programs such as water heat load control.

In an effort to determine how much demand reduction PGE customers can likely achieve, we commissioned The Brattle Group to prepare an assessment of demand response potential for PGE between 2009 and 2029. Table 4-6 below depicts the DR options by customer segment that The Brattle Group determined are available to PGE.

Table 4-6: PGE's Demand Response Opportunities by Sector

DR Options	Residential and Small C&I	Medium C&I (30-499 kW)	Large C&I (500-999 kW)	Largest C&I (>1,000 kW)
Direct Load Control	√	√	√	
Curtailable Rate				√
Demand Buy Back		√	√	√
Peak Time Rebates	√			
Critical Peak Pricing	√	√	√	√
Real Time Pricing	√	√	√	√

Table 4-7 and Table 4-8 below show the demand response potential identified by The Brattle Group and their impacts on summer and winter peak loads, respectively.

Table 4-7: PGE Demand Response Potential for Summer Peak (MW), 2009 - 2029

Program	Segment	Enabling Technology[(a)]	2010	2015	2020	2025	2029
Direct Load Control	Mass Market	PCT (CAC), Switch (WH)	1.5	22.5	67.7	72.9	77.4
Direct Load Control	Med. & Large C&I	Auto-DR	0.8	13.1	41.8	47.8	53.4
Curtailable	Largest C&I >1000 kW	None	8.0	14.2	22.3	25.6	28.5

(a) PCT (CAC) = Programmable communicating thermostats (central air-conditioning)
Switch (WH) = Water heater switch controls
Auto-DR = Automated demand response

Table 4-8: PGE Demand Response Potential for Winter Peak (MW), 2009 - 2029

Program	Segment	Enabling Technology[(a)]	2010	2015	2020	2025	2029
Direct Load Control	Mass Market	PCT, Switch (WH)	1.7	25.9	76.2	80.2	83.7
Direct Load Control	Med. & Large C&I	Auto-DR	0.7	10.7	34.0	38.4	42.4
Curtailable	Largest C&I >1000 kW	None	7.2	12.7	19.8	22.3	24.7

(a) PCT (CAC) = Programmable communicating thermostats for central electric heating
Switch (WH) = Water heater switch controls
Auto-DR = Automated demand response

For modeling purposes, PGE has included DR figures that are consistent with both the Brattle study results, adjusted for our experience, and our demand response RFP combined with the 10 MW we expect to acquire from our large-customer curtailment tariff. The Brattle study assumes a 20% penetration rate for the direct load control (DLC) options. We have reduced that to a 10% penetration rate, which is more consistent with our expectations. Our assumption for curtailable rate, however, was increased to 10% from 5%, consistent with our research. In our IRP analysis, we use the greater of PGE's expected DR capacity acquisition or the Brattle estimates. That is, while Brattle suggests lower amounts of DR available to PGE in the near term, we will instead use the amounts associated with our DR RFP and our curtailment tariff (see discussion of both programs below). In the later years, we transition to the adjusted Brattle study values.

See Table 4-9 below for the annual values of DR both summer and winter. These amounts are included in the portfolios described in Chapter 10.

Table 4-9: Demand Response as included in PGE's IRP

Year	Summer Savings (MW)	Winter Savings (MW)
2010	15	15
2011	35	35
2012	60	60
2013	60	60
2014	60	60
2015	60	60
2016	60	60
2017	66	63
2018	77	73
2019	88	84
2020	99	95
2021	102	96
2022	104	98
2023	106	100
2024	109	102
2025	111	104
2026	114	106
2027	117	108
2028	120	110
2029	122	112

Following are descriptions of PGE's existing customer-based capacity resources.

Firm Demand Response – Direct Load Control

Curtailment Tariff

PGE has implemented a curtailment tariff, in the form of a Firm Load Reduction Pilot Program, which was filed with the OPUC in December 2008 and expected to become effective in July 2009. It is part of a larger demand-side capacity resource package to help meet system capacity needs. The purpose of the program is to provide the utility with access to firm capacity through an optional demand response pilot offered to large non-residential customers (Schedule 75 and 89) able to commit to a load reduction of at least 1 MW at a single point of delivery. Under the program, participating customers receive capacity and energy payments for committing to specific load reductions at PGE's request.

PGE has the right to ask participants to curtail load up to a maximum of 12 times during the 2010 program year, for not more than four-hour peak periods and not more than once per day. In 2010, the pilot is limited to 10 MW of load.

Through the pilot, we expect to gain experience and capability in providing DR capacity incentives to customers. We intend to test pricing, program and incentive structure, customer notification, customer demand, customer satisfaction, and our ability to curtail load on short notice.

Demand Response Peak Capacity Contract

PGE issued a request for proposals in August 2008 soliciting offers to provide us with 50 MW of aggregated firm capacity, to be available to PGE by December 1, 2012. Qualified bids will be evaluated for implementation of a "pilot" demand response program. The pilot program will provide us with greater understanding of the market acceptance and operational requirements of demand response opportunities. To be a qualified bidder, the provider must be able to assure PGE that the capacity is reliable and dispatchable. The resource must be available in blocks no smaller than 5 MW. The resource is to be broken into two components – 25 MW aggregated from PGE's large manufacturing and business customers with an annual average peak demand of 200 kW or more, and 25 MW aggregated from PGE's residential and small general business customers with an annual peak demand of less than 200 kW.

PGE's requirements stipulate that the resource must be available to be dispatched in one-hour time periods on any day of the week. Further, PGE expects that the resource will be available on 10-minute notice during peak hours, for an accumulated maximum of 4 hours per day, during each season of the year for a maximum of two consecutive days. The limit for dispatching this DR resource is up to 10 days per month, up to 50 hours per season and up to 100 hours per year.

Permanent load shifting or use of standby generation to reduce load would not qualify for this contract. PGE's direct access customers also are not eligible to be part of the provider's DR product offer.

Appliance Market Transformation

As early as 2004, PGE has actively supported market transformation of peak load reduction through development of smart appliance technology. We believe that smart appliances have huge potential for peak load reduction. For example, PGE's residential sector contributes about 2,200 MW, or about 55%, of our winter system peak load. We believe that potentially 25% of this load could be avoided – with minimal impact to customer lifestyle or comfort – if major appliances were manufactured to enable a cost-effective and less intrusive method to reduce system peak demand than traditional demand response programs.

We monitor industry players in their efforts to implement various forms of smart appliance response to meet critical peak energy needs. We also are working with consortia of utilities, appliance manufactures and stakeholder groups to advance market acceptance, technology standardization and the development of pilots to advance the opportunities for significant DR in the smart appliance arena. We consistently advocate for legislation that would encourage manufactures to place communications devices in major appliances for both after-market and new retail offerings.

In the 2007 IRP, we reported that we were forming a consortium to work with appliance manufacturers to place communications devices in major appliances for after-market application of demand responses controls. Through this consortium we applied for a USDOE grant to demonstrate the feasibility of smart appliances that can be used for active and transparent demand response at the system (grid) level.

We continue to work within the industry to advocate for standardization of smart appliance technology. Ultimately, the success of market transformation requires enactment and implementation of a national standard.

Appliance market transformation is an important part of PGE's demand response planning. The company continues to actively engage legislators, national regulators, EEI and other industry entrants in this initiative. At the present time, we are working with Utility AMI and National Institute of Standards and Technology (NIST), who are defining communication standards, and EPRI, which is launching a project to define the first appliance standard to support demand response.

Non-Firm Demand Response Pricing Options

Demand Buy-Back Program

PGE currently offers large, non-residential customers a demand buy-back (DBB) program, which can be implemented during critical peak hours. Because DBB is a voluntary program, we do not consider it to be a firm capacity resource. The program typically is triggered under 1-in-5 weather conditions, and has been effective in the past for reducing peak demand. While agreeing to conditionally provide over 25 MW of capacity reductions, our customers tell us their ability to respond depends largely on their varied business operating conditions and circumstances at the time. During the regional heat event triggered in July 2006, we learned that PGE could count on approximately 4 MW of capacity through DBB on short notice (intra-day or a few hours in advance) for resource planning purposes. The actual reduction may be larger when customers are given longer advance notice about the DBB event. Because of the limited experience with non-firm demand response pricing programs in the Pacific Northwest climate, we do not yet have adequate estimates of the reliable size of these resources when called.

Energy Information Service

PGE's large non-residential customers with greater than 30 kW of demand (Schedule 83 customers) are eligible for PGE's energy information services (EIS). As of June 2009, a total of 140 customers, representing over 600 meters, have signed up for EIS. EIS provides graphs depicting energy use in 15-minute intervals showing precisely how much energy is being used by a customer facility at a given time. 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 DBB, real-time pricing or contract curtailment. EIS can also be used to track the effects of EE initiatives.

Time-of-Day Pricing

PGE's large non-COS customers (with more than 1,000 kW of monthly demand) take service from PGE under time-of-day pricing, with daytime hours designated as peak hours which are priced higher than non-peak hours at night.

Real-Time Pricing

PGE offers real-time pricing service under Schedule 87 of its retail tariff. Real-time pricing is a rate option designed to flatten peak load and improve load factor by offering business customers hourly prices reflective of costs. The potential customer benefit is to lower their energy bill. Customers agree to a baseline hourly load shape based on their consumption patterns for their business. Customers are charged higher prices when they go above the baseline, and are rewarded with lower prices reflective of market costs when they go below it.

We offer real-time pricing under a two-part schedule. First, we recover our costs through a fixed customer baseline load charge that is priced using the annual cost-of-service rates of the otherwise applicable rate schedule. The second part of the schedule provides a credit or charge to the customer based on deviations of actual usage from the customer baseline load, priced at marginal cost.

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. Participants report that they are pleased with the option and the program generally contributes to higher satisfaction with the utility.

With the coming of smart metering, which would make it possible to enroll residential and small non-residential customers without having to change out their meters, there may be greater potential for TOU-type programs. As noted below, we are taking advantage of smart metering in the near term by implementing a residential critical peak pricing pilot.

Critical Peak Pricing

In March 2009, we filed a request with the OPUC to implement, on a pilot basis, a residential critical peak pricing (CPP) DR program. Rate Schedule 12 was approved by the OPUC on September 22, 2009. 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 3,500 participants and is expected to be active from November 2010 through October 2011. Based on results of the pilot, a residential CPP program may be made available to a broader group of customers. Until enough experience with customer response provides a reliable estimate of capacity, it is considered a non-firm resource.

Under the tariff, the Company will provide day-ahead notice to participants for expected critical peak day events. For a 4-hour “critical peak” period (Sundays and holidays are excluded and billed at normal off-peak rates), the customer’s energy price will be about 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 for a customer to 10 events in the summer and 10 events in the winter.

From similar tests conducted by other utilities (e.g., Puget Sound Energy, Anaheim, Ameren), there is clearly a level of customer interest, participation and satisfaction that may make a CPP tariff attractive to a broad spectrum of residential customers. Since each area of the country differs in how such a program should be designed and would work, we expect that this pilot will allow us to refine the program to maximize its potential given our circumstances in Oregon.

Advanced Metering Infrastructure (PGE's Smart Metering Project)

In May 2008, the OPUC approved PGE's request to implement our advanced metering infrastructure (AMI) project, now commonly referred to as our smart metering project. We successfully completed system acceptance testing in April 2009 and have now launched into our full meter deployment phase, which will be completed in the fall of 2010. At that time, all PGE customers will have metering in place that records their electricity usage in hourly (residential and small-business customers) or 15-minute (medium- and large-business customers) increments.

Daily meter data collection is carried out over a two-way fixed wireless communications system that operates on a licensed 900 MHz RF spectrum. The two-way communications capabilities of the system enable us not only to receive register reads and interval data daily but also to send commands to the meter. This capability can, with additional investment, support a variety of DR and direct load control programs.

We consider the smart metering system to be an important foundation for furthering our goals for customer-based EE and DR. In Order 08-245, which authorized PGE to collect from ratepayers the costs (less the benefits) of the AMI system, the OPUC set forth conditions for the development of certain customer demand response capabilities as well as tools through which customers could increase their energy efficiency. We agreed to meet certain deadlines and provide quarterly reporting to the Commission on our progress in the following areas:

- Information-driven Energy Savings (IDES)
- Voluntary Critical Peak Pricing
- Appliance Market Transformation
- Firm Energy Curtailment

We believe that as we gain experience with smart metering, we will be able to explore additional ways to leverage the smart metering system to achieve further opportunities in both the EE and DR arenas.

To accelerate our efforts and further leverage our AMI investment, PGE has applied to the U.S. Department of Energy for $76.2 million from the federal Smart Grid Investment Grant program to help support the existing AMI deployment as well as a smart grid initiative that will result in significant modernization and automation of our distribution and delivery systems over the next 5-10 years.

Specifically, PGE seeks funding assistance from DOE for four projects that are central components of our Smart Grid Roadmap: (1) AMI Smart Metering implementation (currently in progress); (2) Sense & Respond, a real-time data processing architecture, (3) Secure Energy Network (currently in progress), a cyber security measure for critical transmission & distribution assets, and (4) Distribution Technology Upgrade to enable usage of interval data and allow for smart grid functions. In addition to other functionality, these investments will enable outage and voltage events generated at the meter to flow to Repair Dispatchers, usage information to flow to customers, and a secure communication network to send price and control information into every customer premise.

If funded, these projects will build upon the AMI platform by adding new, time-responsive functionality that increases access to information in real-time so that we can more effectively address problems as they arise and help prevent situations, such as outages from distribution equipment failure, from occurring. These projects also will improve the customer experience by (1) increasing customers' understanding of their energy usage, (2) providing demand response program opportunities, (3) improving PGE's outage response capabilities and (4) increasing the overall reliability and cost effectiveness of our distribution system.

5. Fuels

Fuel prices, particularly natural gas, are a major driver of wholesale electricity market prices and the economics of new generation resources. Currently, a natural gas combined-cycle combustion turbine is the marginal resource in the WECC (i.e., sets the market price). Over half of the levelized cost of energy of a natural gas CCCT is determined by the fuel cost (See Figure 7-3 in Chapter 7). In addition, fuel costs and risks are increasingly influenced by demand and supply drivers and political events on a global, national and local level. Given these factors, analysis of fuel supply availability and price is an integral part of the IRP process.

Our general approach to projecting fuel prices is to develop a reference-case fuel price forecast based on near-term market indications and longer-term fundamentals, as determined by third-party, expert sources. For this IRP, we utilized independent third-party fundamental research and price forecasts from PIRA Energy Group for both coal and natural gas.

Chapter Highlights

- Our base-case natural gas forecast, derived from market price indications combined with PIRA's long-term forecasts, is $7.24/ MMbtu (real levelized in 2009$ for the period 2010-2025). Our high-case forecast is $11.28, and our low-case forecast is $5.22. After 2025, prices are assumed to increase at inflation, resulting in a reference case of $7.86, high case of $12.84, and low case of $5.19 in 2009$ for the period 2010-2040.
- We priced gas transport based on current 2009 rates of $.38 per dekatherm on NW Pipeline and $.43 per dekatherm on GTN and adjusted these rates by approximately 10% for near-term expansion, resulting in $.42 for NW Pipeline and $.48 for GTN. We then assumed escalation at inflation starting in 2010.
- PGE monitors pipeline expansion projects and continuously explores opportunities to purchase physical gas supplies, either as gas reserves in the ground or long term physical contracts (index or fixed price) to be used as a physical hedge as part of our overall gas supply portfolio.
- Delivered prices for Powder River Basin 8,400 Btu/lb. low- sulfur coal are $49/ short ton real levelized in 2009$ for the period 2010 - 2040. Prices were derived from PGE coal supply contract prices, PIRA and EIA forecasts, and projected rail cost forecasts.
- For Colstrip, we use planned plant coal commodity costs for 2009 – 2013. For 2014 and beyond, we apply the escalation factor based on the average escalation during 2009 - 2013. After 2025, costs are assumed to grow at inflation. The resulting cost is $30 real levelized in 2009$ for the period 2010 - 2040.

5.1 Natural Gas

The natural gas forecast used in the base case of this IRP is partly derived from market price indications through 2011. We then rely on PIRA's long-term fundamental forecast[37] starting in 2014 and going through 2025 for the long-term Henry Hub price and basis differentials to Sumas, AECO and other WECC supply hubs[38]. PIRA's forecasts are available through 2025; after 2025 we escalate at inflation.

We continue to use PIRA because they:

- Provide transparent assumptions;
- Identify a reference case and its probability of occurrence;
- Have a strong reputation for energy commodity fundamental research and forecasting; and
- Project both Henry Hub prices and all main hub basis differentials with Henry Hub in a format that meets our modeling needs.

We transition from the market curve to PIRA's long-term forecast by linearly interpolating for two years (2012 – 2013). For our portfolio analysis, we examine alternative price scenarios based on our high and low gas price scenarios. An example of the forecasts is shown for an average of Sumas and AECO hubs in Figure 5-1[39].

For natural gas prices, we model uncertainty around the base case using both stochastic and scenario analyses. Fuel prices are then used to project electricity prices in our AURORAxmp model and to assess the performance and dispatch of PGE and WECC power plants. See Chapter 10 for PGE's market electricity prices and a discussion of our stochastic analysis.

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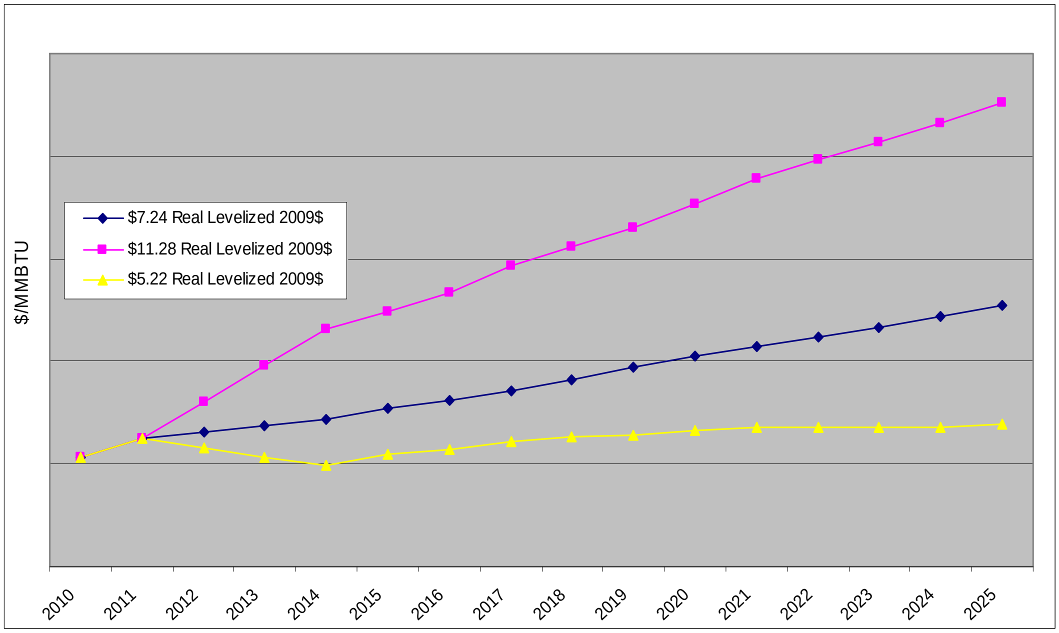
[37] PIRA Energy Group. Scenario Planning Service Annual Guidebook 2009, February 2009.

[38] Sumas and AECO are the two primary Pacific Northwest natural gas trading hubs from which we fuel our plants. Hub deltas are calculated as an annual percentage difference to Henry Hub prices.

[39] Due to PIRA license restrictions, PGE cannot show the Y-axis for PIRA forecasts.

Figure 5-1: IRP Long-term Forecast – Average of Sumas and AECO Hub Prices



Update to PGE Gas Forecast

PIRA provides quarterly updates of its long-term analysis, the most recent of which was issued on August 7, 2009. In the latest scenario assessment, PIRA slightly raised their reference case real levelized price for the period of 2010 to 2025, resulting in our current outlook of $7.24 (2009$ for the period 2010-2025).

The drivers behind recent decreases in gas prices include:

- Abundant non-conventional gas exerting downward pressure on prices.
- North America not requiring additional LNG imports to meet demand growth.
- The downturn in the U.S. economy causing concern about the potential for an extended period of weak economic growth that in turn impacts industrial and power generation growth.

PIRA's new reference case scenario suggests that the current lower prices will resume an upward trend over the years, with the expectation that volatility will continue due to short- and medium-term factors such as weather, changes in drilling costs, LNG supply and demand, oil prices, and economic conditions.

Natural Gas Forecast Fundamentals

On the demand side, uncertain economic growth is the main driver behind near-term changes to the reference case gas price forecast. The immediate outlook calling for a sharp recession followed by a relatively weak recovery will significantly decrease the demand for industrial and power generation in the near term and possibly in the longer term. Only slight growth in power generation (1.5% per year between 2009 and 2025) is expected. The growth in gas-fired electric generation is partly due to continued weakness of new coal-fired generation and limited nuclear possibilities, and is tempered by a slowing of traditional electricity demand due to conservation measures. Weak growth in the U.S. economy will continue to pose a downside risk for industrial gas use and power generation demand.

Priorities expressed by the current presidential administration and congressional leadership raise the prospect of more activist policies with respect to energy and the environment. A move toward greenhouse gas reduction legislation appears likely. This may also be accompanied by a more aggressive policy focus on renewables, which may come at the expense of new gas-fired generation capacity.

On the supply side, the long-term U.S. and global outlook for natural gas has changed dramatically from last year due to the continued expansion in North American non-conventional gas resource development. Gas production from shale has evolved from a source of steady upward adjustment to one of a significant proportion of supply availability. These shale gas supplies are expected to continue to grow to meet demand at least through 2025.

The explosive growth of shale supplies has had some unforeseen consequences on other projects as well. The likelihood of construction of either the Alaskan Pipeline or the MacKenzie Gas Project has been reduced due to the refocusing on non-conventional resources in both Canada and the U.S. In addition, the likely consequence of stronger domestic production is the near elimination of the need for LNG imports to balance supply and demand. LNG import volumes plunged in 2008 despite growth in import capacity due to the significant reduction in North American LNG demand.

PIRA's outlook on LNG is that the import capacity will be less than 20% utilized and LNG imports will be a matter of choice and opportunistic arbitrage, not a necessity. This is a significant departure from last year's outlook where there was concern about the lack of commitments for the next generation of LNG projects.

Despite the lack of concern about LNG as a contributor to North American supply, PGE is still closely monitoring the development of potential LNG import terminals in the Pacific Northwest and Oregon, including proposed facilities at Bradwood, Oregon (Northern Star LNG), Warrenton, Oregon (Oregon LNG), and Coos Bay, Oregon (Jordan Cove Energy Project), and the British Columbia coast, where an export LNG terminal is being proposed.

For PIRA's high gas price scenario, drivers include possible decline in some of the new non-conventional basins, restricted access to production sites or tighter environmental standards imposed by the government, and policies reducing coal-fired generation and mandating natural gas vehicles justified on the assumption that huge domestic reserves of natural gas exist. This scenario also presumes that when the momentum for demand growth is not met by non-conventional production, there is little help from incremental LNG as the global market out-prices the U.S. and we remain the market of last resort.

For PIRA's low gas price scenario, drivers include low oil prices, slow industrial and power generation growth due to a weak U.S. economy, continued non-conventional production growth, Alaskan Pipeline and Mackenzie delta project moving forward due to government support, and additional LNG coming to North America as European and Asian demand slackens.

5.2 Gas Transportation Cost

PGE has contracts for gas transportation for existing plants (see next section for more detail). For new gas plants, forecasting the cost of gas transportation without knowledge of the exact location, construction timing and supply options is a challenging exercise and requires market insights as well as professional judgment.

For planning purposes, we chose a conservative approach and priced gas transport based on current 2009 rates of $.38 per dekatherm on NW Pipeline (NWP) and $.43 per dekatherm on Gas Transmission Northwest (GTN, a unit of TransCanada Pipelines Limited). Starting with these rates, we adjusted by approximately 10% for near-term expansion plans, resulting in $.42 for NWP and $.48 for GTN. We then assumed escalation at inflation starting in 2010. We feel this is a reasonable proxy for any future transportation requirements to meet gas-fired plant fuel needs.

NWP's system extends from the Rockies region to the Canadian Border (Sumas, Washington). This pipeline interconnects with K-B Pipeline and serves our Port Westward and Beaver plants. Gas Transmission Northwest's system extends from the Canadian Border (Kingsgate, Idaho) to Malin, Oregon. This pipeline serves our Coyote Springs plant. These two pipelines comprise the primary system for long-haul natural gas transmission from Canadian and Rocky Mountain supply basins to Pacific Northwest demand.

5.3 Gas Acquisition Strategy

Fuel prices, particularly natural gas, are a major driver of wholesale electricity market prices and the economics of new generation resources. PGE's natural gas-fired generation requirements have increased over the years and are expected to grow in the future. In the past year, North American gas markets have seen unprecedented price volatility, and because natural gas currently represents approximately 20-25% of PGE's generation portfolio, it is an important issue for our company to manage in order to provide reliable and cost-effective resources to meet our customers' requirements.

Guideline 5 of Order No. 07-002 instructs utilities to include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability. This section, and the corresponding discussion on our proposed gas benchmark resources in Chapter 9, address natural gas transportation and supply acquisition in response to Guideline 5.

Supply Contracts

Gas supply contracts typically have a shorter duration than pipeline transportation contracts, with terms that coincide with the winter months, summer months and annual contracts that are actively traded in the market. We currently secure physical gas contracts for a portion of our anticipated fuel needs up to two years in advance. We also balance daily positions using storage, day-ahead purchases, and off-system sales transactions. On a daily basis we make decisions regarding the dispatch of our gas plants. In doing so, we compare market prices for power and natural gas, dispatching our gas plants when the cost (including fuel) is below the price of electricity. This economic dispatch approach provides the least-cost solution for our customers.

To increase future price and supply certainty, PGE is exploring opportunities to secure longer term physical supply contracts for a portion of its natural gas fueling needs. This approach would also need to balance contract durations, as well as the mix of fixed and variable price structures in order to avoid the risk of making a single price commitment that could prove unattractive over time. A layering strategy that achieves diversity of term and price structure would both reduce cost variability, while avoiding overexposure to a single price environment. Pursuit of longer term natural gas supplies would be used in conjunction with PGE's current short and mid-term purchasing approach to create a balance of supply commitments over several years.

PGE also uses market instruments such as fixed-price financial swap transactions as a means to hedge our gas price exposure in our portfolio. This allows us to fix the price of gas without buying the physical fixed-cost supply until it is required, reduces variability in our fuel costs and helps provide stability in customer prices. The market as a whole has transitioned from long-term physical purchases to an increased reliance on financial derivative instruments. The liquidity in the financial forward market allows PGE to better manage a changing forward position. The fundamental market outlook points to a potential for ongoing volatility in prices due to uncertainty about LNG imports, domestic unconventional production, pipeline expansions, oil prices and customer demand. These uncertainties support a strategy to hedge prices.

Long-term gas supply planning for a new generating resource is difficult because determining a transportation path--which in turn will determine the supply source--is dependent upon the location of the generating plant, which may not be known in the early stages of planning.

Gas In-Ground Reserves

PGE is exploring opportunities to purchase reserves in the ground to be used as a physical hedge as part of our overall gas supply portfolio. This would be a long-term supply acquisition with the objective of further reducing our exposure to fuel price volatility.

With respect to securing gas reserves, there are generally, two types of potential structures currently available. The first one is a structured partnership whereby the purchaser invests in and receives 100% of the net proved and developed supply. The producer investment partner(s) capitalize and develop additional proved, but undeveloped reserves associated with the partnership site(s).

The second type of contract is a Volumetric Production Payment (VPP) structure whereby a gas purchaser acquires a specified production volume from specific reservoirs. Typically, under these structures the present value of the expected contract payments is paid to the producer in advance.

VPP transactions generally expire after a certain length of time or after a pre-determined aggregate volume of gas has been delivered. Under a VPP contract, if the producer can't meet the supply quota for a given month, the unmet portion will be made up in the next cycle. Make-up deliveries continue until the buyer is made financially whole.

PGE's Mid-Term Gas Strategy

Gas-fired generation contributes to variability in electricity costs. In an effort to reduce volatility in our power supply portfolio, PGE developed the Mid-Term Purchasing Strategy. The Mid-Term Strategy is the next step beyond the 24-month rolling physical gas purchases. The goal is to reduce or minimize year-over-year increases in PGE's net variable power costs. While the Mid-Term Strategy includes both power and fuel, a primary focus is purchasing fixed-price gas via financial instruments with terms spanning two to five years forward.

Pipelines/Transportation Overview

PGE holds firm pipeline transportation on NWP, GTN, TransCanada's B.C. System (TCPL-BC) and TransCanada's Alberta System (TCPL-Alberta). PGE holds 57,000 dekatherms per day of capacity at the Sumas Hub and 30,000 dekatherms per day of capacity at the Rockies Hub for a total of 87,000 dekatherms per day of gas pipeline capacity. This allows PGE to fully supply Port Westward's base load and peaking operations, and to supply Beaver with sufficient transport and storage capacity to meet its expected dispatch and fueling needs. Table 5-1 below lists PGE's current pipeline contract capacity.

Table 5-1: Existing Pipeline Contract Capacity (Dekatherms per day)

Pipeline	Contract Demand (Dth/dy)	Termination Date
NWP (Sumas)	30,000	9/30/2018
NWP (Sumas)	11,000	9/30/2013
NWP (Rockies)	16,000	9/30/2013
NWP (Sumas)	16,000	10/31/2010
NWP (Rockies)	14,000	10/31/2010
TCPL-Alberta (AECO)	42,369	Annual Evergreen
TCPL-BC (AECO to Kingsgate)	41,524	Annual Evergreen
TCPL-GTN (Kingsgate to Coyote)	41,000	10/31/2015
Coyote Lateral	52,673	10/31/2015

PGE's approach to natural gas transportation is to contract for enough firm capacity to meet baseload requirements and to hold a small amount of firm capacity coupled with storage for peaking capability. Determining a reasonable amount of firm transportation can be challenging: too much leads to unutilized capacity and excess demand charges, and too little can constrain generation availability and threaten reliability. The right level of firm transportation is determined by risk and cost analysis and professional judgment, taking into account a variety of factors, including changes in the availability of infrastructure (pipelines, storage and LNG), changing fundamental views of natural gas production at applicable supply basins, local and global market and political considerations, and expected customer requirements.

Estimating the cost of gas transportation without knowledge of the exact location, construction timing and supply options for new generation resources is a challenging exercise and requires robust research, analysis and well-reasoned decision-making. Currently, there are several pipeline expansions being proposed that PGE is watching (see Table 5-2 below), and PGE has executed Precedent Agreements (binding contracts in which both parties have the ability to terminate if certain conditions are not met) for a couple of those projects.

Table 5-2: Proposed Pipeline Expansions

Name	Description
Blue Bridge Pipeline	Expansion from Stanfield, Oregon to Seattle area
Sunstone Pipeline	Expansion from Opal, Wyoming to Stanfield, Oregon
Ruby Pipeline	Expansion from Opal, Wyoming to Malin, Oregon
Palomar Pipeline	Expansion from NWP's Grants Pass Lateral (Molalla) to GTN (Madras)-bidirectional

Storage

PGE contracted with NW Natural for a 10-year firm natural gas storage service agreement under which we are able to store up to 1.26 million dekatherms of natural gas in the Mist gas storage facility near Clatskanie. We use the stored gas to augment gas pipeline transportation service to our Beaver and Port Westward plants. These gas storage facilities allow us to purchase gas during shoulder months at prices that are typically lower than during high demand months, and ensure gas availability during peak periods without paying peak prices. Beaver also has four 243,000-barrel oil storage tanks, three of which are in service, and three 44,000-barrel tanks. These oil storage facilities allow us to purchase fuel oil opportunistically during low commodity demand periods that usually coincide with recessions and use the oil during peak periods as an alternative to natural gas. The carry time for oil storage is usually measured in years, whereas natural gas storage is usually months. This type of operational flexibility provides significant benefits for our customers.

NW Natural has indicated that they are expanding their storage facility. PGE will value incremental storage cost against incremental pipeline transportation cost to determine which option provides the least cost for our customers.

Natural gas-fired resources are typically fueled with firm transportation that is equivalent to the plant's expected dispatch or its maximum generation capability. However, PGE's observation in practice with the Port Westward and Beaver sites is that a combination of firm transport and natural gas storage can provide a more flexible and lower cost solution than exclusively using firm transport to supply all the needs of the plant.

For gas-fueled resources that are highly efficient (e.g. a newer vintage combined-cycle plant), and thereby exhibit a lower marginal cost and higher dispatch rate, a higher proportion of firm transport would be necessary. Since the plant's fueling requirements are less dynamic, natural gas storage would play a smaller role in fueling such a facility. At the other end of the spectrum, a higher heat rate natural gas peaking plant dispatches on a more variable basis, suggesting the need for a more flexible fueling plan that would include a larger proportion of natural gas storage. Ultimately, the natural gas delivery requirement for each plant must consider expected dispatch (both economic and potential regulation and load-following requirements), as well as the location and relative cost and availability of firm transport and gas storage at the time the decision is made to acquire the generation resource. Depending on cost and availability, our experience suggests that a combination of both firm transport and gas-storage can provide reliability of fuel supply, flexibility in meeting variable dispatch requirements and reduced aggregate fueling costs.

Supply Outlook

PGE sources gas supplies from several different supply basins. Our firm transportation rights provide access to production in the Rockies, British Columbia and Alberta. The fundamental outlook for those supply basins has changed significantly over the years. In the Rocky Mountain region, there has been unprecedented growth due to unconventional drilling in shale formations. This growth is expected to continue for several years. In Alberta, while the forecast for production is relatively flat going forward (due to declines in conventional production and increased use of gas in oil sands production), the potential for proposed pipelines bringing shale gas from northeast British Columbia may ultimately boost the flow of gas to the Alberta province and integrate the two gas markets. However, the shift from conventional reserves to shale and tight formations will continue to be dictated by the economics of drilling and production costs compared to market prices for gas. Current downward pressure on gas prices has already begun to weigh on drilling programs, and as a result future production growth may be severely impacted.

LNG

Currently, there are no LNG import terminals on the West Coast of the United States, but at least three terminals are being proposed in Oregon. While the impact of LNG on U.S. natural gas prices remains uncertain, the need for access to additional supply is an ongoing issue for the Pacific Northwest. Whether it will be met by a new pipeline capacity or LNG terminals is undetermined at this time. PGE will watch proposed projects (see Table 5-3 below) that may impact the natural gas infrastructure in our region and our customers.

Table 5-3: Proposed LNG Terminals in Oregon

Name	Description
Bradwood Landing	Between Astoria and Clatskanie on the Columbia River
Oregon LNG	Warrenton, Oregon
Cove Point	Coos Bay, Oregon

5.4 Coal Price Forecasts, Supply, and Market Conditions

Coal Price Forecasts

PGE's approach for developing coal price forecasts is similar to that used for natural gas. We rely on current contracts for coal delivered to Boardman through 2011. We use the average of the EIA Annual Energy Outlook 2009 (AEO) and PIRA August 2009 forecasts for 2012 forward[40]. As with natural gas, PIRA's forecasts are available only through 2025; after 2025 we escalate at inflation. PIRA forecasts Powder River Basin (PRB) 8,800 Btu/lb coal. We derate their price to 8,400 Btu/lb. to match the quality of coal used at Boardman[41]. According to our staff experts, this derating alone does not result in a total dollar for dollar difference, as the 8,800 Btu/lb is in higher demand than the 8,400 Btu/lb. To

[40] PIRA Energy Group. Scenario Planning Service Annual Guidebook 2009, February 2009.

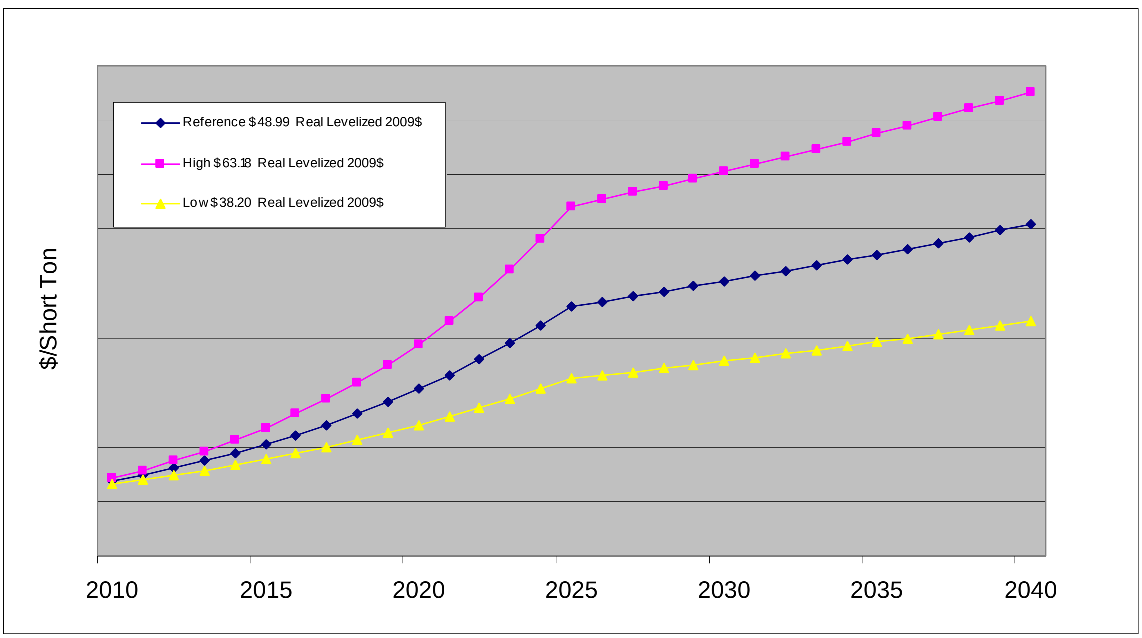
[41] We reduced PIRA's price forecast from 8,800 Btu/lb. coal to 8,400 Btu/lb. coal by the percentage difference in the heat rate (about 5%).

alleviate this we average the adjusted PIRA prices with the EIA forecast for PRB, which is based on 8,400 Btu/lb coal.

We also add transportation costs to the coal commodity price forecast. Transportation can amount to approximately two-thirds of the total costs. For non-mine mouth plants in the West, approximately 70% of coal shipments are delivered via rail. Coal transportation costs are based on PGE's forecasted transportation including surcharges. We base rail delivery costs on PGE contracts through 2013 and assume annual nominal escalation of 5% through 2013. After 2014, we have relied on an outside consultant to forecast coal transportation costs and potential surcharges.

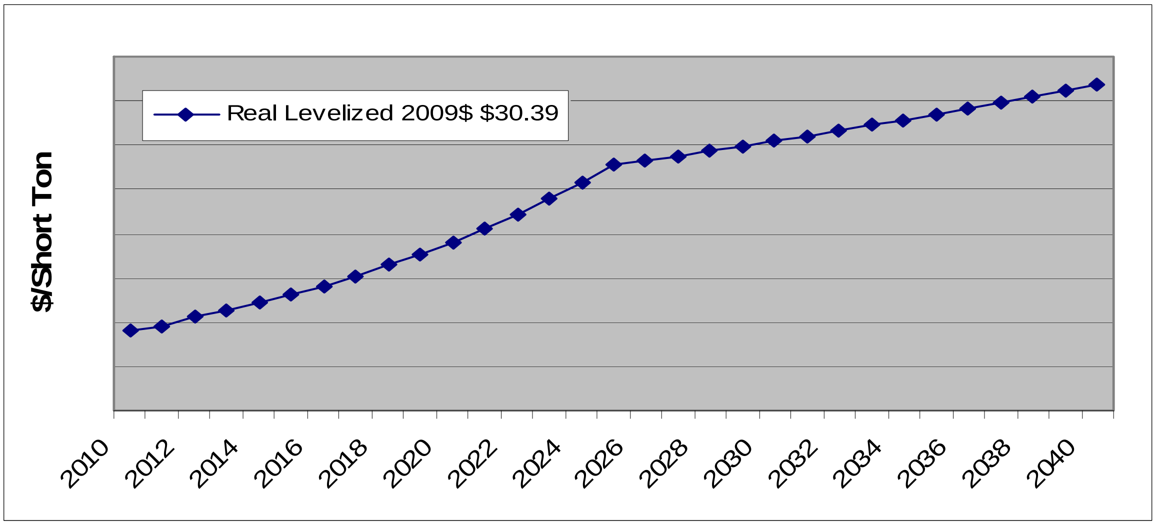
The resulting forecasts for the period 2010-2040 are shown in Figure 5-2. We do not apply stochastic analysis to coal commodity prices because coal represents a small proportion of the overall real levelized cost for coal plants and coal has not historically exhibited the level of price variability of other energy commodities such as oil, natural gas, and electricity. This is in part attributable to the relatively abundant national and global supply and more limited substitution potential of coal.

Figure 5-2: PRB 8,400 Btu/lb. Low Sulfur Delivered Coal, Nominal $/ Short Ton



For Colstrip, we use planned plant coal commodity costs for 2009 – 2013. For 2014 and beyond, we apply the escalation factor based on the average escalation during 2009 - 2013. After 2025, costs are assumed to grow at inflation. The resulting fuel forecast is shown in Figure 5-3 for the period 2010-2040.

Figure 5-3: Colstrip Commodity Cost of 8,500 Btu/lb. Coal, Nominal $/Short Ton



For other WECC coal price forecasts used in AURORAxmp, we used updated delivered coal prices from the EIA's Electric Power Monthly February 2009 Table 4.10a and applied an escalation factor based on rail escalation costs from a consultant.

Coal Supply

U.S. coal supply in recent years has seen strong growth in sub-bituminous production from the Southern Powder River Basin (SPRB). Today this basin represents almost 40% of U.S. coal production on a tonnage basis and is expected to grow to roughly 50% by the end of this long-term forecast horizon. According to PIRA, SPRB coal prices in the reference case are expected to essentially mirror the long-run rate of inflation given their relatively low mining costs and access to major rail networks.

Near term, PIRA sees an increase in U.S. bituminous coal stocks in the power sector due to coal demand destruction caused by slowing economic activity and the lower prices for natural gas, as well as a contraction in exports. In the long term, PIRA projects an increase of about 20% in SPRB coal supply through the forecast term. If new mine, railroad and port projects are delayed too long, eventually resurgent demand could overwhelm supply and cause prices to increase.

On the demand side, PIRA states that uncertainty surrounding environmental externalities is the largest risk (downside) to the outlook. PIRA believes that CO_2 emissions will eventually be regulated, either directly or indirectly. U.S. coal demand will likely be affected by regulatory cost adders, including costs of emitting (i.e., cap and trade) or costs for mitigation (i.e., carbon capture and sequestration). Challenges with permitting new coal and competition from lower-emission resources such as natural gas, nuclear and renewables are also likely to constrain U.S. coal demand.

Market Conditions

PIRA's high and low case forecasts are largely driven by the impact on the coal market of oil and gas scenarios and do not explore the full range of uncertainties regarding price and volume in the coal markets. In the low case, lower gas prices translate into lower coal prices through inter-fuel competition. The primary driver for lower gas prices is slower economic growth and, to a lesser extent, increased gas production. PIRA limits the downside for coal prices based on their estimate of long-run production costs. In the SPRB, marginal costs are very close to marginal revenue. Coal demand is lower in the low case due to weaker economic growth.

In PIRA's high case, natural gas prices are significantly higher due to a combination of disappointing supply and a substitution of gas for coal in power generation to limit CO_2 emissions. Coal demand in the high case is also lower, due to policy-driven gas for coal substitution and the resulting slower growth in coal fired generation.

The AEO 2009 reference case coal price is higher than in previous years and rises toward the end of the projection as consumption grows. Both the wage rate for U.S. coal miners and mine equipment costs are assumed to remain constant over the projection period. SPRB productivity, however, is forecasted to have an annual average decline of .8% through 2030 (which is lower than the decline in productivity for Appalachia, but higher than the national average).

In the AEO's low mining cost case, coal mine labor productivity is assumed to increase at an average rate of 3.6% per year through 2030. Coal mining wages, mine equipment costs and other mine supply costs are all assumed to be about 20% lower by 2030 in real terms. In the high mining cost case, coal mine labor productivity is assumed to decline at an average rate of 3.6% per year through 2030. Coal mining wages, mine equipment costs, and other mine supply costs are all assumed to be about 20% higher by 2030 in real terms.

Infrastructure constraints, particularly on the Joint Line out of the PRB, have improved significantly over the past couple of years due to the construction of triple and quadruple tracking. However, rail fluidity remains a risk to due to potential resurgence of demand in inter-modal (rail-to-truck) traffic and the demand for U.S. exports if economic conditions improve domestically or for export markets. At the same time, railroad costs have escalated in the areas of fuel, capital equipment and labor.

PGE's coal price forecasts are based on the best information available at the time forecasts are prepared. However, market conditions are not static and there is currently uncertainty around a number of key factors. These include the following:

- Investment in rail infrastructure, from terminals to equipment, could be slower than expected.
- Transportation capacity (rail and locomotives), and the availability of train crews as the workforce ages, can also impact the rail rates faced by shippers.
- Railroads could place more emphasis on growth of inter-modal traffic, decreasing available cars and track capacity for coal shipments.
- Volatility in the price of diesel, which is a significant cost to rail rates and the cost of mining.
- The impact of greenhouse gas legislation and any carbon legislation will have a significant impact on the coal industry and will be a key driver for the demand for the coal.
- The commercial viability of carbon capture and sequestration technologies, which will also have an impact on the long term demand and price of coal.
- Global demand, particularly the impact of economic development in China, India and other Southeast Asian countries, could increase demand for Eastern coal.
- Additional Eastern utilities could switch to PRB coal (due to the relative price advantage of PRB coal), even after plant retrofits.
- Producer discipline to respond to changes in demand for coal and shippers' inventory levels in the near term.

PGE closely monitors these issues as well as other potential drivers of higher or lower coal prices.

6. Environmental Assumptions

We recognize that one of the biggest challenges we face is to meet the growing energy needs of customers at a reasonable cost while being good stewards of the environment. We also recognize that we are operating in an environment of increasing public awareness of, and concern for both environmental and economic issues. At the same time, the political and public policy climate related to future energy and environmental issues remains fluid. Consequently, the potential for increased environmental regulations and major shifts in energy policy add a significant element of uncertainty to resource planning.

This section outlines our position on climate change and the environmental assumptions used in our analysis. It also assesses uncertainties related to potential environmental regulation and policy developments, and discusses the potential effects of Oregon's RPS on our resource planning and procurement. The assumptions described here are used in determining the real levelized costs of the generation resources outlined in Chapter 7.

Chapter Highlights

- We model a carbon dioxide (CO_2) compliance cost in our base case of $30.00 per short ton (in real levelized 2009$) based on EIA and EPA studies of proposed federal legislation.
- We also model five CO_2 cost sensitivities in our portfolio analysis: no carbon cost, $12/ short ton, $20/ton, $45/ton and $65/ton (in real levelized 2009$).
- The real levelized costs for new gas, combined heat and power, and IGCC coal generating plants include estimates for offset payments to the Climate Trust per OEFSC rules.
- PGE's Boardman and Beaver generating plants are subject to the RH BART process.
- PGE is evaluating the installation of emissions controls at Boardman, as required by the RH BART process and the Oregon Utility Mercury Rule. We expect Boardman's useful life to extend to 2040.
- All of our portfolios comply with Oregon's RPS.

6.1 Climate Change Impacts – PGE's Principles for Action

PGE believes responsible protection of the environment and cost-effective business practices are compatible. Further, a corporate policy that ensures that we are addressing environmental issues is in the best long-term interest of the communities we serve, our customers, shareholders and employees.

We believe that it is prudent to take reasonable steps to reduce greenhouse gas emissions and mitigate potential emission impacts as the scientific community continues to improve our understanding of global climate change. PGE will use the following framework to make proactive decisions and to take action.

We encourage:

- Passage of federal legislation addressing greenhouse gas emissions – to ensure mitigation is encouraged and achieved efficiently with costs borne fairly across geographic boundaries.
- Economy-wide climate change mitigation actions that apply proportionally to stationary (generating and manufacturing plants) and mobile (vehicular) sources and are borne equitably among all types of fuel producers and consumers.
- Mitigation measures attributed to power production that are borne equitably among all retail customers whether they are served by a public or private utility and whether they are located in a high or low load growth area.
- The inclusion of policy tools that provide a smooth transition to a low-carbon economy, including but not limited to the provision of emission allowances for rate-regulated utilities.
- The reinvestment of revenues derived from a greenhouse gas reduction program into low-carbon technology development and assistance for households most affected by price increases.
- Credit for early action in any greenhouse gas mitigation strategy or policy, e.g., 1992 Energy Policy Act USDOE1605b registry, public purpose charge, green power, Climate Trust contributions and hydro relicensing.
- Adoption of complementary measures at the state level that position Oregon favorably for eventual federal regulation of greenhouse gases.
- The inclusion of Oregon's business and residential communities in all groups tasked with developing Oregon's policy on climate change.

We will:

Supply Position

- Plan our resource portfolio with standards that reflect the likelihood and magnitude of the project costs over the life of each plant as demonstrated in our IRP process.
- Based on the results of the IRP process, select that mix of resource options that yield, for customer and society over the long run, the optimum combination of expected costs and associated risks and uncertainties.
- Give preference to actions that minimize emissions where emissions would be a deciding factor between otherwise equally viable options in making our final resource choices.
- Evaluate and give preference to innovative approaches to reduce or offset greenhouse gas emissions, while providing the power that our customers need. For example, we will continue our promotion of renewable resources such as wind power and will investigate carbon sequestration and new emission mitigation techniques that optimize fuel usage.

Operational Excellence

- Evaluate and give preference to cost-effective efficiency improvements so that additional power can be produced at our plants without increasing greenhouse gas emissions or with a minimal increase in greenhouse gas emissions.
- Address non-resource planning activities that have emissions effects by eliminating the activity or changing it at a reasonable cost to reduce the emissions.
- Purposefully seek and monitor specific PGE carbon mitigation or offset opportunities/projects, past, present and projected.

Customer Value

- Be influential, active participants within the state, regional and national climate change arenas and support these principles for the benefit of our customers and investors.
- Continue to work with our customers to improve energy efficiency and other complementary measures, which ultimately contribute to the mitigation or reduction of power plant emissions.

- Continue to solicit input from a cross-section of our customers on climate change and its impacts on them.
- Continue to recognize and support the efforts of our employees, customers and communities that are focused on addressing climate change actions.

Economic Growth

- Support regional efforts to create family-wage jobs by recruiting businesses that manufacture solutions to global climate change.
- Encourage climate policies that apply equitably between states and regions and that account for differences between regulated and unregulated competitors in international trade.

6.2 PGE Activities in Support of a Sustainable, Diversified Future

An ongoing objective at PGE is to undertake, where cost-effective, those actions that are environmentally responsible, while also providing greater supply diversity. The following activities, some of which are discussed further in other sections of this or other chapters, demonstrate the commitment of PGE and our customers to meet growing energy needs at a reasonable cost while being good stewards of the environment:

1. Upon completion of the third phase of Biglow Canyon in 2010, PGE will have 550 MW of wind in its portfolio. Based on AWEA projected year-end 2009 data, PGE ranks firmly in the top 10 among domestic investor-owned utilities (IOUs) for wind as a % of load – see Table 6-1. We lead the WECC in this respect, ranking ahead of other West Coast electric utilities. While AWEA does not have a forecast for year-end 2010 wind additions, when including the final phase of Biglow (175 MW) in 2010, PGE's position as an early leader in wind will likely improve over 2009.

Table 6-1: Investor-Owned Utilities' Wind as a Percentage of Load

Utility	2008		2009	
	Wind as % of Load*	Rank	Wind as % of Load	Rank
Empire District Electric Company	20.7%	1	20.7%	1
Otter Tail Power	14.9%	2	14.9%	2
Xcel Energy	10.7%	3	11.6%	3
MidAmerican Energy	8.1%	4	9.2%	4
Public Service New Mexico	6.2%	5	6.2%	6
Luminant	5.6%	6	5.6%	7
Alliant Energy	5.4%	7	7.8%	5
Puget Sound Energy	5.3%	8	5.3%	9
Northwestern Energy	5.0%	9	5.0%	10
Minnesota Power	4.6%	10	4.6%	11
Aquila	3.9%	11	3.9%	12
Portland General Electric	3.3%	12	5.5%	8
Southern California Edison	3.1%	13	3.1%	13

*Analysis results from USDOE 2008 Wind Technologies Market Report; 2009 wind date from AWEA draft values.

2. Likewise, while amounts are still small, PGE is also a top 10 national leader in solar penetration and has the lead in the Pacific Northwest. This includes working with the State of Oregon to have the nation's first solar highway project.

3. PGE took a lead position in the addition to the SB 838 legislation allowing for dynamic additional funding for EE. This has led to an expansion in ETO EE activities to the maximum achievable at the prescribed cost-effectiveness limits. In many instances, the EE acquired would otherwise have become a lost opportunity. The investment in EE also provides a beneficial impact to PGE's load factor by having a 50% greater impact on winter demand compared to average annual reductions.

4. In 2006, we were among the first IOUs in the U.S. to call for and signal support to federal legislation for economy-wide CO_2 emissions regulation.

5. With construction of the Port Westward facility, PGE boasts one of the most efficient natural gas generators in the U.S.

6. Our customers are among the top three utilities in the nation for participation in green tariffs, such as the Clean Wind program.

7. PGE is rolling out Smart Meters throughout its service area, which will provide customers with better information about energy use patterns, enable time-based tariffs and, potentially, direct load control.

8. PGE has always sought out the potential for efficiency upgrades to its thermal and hydro plants, resulting today in these plants producing 80 MW more output than at original design for no more fuel input.

9. In a February, 2009 JD Power survey, we are viewed by our customers as the top performing utility in the nation, by a wide margin, when it comes to corporate citizenship in the "environment" category. We are ranked third in the nation in the "new energy efficiency" corporate citizenship category.

10. PGE continues to support local efforts to develop wave energy, has an ongoing assessment at the Boardman plant for algal-based CO_2 and NOx sequestration, and is actively examining the potential for biomass co-firing.

11. PGE, following the lead of the Governor's office, has been a utility leader in helping attract solar manufacturing facilities to this area.

12. PGE is a leading utility in nascent efforts to build an initial electric vehicle public recharging infrastructure, which has in turn attracted interest by the vehicle manufacturing industry to use Portland as a test base for plug-in electric vehicles.

As discussed in this Chapter, we will continue to seek opportunities to play a leadership role in developing a sustainable, diversified supply portfolio for the future.

6.3 American Recovery and Reinvestment Act Opportunities

In February 2009, President Obama signed the American Recovery & Reinvestment Act ("Recovery Act") into law. The Recovery Act provides a number of opportunities of interest to utilities, from changes in the application of tax credits for renewable power generation facilities and bonus depreciation, to competitive grant opportunities related to transformational energy projects, energy efficiency, transportation electrification and smart grid infrastructure.

Following passage of the legislation PGE formed a task group to identify potential opportunities for Recovery Act funding. Our focus was to examine projects that will both meet the goals of the Recovery Act and benefit our customers. Below we describe the opportunities PGE will pursue if awarded grant money.

Algae Carbon Capture and Sequestration at Boardman

This project is part of a consortium's efforts in advancing the state of the art on algal biofuels. Through PGE's participation in this project we will be able to use algae to capture CO_2 from flue gas emissions. The algae grown in this project will then be harvested and the algae oil extracted for jet fuel, biodiesel and ethanol.

Information Technology for the Smart Grid

This project proposed to increase PGE's ability to consume and respond to the large amounts of data streaming from the Advanced Metering Infrastructure we are currently deploying in our service territory. By upgrading our key distribution management systems, we will be able to implement a Sense and Respond architecture that monitors and identifies data patterns from our smart meters and alerts customers in real time with proposed responses that will help them reduce their overall energy consumption. In late October 2009, this grant application was denied.

Feeder Advanced Storage Transaction

Proposed as part of a regional smart grid demonstration effort with Bonneville Power Administration and Battelle Memorial Institute, this project will demonstrate automated line switching. The project will further customer and system reliability by integrating distributed generation (Dispatchable Standby Generation and solar) and demand response to intentionally island a feeder and seamlessly create a microgrid that simultaneously keeps customers powered while relieving system demand for the purposes of peaking, wind balancing and other system reliability needs.

6.4 Greenhouse Gas Regulation

Federal, State and Regional Legislation

Since December 2006, PGE has supported federal legislation addressing global climate change. Over the years, we have been engaged in the development of climate policy at the local, state, regional and federal level. We continue to believe that regulation of greenhouse gas emissions is best done at the federal level, though there are many complementary policies that can be pursued at all levels of government. This IRP is being developed as policymakers continue their work on climate legislation. While much uncertainty remains about the exact outcomes of this process, we have attempted to incorporate what we know about climate policy today, where future climate policy is headed and how such policy changes may impact our resource choices.

At the federal level, the Congress is actively examining the climate issue and is debating legislation that would establish a mandatory greenhouse gas cap and trade program. On June 26, 2009, the House of Representatives recently passed the American Clean Energy and Security Act of 2009, commonly referred to as the Waxman-Markey bill (H.R. 2454), by a vote of 219 - 212. On September 30, 2009, Senators John Kerry and Barbara Boxer introduced S. 1733, the "Clean Energy Jobs and American Power Act". No formal action has occurred on this bill but committee mark-ups are expected to occur in 2009.

The Waxman-Markey legislation would establish a carbon cap and trade program in 2012, with the goal of reducing greenhouse gas emissions by 17% below 2005 levels in 2020 and 83% below 2005 levels by 2050. All major sources of greenhouse gas emissions would be capped under the program except for the agriculture sector. Regulated entities would meet their annual compliance obligation by holding the requisite number of carbon emission allowances equal to their emissions of greenhouse gases in the prior year. The point of regulation for the electricity sector would be at the generator-level, meaning PGE would be directly responsible for ensuring compliance of its fossil fuel-fired plants. Tradable carbon emission allowances can be sold or retired, banked, and borrowed from future allocations under certain limitations.

Under the Waxman-Markey bill a number of free carbon emission allowances are distributed to the electric sector in the early years of the program. These are phased out in favor of auctioned allowances by 2030. For retail electric distribution utilities like PGE, these allowances are allocated based on a formula that considers both overall retail electric deliveries and the historic emissions associated with serving load. These allowances must be used to benefit ratepayers in coordination with the PUC.

Regulated entities could also meet their compliance obligation in part with certified international or domestic offset credits. However, there are many qualitative and quantitative restrictions outlined in the bill, making it difficult to predict with certainty the availability of such instruments. In addition, the Waxman-Markey bill would allow the use of allowances purchased from comparable foreign cap and trade regimes. However, all of these cost containment tools are subject to various EPA rulemakings. The degree to which these measures are ultimately made accessible by the EPA will greatly impact the anticipated market price of allowances and the overall cost of compliance in a future cap and trade program.

The Waxman-Markey bill does not include a so-called "safety valve" provision or a set price collar on allowance trading, so there is no ceiling on the potential cost of emission allowances. As an alternative, the bill proposes a strategic reserve of allowances which would only be available at auction to regulated entities (and not other potential market participants). However, because the strategic reserve allowances are derived from the overall pool of allowances, they are limited in number and therefore may not be an effective means of limiting price spikes and market manipulation.

The Kerry-Boxer bill (S.1733) is the Senate's counterpart to the House-passed Waxman-Markey bill. As of this writing, many details of the Senate bill have yet to be resolved. The Kerry-Boxer cap and trade language closely tracks with the program outlined in the Waxman-Markey bill. The Kerry-Boxer proposal would establish a mandatory cap and trade program starting in 2012 (with the first compliance allowances due in 2013). The overall reduction goals closely align with Waxman-Markey except for the 2020 goal, which is a more rigorous 20 percent below 2005 levels. Specifically, the Kerry-Boxer goals are: three percent below 2005 levels by 2012, 20 percent below 2005 levels by 2020, 42 percent below 2005 levels by 2030 and 83 percent below 2005 levels by 2050.

Like Waxman-Markey, the bill proposes a nearly economy-wide cap and trade program covering all emitting sectors aside from the agriculture and forestry sector. Electric utilities are covered in 2012 while industrials come under the cap in 2014, and commercial and residential natural gas consumption is covered by 2016. The Kerry-Boxer bill does not spell out the exact quantity of free allowances that will go to various regulated industries or programs – this will apparently be developed later in the committee process. It does, however, describe which industries should receive allowances and how those allowances should be distributed within each industry. The language for distributing allowances to electric utilities retains the basic formula contained in the House bill and considers both overall retail electric deliveries and the historic emissions associated with serving load. Again, these allowances must be used to benefit ratepayers in coordination with the state public utility commission.

Despite all of the uncertainties and the changing political dynamics, we believe – based on the information available to us at this time – that it is reasonable to assume that a federal cap and trade program for greenhouse gases will be in place and effective by 2013.

Strong support for new energy and climate policy also exists at the Executive Branch of the federal government. President Obama has made passage of climate legislation one of his key priorities. This emphasis is evidenced by recent federal agency action. Earlier this year, in response to the U.S. Supreme Court decision in Massachusetts v. EPA, 549 US 497 (2007),the Environmental Protection Agency (EPA) proposed a finding that greenhouse gases (GHGs) in the atmosphere cause or contribute to the endangerment of human health and welfare under the Clean Air Act, and the Administration's budget blueprint assumed cap and trade generated revenues will begin by 2012. In addition, EPA proposes to find under section 202(a) of the Clean Air Act (CAA) that emissions of GHGs including carbon dioxide, methane, nitrous oxide and hydrofluorocarbons, from new motor vehicles and their engines cause or contribute to this mix of GHGs[42]. It is expected that both the endangerment finding and these new motor vehicle regulations will be finalized before the second quarter of 2010.

Regulation of GHGs as "pollutants" under sections of the Clean Air Act concerning mobile sources such as motor vehicles can trigger other CAA requirements that will affect those same GHG pollutants for stationary sources, such as electric generating facilities. CAA requirements that can be triggered in this manner include the Prevention of Significant Deterioration program and the Title V operating permit programs affecting stationary sources. Therefore, on September 30, 2009, in anticipation of such a possibility, the EPA proposed additional new regulations to impose reasonable limitations on what large stationary sources would need to obtain permits under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs (referred to as the "tailoring rule"[43]) should GHGs become regulated pollutants under the CAA.

Under the new source review (NSR) requirements of the PSD program, stationary sources of "pollutants subject to regulation" are required to obtain permits if they are new sources or existing sources that have undergone "major modifications". A major modification of an existing source is defined as a physical change or a change in the method of operation that results in a significant increase of emissions. New sources or existing sources that undergo major modifications are required to obtain PSD permits and demonstrate the use of "Best Available Control technology" (BACT). The proposed EPA "tailoring rule" would do the following:

- Limit the PSD permitting requirements to sources emitting 25,000 or more tons of CO_2.

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[42] 74 Federal Register 49454 (September 28, 2009).

[43] 74 FR 55291-55365 (October 27, 2009)

- Change the significance threshold for projects at these sources that result in increases of GHGs to a level that could range from 10,000 to 25,000 tons of carbon dioxide equivalent (CO_2e).

If a source is required to obtain a PSD permit, BACT must be determined for that source. BACT determinations are made on a case-by-case basis subject to EPA guidance. Currently, there is no guidance for BACT determinations involving GHGs from electric generating units. EPA is in the process of reviewing and updating its BACT guidance for this purpose. BACT could potentially include best operating practices, efficiency measures, emission control technologies, or other available control measures.

If and when the tailoring rule is finalized (anticipated before the second quarter of 2010), it would not become immediately applicable in the State of Oregon without State action (rulemaking or legislation). However, it is expected that the State would quickly take steps necessary to make these requirements applicable to sources in Oregon.

Existing PGE generating resources that are fueled with coal or natural gas generally emit in excess of 25,000 tons of CO_2e. Any new natural gas-fired electric generating projects are expected to emit in excess of 25,000 tons CO_2e and would be required to obtain PSD permits and install BACT when these requirements are adopted in the State of Oregon. Only existing sources that make major modifications would be subject to PSD permitting requirements and no projects of this nature are planned by PGE at this time. As discussed above, it is too early to speculate on what would constitute BACT for sources that are subject to PSD permitting.

For Title V permitting purposes, EPA's "tailoring rule" proposes to limit the permit applicability threshold to sources that emit 25,000 tons or more of CO_2e. Title V operating permits contain air emissions control requirements that apply to a facility, such as national emissions standards for hazardous air pollutants, new source performance standards, or best available control technologies required by a PSD permit. In general, since there are currently no such air emission control requirements, existing facilities with GHG emissions greater than 25,000 tons per year that already have operating permits would not need to immediately revise them. At the end of a five-year period when the operating permit must be renewed, these facilities would be required to include estimates of their GHG emissions in their permit applications. Facilities may use the same data reported to EPA under its reporting rules.

It is possible that EPA will proceed with additional regulation of GHGs from stationary sources under the CAA, but it is too early to predict what form these additional regulations would take. In mid-2008, EPA issued an Advance Notice of Proposed Rulemaking to gather significant input from the public on options and questions to be considered for possible greenhouse gas regulations under the CAA[44]. Several options were addressed including the development of regulations under the "new source performance standards" section of the CAA. How the regulation of greenhouse gases would proceed under these and other existing CAA provisions is open to question. It is also noteworthy that the Waxman-Markey legislation approved by the U.S. House of Representatives in June 2009 would exempt sources subject to the cap and trade title of the legislation from making any additional reductions under other provisions of the CAA such as those discussed above.

PGE currently reports three greenhouse gases emitted by our operations – CO_2, methane and nitrous oxide, of which CO_2 is the most significant by volume. PGE is undertaking significant efforts to test and monitor technologically feasible and commercially available alternatives for carbon capture and sequestration. In addition, PGE has reduced air pollutants by improving the efficiency of its combustion processes (e.g., super critical boilers and new generation gas combustion units). See Chapter 7 for more information on carbon capture and sequestration and fossil fuel plant efficiency gains.

On September 22, 2009, the U.S. EPA issued a final rule for the mandatory reporting of GHGs from large sources of GHGs in the United States. GHGs covered by this rule include CO_2, CH_4, N_2O, and the fluorinated GHGs (e.g., HFCs, PFCs, SF_6). In general, the threshold for reporting is 25,000 metric tons or more of CO_2e per year. Reporting is at the facility level, including electric generating units, except that certain suppliers of fossil fuels and industrial greenhouse gases along with vehicle and engine manufacturers will report at the corporate level. Facilities and suppliers will begin collecting data on January 1, 2010. The first emissions report is due on March 31, 2011, for emissions during 2010. For PGE, the rules will require reporting of CO_2, CH_4 and N_2O emitted from our coal and natural gas electric generation resources. The rules do not require reporting of SF_6 from electrical equipment.

At the regional and state level, the Western Climate Initiative partners continue to work on cap and trade design issues. However, most WCI member state legislatures have not taken action to authorize new programs under the auspices of the WCI. The Washington Legislature did not adopt the cap and trade design suggested by the WCI. However, on May 21, 2009, Washington Governor Christine Gregoire issued Executive Order 09-05 that would require state agencies to prepare strategies for emission reducing activities, to influence regional and federal policy efforts, to increase transportation and fuel-

[44] 73 Federal Register 44353 (July 30, 2008).

conservation options, and to prepare climate change mitigation options using existing authorities. Montana, another signatory to the WCI agreement, did not take any significant action on the issue of GHG emissions during its 2009 legislative session. In Oregon, the Legislature considered, but did not adopt several pieces of climate legislation including a state-based mandatory carbon cap and trade intended to fit within the WCI context, a cap only program, and a bill that would have provided for an assessment, ranking and planning process for obtaining reductions.

The State Legislature also adopted a number of other measures that would affect greenhouse gas emissions in the State. Three are specifically worth noting. First, an emissions performance standard has been adopted (SB101), setting a limit on new investments in baseload generation sources and prohibiting emissions from those sources that exceed 1,100 lbs CO_2/MWh. Second, a low-carbon fuel standard has been adopted (HB2186). The standard would require the carbon content of motor vehicle fuels to be reduced by 10% by 2020. And third, HB2626 was adopted setting up a broad and complex mechanism for encouraging property owners to install more energy efficiency measures, including allowing property owners to pay for the cost of the measures through their utility bills.

Carbon Costs in IRP Analysis

Guideline 8 of the Commission's IRP Guidelines requires us to construct a base-case scenario to reflect what we believe to be the most likely regulatory compliance future for CO_2, nitrogen oxides, sulfur oxides and mercury emissions. Consistent with the Guideline, we have modeled a CO_2 price in our base case. We believe a cost for CO_2 is likely because of: 1) growing public interest in greenhouse gas emissions, 2) legislative proposals to introduce carbon regulation in the U.S. as described above, 3) a changing federal political landscape and 4) input received in our public meetings and our dialogue with stakeholders. By incorporating potential carbon costs in our analyses, we are able to assess the risk of changes in the performance of future resource choices.

Our IRP reference case charges all CO_2-emitting electric power plants in the WECC with a carbon cost based on the plant's emissions profile. For modeling purposes, in our reference case assumptions we set this charge to $30.00 per short ton (real, levelized 2009$), starting in 2013, using the average growth rate from Energy Information Administration (EIA) studies commissioned by Congress of the Bingaman-Specter, Lieberman-Warner, McCain-Lieberman and Waxman-Markey congressional legislative proposals and an EPA legislative study of the Waxman-Markey bill[45]. The reference case price was calculated by taking the

[45] Lieberman Warner (S.2191), McCain Lieberman (S.280), Bingaman Specter (S.1766) and Waxman Markey (HR2454).

average, real levelized CO_2 price outcome for each proposed bill based on the respective future scenarios analyzed by the EIA and EPA. The EIA studies covered the period of 2012 through 2030. After 2030 we escalate the CO_2 price at the average growth rate across the last ten years from the EIA analyses.

We believe that one scenario, Limited Alternative without International Offsets, from the analysis of Lieberman-Warner and Waxman-Markey, is unrealistic due to the unreasonably restrictive policy implementation assumptions and resource alternative constraints imposed. Therefore, we excluded that scenario when calculating the average CO_2 price under Lieberman-Warner and Waxman-Markey. This is the only one of the 22 scenarios analyzed by EIA and EPA for the four legislative proposals that we deemed too improbable to include in our composite price method. We calculated a mean price for each legislative study based on the results for the scenarios analyzed. We then averaged the resulting mean price for each EIA legislative study and the EPA legislative study to develop a composite CO_2 price. This average, or composite, of CO_2 prices across the four proposed bills is used as our reference CO_2 price. The resulting reference case CO_2 price is $30 (real levelized 2009$). The reference case start date for CO_2 costs is 2013. We selected a CO_2 cost start date of 2013 based on our current assessment of the potential timing for passage and implementation for any new federal greenhouse gas emissions legislation. However, the exact timing for the implementation of carbon costs will not be known until detailed legislation is passed. See Figure 6-1 below.

Figure 6-1: EIA and EPA Carbon Cost Case Study Results

	EIA				EPA
	Lieberman Warner (HR 2191)	**Lieberman McCain (HR 280)**	**Bingaman Specter (HR 1766)**	**Waxman Markey (HR 2454)**	**Waxman Markey (HR 2454)**
Policy Case	$ 37.78	$ 29.21	$ 16.75	$ 38.24	$ 19.02
Limited Alt	$ 56.92	$ 37.38	$ 17.11	$ 43.78	
Limited Alt w/ CCS		$ 32.46			
Without Int		$ 36.99		$ 62.74	
Limited Alt w/out International	$ 101.64			$ 112.39	$ 34.45
Limited Gas Supply		$ 37.82			
High Auction		$ 29.51			
All Comm. Coverage		$ 28.48		$ 36.73	
High Technology		$ 24.60	$ 15.94	$ 33.49	
No Nuclear		$ 30.80			$ 21.84
4% Banking Cost		$ 24.26		$ 23.95	
30% offset		$ 18.73			
Unlimited Offset		$ 18.89		$ 24.72	
High Tech w/ RPS			$ 15.76		
Reference w/ RPS			$ 16.59		
Half Credit for CCS			$ 16.88		
High Development Cost	$ 48.49			$ 42.61	
W/out_EE					$ 19.42
W/out_Rebate					$ 19.09
W/out_EE/Rebates/LDC_Alloc					$ 19.07
Accelerated CAFÉ				$ 37.95	
High Banking				$ 43.83	
Average (w/out L.A.w/out Int)	**$ 47.73**	**$ 29.09**	**$ 16.51**	**$ 38.80**	**$ 19.69**
Proposed CO2 Cost 2013 start	**$ 30.36**				

Note: All prices are Real Levelized 2009$

The Commission's IRP Guidelines also require us to develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Accordingly, we include a future with no carbon price or cost in our analysis. While we believe that a carbon price is likely, the future without a carbon price is useful as it describes our current state and provides a comparison with futures that do include a carbon price demonstrating the potential impacts of different levels of CO_2 price.

Our low price case uses a real levelized 2009$ price of $12/short ton. Bingaman Specter included a Technology Accelerator Payment (TAP) price of $12/metric ton. We believe that this is a reasonable figure to use as our low price future.

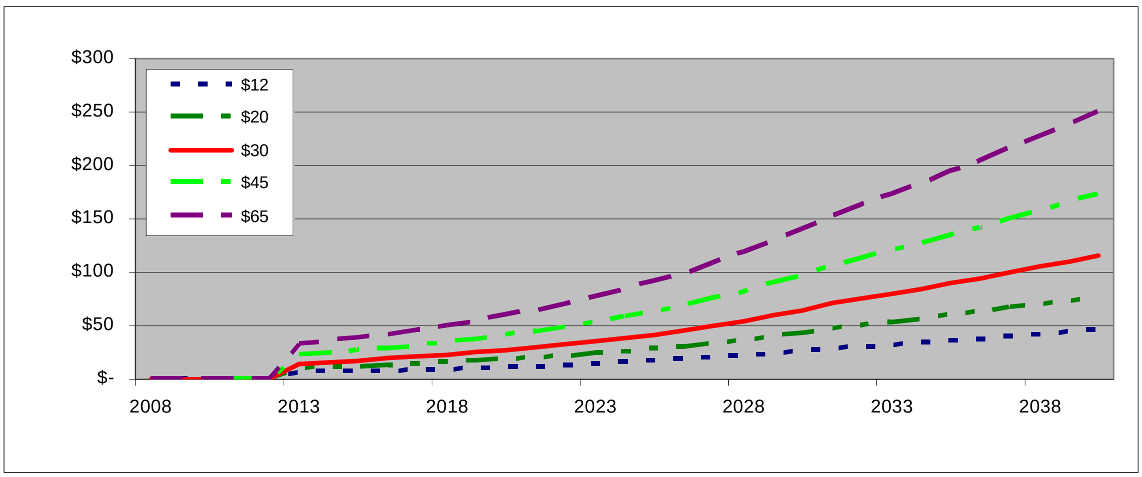
We use $65/short ton (real levelized 2009$) as our high price future. To develop our high CO_2 price future we looked at a Massachusetts Institute of Technology (MIT) assessment of legislative cap and trade proposals.[46] Specifically, we used the MIT forecast of CO_2 prices for Lieberman Warner assuming 15% offsets and a carbon capture and sequestration subsidy. This resulted in a real 2009$, levelized

[46] Paltsev, Sergey, et al., April 2008. MIT Joint Program on the Science and Policy of Global Change, Report NO. 146, April 2007, Appendix D, page D8.

cost of $64.61 per short ton of CO_2, which we rounded to $65. This price also captures the high price scenarios that were included in our analysis of the EIA legislative studies.

For our medium low case ($20/short ton) and medium high case ($45/short ton) we selected a price that is approximately mid-way between our low case and reference case, and our reference case and our high case, respectively. We believe that the CO_2 price levels analyzed in our reference case and alternative price scenarios represent a plausible range of future outcomes, and therefore provide a robust view of the potential carbon cost and risk associated with future resource alternatives.

Figure 6-2: CO_2 Price Scenarios (Nominal Dollars)



Note: the legend reports the CO_2 real levelized price in 2009$.

As discussed above, we escalate the CO_2 charge for each of the scenarios, starting in 2013, using the average growth rate from EIA studies of the Bingaman-Specter, Lieberman-Warner and McCain-Lieberman congressional legislative proposals. The EIA studies covered the period of 2012 through 2030[47]. After 2030

[47] Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007, Energy Information Administration Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC 20585, April 2008.

Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007, Energy Information Administration Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC 20585, January 2008.

Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007, Energy Information Administration Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC 20585, July 2007.

we escalate the CO_2 price at the average growth rate across the last 10 years from the EIA analyses. See Figure 6-2.

OEFSC Rules - Climate Trust Offset Payment

In 1997, the Oregon legislature gave the Oregon Energy Facility Siting Council (OEFSC) authority to set CO_2 emission standards for new energy facilities. Under Division 24 of the OEFSC rules, beginning at OAR 345-024-0500, there are specific standards for baseload gas plants, non-baseload (peaking) power plants and non-generating energy facilities that emit CO_2. See Table 6-2.

Table 6-2: OEFSC Carbon Dioxide Emissions Standards

Plant Type	Emission
Baseload gas plants	0.675 lb. CO_2 / kWh
Non-baseload gas plants	0.675 lb. CO_2 / kWh
Non-generating facilities	0.504 lb. CO_2 / horsepower-hour

The standard for baseload plants currently applies only to natural-gas-fired plants. The standards for non-baseload plants and non-generating facilities apply to all fuels. The OEFSC has not yet set a CO_2 emission standard for baseload power plants using other fossil fuels (i.e., coal). However, we believe the most likely regulatory future is that the baseload gas plant CO_2 emissions standards would apply to new coal plants as well as new natural gas plants and new natural gas combined heat and power (CHP) plants.

At their discretion, applicants for site certificates can propose CO_2 offset projects that they or a third party will manage, or the applicant can provide funds via the monetary path to the Climate Trust, which has been designated as a qualified organization by the OEFSC. Under the monetary path, the site certificate holder is responsible for two types of payments: 1) offset funds of $1.27 per short ton of excess CO_2 emissions; and 2) selection and contracting funds. The real levelized costs for new gas generating plants and new IGCC and SCPC plants shown in Chapter 7 include estimates for these payments to the Climate Trust. In the event of a federal carbon tax, or an Oregon emissions standard, it is not clear whether the current OEFSC rules would continue. For modeling purposes, we have assumed they would continue.

6.5 Sulfur Dioxide, Nitrogen Oxide and Particulate

In accordance with new federal regional haze rules, the Oregon Department of Environmental Quality (DEQ) is conducting an assessment of emission sources pursuant to the Regional Haze Best Available Retrofit Technology (RH BART)[48] process. Those sources determined to cause or contribute to visibility impairment at protected areas within 300 kilometers of each source will be subject to an RH BART determination. Several other states are conducting a similar process. The DEQ is working with approximately seven RH BART eligible sources in Oregon, including our Boardman and Beaver thermal generating plants. In January 2006, we volunteered to participate in a DEQ pilot project that analyzed information about air emissions from Boardman to determine their effect on visibility in the region, particularly in wilderness and scenic areas. An exemption modeling analysis for identified sources begun in September 2006 indicated that the Boardman and Beaver facilities may cause or contribute to visibility impairment in several protected areas. The objectives of the RH BART analysis and recommendations include significant reductions of sulfur dioxide (SO_2), nitrogen oxide (NOx) and particulate emissions.

As Beaver is a BART eligible source, PGE elected to apply for a federally enforceable permit limit restricting the quantity of diesel oil that can be combusted per day at the plant. In addition to the oil quantity limit, PGE also elected to limit the type of diesel purchased to ultra-low sulfur (15 ppm) diesel as opposed to the historic use of low sulfur (500 ppm) diesel. These voluntary actions showed significant visibility improvements in the Class I areas that were modeled as well as the Columbia River Gorge Scenic Area. The subsequent improvements to visibility associated with the federally enforceable permit limits satisfy the Regional Haze Rule and are consistent with Appendix Y to 40 CFR Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule.

The permit limits on daily oil combustion are based on a regression analysis equation. The quantity of oil that can be combusted on a daily basis increases as the sulfur level in the oil decreases. Current sulfur testing on oil inventories indicates the plant can operate on oil for approximately 16 hours per day. There are no limits to the number of hours that the facility can operate while combusting natural gas.

Table 6-3 below summarizes the base case emissions adders we used in our calculations of the real levelized costs of thermal resources. All existing and new plants meet particulate regulation; compliance costs for particulates are included in the capital costs.

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[48] Regional Haze Best Available Retrofit Technology (RH BART) is a requirement under the Environmental Protection Agency's Regional Haze Regulations.

Table 6-3: Regulatory Compliance Costs for Environmental Emissions

	BASE CASE EMISSIONS ADDERS					SENSITIVITIES	
	To Investment Cost (for new thermal plants)	To Variable Cost (adders to all thermal plants)					
	Description	Description	Cost ($)	Start Date	Annual Escalation	Cost ($)	Start Date
CO_2	Offset payment to Climate Trust per OEFSC rules	EIA and EPA analysis of proposed federal legislation	$30 per short ton, real levelized $2009	2013	NA	0,12, 20, 45, 65 (real levelized 2009$ per short ton)	2013
NOx	Cost of BACT[1] included in generic capital cost assumption	NA	-	-	-		
SO_2	Cost of BACT[1] included in generic capital cost assumption	SO_2 allowances cost per Title IV of the Clean Air Act	$165 per short ton ($2009)	ongoing	2009 Market quotes: declining from $165 to $56 in 2012	NA	ongoing
Hg	Cost of CAMR compliance[2] included in generic capital cost assumption	NA	-	-	-	NA	NA

1) Best Available Control Technology

2) CAMR rules only apply to new coal plants, not gas plants.

6.6 Mercury

In October 2006, the Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating units, including Colstrip, which set strict mercury emission limits by 2010 and established a review process to ensure that such facilities continue to utilize the latest mercury emission control technology.

In December 2006, Oregon's Environmental Quality Commission adopted the Utility Mercury Rule, which limits mercury emissions from new coal-fired power plants. Beginning in 2018, the Oregon Utility Mercury Rule will limit mercury emissions from all coal-fired plants to a total of 60 pounds per year. The Boardman plant will receive the full 60 pounds of the cap, until and unless, new coal-fired units are operated in Oregon. If new coal-fired plants are operated, Boardman shall receive a total of 35 pounds of the cap with the remaining 25 pounds being distributed on a first-come-first-served basis. Once the cap is reached, no new mercury allowances will be available for new coal-fired plants in Oregon. The rule also requires installation of mercury control technology on the Boardman plant and requires the plant to reduce its mercury emissions by 90% or to 0.6 lb/TBTU by July 1, 2012, with a possible one-year extension.

6.7 Compliance with Guideline 8 (Order 08-339)

As we discuss in Section 6.3 above, Guideline 8 requires that our portfolio planning reflect the most likely regulatory compliance future for CO_2, nitrogen oxides (NOx), sulfur oxides (SOx) and mercury emissions. In addition, the Guideline directs that "the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection." In Section 6.3 we discussed how our planning reflects likely CO_2 compliance cost scenarios. As discussed below, PGE's emissions levels of NOx, SOx and mercury do not have a material impact on our resource decisions because new resources enter service compliant with emissions requirements, while existing resources are or will be compliant with reasonably predictable compliance futures. As such, we did not conduct sensitivity analyses on these emissions.

New Resources

For new resources, fossil fuel plants are built to BACT standards, hence they enter service compliant with the current emissions requirements. Natural-gas-fueled plants have only small amounts of NOx and SOx emissions and are not regulated by mercury rules. Furthermore, PGE does not propose a new traditional pulverized-coal plant in any of its portfolios. All PGE portfolios for new resources thus reflect the most likely regulatory compliance futures for federal emissions requirements for CO_2, SOx, NOx, and mercury.

Existing Resources

With regard to PGE's existing resources, as stated above, our natural-gas-fired plants have only small amounts of NOx and SOx emissions and are not regulated by mercury rules. Thus, any sensitivity analysis would be immaterial.

PGE is planning a stringent emissions control retrofit for the Boardman plant. In this IRP, PGE proposes to fully adopt the DEQ RH BART and Reasonable Progress proposal by installing low-NOx burners, mercury controls, scrubbers and selective catalytic reduction in three stages between 2011 and 2017. This will significantly reduce SOx, NOx, and mercury emissions, leaving Boardman fully compliant through the end of its remaining operating life. Please refer to Chapter 12 for additional detail.

PGE's also maintains a minority ownership interest in Colstrip units 3 & 4. These plants were built approximately five years after Boardman was placed in service and have scrubbers which were required subsequent to the construction of Boardman. PGE and the plant co-owners recently installed low-NOx burners on the units and plan to install mercury reduction components in 2010. At this point, we have no basis to conclude that a reasonably possible regulatory future will require additional controls. Therefore, we have not provided a sensitivity in our modeling reflecting additional controls for these units.

6.8 Renewable Portfolio Standard

On June 6, 2007, Oregon adopted a Renewable Portfolio Standard (RPS) ORS 469A). The Oregon RPS requires that 25% of our retail energy load be served by qualifying renewable resources by 2025, with interim targets of 5% by 2011, 15% by 2015, and 20% by 2020. Qualifying resources include generating facilities placed into operation on or after January 1, 1995, and their incremental improvements.

Qualifying resources include:

- 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 of energy generated from certified low-impact hydroelectric facilities

The legislation further provides that Tradable Renewable Energy Credits, commonly known as Renewable Energy Credits (RECs) or Green Tags[49], may be used to fulfill the RPS targets if independently verified and tracked. Bundled

[49] RECs are the separable renewable attribute associated with energy generated by qualified renewable power resources. RECs have a market value and, if unbundled and sold, the green energy associated with such RECs is reclassified into undifferentiated energy as though it were generated from a non-renewable power source. Typically, one REC equals one MWh of generation from a qualifying renewable project. These can be sold into the market over various time periods. For example, a 10 MWa wind project which sold its RECs for one year would generate (10 MW * 8,760 hours) = 87,600 RECs during that time period.

RECs[50] must physically reside within the U.S. portion of the WECC. For unbundled RECs, the facility that generates the qualifying electricity must be located within the geographic boundary of the WECC. RECs obtained by utilities through voluntary green power programs do not apply toward meeting the RPS compliance targets.

The legislation allows a REC to be carried forward or "banked" and used to meet RPS requirements in a future compliance year other than in the calendar year it was generated, with specific limitations. RECs are tracked via the Western Renewable Energy Generation Information System (WREGIS). According to Oregon Administrative Rule 330-160-0030(1), the banking of RECs begins January 1, 2007. Unbundled RECs may be used to meet a maximum of 20% of a utility's annual REC requirement. Under ORS 469A.180, an electric company or ESS may also use alternative compliance payments to meet the RPS requirements.

The Oregon RPS requires that each electric company and each ESS must file a compliance report annually and that each electric company must file an implementation plan at least once every two years[51].

Under ORS 469A.100, an electric company or an ESS is not required to comply with the RPS to the extent that the incremental cost of compliance would exceed 4% of its revenue requirement in a compliance year. The cost cap is met by applying the incremental cost of development of a renewable resource over an equivalent nonrenewable resource[52]. If subject utilities fail to meet the compliance target for reasons other than reaching the cost cap, then they may be subject to a penalty imposed and determined by the OPUC. All prudently incurred costs associated with RPS compliance are recoverable under the RPS legislation, including those associated with transmission and development.

AR 518

AR 518 is a rulemaking docket which addresses the effects of the RPS. The OPUC Staff has conducted numerous workshops to discuss the amendments to the statutes enacted under the RPS. The rulemaking proceeding has been separated into phases to address various deadlines in the RPS.

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[50] A bundled tradable renewable energy certificate includes both the underlying qualifying electricity and the renewable certificate that was issued for the electricity.

[51] PGE's first Implementation Plan is due Jan. 1, 2010. It will include an estimate of our expected compliance seven years out. The first Compliance Report is due June 1, 2012.

[52] The incremental levelized cost difference between nonrenewable and renewable resource choices is applied evenly towards the cost cap throughout the life of the project.

Phase I of the rulemaking was adopted on December 18, 2007 by PUC Order No. 07-561. This order addressed Section 27 of SB 838 (the RPS legislation) which provides that the new renewable energy portion of the public purpose charge must be spent exclusively on projects 20 megawatts or less in size and provides for the extension of the sunset date to January 1, 2026.

Phase II of the rulemaking addressed RECs that may be used to meet the RPS, as they relate to power source disclosures. The rules were adopted by the Commission on June 15, 2009, Final Order No. 09-225.

Phase III of the rulemaking addresses estimating the annual revenue requirement and the incremental cost of compliance, the timing of updated information on costs, a general outline for the bi-annual implementation plan, a general outline for the annual compliance reports, and a general outline for compliance standards and alternative compliance payment rates and use of such funds. The rules were adopted by the Commission on August 3, 2009, Final Order No. 09-299.

Status of PGE's RPS Compliance

In our 2007 IRP, we targeted 218 MWa of new renewables to achieve physical resource compliance with Oregon RPS requirements in 2015. Due to the recession and resulting reduction in the forecast for electric demand and other factors, we now project a reduced renewable need as compared to the filed 2007 IRP. The current forecasted need is 122 MWa. The main drivers of the reduction are the inclusion of 50 MWa of low-impact hydro from Pelton / Round Butte, a reduction in our load forecast and improved production at our Biglow Canyon wind project. Table 6-4 provides the reconciliation.

Table 6-4: 2015 RPS Requirement to Reach Physical Compliance

Current vs. 2007 IRP – Reconciliation	MWa	
2007 IRP Action Plan Target*		**218**
Adjustments:		
Allowed Low-impact Hydro Certification	50	
2015 Load Forecast Reduction (178 MW @ 15%)	27	
Increased EE Expectation (cum. to 2015; 41 MW @ 15%)	6	
Improved 2015 Biglow Production Expectation	9	
Sunsetting of Klondike II for Green Tariff & Other	4	
Total Adjustments	**96**	
2009 IRP Compliance Requirement for 2015		**122**

* Also used as the 2008 RFP target for new renewables

Table 6-5 compares PGE's load-based renewable resource requirement by year vs. RECs that we generate from existing renewable resources and from IRP renewable acquisitions recommended in the 2007 IRP to achieve the 2015 target. The table incorporates the updated target (122 MWa, assumed to be acquired by year-end 2012) to reach physical compliance with the 2015 RPS target.

Table 6-5: PGE Estimated RPS Position by Year (in MWa)

	2011	2015	2020	2025
Calculate Renewable Resource Requirement:				
PGE retail bus bar Load	2,442	2,624	2,886	3,179
Remove incremental EE	(16)	(86)	(135)	(135)
Remove Schedule 483 5-yr. load	(27)	(28)	(28)	(28)
A) Net PGE load	2,399	2,510	2,723	3,016
Renewable resources target load %	5%	15%	20%	25%
B) Renewable Resources Requirement	**120**	**376**	**545**	**754**
Existing renewable resources at Bus:				
Vansycle Ridge	8	8	8	8
Klondike II	26	26	26	26
Klondike II dedicated to PGE green tariff	(5)	0	0	0
Sales of RECs	0	0	0	0
Biglow Canyon Phase I (year-end 2007)	48	48	48	48
Biglow Canyon Phases II and III (year-end 2008, 2010)	114	114	114	114
Post-1999 Hydro Upgrades	9	9	9	9
Pelton Round Butte LIHI Certification	50	50	50	50
C) Total Qualifying Renewable Resources	**250**	**255**	**255**	**255**
Compliance positions & RECs banking:				
D) Excess/(deficit) RECs B4 new IRP Actions (C less B)	130	(122)	(290)	(499)
E) IRP Action Plan* -- additional resources for 2015 compliance	0	122	122	122
F) Total PGE renewable resources (C plus E)	250	377	377	377
G) % of load served via RPS renewables (F divided by A)	10.4%	15.%	13.9%	12.5%
H) Excess/(deficit) RECs w/ IRP Actions (D plus E)	130	0	(168)	(377)
I)Cumulative Banked RECs after IRP Actions	**709**	**1,408**	**1,185**	**200**
J) Cumulative Non-LIH Banked RECs after IRP Actions	**509**	**1,208**	**985**	**-180**

* previously approved action from the 2007 IRP

With the sharp rise in the renewable resource requirement from 5% of load in 2011 to 15% by 2015, banking RECs from early renewable resource actions provides a significant cushion for meeting RPS compliance. We expect that our existing actions, including successful acquisition of 122 MWa of new renewable resources by year-end 2012, will provide sufficient RECs to meet RPS requirements through 2024.

While banked RECs provide an important balancing mechanism, potentially enabling us to delay the addition of physical resources and the associated investment costs, our RPS renewable need escalates rapidly once the bank is depleted. As shown in Table 6-6 the annual need quickly surpasses 400 MWa, topping out at 467 MWa in 2030, if banked RECs are used to meet RPS compliance in lieu of physical resources. See the following table for PGE's needs after 2024. By 2026 PGE's RPS renewables need would require the acquisition of a wind farm with a nameplate capacity of 1,270 MW (based on a 31% capacity factor). This is almost three times the total size of Biglow Canyon Phases I-III.

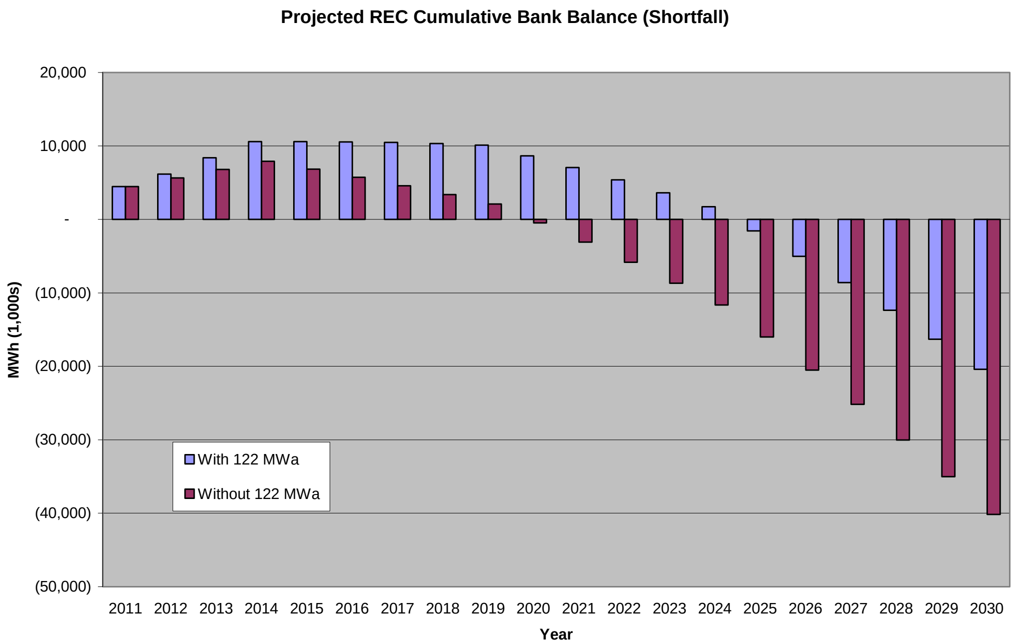
Table 6-6: Renewable Need 2025 and Forward – After Banking (MWa)

Year	Renewables Required	Useable Bank*	Generation**	Remaining Need	Wind w/33% CF
2025	754	247	327	180	546
2026	770	50	327	393	1,192
2027	786	50	327	409	1,240
2028	803	50	327	426	1,292
2029	819	50	318	450	1,365
2030	836	50	318	467	1,416

*Usable bank includes any banked generation, purchases and up to 50 MWa of Pelton / Round Butte low-impact hydro (P/RB).
**Generation does not include 50 MWa of P/RB – due to regulatory / timing issues P/RB is always used from banked position, not in year that MWhs are generated

See Figure 6-3 for a visual representation of the rapid depletion of early generated RECs. In 2014, the year of PGE's largest balance, there are approximately 10.6 million MWhs or RECs. While this balance may appear to be significant, it rapidly diminishes without acquisition of additional renewable resources, reaching a negative balance of over 20 million RECs by 2030. If we are unable to procure our targeted 122 MWa of renewable energy (by 2015), the negative balance would exceed 40 million RECs by 2030. The graph below represents two REC utilization scenarios: one assumes no incremental renewable additions (beyond our planned completion of Biglow Canyon); the second assumes the addition of 122 MWa, with 61 MWa coming online in 2012 and the remainder online in 2013.

Figure 6-3: Projected REC Cumulative Bank Balance or Shortfall



From the chart it is evident that acquiring physical resources early can be beneficial in reducing performance risk in meeting Oregon's RPS requirements over the long run.

Banking RECs can provide an effective hedge against future renewable resource cost increases. In addition to financial flexibility, banking RECs provides flexibility in timing of renewable resource acquisitions, as demonstrated in Figure 6-3 above. Flexibility may be particularly important for our customers given the five-year MACRS depreciation for all renewable resources, which provides tax depreciation for 38% of the property in-service basis in its second year of service. This creates challenges in having a sufficient tax liability to use all the depreciation associated with qualifying renewable resource investments in the year generated. While tax losses can be carried forward, their value diminishes over time. Flexibility in timing of adding new renewable resources would allow us to maximize the benefit to our customers of the tax depreciation while minimizing potential tax loss carry-forwards.

There are several factors, in addition to the ability to bank RECs, which favor early acquisition of renewable resources. These include increasing competition for renewals, potentially reducing access to and quality of remaining wind sites, possible expiration or limitation of the Pollution Tax Credit, scarce transmission access, and increasing costs per kW for wind plants based on commodity and construction costs and higher demand. Factors that may suggest later development of renewable resources include the possibility of acquiring larger turbines for wind plants and potential cost and efficiency breakthroughs in non-wind renewable resources such as wave and solar generation.

Sales of RECs

On March 5, 2007, the OPUC issued Order No. 07-083 (in Docket UP 236) in response to PGE's application to sell RECs. Condition 8 of OPUC Order No. 07-083 directs PGE to

> "Analyze, in its [IRP] process, the valuation and risks associated with the disposition of TRCs, including their value for compliance with a potential [RPS] or regulations on greenhouse gas emissions."

The condition also stipulates that value from the sale of RECs flow back to customers, either in the form of rate credits or funding to develop new resources.

Currently there are regulations on greenhouse emissions in place in Oregon via the Climate Trust offset payment (see Section 6.3 above). Given that an Emissions Portfolio Standard is only in the early stages of consideration, it is not clear how such emissions legislation would interact with the Oregon RPS, particularly regarding the valuation of RECs. Furthermore, none of the legislative proposals discussed in Section 6.3 above contain provisions for the usage of RECs to meet emissions targets. The Waxman-Markey bill contains a proposal for a federal RPS, but renewables targets are not as high in this proposal as the Oregon RPS.

An important consideration with respect to PGE's RECs is whether excess RECs that we generate in advance of RPS requirements have more value if banked for future use toward RPS targets, or if they have more value when sold in the marketplace. By selling excess RECs, PGE may achieve immediate cost reductions for our customers, or use funds generated by the sales to acquire additional renewable resources.

At this time, any estimate of the future market for RECs is purely speculative. Many factors will affect the potential value of RECs with one of the major factors being the regulatory definition, e.g. vintage, geographic origin and qualifying resource. Under Oregon regulations RECs essentially may be banked for an unlimited time; other jurisdictions' banking rules differ in many respects and may have a life limited to two years. There are also differences in generation sources of RECs by resource type[53]. In Oregon, unbundled RECs may be used to

[53] Some WECC states have a solar carve out; the value of solar RECs could potentially have higher market value. Energy efficiency does not qualify as a REC in Oregon, but does so in many other jurisdictions.

meet up to 20% of the annual RPS requirement; other states may allow a higher or lower use of unbundled RECs. These and other factors combine to create a large amount of uncertainty in the market regarding future REC prices.

It is difficult at this time to know whether the market price of RECs will favor selling some portion of the RPS bankable RECs that PGE generates vs. retaining REC inventory for future RPS compliance. However, our early renewable resource acquisitions provide flexibility to do both – thus giving us the ability to respond to the market and take appropriate actions most beneficial for our customers.

Table 6-7 below is a further examination of the value of our banked RECs. The number of banked RECs for PGE will continue to grow until 2014. From 2015 forward the bank will decline unless additional renewables are added. As mentioned above, PGE's maximum bank will be approximately 10.6 million RECs in 2014 assuming that PGE adds 122 MWa of renewables by 2013. If there are no renewables added the maximum bank will be approximately 8 million RECs. As Table 6-7 shows, the burn rate for RECs, (i.e. the amount needed for compliance), will rapidly deplete the bank, especially in the out years.

Table 6-7: Banked RECs and Burn Rates

Time Period	RPS Requirement	Average Annual REC Burn Rate	% of maximum banked position	
			Includes 122 MWa by 2012	Without 122 MWa
2011-2014	5%	1,073,832	10%	14%
2015-2019	15%	3,397,205	32%	43%
2020-2024	20%	4,979,381	47%	63%
2025-2030	25%	6,964,492	66%	88%

Evident in the preceding table is the rapid escalation of PGE's renewable resource need over time. For the early years, when the RPS requirement is at 5% of energy, PGE faces a relatively modest average annual need of 123 MWa. The following time block, when the requirement increases to 15%, the average annual need is 388 MWa –would require an increase of generation of 133 MWa – or a wind facility of 402 MW nameplate, assuming a capacity factor of 33%. By the 2025-2030 time frame PGE will need additional generation over 1,600 MW nameplate assuming wind facilities with a 33% capacity factor – see Table 6-8 below.

Table 6-8: Wind Capacity Necessary for RPS Requirements

Time Period	Average Need (MWa)	Current Annual Generation (MWa)	Need as % of Current Generation	Shortfall (MWa)	Implied Wind Nameplate Capacity Needed (33% CF)
2011-2014	123	255	48%		
2015-2019	388	255	152%	133	402
2020-2024	568	255	223%	313	950
2025-2030	795	255	312%	540	1,636

The potential monetary penalties associated with not meeting the RPS targets can be substantial. 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 amount a utility will need to pay per REC for any shortages in the 2011 compliance year. If we were to miss the requirements by 10%, the payment would be approximately $5 million in 2011. As the requirements increase, so do the costs for missing the RPS targets. These costs would average approximately $35 million per year for missing the requirements by 10% in the years 2025-2030. Table 6-9 compares the costs of missing the RPS requirements by 10% for the various time periods in our study.

Table 6-9: Potential Cost Implications of Missing RPS Targets

Years	MWh Short (10% of average annual need)	Millions of Dollars
2011-2014	107,383	$ 5
2015-2019	339,720	$ 17
2020-2024	497,938	$ 25
2025-2030	696,449	$ 35

Also of importance is the cost to build new renewables. In the last four years projections of costs associated with building wind turbines have increased dramatically. In the 2007 IRP PGE projected an all-in revenue requirement cost of $69.32 per MWh in levelized 2007 dollars for wind resources[54]. Our current projection is $93.62 per MWh in levelized 2011 dollars[55]. This indicates a nominal growth rate of 7.8% (with embedded inflation at 1.9%) on an average annual basis. If this level of cost increase were to continue at the same rate, costs of wind

[54] Assuming a wind plant on-line in 2008.

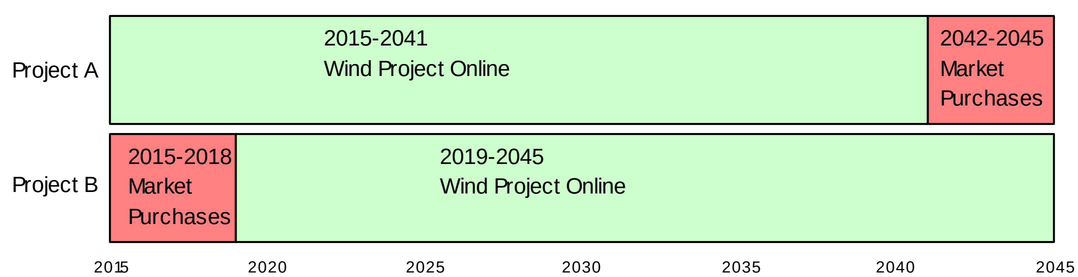
[55] Assuming a wind plant on-line in 2012.

power resources would rise to about $171 per MWh in nominal dollars by 2019, or $141 in 2009$.

On the capital side the real increase in costs has been just as dramatic. In the 2007 IRP the projected overnight capital costs for Tier II wind was $1,700 per kW in 2005 dollars. In our current IRP the corresponding value is $2,117 per kW in 2005 dollars. The nominal average annual growth rate is 7.6% (real growth of 5.6%). In this case a 400 MW nameplate facility (the average need for PGE in the years 2015-2019) built in 2019 instead of 2015 would incur nominally over $435 million of additional overnight capital costs.

It is likely that wind costs will continue to outpace inflation for the foreseeable future, however PGE's cost assumption for wind within the portfolio model is for a constant price in real dollars. Renewable portfolio compliance requirements, combined with potential CO_2 regulation will lead to sustained high demand for turbines. The real growth rate may not stay above 5% for the long run, but even if it fell to 2% there would be considerable cost impacts to delaying construction of a wind project. As a potential example, consider building a 400 MW wind project in 2015 (Project A) versus the same in 2019 (Project B). The wind turbines will have an assumed life span of 27 years, consistent with their book life. The study period covers the years 2015 through 2045, with market purchases supplementing wind generation pre- and post-project construction see Figure 6-4 below.

Figure 6-4: Resource Timeline Comparison



To simplify the analysis, the two projects are assumed to have the same capacity factor – 31%. It is probable that RPS requirements will lead to the rapid depletion of optimal wind sites. Thus Project B could have a much lower capacity factor. The results of the analysis are shown in Table 6-10. For the same total energy (and RECs), delay of the wind farm by four years increases total costs by more than $150 million, or 4.8%.

Table 6-10: Potential NPV Cost Impacts of Delayed Wind Project

	Online Date	Cost ($/MWh)	Project Costs (millions)	Market Costs (millions)	Total Cost (millions)
Project A	2015	$98	$3,147	$405	$3,233
Project B	2019	$106	$ 3,406	$315	$3,387
Cost Increase ($)					$154
Cost Increase (%)					4.8%
All costs are in 2009$					

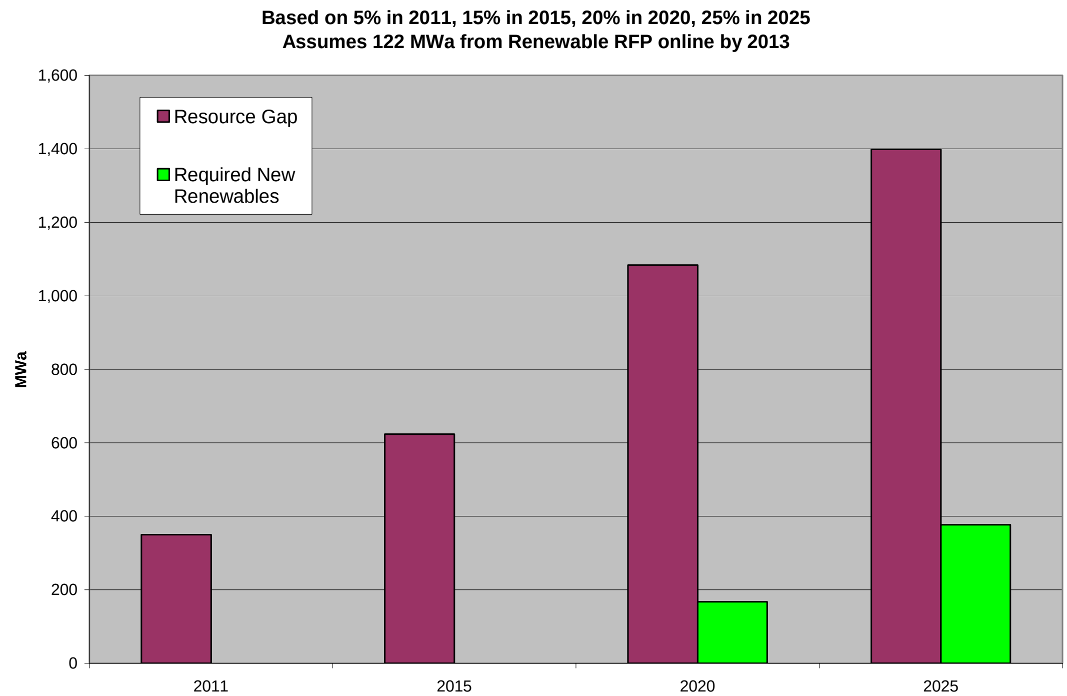
Finally, we should note that PGE is in need of additional energy resources. Renewables bring with them energy, as well as RECs. If we do not add renewables for our energy needs we will need to add thermal resources. While it is difficult at this point in time to assign a value to future RECs, PGE will continue to look for opportunities where trading RECs can offer value or minimize risk to our customers.

Impact of the RPS on PGE's Future Resource Mix

In order to meet the 2025 RPS target, approximately one-fourth of our cumulative energy additions must consist of incremental (new) renewable resources (see Figure 6-5)[56]. The one-fourth figure incorporates the projected resource needs shown in the table along with the 122 MWa acknowledged in our 2007 IRP (assumed here to be acquired by 2013). Given the sharp increase in the compliance requirements of the Oregon RPS between 2011 and 2025 as well as our preference for pursuing a measured implementation strategy, we propose actions in this IRP which will help us achieve our ongoing RPS targets. Such actions include issuing an RFP in which we will bid a benchmark wind resource.

[56] Assuming no use of banked Renewable Energy Credits toward RPS requirements.

Figure 6-5: Oregon RPS Requirements vs. Resource Need



If our RPS target were met entirely by wind, 377 MWa[57], or about 1,142 MW of new wind would be required by 2025. At current estimated costs in 2009$, the bus bar investment (overnight capital costs) required to achieve the RPS by 2025 with all wind is estimated at $3.0 billion (including required backup capacity from incremental SCCTs), vs. $3.1 billion for IGCC coal (sequestration ready and including transmission costs), $2.3 billion for traditional coal (including transmission costs), and $0.6 billion for CCCTs for similar amounts of energy. Nevertheless, initial rate impact differentials are less than capital investment differentials might imply due to incremental fuel and carbon costs of the thermal alternatives (and no such costs for wind) and spreading of the wind investment recovery over more than 25 years. Chapter 7 provides a fully allocated cost comparison, inclusive of substantial fuel costs for the coal and natural gas alternatives.

[57] PGE's renewable need in 2025 is 754 MWa total – the 377 MWa figure assumes continuation of current position (255 MWa) and successful completion of renewable RFP for 122 MWa, i.e., 754-255-122=377.

7. Supply-Side Options

This chapter provides background information on the various resources we considered in the IRP for meeting PGE's future capacity and energy needs. We examine renewable, thermal, contract and distributed generation options. For each option we discuss the criteria for evaluation and selection, present the resource options and associated attributes, and describe the technologies. In addition, we describe our data sources, assumptions for costs and our approach for addressing long-term price trends, anticipated advances in technology and areas of uncertainty. The chapter concludes with a discussion of emerging technologies.

Chapter Highlights

- We included in our analysis those energy supply-side alternatives that are currently available or are expected to become available to meet PGE's resource needs.
- These include combined- (CCCT) and simple-cycle (SCCT) gas turbines, nuclear, IGCC, and utility-scale renewables (biomass, geothermal, solar, wave and wind), as well as reliance upon market purchases.
- We describe the reference case capital and operating costs and underlying assumptions for all resources included in our portfolio analysis.
- We reviewed developing technologies such as high altitude wind, in-stream hydrokinetics, modular-nuclear, solar thermal and pump storage for inclusion in future IRPs.
- We project the effect of expected advances in technology on capital costs for IGCC and solar and on heat rates for natural gas turbines, reciprocating engines, IGCC and SCP coal technologies.

7.1 Renewable Options

Wind

With the extension of the Production Tax Credit (PTC) until December 31, 2012, and the continued expansion of state RPS requirements, we expect the recent rapid growth in new wind generation projects to continue well into the future. Record U.S. installations occurred in 2007 and 2008. Key growth drivers include increasing public awareness of and concern for environmental issues, unstable fossil fuel prices, maturation and scaling of wind generation technology, an influx of capital to the industry, market evolution, and supportive state and federal policy for renewable resources.

As technological advances continue, wind projects are increasing in scale and generating capability. Turbines, towers, rotors and total project size have all increased over the last few years. The typical project size for a new utility scale wind project is now 100 – 400 MW. The typical turbine size is 1.5 MW to 3 MW. Increased scale is improving both wind project efficiency and economics. As a result, geographically advantaged wind sites that have higher wind speeds and lower interconnection costs can be cost-competitive (with the PTC) compared to fossil-fueled generation alternatives.

We evaluated wind performance based on capacity factors at two locations. We model Pacific Northwest wind with a capacity factor of 33%, which reflects the average capacity factor of the short-listed Pacific Northwest wind projects from PGE's 2008 Renewables RFP. The Wyoming wind capacity factor of 37% reflects the actual operating experience, on average, of existing Wyoming wind farms.

The current PTC benefit is approximately $20/MWh nominally (indexed to inflation). Given this substantial economic benefit, the PTC remains critical to the competitiveness of wind for the Pacific Northwest.

Despite the number of wind turbine suppliers opening new manufacturing plants in North America, competition for wind turbines and related components is expected to remain high for the foreseeable future due to anticipated U.S. and global demand-supply tightness. Turbine costs are also expected to increase in part due to increases in commodity costs for steel, oil and related materials.

Beyond turbine availability, potential uncertainties and barriers for increased adoption of wind power include transmission availability and integration costs. The most viable Pacific Northwest wind sites are on the east side of the Cascades. Incremental firm transmission from these areas in the mid and lower Columbia River Gorge area is limited. Montana and Wyoming offer significant wind resource opportunities; however, construction of new transmission lines adds significant cost to these resources.

PGE Wind Integration Study

Because wind generation is an intermittent resource, it poses new challenges for integrating its output into an overall system of baseload and/or dispatchable resources to meet load. Integration refers broadly to conventional ancillary services such as load following, regulation, and maintaining reserves. Costs associated with integration include both incremental costs for variable O&M and fuel and opportunity costs such as redispatching hydro generation from more valuable hours to support wind generation in less valuable hours.

The costs for integrating wind are highly utility-specific, as they are a function of broad factors such as:

- How much wind is being integrated in comparison to load requirements;
- The typical seasonal and daily "shape" of that wind, especially as compared to the shape of the load and availability of other generation (e.g., spring-peaking wind during spring hydro run-off);
- The degree to which the wind resources provide generating diversity among themselves (e.g., one wind farm is summer-peaking where another is winter-peaking);
- The operating characteristics of other generating resources in the portfolio (e.g., dispatchable vs. base-load resources, etc.);
- The depth of the trading market in the specific geographic region and associated seasonal available transmission capacity, and,
- The degree of accuracy with which the wind can be forecasted.

For this reason, to conduct our own study, PGE developed a detailed, hourly dispatch model to estimate our specific self-integration costs based on the unique characteristics of our load, wind and other generation resources. Our initial wind integration study (WIS), described below, had one major objective: to provide an estimate, based on system cost minimization, of 2014 PGE system-specific integration costs where we have acquired sufficient wind generation to meet the Oregon 2015 RPS requirement to supply 15% of our annual load from qualifying renewable resources. (Because wind is the sole renewable available at this time in sufficient economic quantity, we assumed that the requirement would be met almost entirely from wind.) This 2015 estimate is then in turn used as a component in our estimation of the resource cost for wind additions in this time frame. Later in this section, we describe other objectives for developing forecasted wind integration costs that will be addressed in an upcoming second phase WIS.

Wind generation creates additional costs due to its variability and unpredictability. Wind is variable in broad patterns, both seasonally and diurnally. Wind generation also varies from hour-to- hour and minute-to-minute. The utility must dispatch a balancing resource to offset the increase/decrease of the wind generation on both a second-to-second basis (regulating margin) and over longer intervals (load following).

Wind generation itself is, of course, also largely unpredictable. Uncertainty arises when the forecasted generation output of a particular wind plant is scheduled into the system resource mix on a day-ahead or hour-ahead basis and the subsequent actual generation causes the utility's day-ahead and hour-ahead position to be either long or short. The utility must then react to that position either by redispatching its owned resources up or down, or by buying or selling into the market. The first resource of choice for redispatch from a physical point of view is hydro, since it is a form of storage which is also exceptionally flexible.

Currently, PGE integrates Biglow Canyon through the BPA Control Area. BPA supplies the integration services and charges PGE for the Generation Imbalance and Wind Balancing Service. These rates are in BPA's current 2010 Transmission, Ancillary Service and Control Area Service Rate Schedules for FY 2010-2011. This rate is in effect through September 2011, at which time a new, potentially higher costs to reflect increased integration demands, will take effect.

It should be noted that a direct comparison of BPA's integration rates and PGE's wind integration costs is not entirely appropriate. The BPA integration rates do not include all components of PGE's wind integration costs. BPA's integration rates include reserves for three types of balancing services: Regulating Service, Following Reserves and Imbalance Reserves. BPA determined these services to be necessary in order to eliminate the in-hour variability of the wind generation within their control area. PGE's wind integration costs, while including these in-hour balancing costs, also include costs for both day-ahead and hour-ahead system optimization.

We currently receive third-party integration services for our contracts for the output of the Klondike II and Vansycle Ridge wind farms. The integration service for Klondike II is addressed in the terms of the Power Purchase Agreement with Iberdrola Renewables.

We expect PGE self-integration costs to rise as we add increasing levels of wind to our resource portfolio, as we expect to be the case also for BPA and regional

IOUs. We further expect, even as we add more wind to our portfolio over time, that our system capability to integrate will deteriorate due to a declining hydro resource base (both in aggregate and in proportion to our expected load).

Study Scope & Description

While PGE does not currently self-integrate wind, it became evident in 2007 that significant wind generation was going to be a part of PGE's future portfolio and we needed to understand its impact on integration costs. In Order No. 08-246, the OPUC directed PGE to include in its IRP analysis a wind integration study that has been vetted by regional stakeholders. Accordingly, PGE conducted a detailed wind integration study (WIS) with a modeling objective of minimizing system costs while simultaneously self-integrating wind and meeting load.

In February 2007, PGE contracted with Enernex to provide their expertise in how to perform this study. Specifically, Enernex provided a four-step approach for isolating the impact (and costs) of incorporating intermittent wind generation that are apart from and incremental to existing embedded integration costs to meet variable load requirements. Because the granularity of the model would be hourly, Enernex also developed the in-hour component of PGE's integration costs based on system-specific data we provided them.

PGE then formed a small internal project team with expertise both in how PGE's generating resources operate (and their respective constraints) and in linear programming (LP) to develop an LP-based hourly dispatch model to provide the intra-hour integration costs. We also employed a consultant initially to help set up the basic structure of the model based on his prior successful development of an LP-based wind integration model for another Northwest-based utility.

In May of 2008, PGE also requested the assistance of a voluntary Technical Review Committee (TRC) composed of industry experts to vet our study approach, inputs, and findings[58]. The TRC informally participated in our WIS process and provided ideas and feedback to the project team on a recurring basis. Their informal, voluntary participation during the course of this study does not constitute approval of the study results.

We used the National Renewable Energy Laboratory's (NREL) West Wide Wind Study data for site-specific wind generation throughout the Columbia River

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[58] We requested the assistance of the following: J. Charles Smith, Executive Director of the Utility Wind Integration Group; Ken Dragoon, Research Director for the Renewables Northwest Project; Michael Milligan, an analyst for the National Renewable Energy Laboratory; Brendan Kirby, a consultant for the American Wind Energy Association; and Michael Goggin, an engineer for AWEA.

Gorge and Eastern Oregon areas. NREL, in cooperation with 3Tier (a leading wind forecasting company), created a database of actual hourly wind generation and day-ahead forecast generation for 2004, 2005, and 2006 for more than 30,000 points across the Western United States. The TRC advised the PGE Project Team to use the actual hydro from each of these years in conjunction with the wind from that year since it has been documented that there is an observable correlation between the two.

Other inputs beyond the operating characteristics of PGE's generating plants and potential future wind projects included PGE's forecast 2014 hourly load, hourly wholesale market clearing prices from Aurora, and hourly forecast natural gas prices from PIRA. For PGE's thermal plants, we modeled heat rates, ramp rates, and scheduled outages. For our hydro plants, we modeled storage constraints, maximum flow rates, and scheduled outages.

We ran the study for a 2014 dispatch and chose five geographic zones for wind additions, based on the location of the most attractive wind projects bid to us in our 2008 Renewables RFP. The purpose of using five zones was to understand the degree of wind diversity these projects might bring and the impact on integration costs. The RES goal of 15% renewable generation by 2015 amounted to 1,100 MW of nameplate wind capacity for PGE. As a base case starting point, we added no flexible capacity resources (such as natural gas-fired reciprocating generators) to our existing system. Since a portion of PGE's Mid-Columbia hydro contracts expire prior to 2015, we included only those hydro contracts still in place as of the beginning of the year 2014.

The project team held discussions with our traders regarding how to deal with the value of the energy needed to fill the position created by the uncertainty caused by the forecasted wind generation. Consistent with other wind integration studies, we decided to use a Bid-Ask spread of $0.50/MWh for the Preschedule market price. However, due to the decreased liquidity of the market from Preschedule to Real Time, the Team determined that the Bid-Ask spread should be a percentage of market price, or 20%, which corresponds with the BPA Band Two charge for Generation Imbalance[59].

Wind Integration Cost Used in our Analysis

On September 19, 2008, PGE presented the results of this initial WIS to OPUC staff and other IRP Stakeholders in a public meeting. PGE's WIS estimates integration costs to be approximately $13.50/MWh ($2014, or $11.75 in $2008) when averaged across all 8,760 hours of 2014. This is the estimated cost to

[59] See http://www.transmission.bpa.gov/Business/Rates/, "2008 Rate Schedules" pages 69-72.

integrate 1,100 MW of wind energy into the PGE system based on PGE's existing resources (less those that expire prior to then), 2014 loads, market prices, and gas costs, and 2005 hydro and wind data. We note the following caveats regarding this estimate:

- This cost assumes PGE self-integrates its entire wind requirement. Lower amounts of self-integration will lead to lower costs.
- This cost is before the beneficial impact to variable costs of adding new flexible generating resource to PGE's system.
- It assumes that some PGE thermal units not currently on Automatic Generation Control (AGC) will add AGC capability.

We also make two interesting observations that we learned from this study. First, as wind generation becomes a significant portion of our system in terms of nameplate MW, we may need to revisit how to optimize scheduled maintenance of thermal units. Second, while hydro is perceived to be the perfect balancing resource for wind, the opportunity cost associated with de-optimizing its "before wind" dispatch is more expensive than the variable cost of a thermal unit. Ironically, systems that are dominated by many flexible thermal units that provide integration for load variability can provide wind integration more cheaply.

We use this integration cost as an adder to our generic wind generation revenue requirements, as we believe it is a fair representation for our 2015 state before taking any mitigating actions to reduce costs, such as buying BPA or third party services if they are available and lower in price.

WIS Next Steps

PGE realizes that understanding operating requirements and costs for integrating intermittent resources is going to be an ongoing effort with increasing emphasis as more such resources are added. It is also uniquely challenging. To provide an increased capability to address questions that arise, we are currently in the process of converting our model to a different LP platform that is not Excel-based. Early indications are that we should see a very significant performance increase, allowing us, in turn, to insert the additional operating constraints that were not previously possible while also allowing us to run more hours of the year in a given LP solve. PGE hopes to better evaluate the following with a more capable model:

- Self-integration vs. third-party integration;
- The value of adding flexible gas generation in different amounts;

- The incremental integration cost for adding a new wind farm;
- Scheduling planned maintenance to reduce integration costs (while maintaining reliability);
- The impact of reduced forecast error;
- The impact of improved wind diversity;
- Valuing the benefits of regional balancing;
- Understanding the impact of poor water years;
- Understanding the impact of higher natural gas prices; and
- Determining solar integration costs when it becomes a more material part of the PGE system.

Biomass

Biomass is a renewable energy resource fueled by the combustion of organic materials. Although numerous materials can be converted to energy using various technologies, wood is a primary source for biomass fuels. Fuel stocks generally include residue from forest thinning and logging, lumber mill byproducts (bark, mill ends, sawdust, planer shavings), and urban wood waste (tree pruning; used packing materials; and demolition, construction and urban renewal waste). The collected wood waste is converted to chips or pellets and used to fire boilers, producing steam to power electric generators. Typically, biomass facilities also sell excess process steam to an adjacent industry host facility, e.g., a sawmill. Due to the combined heat and power generation, biomass power plants are generally baseload and not dispatchable.

We estimate that approximately 50 MW of biomass projects could be developed within areas that may be accessible to PGE, depending upon transmission availability and financing, at competitive prices with the current subsidies (e.g., PTC, BETC, ETO)[60]. Our compact and more urban service territory and customer base limit viable biomass opportunities to resources that are remote and would be dependent on obtaining firm transmission from a third-party transmission provider and a reliable long-term fuel supply.

[60] Based on estimate from the Biomass Task Force Report issued by the Western Governors Association Clean and Diversified Energy Initiative, January 2006. See http://www.energytrust.org/RR/bio/faq.html for more information on ETO subsidies for biomass.

Geothermal

Geothermal generation captures heat and/or steam naturally produced by sub-surface geologic or volcanic processes and directs the thermal energy through a turbine to produce electricity. Rarer dry resources (steam only) are the easiest to develop and have the benefit of not requiring the additional capital costs of piping and flash tanks needed to separate hot water from steam. Secondary wet sources (hot water with steam) are more prevalent.

Geothermal resources are typically baseload and historically have had high reliability. Generation is only limited by the routine maintenance of the turbine and associated machinery, resulting in an average 86% mechanical availability factor, including planned maintenance.

Potential geothermal resources exist in Oregon's Cascade Range and its associated volcanic thermal sources. However, most of Oregon's geothermal resources are wet resources with lower heat intensity and are used in flash generation. Newberry Crater is the best-known and largest potential project site in Oregon. A developer at Newberry Crater recently sold 120 MW of its project under a long-term power purchase agreement (PPA) to Pacific Gas & Electric (PG&E) with the intention to serve California renewable resource demand. As Newberry Crater is a National Volcanic Monument, exploratory drilling is limited to parcels outside of the crater proper and further away from the known geothermal source at the bottom of the crater. The same developer who sold the PPA to PG&E has recently drilled two dry holes at the site in search of a valid geothermal resource. They are currently seeking to find an experienced industry partner and federal funding to attempt to use the dry holes in an Engineered Geothermal System (EGS) experiment. EGS is a proposed method by which hot dry holes can be turned into productive wells by forcing fractures in the ground to create a reservoir space into which water is added. A total of 240 MW of expected production may still be available at Newberry Crater if a resource outside of the crater can be verified.

Idaho Power also is evaluating a potential development site in Oregon near the Idaho-Oregon border. Recent drilling near Vale, Oregon at Neal Hot Springs has produced a commercial resource that is controlled by U.S. Geothermal. Additionally, Nevada Geothermal Power is readying for drilling at the Crump's Geyser location in southern Oregon and expects to find a commercial resource.

Identified native Oregon geothermal resources are listed in Table 7-1.

Table 7-1: Potential Oregon Geothermal Resources

Top Known Oregon Locations	Expected Production	Recommended Generation Type	Development Stage
Newberry Crater	240 MW	Flash	Phase 3 (PPA executed)
Crump's Geyser	20 MW	Flash	Phase 1 (identified)
Mickey Hot Springs	25 MW	Flash	Unconfirmed
Neal Hot Springs	25 MW	Flash	Phase 2 (confirmed)
Other Sites<=20 MW	70MW	Flash	Unconfirmed

Total expected Oregon potential geothermal generation is 380 MW (including Newberry Crater)[61]. Greater potential lies in southern Idaho and northern Nevada. Idaho possibly has twice the potential as Oregon, and Nevada has potentially thousands of MWs waiting to be exploited. Both of these States pose significant transmission challenges and costs to move the energy produced there back to PGE's service territory. Challenges to developing geothermal generation include permitting (as many of the best resources are on U.S. Forest Service, Bureau of Land Management or National Park lands), and the risk that test wells will not produce economic energy, thereby discouraging development investment (dry-hole risk).

Commercial-scale geothermal energy may be a competitive but limited generation alternative for PGE. Current subsidies under the federal PTC and from the Energy Trust of Oregon (ETO)[62] may make some projects cost-competitive, if developed, and if transmission is accessible. Actual project costs can vary significantly, based on the hydrothermal reservoir quality and location relative to transmission.

Solar Photovoltaic (PV)

We evaluated solar photovoltaic energy production from both crystalline silicon modules and thin film applications. These installations may be ground-mounted (and sometimes integrated with farming and grazing) or built into the roof or walls of a building, known as Building Integrated Photovoltaic (BIPV). Although solar insolation is greater on the east side of the Cascade Range in the Pacific Northwest region, solar PV installations within PGE's service territory act as distributed generation – avoiding the need for transmission lines.

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[61] Source: Western Governor's Association Clean and Diversified Energy Initiative. "Geothermal Task Force Report." January 2006. http://www.westgov.org/wga/initiatives/cdeac/Geothermal-full.pdf

[62] See http://www.energytrust.org/geothermal/index.html for more information on ETO subsidies available for geothermal projects.

Benefits of solar power include no fuel cost, direct pollution or CO_2 emissions and coincidental summer peak period production benefits. The chief disadvantage of any solar installation is availability. In Oregon, the length of the day varies considerably from summer to winter, with winter peak load periods receiving the least amount of insolation.

For portfolio modeling, we evaluated a small-scale, thin-film, roof-mounted solar PV installation located within PGE's service territory. In addition we evaluated an array of ground-mounted, thin-film photovoltaic modules located near our Biglow Canyon wind farm. Most of the O&M costs were assumed to be fixed, e.g., periodic cleaning of the solar modules.

We included integration costs of $6.35/ MWh in 2009$ escalating at inflation in O&M for both solar and wave resources. This cost is reflective of the integration cost for Tier I wind (e.g., the first several wind projects added to our portfolio) used in the 2007 IRP. PGE has not conducted a separate integration cost study for solar, as the quantity of solar generation in our portfolio is currently very small and is not expected to reach significant levels for this IRP cycle. Nor have any such studies been conducted to date in the Northwest. We consider the $6.35/MWh cost a placeholder, subject to revision once solar obtains a meaningful level of penetration in our system and we obtain more years of solar generation data.

On July 22, 2009, HB 3039 became law, establishing a 25 MW solar feed-in tariff[63] for systems less than 500 kW AC, as well as a 20-MW utility solar requirement for systems 500 kW and larger. The legislation specifies that PGE's required share of the 20 MW will be determined by our percentage of all retail electricity sales made in Oregon. PGE's requirement would be about 12 MW. The legislation also gives the OPUC authority to increase the utility requirement to up to 100 MW. As such, solar may reach higher penetration levels in our system in future IRPs.

Wave Energy

The Electric Power Research Institute (EPRI), in partnership with Oregon State University (OSU), concluded a study in 2005 assessing the wave energy potential off the U.S. coastline. The Pacific Ocean has the most potential, with higher energy levels in the north. The Oregon coastline in particular has vast potential. OSU estimates that the wave energy harvested from about 10 square miles of

[63] A feed-in tariff is an incentive structure to encourage the adoption of renewable energy through legislation, whereby the electricity utility is obligated to buy renewable energy at above-market rates set by the government or regulating entity.

ocean off the Oregon coast could produce enough electricity to power the entire state.

Wave energy technology is at an early stage of development, similar to where the wind power industry was 15 to 20 years ago. Early designs and demonstration projects fall into three broad categories: floating devices, oscillating water columns and wave surge devices. Most current floating (or pitching) designs use hydraulic or pneumatic mechanisms to convert wave action into electrical power. OSU has demonstrated direct conversion using a linear generator[64]. Most wave energy generating devices would be located one to three miles offshore. The energy from an array of wave energy devices would be collected at a marine substation and transmitted via a marine cable to connect with the transmission grid on shore.

Wave energy has several advantages over other intermittent renewable resources such as wind or solar, including significantly higher energy density (resulting in lower materials requirements per kWh) and greater predictability. Wave energy also provides a higher capacity value than wind energy and is more consistent with PGE's load profile. Transmission access is also good due to the location of the wave potential off the coast, west of most current generation resources and our service territory.

On the local development front, Ocean Power Technologies, Inc (OPT) and Pacific Northwest Generating Cooperative have signed an agreement to work cooperatively on the development of the Reedsport OPT Wave Park in Douglas County, Oregon. OPT expects to submit their license application for Reedsport in June 2009[65]. They are currently scheduled to deploy a single buoy in spring of 2010 capable of generating 150 kW approximately 2.5 miles off the coast at a depth of 50 meters. Following the initial buoy deployment, OPT plans to deploy nine more buoys in late 2010 with total generating capacity of 1.5 to 2 MW. FERC issued a preliminary permit to OPT for up to 50 MW of capacity at the site.

Several other projects along the West Coast have also filed permit applications with FERC. OPT has filed for a 100-MW wave energy project off the coast of Coos Bay. Jefferson County PUD and WaveGen plan to site a "jetty"-type wave energy generator in the breakwater along the Oregon Coast in Douglas County in the next three to five years. Tillamook County and Columbia Energy Partners

[64] OSU deployed its linear generator buoy for five days during September 2008 off the Oregon Coast at Agate Beach. OSU has received approval from the U.S. Department of Energy to become the nation's research center for wave energy.

[65] OPT is currently in a "Quiet Period" pending issuance of their next Quarterly Report on September 9, 2009 and cannot give out a current schedule or status information before such information is made public, per SCC rules.

are in discussions regarding deployment of wave energy devices along the Oregon coast, west of Tillamook County PUD substations. They plan to submit a license application in the next two to five years.

The wave energy industry has experienced some recent setbacks. All major wave energy manufacturers have experienced delays in producing a prototype and no commercial-scale generator has successfully come on line to date.

7.2 Thermal Options

Combined Cycle Combustion Turbines (CCCT)

Combustion turbines (CT) have been used by PGE since the mid-1970s to provide energy to our customers. CTs can be fueled via a variety of hydrocarbon sources, including natural gas, synthetic gas (syngas), LNG, hydrogen, and No. 2 diesel fuel oil. They can be run in simple cycle, where the expended exhaust gas is vented, or in combined cycle, in which the waste heat in the exhaust gas is used to produce steam in a heat recovery steam generator (HRSG). The steam from the HRSG is used to drive a conventional steam turbine to generate additional electricity without burning additional fuel.

Improvements in CT technology, such as forced cooling of the combustion parts, have resulted in increased efficiency, producing more energy from the same amount of fuel. CCCTs can also be equipped with duct firing to provide added generation capacity (but with somewhat reduced overall efficiency).

Natural Gas Capacity Resources

One of the newer Simple Cycle Combustion Turbine (SCCT) machines is the General Electric LMS100 (LMS100), with a degraded heat rate of 9165. A combination of proven frame and aeroderivative gas turbine technologies, this machine delivers 100 MW with simple-cycle thermal efficiency from 44% to 50%. The design of the CT incorporates an intercooler in the compressor section. The intercooler system takes compressed air from the low-pressure compressor stage, cools the compressed air and redelivers it to the high-pressure compressor stage, increasing mass flow to the CT. The 10-minute start time, load following and cycling capabilities make the LMS100 an ideal unit for integrating renewable energy resources and meeting dynamic variations in customer demand.

Reciprocating engines (e.g., Wartsila and Jenbacher) are another means of meeting capacity, load following and resource integration needs. These internal combustion, piston-driven machines are designed to burn natural gas and other gases, including LNG, syngas and biogas. The gas engine drives a generator set to produce electrical energy. These machines are available in a range of capacities from 1 MW to 20 MW, and have a degraded heat rate of 8640. They can also be combined in a modular approach to create larger overall generation projects. The 10-minute start time, load following and cycling capabilities make reciprocating engines ideal units for meeting incremental capacity needs and for integrating renewable energy resources.

Next Generation Nuclear

Existing U.S. nuclear power plants were largely custom-built – a one-at-a-time process that caused delays in approval and construction along with the potential for large cost overruns. Today, with several standard designs already approved by the Nuclear Regulatory Commission (NRC), builders of nuclear power plants assert that they are much better able to manage costs and maintain quality control for new projects.

New nuclear plant designs feature passive safety systems such as gravity-fed water supplies to cool a reactor core during an emergency to prevent overheating. The simplified designs, with fewer pumps, valves, and piping, have reduced both risk and cost. Large, standardized modules are expected to be built off-site and then delivered and assembled at the plant. The Westinghouse active passive (AP) 600 and AP 1000 configurations are NRC-approved standard designs.

Barriers to construction of the next generation nuclear plants include concerns from the financial community about cost estimates and the potential for overruns. In addition, a permanent nuclear spent fuel repository site has not been approved. The Obama Administration does not view the Yucca Mountain Repository as an option for storing spent nuclear fuel and has rejected funding for the site in the President's recent federal budget proposal. In addition, there are significant political and regulatory barriers to the construction of nuclear power plants, particularly in States such as Oregon where state law prohibits the construction of new nuclear plants.

During PGE's 2007 IRP, the OPUC Staff recommended that PGE include nuclear resources as an option in future plans. Accordingly, we include nuclear plant energy as an out-of-state resource option in this plan. With respect to potential timing of new nuclear development in the U.S., we believe that the new designs discussed above will not be commercially deployed until 2019.

Pulverized Coal

Coal is the most widely used fuel for the production of power in the U.S. The political climate in the Northwest and Oregon in particular is currently not favorable for new pulverized-coal (PC) plants. There are currently no new PC plants being considered or permitted for Oregon or Washington. As mentioned in Chapter 6, once the cap on mercury emissions imposed by the Oregon Utility Mercury Rule is reached, no new mercury allowances will be available for new coal-fired plants in Oregon.

In 2014, PGE has an option to repurchase the 15% of the Boardman plant and AC Intertie transmission rights currently held by Bank of America Leasing (BAL). Until December 31, 2013, BAL's share of Boardman's output is sold under a power purchase arrangement between BAL's lessee and San Diego Gas & Electric (SDG&E). We also have an option to lease the BAL share in lieu of exercising purchase rights. If the purchase or lease rights are exercised, we could acquire an additional approximately 86 MW of capacity (up from our current 65% share) from the Boardman plant along with associated transmission capacity on the AC Intertie. The purchase price would be based on the fair market value for the asset at the time.

Advantages to acquiring this share of the Boardman plant include that it is a stable-priced, reliable resource and the acquisition would not create incremental emissions for the region. Disadvantages include increased single-shaft concentration and uncertainty regarding transmission availability and emissions cost risk.

Integrated Gasification Combined Cycle Coal (IGCC)

IGCC is an evolving technology for coal-fueled generation that offers the potential for significantly lower environmental emissions compared to conventional pulverized coal technology. IGCC has the capability to separate and capture CO_2 and to produce lower non-CO_2 emissions and pipeline quality synthetic natural gas and hydrogen, as well as power.

Coal gasification alone is a mature technology with a history that dates back to the 1800s. Gasification consists of partially oxidizing a carbon-containing feedstock at a high temperature to produce a syngas consisting primarily of CO and hydrogen. A portion of the carbon is completely oxidized to CO_2 to generate sufficient heat required for the gasification reactions. The gasifier operates in a reducing environment that converts most of the sulfur in the feedstock to hydrogen sulfide (H_2S). A small amount of sulfur is converted to carbonyl sulfide. Some sulfur remains in the ash, which is melted and then quenched to produce slag. The cooled, raw syngas is cleaned by various treatments, including filtration, scrubbing with water, catalytic conversion and scrubbing with solvents. The clean syngas is then used to fuel a combustion turbine. The CCCT combustion turbine and steam turbine drive generators to produce energy.

The addition of CO_2 capture equipment will decrease the efficiency of an IGCC plant. The loss in efficiency is due to the need to use a "shift reaction" to convert the maximum amount of carbon to CO_2. The shift reaction requires additional moisture to be injected into the raw syngas. The loss of efficiency for an IGCC plant using a Shell Gasifier with Powder River Basin (PRB) coal would be approximately 14%[66]. This assumes a goal of greater than 90% capture of the coal's carbon content as CO_2 for sequestration.

In the near term, reliability is expected to be lower for an IGCC plant than for a traditional or supercritical PC plant. IGCC plants without spare gasifiers are expected to achieve *long-term* annual availabilities in the 80% to 85% range, which is substantially the same as a traditional coal plant. However, the increased reliability of a spare gasifier also comes with increased cost. Power generation availability can be increased by using natural gas as a back-up when syngas is not available from coal gasification.

PGE retained Black & Veatch to update its study from the 2007 IRP comparing SCPC and IGCC technologies. Black & Veatch developed performance and cost estimates of two baseload generation technology options: an 850 net MW advanced SCPC unit and a 569 net MW IGCC unit. The cost estimates assume that the project would be co-located at our existing Boardman site. Data from the updated Black & Veatch report served as the basis for our IRP generic resource cost estimate for IGCC coal.

Carbon Sequestration

We commissioned a study by Cornforth Consultants, Inc. for our 2007 IRP to examine the feasibility of subsurface or geologic carbon sequestration[67] for an IGCC plant at our Boardman site and at a hypothetical mine-mouth coal plant in Wyoming or Montana. While Cornforth found good potential in this study for sequestration in the deep saline aquifers located in basalt formations near Boardman, a planned test well was put on hold due to concerns about liability. There are currently no plans to proceed with the test well.

Carbon sequestration in basalt remains a theoretical concept, and as such, we did not model sequestration for the IGCC plant in our portfolio analysis. We did,

[66] "Gasification Process Selection Trade-offs and Ironies", Neville Holt, EPRI, Tampa, FL, 1/19/05, Pages 6-7.

[67] Carbon Sequestration is the process of capturing CO_2 from coal power plant exhaust gas and storing it away from the environment. The captured CO_2 can be compressed and injected in to underground geologic formations.

however, model IGCC as sequestration-ready[68]. Sequestration requires substantial load for compression and pumping, perhaps as much as 20% of the energy output of a plant. Due to required testing and development, large-scale geological sequestration is likely well over a decade away. A pilot test is being conducted by Pacific Northwest National Laboratory (Big Sky) near Wallula, Washington for demonstration in summer 2009. PGE will follow continuing developments with respect to geologic sequestration and update our future IRP assumptions as appropriate.

Carbon Solar/Biological Recycling

Another means of reducing CO_2 emissions from coal burning power plants is through biological recycling. Emerging technology enables photosynthesis in algae to convert CO_2 from traditional fossil fuel combustion into a biological energy feedstock – lipid oils. Once the algae are harvested it can be pressed to extract the lipid oils and used as a feedstock to produce biodiesel. Use of the biodiesel would displace burning of fossil fuels and the associated carbon emissions. The remaining biomass can be fermented to ethanol, used for livestock feed, or fired in a biomass energy plant. This approach may be safer than underground storage, which has unknown long-term consequences. This new technology has not been commercialized at a utility scale, and capital and operating costs are not well understood at this time.

An algae test project was conducted at our Boardman coal plant in 2008. Results of this test were positive and are helping us to determine if this is an efficient and cost-effective means of converting Boardman's stack CO_2 emissions to biodiesel. A larger-scale test using photo bioreactors is being planned for 2010, contingent on obtaining funds from the federal stimulus package (see Chapter 6). We will also research the potential of using algal biomass as potential fuel for the Boardman coal plant.

Options to Increase Fossil Fuel Generation Efficiency

PGE has performed a number of upgrades to our thermal generation plants throughout their operating history. Table 7-2 below summarizes upgrades completed to date.

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[68] Although technology and processes exist to capture CO_2 at an IGCC plant, these technologies are evolving and new processes are still being explored. Therefore, in the technical evaluations used to generate our cost estimates, space was allocated in the buildings so that CO_2 capture systems and pipeline injection equipment (compressors) could be added cost effectively.

Table 7-2: PGE Thermal Plant Efficiency Upgrades

Year Completed	Project Description	Increased Output MW	Improved Heat Rate Btu/kWh
1998	Boardman - Upgrade Boiler (add heat transfer area)		(500)
2000	Boardman - Upgrade Low Pressure Steam Turbine	30	
2001	Coyote Springs - Install Duct Firing Capability	2	
2003	Beaver - Upgrade Heat Recovery Steam Generators (HRSGs)	10	
2004	Boardman - Upgrade High Pressure and Intermediate Pressure Steam Turbines	32	
2003	Coyote Springs 1 - Replace Seals on Steam Turbine	3	
2009	Beaver - Replace bypass dampers	2.5	
2010	Coyote Springs 1 - Preheat ammonia injection line	0.35	

Energy improvements are PGE share.

PGE works closely with our Original Equipment Manufacturers (OEM) to evaluate the ongoing performance of our thermal generation plants. GE monitors the performance of our Coyote Springs CT plant, while Mitsubishi monitors the operations of our Port Westward CT plant. Through their evaluation of operational data, they can not only detect deterioration of plant efficiency, they are able to make recommendations to improve efficiency.

We have asked GE for a proposal to retrofit our Coyote Springs (CS) combustion turbine to bring its performance and output up to the 7FA fleet standards. As Coyote's CT was one of the first manufactured in the 7FA fleet, there were modifications adopted in later fleet units that would benefit CS efficiency and output. The proposed modifications to our Coyote Springs plant would also allow us to lower the unit's minimum operating output level (turn-down) during off-peak hours and increase load change ramp rates. At this time, the evaluation of these modifications is too preliminary to include in our portfolio analysis.

In addition, we are currently using a monitoring and software application called SmartSignal to monitor our Boardman coal plant operations. SmartSignal's main function is to catch deteriorating trends in equipment performance. This enables PGE to make necessary repairs or equipment replacements prior to failure. We are also working with SmartSignal to develop operational output algorithms to improve plant performance.

Similarly, we are also evaluating alternatives to increase the operating flexibility of our fossil plant resources. Adding Automatic Generation Control (AGC) to some of our thermal plants would allow these plants to provide regulation and other ancillary services. While these modifications typically will not increase generation output or energy conversion efficiency, they may improve overall system performance and cost by helping to meet growing flexibility demands as we add increasing levels of intermittent and non-dispatchable resources.

7.3 Contracts

Power Contracts have historically represented a viable source of supply for terms of three to 20 years, depending on market depth and liquidity and the availability of unsubscribed generation resources in the region. After a temporary overbuild of capacity following the 1999-2001 energy crisis, development of generation projects aside from wind has slowed dramatically across the West. Today, new generation development is dominated by renewable resources, primarily wind. However, the short-term market for energy trading in the Northwest remains viable, albeit subject to rapid changes in both price and availability of physical energy supply.

One of the consequences of the Western energy crisis and subsequent rapid resource investment and generation expansion was the deterioration of financial capability and, in some cases, insolvency or retrenchment within the merchant and Independent Power Producer (IPP) sector. Many of the prominent IPPs and merchants went bankrupt or pursued restructuring plans that caused them to exit many Western markets, including the Northwest. In some cases, financial speculators such as hedge and private equity funds took over IPP investments and completed certain projects, adding additional capacity to the Northwest. In other cases, banks have provided distressed or undercapitalized developers credit-enhanced structures to enable these entities to make short- to mid-term sales to wholesale market purchasers and utilities. This arrangement may be short-lived, however, as the banks themselves are now struggling under a massive worldwide recapitalization of the finance industry.

Throughout 2008 and well into 2009, the financial industry has been mired in financial losses and deteriorated balance sheets due to write-downs related to their investments in the housing and derivatives markets. The fallout has dramatically changed the landscape of credit and risk-taking for all financial institutions. Some of these same entities were also significant participants in energy commodities markets including Pacific Northwest power and natural gas markets. The IPP industry has not rebounded, while the credit providers have themselves needed extraordinary capital injections, leaving a rather large liquidity gap in the market. Just like in any crisis, there are opportunities for the remaining healthy entities to step into the void, although this will take time since some are new entrants.

Although it faces considerable challenges, the wholesale energy market may still be a viable source of future mid- and long-term supply. However, the extent to which such contracts are available and cost-effective will be subject to several factors, including market depth and liquidity, as well as the continued development of new generation in the region. Potential market products are further discussed below.

Power Purchase Agreements

PPAs are longer-term contracts to provide physical power. They have a variety of terms and conditions, which typically fall into a few basic categories: 1) firm or unit-contingent power delivery, 2) fixed or index price, and 3) delivery location (at PGE system, generation plant bus bar, or at a market hub such as Mid-Columbia). The term of these contracts can range from three to 20 years. Typical PPAs are executed under the WSPP Schedule C, whereby the sellers are obligated to deliver the energy at the contracted price. In case of seller default, the seller must pay liquidated damages to the buyer.

In response to the 2001 energy crisis, and reinforced by the recent turmoil in the financial markets, most long term PPAs come with an imputed debt component and margin requirement cost implications. Credit rating agencies measure and report imputed debt associated with long-term purchase commitments to reflect the future cash flow obligations of the buyer as if it were debt. Once added, credit rating agencies are able to compare the risk of default for different companies, normalized for their choices to build a resource or enter into a PPA. This, in turn, impacts the purchaser's credit rating and cost of borrowing.

Margin requirements are now a standard feature within most fixed price PPAs. This feature is meant to protect both the buyer and the seller from the likelihood of default when market prices move materially from the negotiated fixed price of the PPA. For example, if market prices move up from the negotiated fixed price, a buyer would be exposed to a higher cost for replacing the energy if the seller defaults in order to sell that energy into a higher-priced market. In this case, the margin requirement clause would require the seller to post a cash collateral or letter of credit to the buyer. Likewise a buyer must post cash collateral or a letter of credit to protect the seller if market prices move down.

Though long term PPAs offer a good hedge against market price movements, they bring with them an associated higher cost and potentially higher cash requirements.

Tolling Agreements

Tolling agreements are typically take-and-pay contracts where the buyer must pay a fixed demand payment or option premium for the right to receive energy or dispatch a plant. When these demand rights are exercised, the buyer must make an additional payment for the fuel and/or operating expense to generate electricity. The demand payment is typically paid on a monthly basis.

Tolling agreements can have a financial fuel index or a physical delivered fuel clause. The former allows simplified accounting and administration of the contract, whereas the latter may involve acquisition, delivery logistics and nomination of fuel to the generator associated with the contract. Additional terms in a tolling agreement may include O&M charges, start-up charges, limit on the number of start-ups per year, transmission charges, etc. Further, this type of contract can have other features mentioned for a PPA above, such as unit availability and point of delivery.

Other Market Sources

PPAs and tolling agreements are the two primary market alternatives for mid- and long-term contract electricity today. However, at times opportunities for more structured contracts such as seasonal exchanges and energy or capacity swaps may be available. The advantage of these types of contracts is the ability to monetize any excess capacity or energy resulting from seasonally driven load variations and the ability to target energy purchases to our highest peak periods when it is most needed.

Seasonal exchanges involve the creation of a virtual bank that allows each party to the contract to draw and return energy. In the past, such exchanges were commonly used to take advantage of seasonal, regional diversity (such as summer peaking in California and winter peaking in the PNW). Such seasonal differences are now less pronounced and supplies are less surplus, making seasonal exchanges less economic.

7.4 Natural Gas and Wholesale Electric Market Hedging

For electric utilities, there are two primary energy market exposures that can be hedged: natural gas and wholesale electricity. The former is generally a driver to the latter, since natural gas plants frequently are the marginal resource in regional resource dispatch stacks. To a lesser extent, coal is hedged through long-term purchase agreements and storable fuel oil can be opportunistically purchased during periods of relatively low demand and price. The primary purpose of physical hedging is to assure sufficient supply prior to the need, but it also generally contributes substantially to price stability. By contrast, the sole purpose of financial hedging is to provide price stability.

Natural Gas Hedging

PGE employs a number of physical hedge strategies for natural gas supply:

- PGE layers in contracts of differing durations of up to five years in advance of need for a portion of expected future fueling requirements. As we get closer to our fueling need, purchases are increased to ensure that we have acquired contracts to meet our expected requirements roughly one year in advance. This deliberate layering or time diversification avoids over exposure to a single price and adverse market conditions.
- PGE employs fuel storage as a cost-effective means of providing seasonal reliability and price hedging.
- To improve longer-term price and supply stability, we are also exploring opportunities for gas-in-the-ground reserves, but have not executed any such transactions.

All natural gas hedge transactions are subject to strict corporate governance requirements with regard to credit, collateral, contract limits, transaction authorizations, etc. Physical and financial hedging for natural gas supply is addressed in greater detail in Section 5.3.

Wholesale Electricity Hedging

Spot market electricity can be unusually volatile for the following reasons:

- Unlike most commodities, including natural gas, electricity cannot be stored directly.
- Demand for electricity is in real time.
- Generally, there is no real time consumer price feedback for electricity demand.
- Electricity is particularly vulnerable to shocks, such as extreme weather, generating plant outages, and transmission congestion.
- Natural-gas fired plants tend to be the marginal resource much of the time, where the gas commodity is the dominant cost component and is itself volatile.

The factors that contribute to spot electricity volatility can also make it difficult to hedge. PGE thus believes that the most effective supply and price hedge is to reduce our reliance on spot and short-term purchases of market electricity. PGE's goal in this IRP is to acquire sufficient energy resources, with a diversity of technologies and fuels, to be essentially flat to our annual average load by 2015 and each year thereafter. We say "essentially" because we do recommend continuing to supply up to 100 MWa in any given year from short-term markets as a hedge against load variability. Such energy resources can be a combination of energy efficiency, owned "baseload" generating resources such as wind and natural gas, PPAs, and forward term purchases of one year or longer duration, and fixed price contracts to buy and sell electricity seasonally.

For periods of higher winter and summer demand, where our energy resources are insufficient, we recommend a combination of demand-side and supply-side measures to meet the one-hour annual peak. Such measures include energy efficiency, demand response, dispatchable standby generation, flexible natural gas generation, and seasonal contracts to buy electricity.

In addition, as a mid-term strategy, PGE enters into financial fixed-for-floating wholesale electricity swaps of durations up to five years to balance our portfolio to load and further reduce exposure to wholesale price volatility. As with natural gas, such hedge transactions are also subject to strict corporate governance requirements with regard to credit, collateral, contract limits, transaction authorizations, etc.

Cost and Limitations of Hedging

Hedging is basically a form of insurance to reduce the risk of physical supply disruption or to provide improved price stability. As such, over the long run, this risk reduction comes via a somewhat higher cost or premium. The premium is composed primarily of transaction costs and a liquidity premium, which typically increases with duration, for locking in a fixed price. Financial price hedging can reduce the severity of unwanted price outcomes, but it does so at the cost of also foregoing potentially favorable price changes.

The Role of Hedging in the IRP

Not surprisingly, markets for natural gas and spot electricity (both physical and financial) become less robust and less liquid as the duration of a transaction increases. Ten years is currently the longest transaction term available, however, liquidity diminishes rapidly once terms extend beyond two years from the current point. Of the two, financial hedging instruments are typically available in longer durations than their physical counterparts. Hedging is thus primarily an operational and tactical tool. By contrast, the IRP is primarily a strategic planning tool to aid in long-term resource portfolio decisions. When making an IRP resource decision with up to a 30 year life, hedging tactics play a less prominent role in the decision. For instance, we cannot hedge against a future in which natural gas prices are substantially higher over the long-run than what we had assumed at the time of the resource acquisition decision. Thus, in this example, hedging can reduce the variability of prices, but not the overall level of the prices themselves. For this reason, we do not attempt to employ market hedging instruments in our IRP analysis.

Consideration of hedging reinforces the importance of developing a portfolio that limits exposure to events and price movements that can cause large and adverse changes in value. Hedging is a set of strategies employed to reduce exposure to adverse outcomes, such as price movements. One of the most common forms of hedging with respect to portfolio construction and management is asset diversification. From the stand-point of an electric utility, this can be accomplished by increasing the number and type of resources (both technology and fuel types) used to serve customer demand. By diversifying its portfolio of energy and capacity resources, a utility is less likely to experience large, adverse changes in the cost to produce and deliver electricity to its customers over time.

The Use of Hedging in PGE Modeling

PGE's primary portfolio cost modeling tool, Aurora, is an hourly production cost model that dispatches resources and establishes electricity prices based on marginal costs. Since no long-term markets or forecasts exist for the price or availability of market hedging instruments for electricity or fuels, it is not possible to include these in the long-term production cost model. However, PGE's IRP modeling does explicitly consider the value of hedging with physical resources through varying portfolio composition and examining relative cost and reliability performance. This is accomplished primarily in two ways:

- First, by constructing incremental portfolios that are "pure plays", and deliberately relying on relatively high levels of a single resource type, and then comparing its performance on cost and supply (reliability) risk against portfolios that are more diversified. The diversified portfolios are intrinsically better hedged by reducing exposure to single risks. By constructing portfolios with divergent resource compositions and assessing their price and reliability performance we gain insights into the value of hedging through diversification.

- The second way that we are able to test the value of hedging is by constructing a "market portfolio" that relies heavily on short-term electricity purchases. The cost variability and supply reliability of this portfolio can then be evaluated against portfolios that have long-term assets that "fix" a portion of the price of electricity produced. In this way an electric generator (wind farm, gas plant, etc.) or other long term resource can be viewed as an electric market hedge. The degree of hedge (or risk mitigation) is a function of the proportion of the cost of electricity from the resource that is fixed (and thus not exposed to market price changes), versus the proportion of total cost that is variable and influenced by energy market prices. For example, a geothermal plant has a high proportion of fixed costs (investment and fixed operating costs) and virtually no variable costs that are directly influenced by electricity and fuel prices, and thus provides considerable hedge value against energy market price changes. By contrast, a significant portion of the total electricity cost from a natural gas plant is determined by variable fuel costs, and thus the gas plant provides only a partial mitigation against energy market price risk. The hedge value of acquiring a long-term physical resource can be assessed through comparing the price variability and supply reliability performance of the incremental portfolio dominated by short-term electric market purchases against that of the portfolios which include more long-term resources.

7.5 Distributed Generation Options

Benefits of Distributed Generation

Within PGE's service area, PGE and its customers currently engage in three main types of distributed generation (DG):

1. Foremost in terms of MW capability is our Dispatchable Standby Generation (DSG) program, which is targeted to add 67 MW by 2013. PGE is a market leader in development of DSG. Because DSG provides essential peaking capability, it is a capacity resource and does not confer most of the benefits described below.

2. PGE assumes a limited amount of Combined Heat Power (CHP) within our service area.

3. PGE is engaged in encouraging and supporting distributed solar PV for commercial customers, primarily using rooftop applications. PGE has also been a market leader in pioneering a business model that enables the utility to develop and own these resources.

PGE models all three of these types of DG in conjunction with central-station generation in most of our portfolios, including all of our top-performing portfolios. Our proposed Action Plan recommends ongoing acquisition of DG. It is difficult to know how much cost-effective DG may be available, particularly with solar PV since it is an emerging technology and market with an uncertain maturation curve. We assume that 5 MWa of CHP will be acquired and between 4 and 12 MWa of distributed solar PV will be added.

Distributed generation has well-known advantages over central station generation: it provides enhanced localized reliability; it is more efficient because it avoids line losses; for customers who have installed distributed generation, it can provide a hedge against changing power costs; and it can help defer transmission and distribution (T&D) investment.

The benefits are difficult to quantify for IRP purposes. The first is a reliability benefit rather than an economic benefit. Avoided line losses are incorporated into the economics of the portfolio analysis. The third is a customer-specific benefit that does not accrue to non-participant customers. The last benefit, deferral of T&D investments, is currently not significant enough to be quantifiable. That is, DG at this time is too distributed to make a practical difference in how substations are maintained and upgraded. Furthermore, conservation and energy efficiency (EE) also confer similar benefits and in aggregate currently tend to be larger amounts than DG.

Dispatchable Standby Generation (DSG)

PGE's DSG program uses diesel-fueled back-up generators at commercial and industrial customer sites to supply capacity for PGE's portfolio and enhanced reliability for the host customer. Customers acquire the generators to provide supply reliability in the event that power from the grid is disrupted, for instance, in a severe ice or wind storm. Through communications and technology enhancements, PGE can remotely start the generators to both displace the generator owner's load and supply excess power to the grid. This program increases customer satisfaction and provides PGE with an economic source of capacity that is distributed within our service territory, thereby reducing costs and risks associated with transmission, fuel supply and large single-shaft exposure. The operation of the back-up generators is limited by operating permit restrictions to 400 hours per year. However, they provide benefit as standby operating reserves for PGE during times of the year when they are not dispatched to meet peak energy needs. To our knowledge, no other electric utility in the U.S. has the capability to dispatch from the utility's system control center this level of energy from customer-owned generation.

In June 2006, we cumulatively brought 30 MW of DSG on-line, and as of year-end 2008, PGE had 53 MW of DSG on-line. Our 2009 IRP Capacity Action Plan assumes that we can achieve 67 MW (including 15 MW from the 2007 IRP) of additional DSG by 2013, for a total of 120 MW.

Customer-Sited Combined Heat and Power (CHP)

CHP is a proven application that simultaneously produces electric power and useful thermal energy from a single fuel source. The resulting waste heat or steam may be used for industrial processes or heating and heat-activated cooling, such as absorption chillers. CHP systems are scalable and, under the right conditions, can be a valuable resource to utilities and their customers.

In Oregon, the greatest technical potential for utility-scale CHP projects exists in the industrial sector, specifically the paper and forest products industries. Targeted applications in the commercial/institutional sector, such as colleges and universities, hospitals and healthcare, also appear viable.

While the technical potential remains promising, the actual market potential is contingent on several factors. CHP economics continue to be challenging in the Pacific Northwest, with the region's moderate climate conditions and relatively low overall electricity prices and spark spreads. Customer preferred payback requirements of two to five years also present a significant challenge. To maximize efficiencies and economics, CHP must be used in applications where electrical consumption and onsite thermal loads are relatively consistent. This balance is difficult for customers to achieve, leading to a relatively small pool of economically viable CHP candidates.

Distributed Solar[69]

Solar power diversifies PGE's renewable resource mix and is a good complement to wind. Peak generation for solar is more predictable and more available than for wind during critical peak summer load hours. In addition, there are no transmission constraints for distributed solar projects.

For the last two years, PGE has explored various business models that enable PGE ownership of distributed solar generating resources. As mentioned in Chapter 2, these efforts resulted in two customer-sited solar projects in our service territory using the third party LLC ownership model, the 104 kW ODOT solar highway demonstration project and the 1.1 MW ProLogis thin film installation.

[69] Distributed Solar refers to solar electric power generation sited at a customer's premise. It can be either retail, e.g. on the customer's side of the electricity meter, providing electric energy primarily to offset customer load on that site, or wholesale, e.g. connected directly to the distribution network providing wholesale capacity and energy to an electric utility for use by multiple customers; this section refers to the latter.

While the high capital costs per watt for solar are significantly reduced by federal and state tax credits, PGE's limited tax appetite and the normalization rules required under Section 48 of the IRS Code currently make direct utility investment in such projects uneconomic for PGE customers. By partnering with investors who can fully utilize the tax credits using the third party LLC ownership model, we can develop cost effective solar projects that both fulfill PGE's 2015 RPS requirement and the utility-scale solar requirement under HB 3039 and also respond to growing demand from our customers to site solar installations on their rooftops and other property. As such, we plan to develop an additional 15 MW (almost 2 MWa) of customer-sited distributed solar generation by 2012.

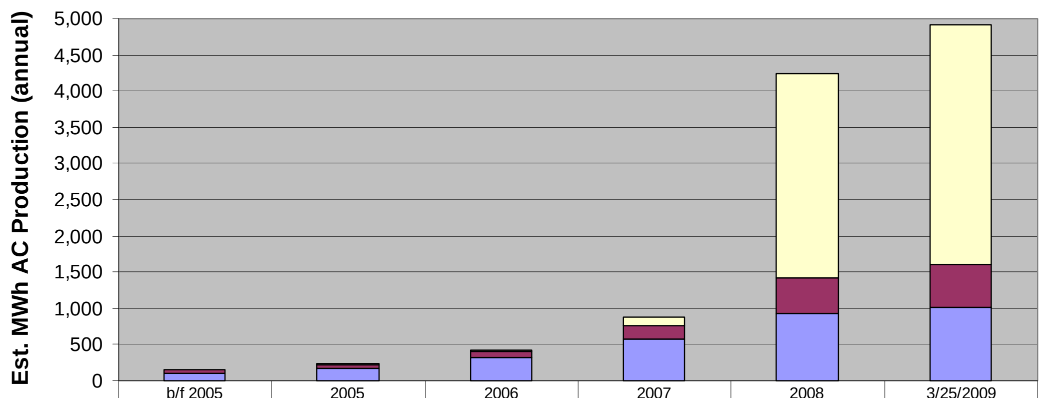
Net Metering

Net metering provides customers with an incentive to install renewable generation. Under this program, customers with renewable power sources may offset part of or their entire load. Generation size is currently capped at 2 MW. Participating customers' energy bills are reduced by the amount of power they generate at their current rate schedule.

Under our net metering program, the customer handles all installation arrangements and its system must meet all applicable codes. We provide a bidirectional meter to allow measurement of energy flowing both to and from the customer's site. We also provide an inspection at the time of the net meter installation. The program is marketed through the PGE website and various publications. Customers installing renewable energy systems for net metering can receive incentives from the ETO, as well as state and federal tax credits.

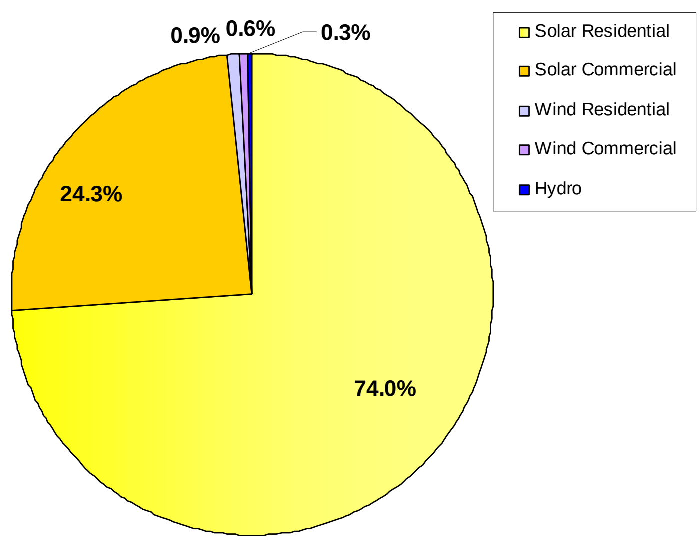
Although net metering is currently used by a relatively small fraction of our customers, the 2 MW cap combined with an increase in the Business Energy Tax Credit (BETC) implemented in 2007 and OPUC streamlined grid interconnection rules (currently under development) have increased participation, especially in the green-conscious commercial sector. In March 2009, renewable energy systems owned by PGE's residential customers exceeded 1 MW of grid-connected capacity. The net metering program has 5.54 MW of capacity as of early August 2009. Of the 436 net metering customers, all but 11 are solar PV systems. Of the eleven non-solar net metering sites, one is a fuel cell, two are hydro units, and eight are wind systems. See Figure 7-1 and Figure 7-2 below.

Figure 7-1: Cumulative PGE Net Metering Capacity



	b/f 2005	2005	2006	2007	2008	3/25/2009
Large Commercial	0.0	12.5	12.5	112.0	2806.9	3301.8
Small Commercial	53.3	65.3	85.7	194.6	494.6	597.0
Residential	103.3	162.3	318.6	571.4	931.0	1013.6

Figure 7-2: Net Metering Customers by Generation Type



7.6 Supply-side Resource Cost Summary

The technological advances in electricity generation in the past 20 years have been impressive and have led to the increasing market penetration of natural gas CCCT plants and wind turbines. Going forward, clean coal, solar thermal, in-stream hydrokinetics and modular-nuclear technologies could play a role in meeting future energy needs. For this IRP, however, we included in our portfolio analysis only those supply-side technology alternatives that are expected to become commercially available during our Action Plan horizon. These are:

- Gas plants: SCCTs, CCCTs and Reciprocating Engines
- Next-generation nuclear (out of state)
- IGCC
- Utility-scale renewable resources including: biomass, geothermal, solar PV, wave and wind energy
- Customer-sited CHP and DSG

Expected Cost per kW

For new WECC resources added in AURORAxmp, we applied the construction and operating parameters and capital and operating costs shown in Table 7-3. Variable O&M includes integration costs for wind, solar and wave. Capital costs include Climate Trust offset payments (see Chapter 6 for more information) and owner's costs[70] for coal and gas plants. For resources located outside of BPA Control Area, capital cost includes the cost of new transmission builds to BPA's system.

[70] Owner's cost represents all those costs that are not typically included in the overnight capital cost estimate. These include expenses for oversight and management during construction, as well as project development costs, access road, water supply, etc. In our estimates, owner's cost does not include interest during construction and fuel supply, which are added as separate components.

Table 7-3: New WECC Resource Costs (2009$)

IRP Modeling Assumptions - 2009$	Typical Nameplate Size MW	Earliest date Available years	Expected Availability %	Overnight Capital Cost /kW [2,3]	Fixed O&M $/kW-yr [2]	Variable O&M $/MWh [4]	Degraded Heat Rate BTU/kWh
WECC Options for Resource Expansion							
Coal - Super Critical Pulverized	850	2016	85%	$ 5,126	$ 39.89	$ 2.61	9,320
Coal - IGCC Sequestration Ready	569	2016	79%	$ 6,504	$ 57.81	$ 6.30	9,152
Wind Plant [/5]	150	2012	31%	$ 2,283	$ 26.49	$ 11.83	N/A
Wind Plant Wyoming	150	2012	37%	$ 4,110	$ 26.49	$ 11.83	N/A
Natural Gas CCCT - Greenfield (G Class)	450	2015	92%	$ 1,306	$ 11.82	$ 2.65	7,038
SCCT - LMS100	200	2013	96%	$ 1,100	$ 3.00	$ 3.66	9,165
Reciprocating Engines	195	2013	98%	$ 1,410	$ 3.28	$ 8.98	8,638
Nuclear	1100	2019	92%	$ 6,701	$ 108.51	$ 1.30	10,400
Combined Heat & Power	2	2012	98%	$ 1,410	$ 3.28	$ 8.98	5,242
Generic Geothermal - Flash	30	2011	86%	$ 4,719	$ -	$ 28.58	N/A
Biomass	20	2011	86%	$ 3,387	$ 80.64	$ 7.77	12,515
Distributed Solar	6	2010	11%	$ 6,280	$ 7.13	$ 6.36	N/A
Central Station Solar	20	2010	17%	$ 7,100	$ 7.13	$ 6.36	N/A
Wave	30	2012	31%	$ 3,642	$ -	$ 29.96	N/A

Notes:
[1] Expected Availability is expected capacity factor for wind, solar and wave
[2] Overnight Capital and O&M include transmission for Coal, Nuclear, and Wyoming Wind
[3] Capital also include OEFSC payments to Climate Trust of Oregon for coal and gas.
[4] Variable O&M includes integration costs for wind, solar and wave
[5] Expected capacity factor for PNW wind built beginning in 2016 is 29%
Fixed fuel costs not reported in the table.

Table 7-4 shows cost assumptions from the 2009 AEO[71], the NWPCC 6th Plan[72], and EPRI[73] compared to PGE's assumptions. PGE's assumptions in Table 7-4 form the basis of the overnight capital costs in Table 7-3; PGE costs in Table 7-4 do not include transmission or OEFSC payments. PGE's costs are generally close to the NWPCC, higher than the AEO, and comparable to EPRI. The AEO and NWPCC costs are for a 2008 price year. The EPRI costs are for 2007, with the exception of wave, which is from 2005. EPRI costs do not include owner's costs, estimated to be an additional 5% to 7%. PGE's costs reflect the most current data available, a 2009 price year. Other significant, technology-specific differences are noted below:

- EPRI CCCT costs are for a GE 7H plant; PGE costs are for a CCCT-G plant.
- NWPCC central-station solar costs are for a single-axis tracking PV system; PGE's central station solar cost represents a fixed ground mount system. Tracking systems have higher capital costs, but also higher efficiency.

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[71] Source: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/tbl8.2.pdf

[72] Source: http://www.nwcouncil.org/energy/grac/Default.htm

[73] Source: EPRI Presentation at PGE April 10, 2009 Public Meeting

- EPRI wave costs from 2005 price year; more recent data was not available.

Cost assumptions tend to be site- and risk-specific, i.e., they depend on contingencies embedded in capital costs estimates according to perceived development and construction risks of the estimating entity. A comparison of average estimates can only be used for indicative order-of-magnitude validation.

Table 7-4: Overnight Capital Cost Comparison (2009$/kW)

Overnight Capital 2009$	PGE	2009 AEO	NWPCC 6th Plan	EPRI
Coal - Super Critical	$ 2,875	$ 2,137	$ 3,703	$ 2,544
Coal - IGCC Sequestration Ready	$ 4,489	$ 2,469	$ 3,809	$ 3,011
Wind Plant	$ 2,283	$ 1,997	$ 2,222	$ 2,072
CCCT - Greenfield with Duct Firing	$ 1,284	$ 984	$ 1,317	$ 851
SCCT - LMS100	$ 1,091	NA	NA	NA
Reciprocating Engines	$ 1,403	NA	NA	NA
Nuclear	$ 5,605	$ 3,445	$ 5,819	$ 4,133
Generic Geothermal	$ 4,719	$ 1,777	$ 4,444	NA
Biomass	$ 3,387	$ 3,910	$ 4,232	$ 3,359
Solar Distributed	$ 6,280	NA	NA	NA
CS Solar	$ 7,100	$ 6,270	$ 9,523	NA
Wave	$ 3,642	NA	NA	$ 2,815

Potential Future Technology and Cost Advances

Advances in technology are usually characterized by a combination of a decline in real cost per kW, due to learning effects and economies of scale, and an increase in conversion efficiency (i.e.,. a better heat rate) for thermal plants (or, alternatively, increases in wind energy capture and conversion efficiency for renewable resources) due to actual technology improvements. We projected anticipated efficiency and/or cost advances based on discussions with CT vendors and power plant developers, as well as a review of generation efficiency trends over the last five years.

Since supply-demand drivers for manufacturing inputs (e.g., steel, oil) and construction costs have been dynamic, we have relied on market evidence of a sustained and material ongoing increase in capital costs for most technologies in 2008. Due to the downturn in the world economy, we are starting to see a fall-off of energy resource commodity pricing. However, the tremendous injection of federal stimulus dollars into U.S. infrastructure and renewable energy projects may increase demand enough to offset deflation pressure resulting from decreased global demand for capital projects and raw materials in other countries. For this reason, we do not project any cost decline per kW for our primary supply-side alternatives.

Simple-cycle technology is both mature and, when fueled with natural gas, has negligible new environmental requirements going forward. Also, while for CCCTs we expect further technological improvements and more mechanical complexity (i.e., from G technology to H technology, etc.), we anticipate no major technological break-through implying higher costs for SCCTs[74].

For IGCC technology, we assume a modest decrease in costs of .5% for 2017 to 2019. The decrease will result from a combination of CT improvements, integration of IGCC system construction and improvements in syngas cleanup.

Estimating the impact of learning effects on the cost of wind turbines is particularly challenging. For modeling purposes, we assume that we have already reached the peak of the learning curve and that any future cost decreases per kW due to improved technology will be offset by increasing global demand for wind turbines, along with the offsetting effect of a possible reduction of tax-driven benefits over time. For this reason, we do not model any capital cost decline for wind projects.

Solar PV capital costs are declining fairly steadily due to decreases in raw silicon costs, increased panel production, efficiency improvements and innovation. We modeled a 12% reduction in capital cost per year for 2013 to 2015 for solar PV[75].

Heat Rate Decline

We used OEM estimates of decreasing heat rates to measure foreseeable improvement in efficiency for thermal plants. Decreasing heat rates for the generic CCCT and IGCC plants mean that plant efficiencies for these technologies are improving. However, expected improvements are modest.

We assumed that IGCC heat rates will stay at current levels, about 8,700 Btu/kWh until 2012, per our Black & Veatch study. We modeled efficiency improvements starting in 2013, with the next generation of plants. We assumed improved efficiency in the gasification process of 10% vs. the current level (following the advice of our consultant) and an improvement in combustion efficiency similar to that assumed for the CCCT. This results in a decrease of 933 Btu/kWh by 2020.

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[74] The new SCCTs and reciprocating engines are currently cost effective. Future improvements will likely be in the area of increased flexibility, which should have a minor impact on increasing capital costs. New, major technological breakthroughs for SCCTs (e.g., more complex equipment, exotic metals) implying higher capital costs are not foreseen at this point.

[75] Source - "Solar Power for Cheap and Cloudy Seattle?" – Presentation by Jim Harding for the Solar Electric Power Association, Seattle, 7/08; slide 15.

SCCT plants are not assumed to have heat rate improvements because of the maturity of the technology and unlikely improvement in the combustion process. Table 7-5 shows PGE's assumed heat rates and capital costs for those technologies assumed to have declining capital costs.

Table 7-5: Projected Heat Rates - PGE Estimate (BTU/kWh)

	CCCT G Class	LMS 100	Reciprocating Engines	Supercritical Pulverized Coal	IGCC	Next Generation Nuclear
2009	6,732	9,165	8,638	9,320	9,152	10,400
2010	6,732	9,165	8,638	9,320	9,152	10,400
2011	6,732	9,165	8,638	9,320	9,152	10,400
2012	6,732	9,165	8,638	9,320	9,152	10,400
2013	6,732	9,165	8,638	9,320	9,152	10,400
2014	6,732	9,165	8,638	9,320	9,152	10,400
2015	6,732	9,165	8,638	9,320	9,152	10,400
2016	6,732	9,165	8,638	9,320	9,152	10,400
2017	6,732	9,165	8,638	9,320	9,152	10,400
2018	6,732	9,165	8,638	9,320	9,152	10,400
2019	6,732	9,165	8,638	9,320	9,152	10,400
2020	6,732	9,073	8,552	9,320	9,152	10,400
2021	6,732	9,073	8,552	9,134	9,152	10,400
2022	6,665	9,073	8,552	9,134	9,152	10,400
2023	6,665	9,073	8,552	9,134	9,060	10,400
2024	6,665	9,073	8,552	9,134	9,060	10,400
2025	6,665	9,073	8,552	9,134	9,060	10,400
2026	6,665	9,073	8,552	8,951	9,060	10,400
2027	6,665	8,983	8,466	8,951	9,060	10,400
2028	6,665	8,983	8,466	8,951	9,060	10,400
2029	6,598	8,983	8,466	8,951	9,060	10,400
2030	6,598	8,983	8,466	8,951	8,970	10,400

7.7 New Resource Real Levelized Costs

Fuel, fuel transportation, emissions and transmission costs were added to the capital and operating costs summarized in Table 7-3 to derive estimated real levelized, fully allocated energy costs for new generating resources available to PGE. (Resources used primarily for flexibility and capacity, such as simple-cyle CTs , are considered separately, since they are not intended for baseload energy.) Capital costs include the cost of new transmission to BPA's system (for coal, nuclear and Wyoming wind), depreciation, property tax, return on capital, income tax and similar costs for ongoing capital additions (see Table 10-2 for a summary of our financial assumptions). O&M rates costs include transmission wheeling and integration.

To calculate a real levelized cost of energy, a traditional life-cycle revenue requirements model was used, in conjunction with our production cost model AURORAxmp. We also applied PGE's incremental cost of capital and widely accepted assumptions about plant book life and tax depreciation in making the calculations. The reference case total levelized costs of energy for our primary supply-side resource alternatives are shown in Figure 7-3.

Figure 7-3: Real Levelized Costs for New PGE Resources

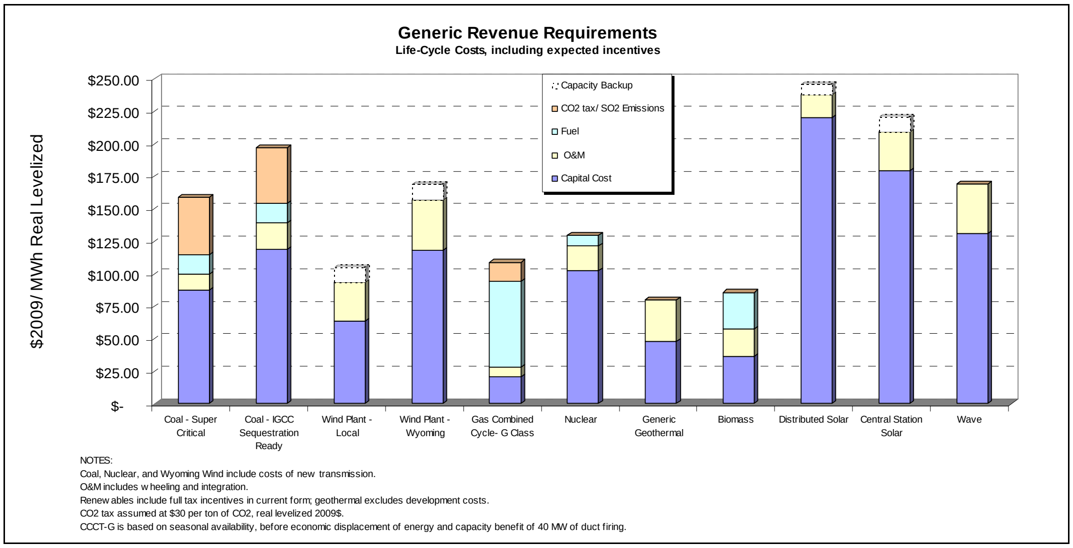


Figure 7-3 represents the cost of energy produced per MWh. For intermittent solar and wind resources, we add the capital costs of a SCCT to make solar and wind projects equivalent to a CCCT for the same nominal annual energy output. In figure 7-3, all of the resources, except the CCCT, are must-run or have low variable costs. Thus, the CCCT is the only resource which is typically displaced by the market, making a cost per kWh comparison to other resources more challenging. For this resource cost comparison, we have included the cost of the CCCT based on its annual availability before consideration of the benefits of economic displacement.

While the stand-alone costs for a given resource type are instructive, the resources become building blocks within portfolio analysis where economic dispatch and risk analysis are added. Further, our portfolio analysis calibrates all candidate portfolios to materially similar capacity and reliability levels. The only exception to this approach is the Market portfolio, which evaluates the cost and risk on not adding long-term or physical resources.

Sources and Assumptions for PGE Real Levelized Costs

We applied the following key assumptions in estimating the reference case resource costs shown in Table 7-3 and Figure 7-3:

BPA wheeling rates are assumed to grow annually at inflation, with real growth of 3% in 2013 and 2016 assumed as a result of Network Open Seasons.

Energy Trust incentives are determined on a project basis and as such, we have included no ETO incentives in our real levelized cost of energy.

Wind

- We included two categories of wind costs - Pacific Northwest, with a capacity factor of 33%, and Wyoming, with a capacity factor of 37%. The Pacific Northwest capacity factor declines to 31% in 2015 and to 29% in 2017 and thereafter, as we assume that fewer high-capacity factor sites will be available in the Pacific Northwest.
- Capital cost estimates are reflective of Phase II of PGE's Biglow Canyon project.
- Ongoing Production Tax Credit (PTC) renewal at current levels and full BETC (total of approximately $21/MWh real levelized in 2009$ for both PTC and BETC).
- Integration costs of $11.83/ MWh in 2009$, escalating at inflation, included in O&M.

Solar

- We included two categories of solar, distributed solar located in PGE's service territory and central station ground mount located in North Central Oregon, both based on thin-film applications.
- Costs are based on our assessment of potential Northwest projects; actual solar project costs may vary significantly depending on location, type of technology and whether or not a tracking system is used.
- ITC at current levels and full BETC (total for both ITC and BETC of approximately $371/MWh for central station solar and $457/MWh for distributed solar, real levelized in 2009$).
- Integration costs of $6.35/ MWh in 2009$, escalating at inflation, included in O&M.

Geothermal

- Costs are indicative of the high range of greenfield development costs from the 2006 Western Governors' Association geothermal task force report, escalated to 2009$.
- Ongoing PTC renewal at current levels and full BETC (approximately $26/MWh real levelized in $2009 for both PTC and BETC).
- Our costs for geothermal do not include exploratory drilling costs (dry-hole risk).

Biomass

- Costs are based on our assessment of potential Northwest projects; actual biomass project costs may vary significantly depending on fuel type and availability, as well as particular site and host characteristics.
- Typically a combined heat and power configuration is required to achieve competitive economics.
- PTC at current levels and full BETC, approximately $16/MWh real levelized in 2009$ (representing 50% of the PTC available for wind and geothermal).

Wave

- We used capital and operating costs based on our assessment of potential Northwest projects.
- PTC at current levels and full BETC, approximately $20/MWh, real levelized in 2009$ (representing 50% of the PTC available for wind and geothermal).
- Integration costs of $6.35/ MWh in 2009$, escalating at inflation, included in O&M.

High-Efficiency Natural Gas

- We used capital and operating costs based on market data from international combustion turbine vendors and EPC contractors.
- We used a long-term real levelized fuel forecast of $7.24/ MMBtu in 2009$ (see Chapter 5 for a discussion of PGE's reference case gas price).

- Costs include a CO_2 offset payment to the Climate Trust of approximately \$22/kW, based on current requirements (see Chapter 6).

- We incorporate the reference case carbon cost of \$30 real levelized in 2009\$ per short ton of CO_2, starting in 2013 (see Chapter 6).

Natural Gas Capacity Resources

- We used capital and operating costs from Black & Veatch for the GE LMS100 SCCT and Wartsila rapid-start reciprocating engine (recips).

- Costs include CO_2 an offset payment to the Climate Trust of approximately \$8/kW for the LMS100 and \$7/kW for the Wartsila recips, based on current OEFSC requirements.

- We incorporate the reference case carbon cost of \$30 real levelized in \$2009 per short ton of CO_2, starting in 2013 (see Chapter 6).

Combined Heat and Power

- We used capital and operating costs based on the cost of a reciprocating engine with heat recovery.

- Costs assume a small (2 MW) commercial/ institutional sector project.

- Costs include CO_2 offset payment to the Climate Trust of approximately \$7/kW, based on current OEFSC requirements.

- Full BETC (\$8/MWh real levelized in 2009\$)

- A reference case carbon cost using of \$30 per short ton of CO_2 real levelized in 2009\$, starting in 2013 (see Chapter 6)

Nuclear

- We used capital and operating costs based on a survey of industry publications and the NWPCC 6th Plan.

IGCC

- Cost data for a new coal plant at the Boardman site comes from the Black & Veatch study commissioned by PGE and updated in late 2008.

- Owner's cost[76] is 20-30% of the total capital cost of the plant, based on PGE's estimate of the Black & Veatch study.

- Cost of additional rail build-out is not included.

- For IGCC, we assumed no federal investment tax credit.

- The capital cost includes a carbon offset of $185/kW for IGCC paid to the Climate Trust, estimated per OEFSC rules.

- Due to the uncertainty of sequestration cost and feasibility, our reference case IGCC plant cost is sequestration ready (as defined in Section 7.2 above), but does not include sequestration.

- A reference case carbon cost using of $30 per short ton of CO_2 real levelized in 2009$, starting in 2013 (see Chapter 6).

7.8 Emerging Technologies

We describe below a number of emerging or evolving technologies which, although not viable to meet our load in the current planning cycle, may present significant potential sources of new supply for future resource plans.

Solar Thermal

Solar thermal may be the largest potential renewable energy source worldwide. The majority of central station solar projects underway are concentrating solar power technologies (CSP). CSP plants are utility-scale generators that use mirrors and/or lenses to concentrate the sun's energy to drive turbines, engines, or high-efficiency photovoltaic (PV) cells. Primary CSP technologies include parabolic troughs, dish-Stirling engine systems, power towers and concentrating PV systems. Parabolic trough plants from 30 to 80 MW in size have been in commercial operation in California since 1985. Dish-Stirling systems are entering commercial production. However, CSP systems currently have high up-front capital costs compared to traditional fossil-fired plants and other commercially available renewable resources such as wind.

Some CSP technologies (tower and trough) can be dispatchable by using thermal storage (molten salts) to deliver firm power during peak demand periods. Solar

[76] Owner's Cost includes capital costs such as project development, legal expenses, owner's project management/engineering support, and initial spare parts.

thermal could also be integrated into existing thermal plants, e.g., using solar Btu to preheat feedwater.

Due to reduced cloud cover, projects east of the Cascades (with transmission to our load) are a more economic alternative for central station solar projects. Locations such as Arizona and Southern California, where insolation is higher, summer demand is greater, and load is more costly to serve are leading the way in the development of next-generation solar technologies. PGE will continue to monitor developments in central station CSP applications.

While CSP technology has been commercially deployed in the western U.S. and is providing power to utilities, we have not modeled CSP in this IRP as a primary resource option for two reasons: 1) cost and suitability to this region (higher solar insolation is more favorable to project economics in the desert Southwest), and 2) distributed solar has a distinct economic advantage in the Northwest due to the incentives available at the state level.

High-Altitude Wind Generation

Flying electric wind turbines are proposed to harness kinetic energy in the powerful, persistent high-altitude winds. Average power density can be as high as 20 kW/m^2 in an approximately 1000-km-wide band around latitude 30° in both the hemispheres of the earth. At 15,000 to 30,000 ft altitude, tethered rotorcraft, with four or more rotors mounted on each unit, could give individual rated outputs of up to 4MW. These aircraft (autocopters) would be remote controlled and could be flown in arrays, making them a large-scale source of near baseload wind power. A240kW craft has been designed to demonstrate the concept at altitude. It is possible that large-scale units, if deployed on a commercial scale, would make stable priced electricity available for grid supply, for hydrogen production or for hydro storage from large-scale generating facilities.

In-stream Hydrokinetic

In-stream hydrokinetic energy is an important energy source. River In-Stream Energy Conversion (RISEC) is a term used to describe the conversion of the kinetic energy of the unimpeded moving water in a river (or man-made canal) into electrical energy. Hydrokinetic flow power provides efficient, reliable, environmentally friendly electrical energy

Hydrokinetic Energy Generators are usually free-standing mechanical devices that are rotated by the flow of passing water. These devices can be open, three blade, horizontal axis rotors attached to a base; shrouded, multi-blade, horizontal axis turbine rotors, or an open, vertical axis, multi-cup rotor submerged in a river or canal.

Modular-Nuclear

In addition to the approved advanced nuclear designs noted above, other companies are taking a different approach to generating nuclear energy. These design concepts involve smaller, modular reactor/steam generators that are built in a factory and shipped to the project site as a complete unit. These modules could be deployed as single units at multiple sites (distributed) or allow for a single site to be built out in phases over time to more closely match load growth. The reactor modules would be paired with conventional steam turbines for generation output. The compact size of this design concept may allow greater flexibility in site selection. We will continue to monitor developments in modular nuclear technology for future resource plans.

Hybrid Technologies

Hybrid technologies such as compressed air energy storage (CAES) may offer potential to address the intermittent nature of wind. CAES stores compressed air underground. The compressed air is used in the combustion stage of an ordinary CCCT, where compression of air requires almost two-thirds of the energy from the combustion. The effect is to dramatically increase the efficiency of the CCCT by using less gas to produce more electricity. Such a facility has high capital costs and efficiency losses in pumping and compression. It also requires a site that has a gas pipeline, transmission, wind, water[77] and suitable underground storage.

A similar hybrid technology involves using wind energy to create and store hydrogen, which is then burned in a CT or reciprocating engine. A variation to this approach is to create hydrogen and nitrogen using off-peak hydro and wind energy. The hydrogen and nitrogen would then be converted to ammonia and stored. The ammonia would in turn be burned in a reciprocating engine during peak hours or when the grid has additional capacity demands. This could potentially convert intermittent wind into a dispatchable resource, but current estimates project high capital costs and reduced efficiency.

[77] The site may not need a lot of water if the CT uses a dry cooling system.

8. Transmission

PGE's service territory is a relatively compact area located primarily in the Willamette Valley and occupying a very small portion of the Pacific Northwest. Most of our existing resources are located outside of our service territory and generally within the Pacific Northwest region. As such, we depend heavily on BPA to provide transmission service to deliver these resources to our customers.

As highlighted in Chapter 2, these resources include hydro in the Mid-Columbia area, thermal and renewable generation resources east of the Cascades and as far away as Montana, and thermal generation between Portland and the Puget Sound area. In addition, we have long-term contracts delivered through the Southern Interties and we acquire additional energy supply from the Mid-Columbia market hub.

As discussed in Chapter 7, the majority of our options for new supply-side resources will require access to long-distance transmission, either from the BPA system or our own transmission assets. In either case, new transmission assets will need to be built to enable us to deliver energy from new resources to our customers. We are examining BPA and self-build options for meeting our transmission needs within the region and assuring the system reliability and capacity that our customers require. We also consider third-party transmission supply for potential resources outside the region.

In this chapter, we examine the implications of transmission constraints on system reliability, our ability to meet the state Renewable Energy Standard and our ability to meet our customers' power needs. We describe how we work cooperatively with our regional counterparts to coordinate regional transmission plans. We also present options for developing our own transmission assets to meet these needs, and the policy considerations that affect these decisions.

Chapter Highlights

- The transmission system in the Northwest is becoming increasingly constrained.
- PGE is heavily reliant on BPA transmission to deliver power to our customers.
- Potential and existing renewable and non-renewable resources needed to meet RPS and energy demand requirements are remotely located and need new transmission in order to deliver the power to our customers.
- We compare the economic benefit and cost of Cascade Crossing Transmission Project versus increased utilization of BPA transmission service.
- We also discuss the reliability benefits of Cascade Crossing.
- PGE proposes construction of Cascade Crossing Transmission Project.

8.1 Transmission Assessment

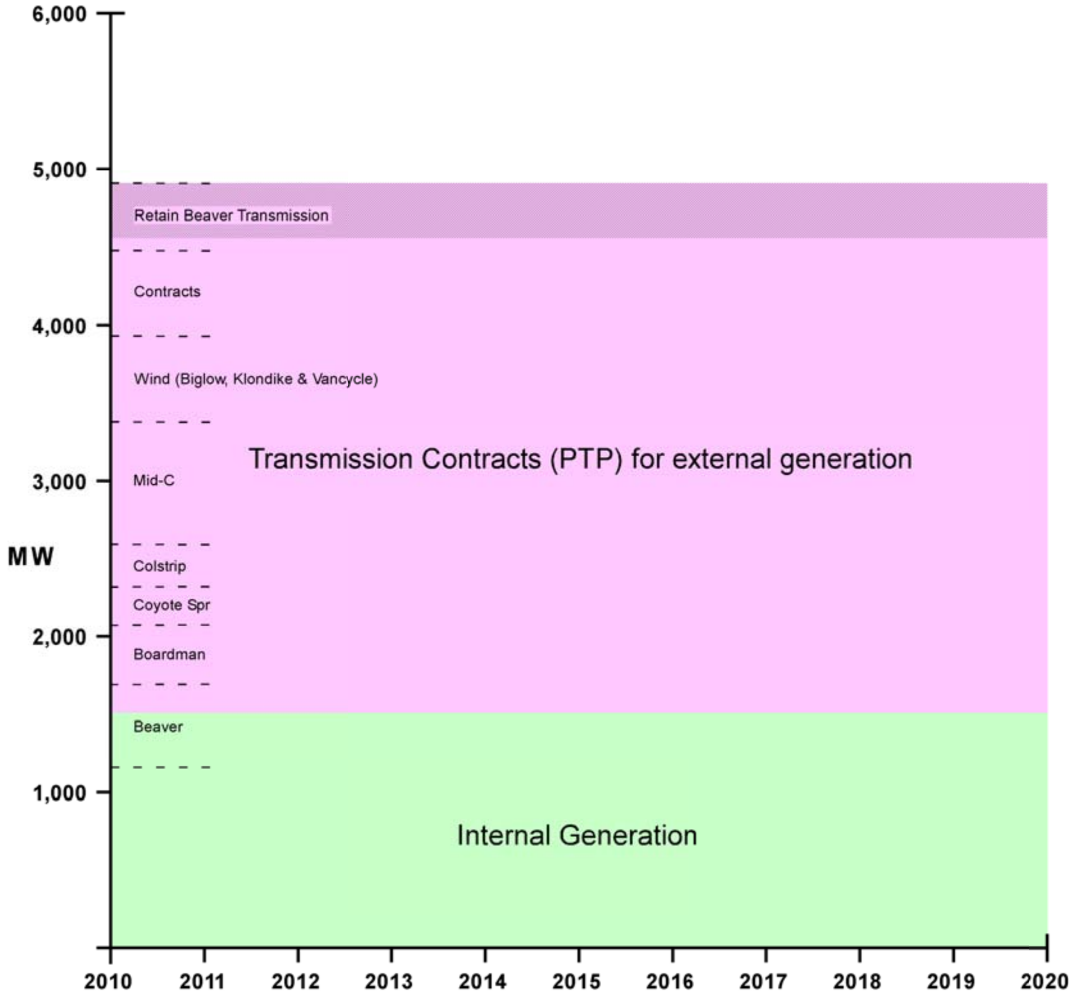
PGE's Transmission Resources

As mentioned above, power from our out-of-area resources is delivered to us primarily through the use of BPA transmission agreements. We presently contract for 3,393 MW of transmission capacity from BPA under two tariff agreements. Currently, most of our owned and long-term contract resources are delivered into our local transmission system pursuant to an Integration of Resources (IR) agreement with BPA. This IR contract represents 2,218 MW of transmission service and expires at the end of 2009. BPA is no longer offering IR service; therefore, we expect that this transmission service will be converted to transmission service under the BPA Open Access Transmission Tariff (OATT). We also hold 1,175 MW of Point-to-Point (PTP) contracts with BPA that are used to deliver our wind resources and to access regional market hubs. All totaled, BPA currently delivers two-thirds of the power we obtain from our existing resources. This is down from three-fourths, which was the case prior to the integration of Port Westward into our transmission system.

Figure 8-1 is a composite chart showing our overall transmission holdings and use. The green area at the bottom of the chart represents internal generation for which BPA transmission to our service territory is not required. The pink area in the middle represents transmission rights acquired from BPA, mapped to our external generation. The cross-hatched area at the top of the chart indicates the uncommitted Beaver plant transmission rights that we may be able to redirect as a result of reterminating Beaver to our Trojan substation. This transmission crosses the South of Allston cutplane[78]. We are considering retaining these rights to meet future load growth. If we do not retain the transmission rights, it is highly likely that these rights will not be available in the future across this critical cutplane.

[78] *Cutplane* – An imaginary line that is used on a transmission map to identify which transmission lines make up a transmission path. Cutplanes are used to minitor power flows on key portions of the transmission system.

Figure 8-1: PGE's Transmission Resources and Use without New Transmission



PGE's Transmission Resources Needed for New Generating Resources

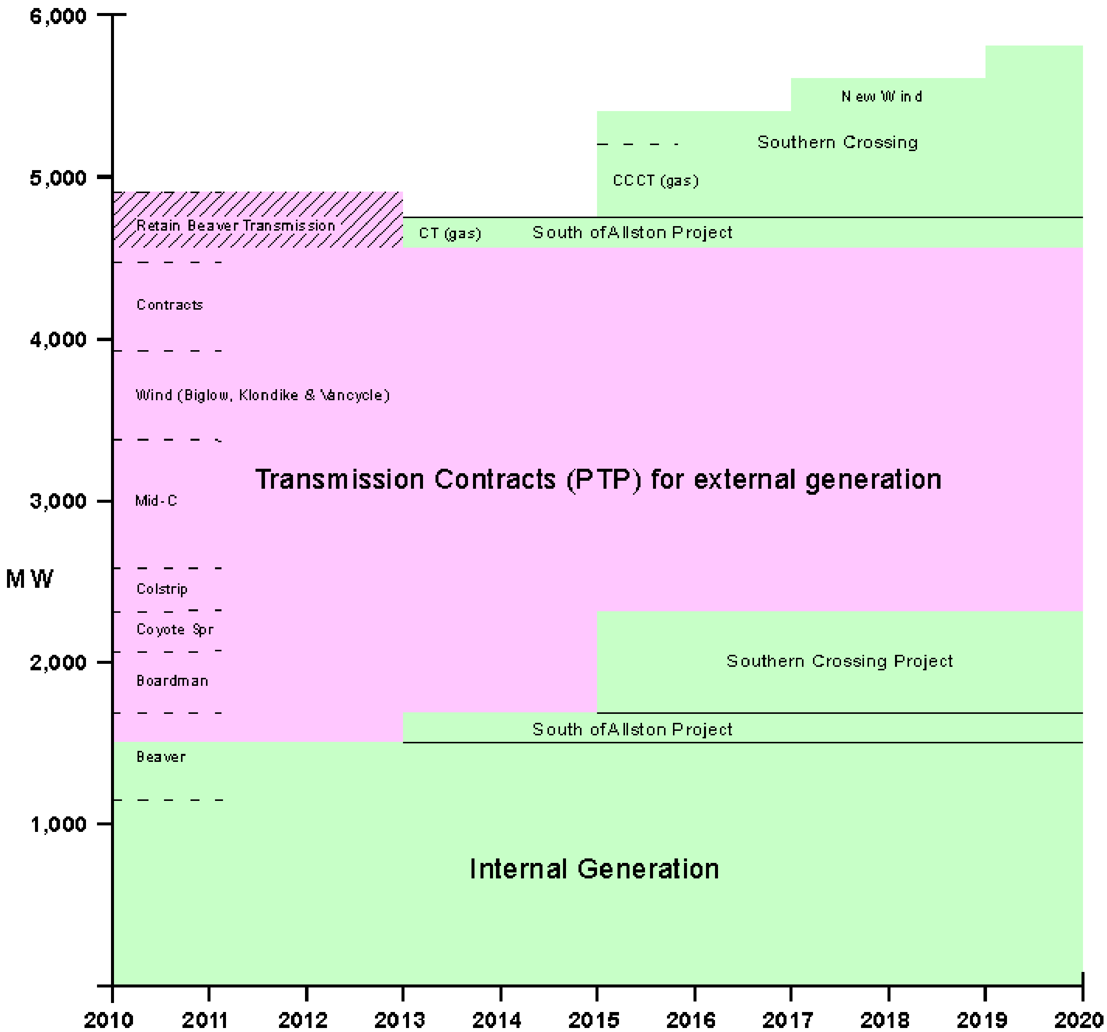
Looking forward, we are concerned about our ability to meet energy needs and system reliability requirements in a constrained transmission environment. Additionally, in the future our transmission needs will increase faster than load growth since the average annual energy output for wind generation is significantly less than nameplate rating and the transmission required for wind generation.

In Chapter 3 and Chapter 6 we identified the need for a new capacity resource, a new energy resource and additional renewable resources to meet the 2020 RPS target. To accomplish the delivery of this energy we have three options: 1) request transmission service from BPA, 2) request transmission service from a third-party transmission provider for resources outside the northwest, or 3) provide the needed transmission service ourselves. In Section 8.5 of this chapter we describe two self-build transmission options to integrate these resources: the

Cascade Crossing Transmission Project (Cascade Crossing) and South of Allston (SoA) project.

In Figure 8-2 we show one possible future scenario which combines generating resources and transmission projects to meet our future load requirements. This demonstrates the potential synergies of our proposed new renewable and non-renewable resources and new PGE transmission.

Figure 8-2: PGE's Transmission Resources and Use with New Transmission



Our proposed South of Allston transmission project involves a new 230 kV line from Trojan that connects to the west side of our service territory. This third line from Trojan to PGE not only provides a significant increase in the transfer capacity of the South of Allston cutplane, but also would fully integrate the remaining Beaver capacity as well as fully integrate a potential new capacity resource. The line is assumed to be in service during 2014 and would address our need for additional firm transmission required to meet 1-in-2 peak load beginning at that time.

Cascade Crossing is a new Cross-Cascades line that would connect our Coyote Springs and Boardman plants directly to PGE, as well as allowing the full integration of a new energy resource near Boardman and new wind generation resources along the line corridor. The transmission line is assumed to be in service during 2015. For illustrative purposes, the wind is shown in Figure 8-5 in three 200-MW blocks.

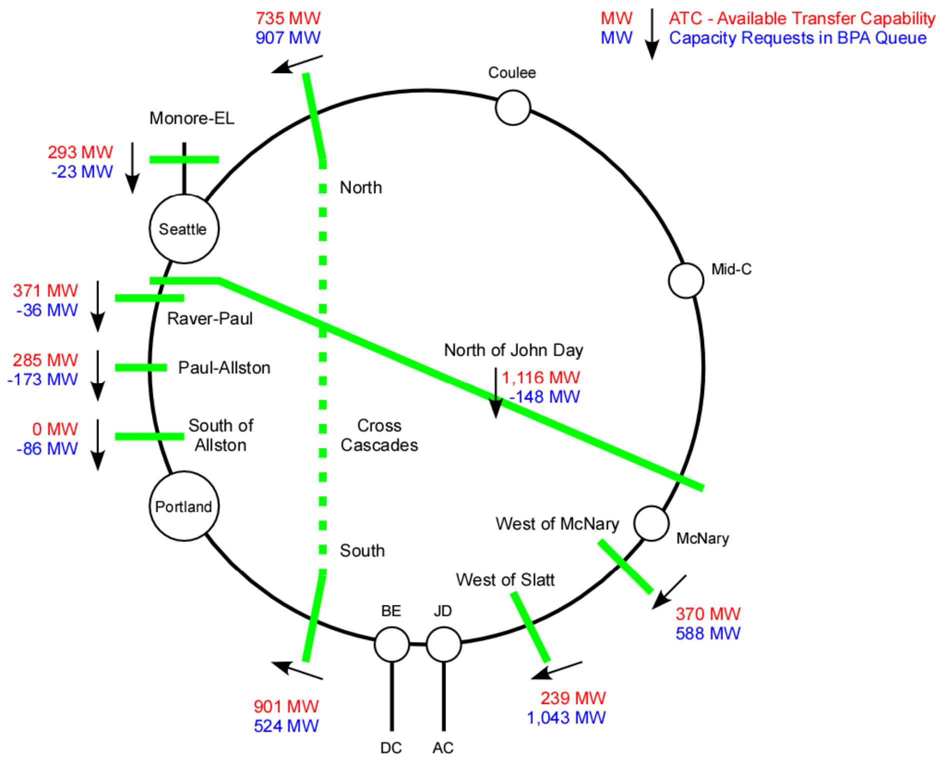
As can be seen from Figure 8-2 above, the Cascade Crossing and South of Allston projects result in a marked reduction in the amount of BPA transmission needed to deliver energy from our resources. In this example, the retained transmission from BPA is approximately 2,250 MW. It should be noted that transmission capacity is procured to support the firm capacity of the resource that it integrates, and that the resource capacity shown in Figure 8-2 includes over 1,100 MW of wind resources. That is, to ensure that we can deliver the full output of intermittent resources, we acquire firm transmission rights to match the nameplate rating of resources. For example, since wind facilities in the region typically have a capacity factor around 33%, the amount of firm transmission capacity we reserve to deliver the power to load is approximately three times the average energy output of the wind facilities.

Available Transmission to Portland

Figure 8-3 depicts the major cutplanes monitored by BPA that affect PGE. The figure shows the long-term available transfer capacity (ATC) that is posted on BPA's Open Access Same-Time Information System (OASIS) and the transmission requests in BPA's queue. The amount of long-term firm ATC, as of October 2009, is shown in red. The amount of new transfer capacity requested on the BPA system is identified in blue. The SoA cutplane, which has no available capacity, is the most critical cutplane for PGE. This constraint limits flows to Portland irrespective of where the source is located due to the flow-based nature of the interconnected power grid. For example, power scheduled from McNary to Portland will divide and flow across both the North and South Cross-Cascades cutplanes. Because transmission capacity to Portland from the east or north is not available, resources in the McNary area cannot be used to serve load in Portland until several limiting cutplanes, particularly in the I-5 corridor, are reinforced. Although substantial transfer capacity currently is available on the Cross-Cascades South cutplane, requests for new capacity nearly exceed the remaining capacity available.

Much of the requested transfer capacity stems from proposed wind projects that are located roughly between BPA's John Day Substation and the Mid-Columbia area in southeastern Washington and northeastern Oregon. The fact that a significant amount of wind generation is proposed for the area along the Columbia River to the east of Portland helps to explain the large demand across the southern portion of the Cross-Cascades transmission system. To meet all of these requests, substantial transmission facility additions will be required throughout the Pacific Northwest grid.

Figure 8-3: Cutplane Capacity Availability, October 2009



It will not be sufficient for the region to develop solutions for just one or two of these transmission constraints. Many parts of the transmission network are simultaneously utilized to deliver power from any proposed east-side resource. While cost-effective generation resources to meet future load growth are available, they are typically located away from load centers. Our benchmark energy and renewable resources, for instance, would require transmission from locations in eastern Oregon. Other potential resources included in our portfolios would require transmission from Idaho and Wyoming. PGE and others in the region also may require increased transmission capacity from Montana, British Columbia and Alberta.

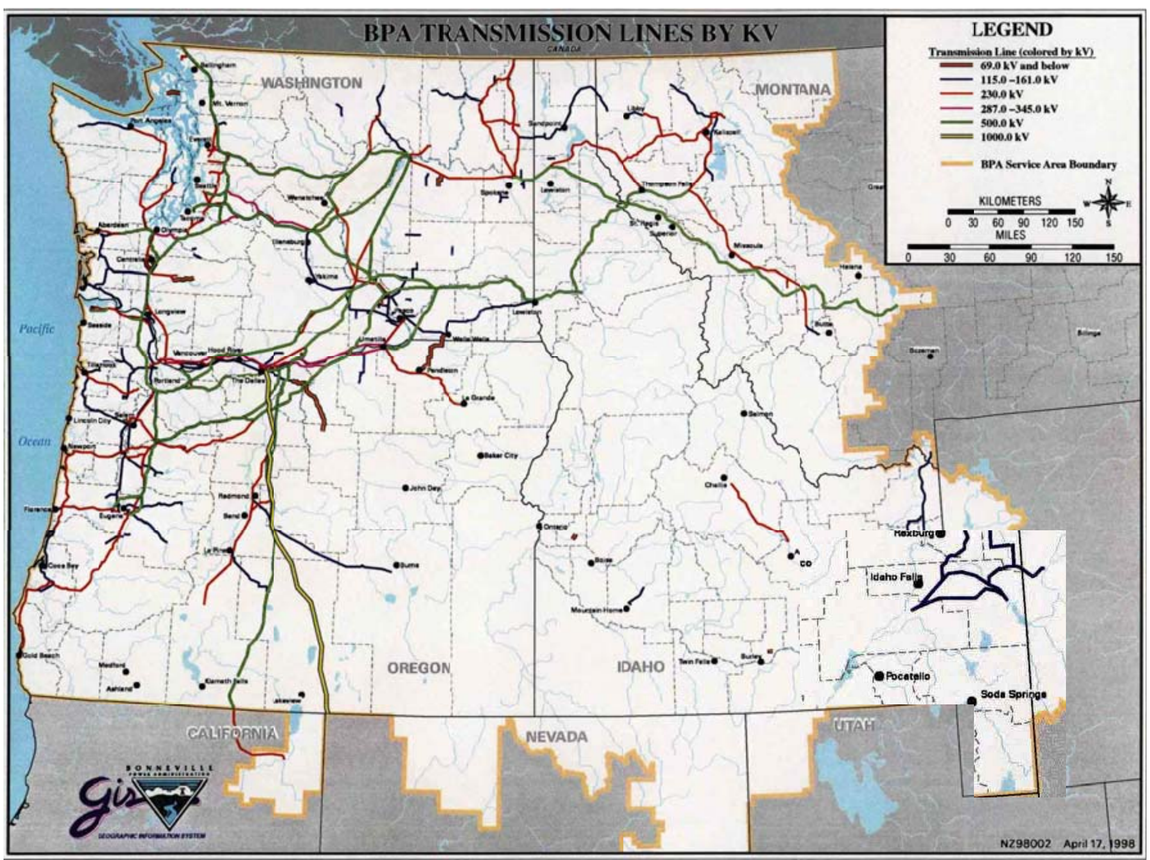
We believe that geographic and fuel diversity of generation assets provides important benefits to our customers and that constructing new transmission facilities is a key factor in allowing us to meet our load and assure continued reliability within the region. PGE's proposed transmission improvements, BPA's NOS process and regional planning activities seek to address these concerns.

These activities and the proposed projects associated with them are described later in this chapter.

Regional Assessment

Since its creation in 1937, BPA has played a central role in managing the power and transmission facilities of the Federal Columbia River Power System in the Pacific Northwest. The BPA transmission system includes 15,000 miles of line and 300 substations in eight states. BPA provides over three-fourths of the Northwest's high-voltage transmission as it moves power from 31 federal hydroelectric stations and one nuclear station to Northwest customers. BPA's large interregional transmission lines connect power systems from as far away as Canada and the Southwest, and allow for the sale of surplus power outside the region and the movement of power within the region. The BPA Service Area Boundary is shown in Figure 8-4 below.

Figure 8-4: BPA Service Area



http://www.bpa.gov/corporate/pubs/EX_A_BPA_Service_Area.pdf

Unfortunately, the regional transmission infrastructure is becoming increasingly stressed due to continued regional load growth and soon may not be capable of reliably delivering all of the region's current and new diverse resources to the populous areas where the power is needed. These resources include both renewable energy, such as wind, solar and geothermal, and non-renewable resources, both of which typically exist in locations remote from existing transmission corridors and population centers.

The increased stress on BPA's transmission system has led BPA to change the way it manages the system and the transmission products it offers. BPA now uses flow-based techniques to assess the usage of the transmission system. The usage of the system consumes available transfer capacity of the cutplanes. BPA will limit, or curtail, the usage of the system to stay within the transfer limits of the cutplanes. BPA offers generation dispatch as another method of staying within cutplane limits. Further, BPA is now offering a conditional firm transmission product which allows BPA to maximize usage of the system, recognizing that outside of peak seasons much of the transfer capacity goes unused. This can have the effect of making existing firm transmission rights less reliable and more likely to be curtailed. The overall impact of squeezing out the remaining transmission capacity in the region's transmission system has been to produce a very complex constraint management system in order to ensure reliability.

Figure 8-5: Pacific Northwest Transmission System

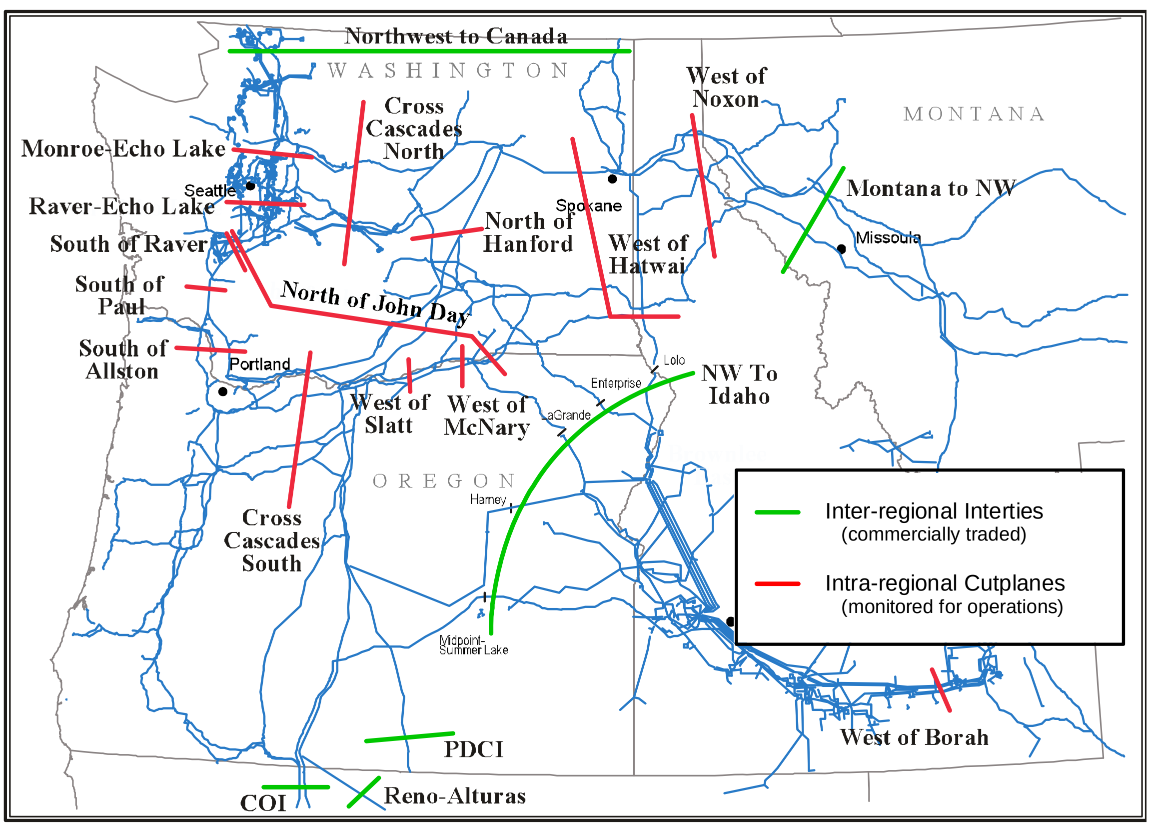


Figure 8-5 provides a graphical representation of the Pacific Northwest transmission system and its current constrained transmission paths. The blue lines drawn on the figure are the major transmission lines that serve the Pacific Northwest. The green lines show inter-regional interties and the red lines show the major intra-regional cutplanes that BPA manages daily. These interties and cutplanes limit both intra- and inter-regional transfers.

The highest stress on the system, and hence when congestion is greatest, occurs during the summer and winter months. During the summer, high levels of hydro generation in Canada and the Pacific Northwest are transmitted to California and the Desert Southwest, which creates high north-to-south flow conditions. These flows to California can be limited by the flow on the North of John Day cutplane. During the winter, high levels of hydro generation in the Pacific Northwest, combined with thermal resources located east of the Cascades, are transmitted to the west-side load centers in Washington and Oregon. This creates high east-to-west flow conditions across the Cascades. The ability to serve west-side load centers from east-side resources can be limited by the flows on the Cross-Cascades North and South cutplanes.

To eliminate these transfer constraints within the transmission system, new transmission is needed. However, very few major transmission facility additions have occurred in the Pacific Northwest in the last two decades. In that same period regional loads have grown, generation facilities have been added and ratings on transmission lines have been increased. For example, from 1989 to 2008 PGE's net system average energy increased 32% and peak load increased 14.5%. In the last 20 years we have also added Coyote Springs, Port Westward and Biglow I and II generating facilities. Additionally, from 1992 to 2007 regional loads have increased 29% (excluding DSI load) requiring the construction of several thermal plants in the McNary area and, more recently, several thousand MW of wind facilities have been completed east of the Cascades. All of these changes have placed greater stress on the system as energy throughput has increased, resulting in the marked reduction in transmission system available capacity and increasing the number of events challenging system reliability.

Approximately 15 years ago, the capacities of the Canadian and California Interties were increased by 50% in the north-to-south direction. While the capacity of the California Intertie was achieved with new construction, the Canadian Intertie capacity was achieved with few transmission facility additions. These capacity increases allowed more transmission rights to be sold from north to south. This increased southbound flow has put additional stress on the system, particularly on the I-5 corridor between Seattle and Portland. During those 15 years, increasing loads and new generation sources along the I-5 corridor have also placed more stress on the I-5 corridor. As a result, the I-5 corridor cutplanes have become more constrained, making transmission access more challenging for PGE to meet our load requirements.

The only recent transmission additions in the Pacific Northwest have occurred on the eastern side of the Cascades and were associated with the North of Hanford and the West of Hatwai cutplanes. These additions were associated with restoring transmission capacity to meet existing obligations.

Many of the Pacific Northwest utilities and regional stakeholders are participating in a coordinated effort to address the integration requirements and transmission needs of as much as 6,000 MW of wind power in the region by 2025. The Northwest Wind Integration Action Plan[79], co-chaired by the NWPCC and BPA, is evaluating this issue. We are participating in this region-wide effort.

8.2 Regional Transmission Planning

Clearly, there is a need for coordinated transmission planning to address the region's transmission challenges. The Congress and FERC have also recognized the need to improve regional transmission planning. As a result, transmission planning has undergone significant transformation over the past 25 years through a series of acts enacted by Congress and orders issued by the FERC. Currently, transmission planning remains a complex function that is coordinated between affected utilities and the various processes and procedures that are established in multiple organizations. These organizations have differing roles in the various aspects of the transmission planning function. We describe our Transmission Planning Process in Attachment K to our Open Access Transmission Tariff (OATT). Here, we will briefly describe the organizations that we participate in and the roles they play. The objective of the rules and processes that guide our planning efforts is to ensure that needed transmission facilities are identified and evaluated in open and transparent processes that will provide reliable and cost-effective solutions to deliver resources to customer loads.

PGE is a member of the Western Electricity Coordinating Council (WECC). WECC is one of eight regional councils of the North American Electric Reliability Council (NERC) and includes two provinces of Canada, portions of Mexico and all or most of 14 Western states. WECC is responsible for ensuring the overall reliability of the regional system, and does so by coordinating operational and planning activities in the region. The Planning Coordination Committee (PCC) oversees member adherence to the three processes relevant to transmission

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[79] More information on the Fifth Power Plan and the Northwest Wind Integration Action Plan can be found at http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf.

planning: regional planning, project rating and project reporting. These activities ensure that facility additions are communicated to WECC members, are provided ratings and meet reliability criteria. WECC also conducts regional economic studies on the transmission system through the Transmission Expansion Planning Policy Committee (TEPPC) and its subcommittees.

While WECC is a forum for coordinating planning activities, it does not perform the actual planning of facilities. This function resides with the utility planners and is further coordinated in sub-regional planning forums such as Northern Tier Transmission Group (NTTG) and ColumbiaGrid. In July 2007, FERC issued Order 890 which, in part, introduced new planning policies for the industry to follow, including the requirement to adopt an open, transparent and coordinated transmission planning process. Order 890 requires transmission providers to adhere to additional requirements, such as comparability, information exchange, dispute resolution, regional participation, processing of economic planning studies to address congestion or the integration of new resources, and development of a process for cost allocation.

As a result of Order 890, existing regional planning groups have adapted their processes to implement the requirements of the Order and new sub-regional planning groups have formed. The regional and sub-regional planning groups that address issues relevant to PGE include TEPPC, NTTG, ColumbiaGrid, and the Transmission Coordination Work Group (TCWG).

TEPPC

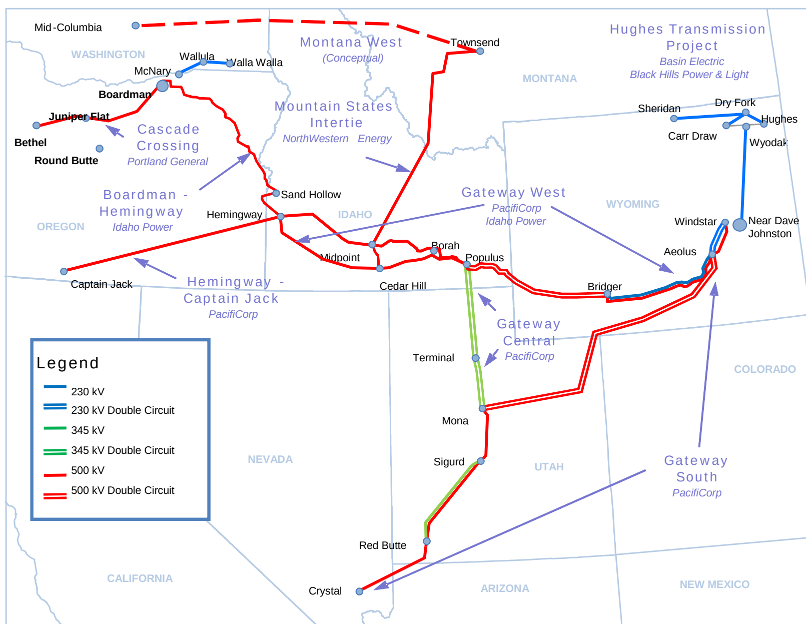
TEPPC is a Board committee of WECC that provides policy direction and management of the economic transmission planning process. It guides the analyses and modeling for the Western interconnection and oversees a specialized database for this purpose.

NTTG

NTTG was formed in 2007 to address future sub-regional transmission and resource needs and to support the regional WECC process. We became a member in 2008. Other participating utilities include PacifiCorp, Idaho Power, NorthWestern Energy, Deseret Power Electric Cooperative and Utah Associated Municipal Power Systems.

PGE is a Funding Member of NTTG and satisfies our sub-regional transmission planning commitment and objectives through NTTG. NTTG focuses on evaluation of transmission projects that move power across the sub-regional bulk transmission system, servicing loads that include parts of Utah, Wyoming, Montana, Idaho, Oregon, Washington and California. NTTG also provides an open forum for coordinated analysis between sub-regional planning efforts with adjacent sub-regional groups and other planning entities that impact the planning decisions, system adequacy and operation of multiple transmission providers. This effort allows us, along with other entities, to address local transmission needs due to future load growth and resource additions, and avoid duplication of study efforts through coordination within sub-regional and regional transmission planning forums. Figure 8-6 shows the NTTG footprint and current projects under evaluation.

Figure 8-6: Projects Undergoing NTTG Review



NTTG is currently in quarter seven of an eight-quarter biennial transmission planning cycle that began in January 2008. The biennial plan spans 10 years and is intended to coordinate the system transmission plans of member transmission providers, to provide for the integration of new generation and to reduce transmission congestion. Work in 2009 (the second half of the biennial cycle) will provide for review of the study results and continuation of any needed scenarios or alternative studies, followed by preparation and delivery of a final transmission plan in December 2009. The final sub-regional transmission plan will be available for stakeholder review and will facilitate regional assessments and reports by WECC and TEPPC.

PGE also is a member of the planning committee and actively participates in a Technical Work Group (TWG) consisting of planning engineers from the NTTG member transmission providers. In addition to Cascade Crossing, current projects being studied by the TWG include:

- Hughes Transmission Project (Basin Electric Power Co-op)
- Mountain States Transmission Intertie (Black Hills Power)
- Gateway South (PacifiCorp)
- Gateway Central (PacifiCorp)
- Gateway West (PacifiCorp/Idaho Power)
- Boardman – Hemingway (Idaho Power)
- Hemingway – Captain Jack (PacifiCorp)
- Walla Walla – McNary (PacifiCorp)

Although none of these proposed projects resolve the issues that will be addressed by Cascade Crossing or proposed improvements to the South of Allston cutplane, several of the projects will offer benefits to PGE. Of these third-party projects, the most significant to PGE is the Boardman to Hemingway (Idaho Power) project, which could provide a transmission path to the proposed Northeast Oregon (NEO) station. We also recently signed a Memorandum of Understanding with Idaho Power Company to coordinate planning and development activities for Idaho's Boardman – Hemingway Project and Cascade Crossing.

ColumbiaGrid

ColumbiaGrid is a non-profit membership corporation formed to improve the operational efficiency, reliability and planned expansion of the sub-regional portion of the Northwest transmission grid owned and operated by its members, which are located primarily in Washington State. We participate in ColumbiaGrid forums, but are not a member.

Transmission Coordination Work Group

We jointly formed the TCWG with eight other transmission providers to comprehensively and simultaneously study the interactions of several proposed WECC-wide regional projects and to coordinate project rating studies that will meet the WECC Project Rating Review process. TCWG has a wider footprint than either NTTG or ColumbiaGrid, and includes out-of-region project sponsors such as TransCanada (Northern Lights), Pacific Gas & Electric (Canada-Northwest-California) and Sea Breeze (West Coast Cable). The kickoff meeting was held on January 24, 2008.

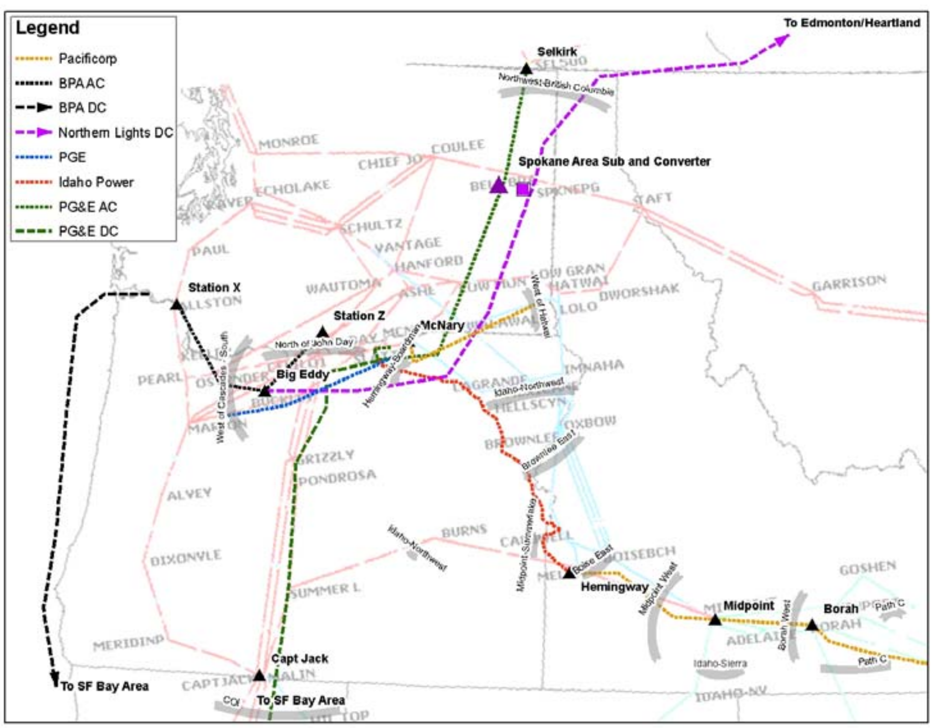
The TCWG is presently coordinating an open transmission planning process with the other transmission providers/developers who are working to establish a

WECC rating for projects proposed in, or connected to, the Northwest. In addition to Cascade Crossing (shown in blue), the TCWG is studying the projects listed below and depicted in Figure 8-7.

- West of McNary Generation Integration Project (BPA)
- I-5 Corridor Reinforcement (BPA)
- Boardman – Hemingway (Idaho Power Co.)
- Hemingway – Captain Jack, Walla Walla to McNary (PacifiCorp)
- Canada to Northwest to California (Pacific Gas & Electric)
- Canada to Northern California, Avista Interconnection (Avista)
- Northern Lights to Buckley Project (TransCanada)
- Juan de Fuca Cable Project (Sea Breeze)
- West Coast Cable Project (Sea Breeze).

Our WECC Regional Planning Process for Cascade Crossing is being coordinated through TCWG. TCWG also presents study results and status updates to a "big tent" forum, which is open to all interested participants. The regional planning activities conducted in this forum supplement the regional planning activities addressed in Attachment K of our OATT.

Figure 8-7: Regional Projects Being Studied by TCWG



8.3 BPA's Network Open Seasons

Notwithstanding recent efforts to improve regional transmission planning, little significant transmission has been built recently in the Northwest. As a result of the lack of new transmission capacity and resulting system congestion, BPA has had to resort to remedial actions and reactive power compensation to maximize the existing transmission capacity and the development of curtailment calculators to maintain reliability. Prior to 2008, BPA's long-term transmission service queue contained over 14,000 MW of service requests, excluding Intertie service, yet few transmission projects were being built. A major hurdle to the development of new transmission was that customers were required to provide all of the capital funding for the transmission system upgrades and expansions to support their individual projects.

In 2008, BPA introduced its first NOS process to alleviate the bottleneck created as a result of previous transmission planning and funding mechanisms. Under the NOS, parties requesting new transmission service must commit, in advance, to purchase service at embedded-cost rates by signing a precedent transmission service agreement. Importantly, the NOS approach does not require BPA's customers to fund, in advance, the entire cost of transmission network facilities needed to provide the service. BPA makes the necessary investment through its borrowing authority or other arrangements. The requesting party is responsible for submitting a refundable security deposit equal to one year of service once it signs the precedent agreement. If necessary and available, BPA may offer conditional firm service to bridge service until facilities can be completed.

In addition, under NOS, BPA does not conduct individual system impact studies on each transmission request. Instead, the agency performs a single cluster study of all requests to determine what new facilities, if any, will be needed to accommodate all of the requests. The clustering of transmission requests not only speeds up the system impact analyses, it allows BPA to evaluate the network effects that result from interactions among requests, including implications on system reliability.

As a result of the 2008 NOS, BPA was able to clear the queue by eliminating requests that were not backed with a precedent agreement. Approximately 8,054 MW of prior requests for service were removed from the queue. As a result of clearing the queue, BPA was able to offer 1,834 MW of service without building additional reinforcements. In its 2008 NOS process BPA identified five projects that will enable it to grant an additional 3,585 MW of requests. The total estimated direct transmission cost for the projects is $802.5 million and is expected to cause an approximate 2 to 3 percent increase in a future transmission tariff rate.

The 2009 NOS process was initiated on June 1, 2009, and BPA obtained a commitment of 1,553 MW in precedent agreements and removed an additional 3,304 MW from the queue. By May of 2010, BPA will announce which transmission projects, if any, it will construct as a result of the NOS process.

We did not sign a precedent transmission service agreement as part of the 2008 or 2009 NOS processes because we had sufficient transmission and no new generation resources to integrate at that time. That will change by 2015, as shown earlier in Figure 8-2. As a result, we will consider participating in a future NOS process. However, we recognize that our future participation in a NOS process, in and of itself, does not guarantee that we can acquire existing transmission or that there will be sufficient interest by other parties to enable BPA to proceed with construction of transmission projects that meet our needs. Participation in a BPA NOS process also does not guarantee that a BPA transmission project would be the most cost-effective transmission option to meet our transmission needs. Indeed, as discussed below, our analysis indicates that in several cases constructing Cascade Crossing is more economic than purchasing BPA transmission.

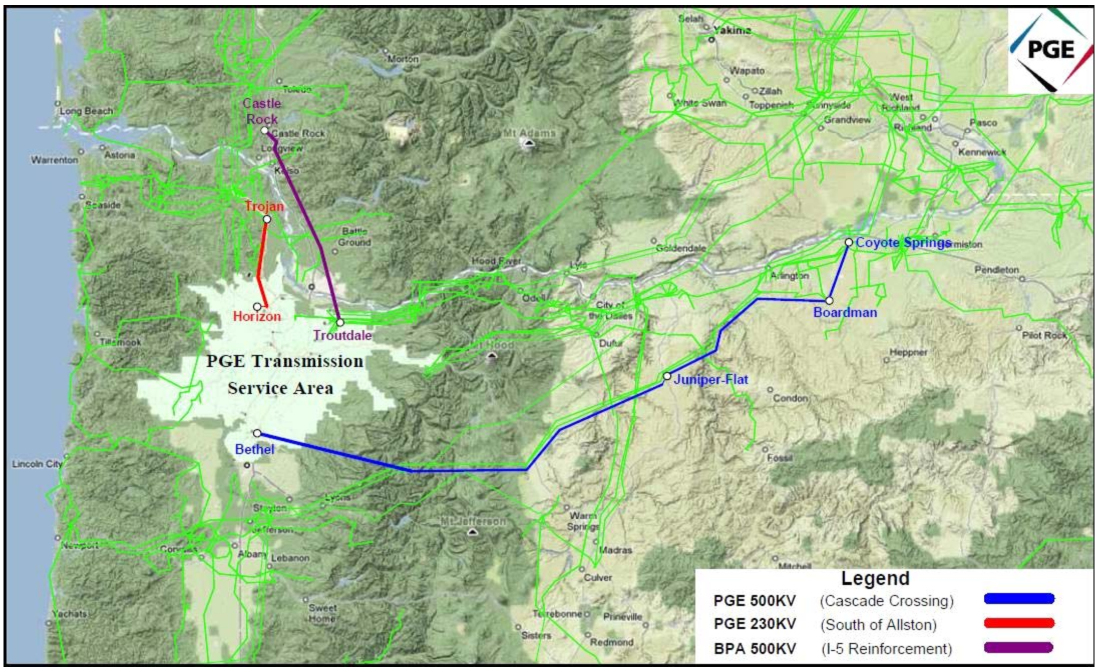
8.4 Transmission External to BPA

Consistent with OPUC IRP Guideline 4c, we have modeled all of our existing transmission rights, as well as future transmission additions associated with the resource portfolios tested. For modeling purposes, generation projects in our portfolios that require BPA transmission are assigned tariff rates. Generation projects external to BPA's transmission system are dependent on new third-party transmission projects. In our portfolio analysis we included an analysis of nuclear power in eastern Idaho and both mine-mouth coal and wind from Wyoming. These resources would require new transmission infrastructure to deliver the power to the Northwest because there is no available east-to-west transfer capacity on the existing transmission infrastructure. Although transmission project costs have not been made public, we used our cost estimate for Cascade Crossing to estimate the cost of the Boardman – Hemingway project (Idaho Power Company) and the Hemingway – Captain Jack project (PacifiCorp). In addition, PacifiCorp has publicly stated that its Gateway West project will cost $6 billion. We computed a MW cost of participation and assigned that cost to the resource capacity assumed in our portfolio analysis.

8.5 PGE Transmission Options

We are analyzing two important transmission projects (Figure 8-8) that we believe will significantly help address our transmission needs. One is the South of Allston project, which will relieve congestion and improve system reliability, and the other is Cascade Crossing, which would enable us to resolve future anticipated Cross-Cascades South congestion and make it possible to access resources on the east side. Both of these options are discussed below.

Figure 8-8: PGE's Proposed New Transmission Projects



Trojan / South of Allston Addition

The South of Allston (SoA) path is the most critical transmission path in the region in determining transmission availability for PGE and all other entities that desire to move energy from north to south or east to west. This is because the SoA cutplane is the point within the transmission system that has the least amount of ATC.

We anticipate that ATC on the SoA path will remain unavailable and that requests for transmission service across the path may increase as a result of future load growth in the I-5 corridor, which includes our service territory. As a result, our ability to deliver energy from our Beaver plant and new energy or capacity resources within the region to our service territory will be impacted. To alleviate some of this constraint we recently re-terminated our Beaver plant to our Trojan substation, enabling a partial direct integration of the facility. This allowed us to reduce our system costs, improve our reliability and redirect some of our existing BPA transmission rights previously dedicated to the Beaver plant to accessing other resources. While this re-termination created a partial workaround for the SoA issue, it did not eliminate it as a system constraint.

In an attempt to address this issue BPA is in the planning stages for construction of a 500 kV high-voltage transmission line (I-5 Corridor Reinforcement) and related substation upgrades. BPA will begin preliminary engineering, environmental and public processes in 2009. This high-voltage line is expected to be put into service no earlier than 2015, and this new line addition will require upgrades to the low- and mid-voltage transmission systems. Two options are being evaluated – Station K (near Castle Rock, Washington) to Troutdale, Oregon, and Station K to Pearl (west side of Portland).

However, BPA's proposed new line will not be completed in time to meet our resource needs. Further, BPA has not committed to either of these options. Therefore, we do not know if BPA will construct the I-5 Corridor Reinforcement or when the project might be completed. Accordingly, in order to provide additional capacity for the critical SoA path, we are proposing to construct a 230 kV transmission line with a proposed corridor from our Trojan substation at Rainier to a point near our Sunset substation in Hillsboro. We anticipate that this mid-voltage transmission line, which could be built within the existing BPA corridor, will provide needed transfer capability and congestion relief on the SoA path. We anticipate that the line could be in service by 2014, which will allow an increase in flows over the SoA cutplane before BPA completes its reinforcement project. In addition, this concept should address some of the low- and mid-voltage loading issues identified in BPA's I-5 Corridor Reinforcement Project report and allow full integration and power delivery from our Beaver, Port Westward and a new proposed benchmark capacity resource located at Beaver to our load service territory. Finally, this 230 kV option would significantly increase the benefits and value of BPA's I-5 Corridor Reinforcement Project should it decide to construct the upgrade.

South of Allston 230 kV Option Project Timeline and Budget

The 230 kV transmission line option with a proposed corridor from our Trojan substation in the Rainier area to a point near our Sunset substation could be in service by 2014. At this point, this is a conceptual estimate. A detailed cost estimate and timeline schedule is dependent on the execution of a Facilities Study Agreement.

General Projected Timeline

- Q4 2010 - File Notice of Intent (NOI) with the Energy Facilities Siting Council (EFSC)
- Q1 2011 through Q4 2012 - Site Certificate Application process with EFSC
- Q1 through Q3 2013 – Engineering procurement and construction
- Q4 2013 – Begin construction
- Q4 2014 – Complete construction

Key Financial Assumptions (2009 $)

Below are projected PGE incremental capital expenditures related to the South of Allston 230 kV Option project (2009 $):

- Substation expansion – approximately $2 million
- Transmission Line – approximately $33 million
- Contingency and other costs – approximately $10 million, which consists of 25% of PGE's incremental cost and includes an allowance for land acquisition.

Other Assumptions:

- EFSC approval can be obtained in two years.
- Plan to use existing rights-of-way (R/W) or build parallel to existing rights-of-way, thus minimizing land acquisition costs.

Based on the above assumptions, the preliminary cost estimate for SoA is approximately $45 million. We will provide the Commission an updated cost estimate and timeline in a future IRP filing as further studies and analyses are completed.

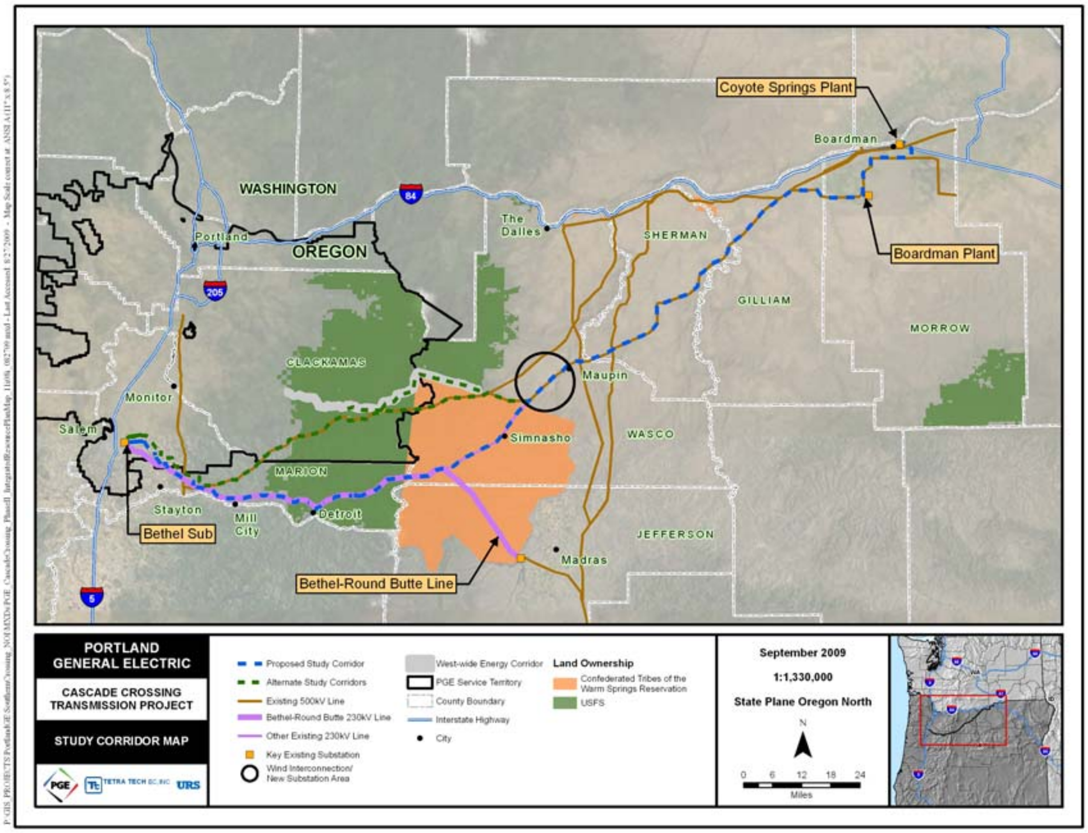
Cascade Crossing Transmission Project

Because of constraints on the Cross-Cascades South transmission path and the potential to access significant generation resources east of the mountains, we are proposing to construct a new 200-mile, high-voltage transmission facility across the Oregon Cascades (Figure 8-9). The corridor shown represents one of the options currently under review.

The proposed facility passes through a renewable-resource-rich area of eastern Oregon, directly into our service area near Salem. Cascade Crossing was conceived to meet a number of objectives and benefits, including:

- Meet all NERC/WECC reliability criteria when accessing new generation resources east of the Cascades
- Increase the Cross-Cascades South path transmission capacity and connect this directly to PGE's service territory through a new delivery point
- Utilize existing R/W and transmission corridors to the maximum extent possible
- Integrate existing PGE generation resources (i.e., Boardman and Coyote Springs) that currently rely on BPA transmission
- Integrate up to 600 MW of additional renewable wind generation to meet 2020 RPS
- Integrate new energy resource additions, and
- Capture synergies of several inter-regional proposed transmission projects that are in proximity to the Boardman area, including the ability to access out-of-region power supplies.

Figure 8-9: Corridor Options for Cascade Crossing



PGE's transmission department (PGET) initially began studying Cascade Crossing in response to 1,260 MW of requests for service submitted by PGE merchant transmission (PGEM) under PGE's OATT. PGEM submitted these requests for the purposes of integrating new and existing energy resources more cost-effectively and increasing system reliability. The resources contemplated for integration are comprised of 200 MW of new wind in eastern Oregon, 385 MW for Boardman, 256 MW for Coyote Springs and 450 MW for a new energy resource near Boardman. PGEM also has submitted Network Integration Transmission Service (NITS) requests totaling 1,291 MW to PGET for the purposes of moving energy across the PGET transmission system.

PGET can accommodate all of the current NITS requests submitted by PGEM by constructing Cascade Crossing as a single-circuit facility, assuming it achieves a path rating of 1,500 MW. However, PGET recently received a third-party request for 500 MW of wind generation integration near Arlington, Oregon. If the third party requests transmission service for the 500 MW of wind being integrated, then that request, in combination with PGEM's requests, would exceed the capacity of a single-circuit line.

Given the additional interconnection request and the limited amount of excess capacity even in the absence of any additional transmission service requests, we are requesting acknowledgment to design, site and permit a double-circuit 500 kV facility. This provides the flexibility if circumstances change to (a) construct a single-circuit facility, (b) construct a double-circuit facility and conductor the first circuit initially and then add the second circuit when needed, either by a third party or PGEM, or (c) construct a double-circuit facility with both circuits conductored. The decision of which option to construct will be made prior to starting the engineering procurement construction process and will depend on an updated economic analysis, the transmission requests submitted at that time and other factors.

The proposed project would consist of a 500 kV transmission line connecting our Boardman and Coyote Springs plants near Boardman, Oregon to the southern portion of our service territory near Salem, Oregon. The project will begin at our Coyote Springs substation, then to the Boardman plant, and terminate at our Bethel substation. The project will parallel existing utility lines for the first 106 miles from the Boardman substation toward Bethel, and parallel our existing Bethel-to-Round Butte 230 kV line over the Cascades for the last 77 miles. New rights-of-way will be needed for the new 500 kV transmission line between Boardman and the Coyote Springs plant which is approximately 17 miles (Figure 8-9). We currently plan to retain the connection between the Coyote Springs plant and the BPA McNary-Slatt 500 kV line. This proposed path will minimize the need for a new transmission corridor because we will build the proposed project adjacent to existing transmission lines to the maximum extent possible.

Cascade Crossing will also require the construction of a new 500/230 kV substation, tentatively called "Juniper Flat", located along the proposed transmission corridor between the Confederated Tribes of Warm Springs reservation border and the town of Maupin, Oregon. The new 500 kV transmission lines will terminate at this proposed substation where a 500/230 kV transformer will also be installed. The 230 kV bus will be the interconnection point for the new wind generation project that is the subject of a generation interconnection request by PGEM. The Boardman and Coyote Springs substations will be expanded to accommodate the additional circuit breaker positions. The project also includes the installation of a new 500/230 kV transformer bank at Bethel.

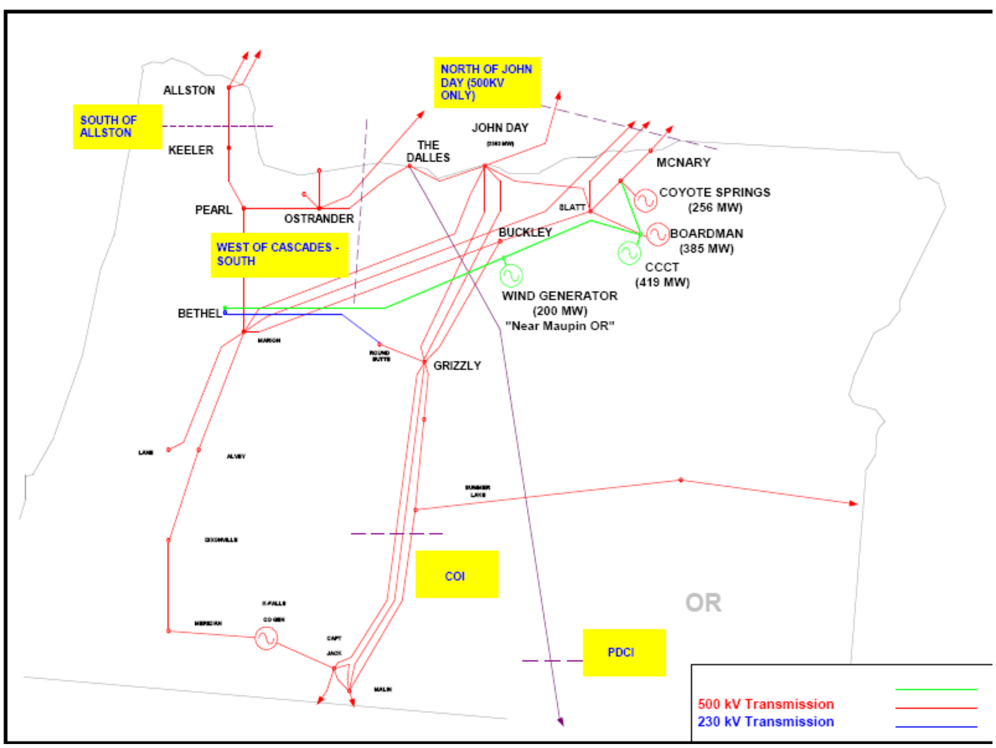
WECC Study Process

We are currently seeking an Accepted WECC path rating for Cascade Crossing in the single-circuit configuration; however, we anticipate modifying our Phase 2 study to reflect a double-circuit configuration. We initiated the WECC Project Rating Review Process for Cascade Crossing with notification to the WECC

Planning Coordination Committee (PCC) and Technical Studies Subcommittee (TSS) on January 18, 2008. We solicited participation for a technical studies review group that initiated activities on March 20, 2008. Subsequently, we determined that Cascade Crossing should go through the WECC Regional Planning Process. Notice was sent to WECC on August 15, 2008 informing them of our intent to operate the processes in parallel. We completed the WECC Regional Planning Process in May 2009 and submitted the Comprehensive Progress Report for a 60-day review on May 7, 2009. WECC acceptance of this report will complete Phase 1 of the WECC Project Rating Review Process.

In our Comprehensive Progress Report we proposed a Planned Rating of 1,500 MW east-to-west in winter and 1,450 MW east-to-west in summer for Cascade Crossing as a single-circuit line. The WECC Phase 1 studies demonstrate that Cascade Crossing can achieve these ratings, provide a firm transmission path and improve the reliability for our Boardman and Coyote Springs generating plants, as well as interconnect two potential generation plants – a CCCT plant located near Boardman (the Carty Plant) and a 200-MW wind farm in eastern Oregon. The study also shows that the project would meet all applicable NERC/WECC Planning Standards and Reliability Criteria. These studies will continue during the WECC Phase 2 study process.

Figure 8-10: Cascade Crossing Representation to WECC



The project has been evaluated by regional and sub-regional transmission planning groups who all concur that it is complementary to other proposed projects. For example, NTTG has included Cascade Crossing in its draft Biennial Transmission Plan. Study results have shown that Cascade Crossing is complementary to other system reinforcement projects submitted and studied by NTTG members. These results will be included in the NTTG Biennial Plan report scheduled to be released at the end of 2009. Columbia Grid studies also have shown that Cascade Crossing is complementary to other system reinforcement projects planned by BPA. Cascade Crossing is also ranked by the Idaho National Laboratory[80] as the fourth-most-important transmission upgrade to the Northwest economy.

There are several other proposed projects in the WECC path rating processes that may either interconnect with or be built in close proximity to this project. We are working closely with the sponsors of these projects to help foster efficient, coordinated upgrades. To that end, we have signed a Memorandum of Understanding (MOU) with Idaho Power Company (IPC) to cooperate on the development of transmission in the Boardman area. Another potential benefit of partnering with IPC is that its Boardman – Hemingway line could give us access to generation projects in southern Idaho and Wyoming. We are also exploring partnership potential with other entities.

The project rating will be further refined in the WECC Phase 2 rating process which examines the project performance in concert with the existing transmission system and other proposed projects in the region. During the WECC Phase 2 studies, we anticipate that interactions with other Phase 2 projects may provide an increase in the Planned Rating.

Project Need and Benefits

Cascade Crossing will directly connect west-side load to existing and new resources on the east side of the Cascades. The project will significantly add transfer capacity to the Cross-Cascades South and West of Slatt cutplanes, as well as reduce the stress on the I-5 cutplanes by providing another path to our system from the south. All of these cutplanes are vitally important in meeting our future load requirements. Furthermore, Cascade Crossing would provide us with firm transmission service as an alternate to BPA service for our existing Boardman and Coyote Springs generating plants, while at the same time improving reliability to both plants by providing an additional transmission circuit.

[80] *The Cost of Not Building Transmission: Economic Impact of Proposed Transmission Line Projects for the Pacific Northwest Economic Region*," McBride et al., Idaho National Laboratory, prepared for the Pacific Northwest Economic Region, July 2008, page 6.

Reliability Benefits

In addition to allowing us to directly integrate existing and new generating resources into our own system, Cascade Crossing will provide important reliability benefits to PGE. For example, the project would relieve loading levels on transfer paths parallel to Cascade Crossing, which would reduce the severity of currently limiting contingencies.

In our power flow analyses, the addition of Cascade Crossing was sufficient to reduce flows on the parallel transfer path to less than the emergency rating during all of the identified contingencies. Our contingency analysis studied 164 contingencies for each season with and without the project. The summer and the winter benchmark cases were modeled at the same east-to-west generation dispatch as the Cascade Crossing case.

In the summer case there were 54 contingencies that overloaded individual transmission lines in the path to more than 100% of the emergency rating. By including Cascade Crossing, all of these overloads were reduced by 5% or more, and 13 of the contingencies showed an improvement of 20% or more. Again, flows were reduced in all contingencies to less than the emergency rating.

In the winter case there were 34 contingencies that overloaded to over 100% of the emergency rating. By including Cascade Crossing, all of these overloads were reduced by 5% or more, and five of the contingencies showed an improvement of 12% or more, with all flows reduced to less than the emergency rating.

Cascade Crossing would further improve the reliability of delivering energy from our generation projects to our customers by adding another transmission circuit on which to transmit energy. We would retain the connection of the Coyote Springs plant to the BPA McNary-Slatt 500 kV line, and retain the connection of the Boardman plant to the Boardman-Slatt 500 kV line. The addition of Cascade Crossing would therefore improve transmission service reliability to the Boardman plant, the proposed Carty plant and the Coyote Springs generating plant.

Cascade Crossing would also reduce the impacts of north-to-south transfers. Our studies show that north-to-south transfers on the SoA Path are reduced by approximately 170 MW. This reduction in flow helps to reduce our exposure to summer curtailments on the SoA Path. However, preliminary thermal power flow screening indicates that even with the construction of Cascade Crossing, we will still need to go forward with the SoA addition described above because Cascade Crossing will have minimal impact on the SoA path limit.

There are currently no identified plans by BPA or others to address the Cross-Cascades cutplanes, and inspection of the BPA transmission queue shows that these cutplanes may be fully subscribed or in need of significant expansion in the near future. Cascade Crossing reduces the contingency line flows on transfer paths that parallel Cascade Crossing, which benefits the system by lessening the impact of existing limiting contingencies.

Finally, by providing another path that injects power into our system from the south, Cascade Crossing will increase the east-to-west transfer capability, thereby providing benefits not only to PGE but to the entire Pacific Northwest as well. For example, preliminary studies show that BPA average system losses would decrease by an estimated 20 MWa. This reduction in losses is equivalent to the energy output of a 60-MW wind facility or a reduction in CO_2 emissions of approximately 72,000 tons per year from a very efficient combined-cycle combustion turbine, such as Port Westward. While PGE may not be able to capitalize on this benefit, it is a benefit to the Northwest that accrues as a direct result of the project.

Project Timeline and Budget

The target in-service date for Cascade Crossing is 2015. This schedule is dependent on the execution of one or more Large Generator Interconnection Agreements (LGIA), duration of the permitting process, lead times for major equipment and materials, availability of construction labor, and weather conditions during the construction phase of the project.

Below is a summary of key milestones and financial assumptions associated with Cascade Crossing.

General Timeline – Milestones

- Q4 2009 – File Notice of Intent (NOI) with the Energy Facilities Siting Council (EFSC)
- Q4 2009 – Initiate federal NEPA permit process
- Q2 2010 through Q2 2012 – Site Certificate Application process with EFSC
- Q4 2009 through Q3 2012 – NEPA process
- Q3 2012 through Q4 2012 – Select engineering procurement construction (EPC) contractor
- Q1 2013 – Begin construction
- Q2 2015 – Complete construction

Key Financial Assumptions – Single Circuit (2009 $)

The preliminary cost estimate for Cascade Crossing in the single-circuit configuration is $613 million, which includes $55 million for overall contingency (estimated by PGE consulting engineer, Black & Veatch). The project total cost, however, excludes property taxes (estimated at 1.5% of the project total cost) and allowance for funds used during construction. See Table 8-1.

Table 8-1: Cascade Crossing Capital Cost (Single-Circuit)

Capital Expenditures	Total
Substations	$146,700,000
Transmission - Structures	$267,000,000
Transmission - Conductors	$82,600,000
Transmission - Capacitor Banks	$19,200,000
Power Transformer at Bethel Sub	$25,800,000
Land and Rights-of-Way	$38,200,000
Environmental Assessment & Studies	$4,600,000
Permitting, Licenses & Fees	$2,600,000
Project Management	$4,100,000
Outside Legal Services	$1,000,000
Preliminary Engineering	$500,000
Public Relations & Education	$1,400,000
Habitat Mitigation Costs	$10,200,000
Contingency & Other Costs	$6,200,000
Total Project Cost	$613,100,000

Other potential costs (not included above) that could significantly influence the project valuation are:

- Additional $9 million land and R/W maximum contingency
- Additional $10 million for potential habitat mitigation costs

In addition, our costs would be less if another party purchases an equity stake in Cascade Crossing.

Project Economic Analysis – Single-Circuit

In order to analyze the economic benefits of Cascade Crossing, we defined the net benefits as the cost of utilizing BPA transmission service minus the cost of

Cascade Crossing. That is, net benefits are the cost of transmission service and associated energy losses from utilizing BPA transmission for that subset of our own generation that could connect to Cascade Crossing minus the cost of Cascade Crossing net of upgrades that would be necessary to integrate new resources through BPA. Incremental revenues from selling excess transmission capacity and an increase in revenues from existing firm transmission customers are netted from the cost of Cascade Crossing to determine the overall net economic benefit. Specifically, the comparison is between the 2009 real levelized cost per kW-Month of using BPA transmission service and Cascade Crossing transmission for the period from 2015, the projected project on-line date, through 2082, which is the end of the project's useful life. The assumed cost of using BPA transmission service includes approximately $65.5 million in transmission substations and radial lines needed to connect resources to BPA in the absence of Cascade Crossing.

Stated differently, the potential benefits of building Cascade Crossing include the difference between the cost of Cascade Crossing and purchasing transmission service from BPA to serve PGE generation, including the Boardman plant, Coyote Springs plant, a CCCT plant located at Boardman (the Carty Generating Station – see Chapter 9) and up to 773 MW of new wind generation in eastern Oregon. The amount of our resources that would use Cascade Crossing, rather than BPA transmission, includes the amounts described above plus provisions to provide station service for Boardman and Coyote Springs of 20.2 MW and 3.7 MW, respectively. This assumes that we will have to obtain transmission service for station service to Boardman and Coyote Springs after our IR contracts are converted to service under BPA's OATT.

Wind integration services are an ancillary service provided by BPA's Balancing Authority (BA), and are not a transmission service provided under BPA's OATT. As such, we believe that future wind resources could be included in BPA's BA so that PGE could purchase wind integration services from BPA for use with transmission over the Cascade Crossing line or for transmission on the BPA system. The wind integration costs would be the same whether or not we utilized Cascade Crossing or BPA transmission. Therefore, wind integration costs would have no impact on the economic analysis of Cascade Crossing.

In addition, at this time we do not know whether BPA will be able to provide wind integration services in the future for new wind resources, nor do we know what the price of BPA's wind integration service will be if it is available. Because of these factors, we do not include wind integration costs in our analysis of Cascade Crossing.

We analyzed the economic benefit for the top three preferred scenarios against five cases. The five cases utilize different assumptions for the growth rate of the

BPA transmission tariff rate and the extent to which we partner with other transmission providers in the project. Our three candidate portfolios that were analyzed under each of the five cases are "Diversified Thermal with Green", "Diversified Green" and "Diversified Green with On-peak Energy Target." These portfolios are described in Chapter 10. It should be noted that our analysis assumes that, in the absence of Cascade Crossing, BPA would construct new transmission that would enable us to transmit power from our existing and proposed resources to our load and that we will pay BPA for the transmission at BPA's embedded tariff rates. However, as discussed above, BPA is not currently proposing to develop such transmission and – even if it were to construct new facilities in response to a transmission request from PGE – it is not likely that such transmission could be completed in time to meet our resource needs.

The five cases that were investigated are identified as Case 1 to Case 5. Subsequent cases build on the previous cases. Based on our WECC Phase 1 studies, the capacity of the single-circuit option assumed in all cases is 1500 MW. The assumptions in Case 1 are that we partner with a third party for the 17-mile segment between the Boardman and Coyote Springs plants, and that BPA's transmission tariff rate increases at an average nominal rate of 4.0% from 2011 to 2025 after which the growth rate decreases to 2.5%, with a one-time increase in rates of 10% in 2015. A nominal rate of 4.0% is equivalent to a real growth rate of 2.06% given our inflation assumption of 1.9%, and a 2.5% growth rate is equivalent to a real growth rate of 0.588%.

In Case 1, PGEM utilizes all 1,500 MW of transfer capability from Boardman substation to Bethel. Note that this assumes use of transmission rights in an east-to-west direction up to the capacity of the facility, but assumes zero transmission sales or use west-to-east. In addition, our economic analysis does not include sales of excess capacity that may be available on a short-term firm or non-firm basis for any of the cases.

Case 2 is identical to Case 1 except that the assumed increase in BPA's transmission tariff after 2025 is 3.2% per year. A nominal rate of 3.2% is equivalent to a real growth rate of 1.276% given our inflation assumption of 1.9%.

Case 3 builds on Case 2, but adds an assumption that we partner with another transmission provider for the Coyote Springs substation expansion, which further reduces project costs to PGE.

Case 4 is identical to Case 3 except that another party purchases an equity share of the project equal to 209 MW of transfer capacity, which reduces our capital cost.

Case 5 is identical to Case 4 except that BPA's transmission tariff increases at a nominal 3.5% per year after 2025. A nominal rate of 3.5% is equivalent to a real growth rate of 1.57%.

Results – Single-Circuit

The two tables below show the results of our analysis comparing the alternative of purchasing transmission service from BPA for existing and future generating resources and constructing Cascade Crossing based on the aforementioned candidate portfolios and cases. The "Diversified Green" portfolio does not include the 450-MW natural gas combined-cycle resource, so in that portfolio we have assumed that the 450-MW transmission service request could be transferred to wind resources in the area. As a result, in the "Diversified Green" portfolio the amount of Cascade Crossing's capacity that wind generation facilities could utilize is capped at 773 MW.

Table 8-2 lists the difference in the Real Levelized Cost per kW-month of purchasing transmission service over the life of the project from BPA and from Cascade Crossing. Similarly, Table 8-3 lists the difference in the NPV, expressed in 2009 dollars (1,000s), of purchasing transmission service over the life of the project from BPA and from the project. In both tables, negative values indicate that it may be more cost effective to purchase transmission service from BPA rather than from Cascade Crossing. Conversely, positive values indicate that the project would provide an economic benefit in excess of costs, which includes a return on investment.

Table 8-2: Cost Differential between Cascade Crossing & BPA-provided Transmission Service (Single-Circuit)

	Net Real Lev./KW-mo.(2009$)		
	Portfolio		
Case	Diversified Thermal w/ Green	Diversified Green	Diversified Green w/ on-peak Energy Target
1	(0.2205)	(0.2591)	(0.1805)
2	(0.0766)	(0.1152)	(0.0366)
3	0.0318	(0.0023)	0.0725
4	0.1517	0.0951	0.0432
5	0.2125	0.1560	0.2308

Table 8-3: NPV Differential between Cascade Crossing & BPA-provided Transmission Service (Single-Circuit)

	Net NPV (2009$)		
	Portfolio Diversified Thermal w/ Green	Diversified Green	Diversified Green w/ on-peak Energy Target
1	($76,386)	($89,762)	($62,519)
2	($26,551)	($39,927)	($12,684)
3	$11,026	($798)	$25,104
4	$52,543	$32,963	$58,865
5	$73,635	$54,055	$79,957

The results across portfolios are generally consistent for each case. That is, while the level of net benefits or cost varies by portfolio, the results are generally positive or negative for all portfolios for a given case. The net benefits for all three portfolios are negative for Case 1 and Case 2, while the benefits for Case 4 and Case 5 are all positive. The exception is Case 3, where the result for "Diversified Green" shows a negative NPV, while the other two portfolios demonstrate positive NPVs.

We believe that the partnership and usage assumptions for the cases cover a range of reasonable and conservative possibilities. Further, a request has recently been submitted to PGE Transmission and Reliability Services to interconnect 500 MW of wind generation near Arlington and we are in active discussions with other potential partners to the project. We also believe that the assumed growth rates in BPA's transmission tariff are reasonable.

A sensitivity test was conducted to determine the BPA transmission rate increase which would result in a $0 NPV for Case 3 with the "Diversified Thermal with Green" portfolio. That is, at what BPA annual rate increase would we and our customers be indifferent between purchasing BPA transmission service and building Cascade Crossing? Our analysis shows that Cascade Crossing would break even if BPA's transmission rate increased at a nominal 3.76% per year for the life of the project. This translates into a real growth rate of 1.8% per year.

Key Financial Assumptions – Double-Circuit (2009 $)

The preliminary cost estimate for Cascade Crossing in the double-circuit configuration is $823 million (estimated by PGE consulting engineer, Black & Veatch). The project total cost, however, excludes property taxes (estimated at 1.5% of the project total cost) and allowance for funds used during construction. See Table 8-4.

Table 8-4: Cascade Crossing Capital Cost (Double-Circuit)

Capital Expenditures	Total
Substations	$201,500,000
Transmission - Structures	$377,000,000
Transmission - Conductors	$125,300,000
Transmission - Capacitor Banks	$19,200,000
Power Transformer at Bethel Sub	$25,800,000
Land and Rights-of-Way	$43,300,000
Environmental Assessment & Studies	$4,600,000
Permitting, Licenses & Fees	$2,600,000
Project Management	$4,100,000
Outside Legal Services	$1,000,000
Preliminary Engineering	$500,000
Public Relations & Education	$1,400,000
Habitat Mitigation Costs	$10,200,000
Contingency & Other Costs	$6,200,000
Total Project Cost	$822,700,000

Project Economic Analysis – Double-Circuit

Below we describe the cases and results for a double-circuit 500 kV transmission line with both lines strung. As with the single-circuit option, the economic analysis for the double-circuit option does not include sales of excess capacity that may be available on a short-term firm or non-firm basis for any of the cases.

In all cases, the assumed capacity of the double circuit option is 2,200 MW. As with the single-circuit option, the assumptions in Case 1 are that we partner with a third party for the 17-mile segment between the Boardman and Coyote Springs plants, and that BPA's transmission tariff rate increases at an average nominal rate of 4.0% from 2011 to 2025, after which the growth rate decreases to 2.5%, with a one-time increase in rates of 10% in 2015.

Case 2 is identical to Case 1 except that the assumed increase in BPA's transmission tariff after 2025 is 3.2%.

Case 3 builds on Case 2, but adds an assumption that we partner with another transmission provider for the Coyote Springs substation expansion.

Case 4 is identical to Case 3 except that an ownership share of the project equal to 300-MW transfer capacity is sold to a third party. This reduces our capital cost, but also eliminates our ability to sell the excess capacity.

Case 5 is identical to Case 4 except that BPA's transmission tariff increases at a nominal 3.5% per year after 2025.

Results – Double-Circuit

The two tables below show the results of our analysis comparing the alternative of purchasing transmission service from BPA for our existing and future generation plants and constructing Cascade Crossing as a double-circuit facility based on the aforementioned candidate portfolios and cases.

Table 8-5 lists the difference in the real levelized cost per kW-month of purchasing transmission over the life of the project from BPA and from Cascade Crossing. Similarly, Table 8-6 lists the difference in the NPV, expressed in 2009 dollars (1,000s), of purchasing transmission over the life of the project from BPA and from the project. In both tables, negative values indicate that it may be more cost effective to purchase transmission service from BPA rather than from Cascade Crossing. Conversely, positive values indicate that the project would provide an economic benefit in excess of costs, which includes a return on investment.

Table 8-5: Cost Differential between Cascade Crossing & BPA-provided Transmission Service (Double-Circuit)

	Net Real Lev./KW-mo.(2009$)		
	Portfolio		
Case	Diversified Thermal w/ Green	Diversified Green	Diversified Green w/ on-peak Energy Target
1	(0.5470)	(0.5683)	(0.4530)
2	(0.3648)	(0.3861)	(0.2708)
3	(0.2272)	(0.2472)	(0.1312)
4	0.1519	0.1359	0.2541
5	0.2415	0.2255	0.3437

Table 8-6: NPV Differential between Cascade Crossing & BPA-provided Transmission Service (Double-Circuit)

	Net NPV (2009$)		
	Portfolio		
	Diversified Thermal w/ Green	Diversified Green	Diversified Green w/ on-peak Energy Target
1	($189,513)	($196,883)	($156,929)
2	($126,388)	($133,758)	($93,804)
3	($78,722)	($85,656)	($45,461)
4	$52,635	$47,084	$88,044
5	$83,677	$78,126	$119,085

The results across portfolios are consistent for each case with results either positive or negative for all portfolios for a given case. The net benefits for all three portfolios are negative for Case 1, Case 2 and Case 3, while the benefits for Case 4 and Case 5 are all positive.

A sensitivity test was conducted to determine the annual BPA transmission rate increase which would result in a $0 net NPV for Case 4 with the Diversified Thermal with Green portfolio. That is, at what BPA annual rate increase would we and our customers be indifferent between purchasing BPA transmission service and building Cascade Crossing? Our analysis shows that Cascade Crossing would break even if BPA's transmission rate increased at a nominal 3.55% per year for the life of the project. This translates into a real growth rate of 1.6% per year.

Based on this analysis and the assumptions therein, the results suggest that, if the decision to develop Cascade Crossing as a double-circuit facility were based solely on the economics, we would only construct Cascade Crossing as a double-circuit facility if there were an equity partnership arrangement.

As mentioned above, the decision whether to proceed with Cascade Crossing and which option to construct will depend on an updated economic analysis. The results of the economic analysis inherently depend on the path rating, refined cost estimates, the level of equity participation in the project, the transmission service requests submitted to PGET and our generation facilities that would utilize the project.

A number of other considerations could lead to the determination that constructing a double-circuit 500 kV facility is the preferred option. These factors include optionality or flexibility to meet future need, efficiency of permitting process and mitigation of environmental impact. That is, siting and constructing a double-circuit facility may be prudent even if near-term needs would not immediately justify the additional circuit. Specifically, proceeding with the double-circuit option would create flexibility to meet future needs and require only one siting process, which is more efficient for the regulatory agencies, the utility and stakeholders. This would be analogous to siting a new generation plant site for multiple units and initially constructing one facility. Further, it could mitigate environmental impact since it would require only one R/W and would require less land, fewer structures and less visual impact.

Historical Context

For many years, the region enjoyed the benefits of having surplus transmission capacity. This surplus in transmission capacity has allowed transmission providers in the region to avoid making major transmission investments and to keep transmission rates relatively stable. For example, BPA has added relatively little new transmission facilities since it completed its portion of the third AC Intertie in 1993. However, the regional transmission system no longer has excess capacity, and is, in fact, constrained in its ability to meet current and future needs. As discussed earlier in this chapter, the region is now facing significant transmission constraints due to regional load growth. As a result, transmission providers, including BPA, are currently planning to add new, major transmission additions to address the lack of transmission capacity, which will likely put upward pressure on transmission rates.

In order to test our assumptions around the future growth rate in BPA's transmission tariff, we analyzed the historic growth rate of BPA's transmission tariff. The average growth rate in BPA's transmission tariff from 1991 to 2008 was 3.15% in nominal terms. The average growth rate of the consumer price index (CPI) over the same period was 2.73%. From 1993 to 2008 BPA's transmission tariff rate increased on average 2.2% in nominal terms, during which time the CPI increased at an annual rate of 2.69%. In other words, comparing growth rates from before and after BPA made one major transmission investment shows that the average growth rate of BPA's transmission tariff increased by approximately 1% due to adding one major project.

Through its open season process, BPA identified five transmission facilities that it plans to construct. BPA projects that these facilities will increase BPA's embedded-cost transmission rates by an average of 2.02% per year over the next 20 years on top of an assumed 1% annual rate increase in embedded rates if BPA made no transmission investments. This would result in an annual increase in embedded rates for the next 20 years of 3.04%. This assumes that the projects are built on time and on budget. BPA also assumes a 2% rate of inflation. Given BPA's historic rate increases, we believe that it is unrealistic to assume that BPA's "no-build" transmission rates will increase at a rate one full percentage point below inflation, and that adding five major transmission projects will increase its rates for the next 20 years only 1% above inflation. Furthermore, BPA recently received an additional $3.25 billion in borrowing authority to build transmission facilities in order to serve new renewable generation and other needs, which should increase BPA's ability to finance and construct a considerable amount of new transmission[81]. We believe that BPA's transmission tariff rate in the future will increase at a higher than historic rate. We also believe that BPA's transmission rates will increase more quickly than inflation and that BPA's rates may jump if BPA utilizes its additional $3.25 billion in borrowing authority to construct new transmission facilities. Further, although we are conducting our

[81] None of the projects that BPA has identified will resolve the need being addressed by Cascade Crossing.

economic analysis by comparing Cascade Crossing to assumed BPA tariff rates, we do not know that BPA will, in fact, build transmission that meets our needs or, if it does, at what cost.

Summary

Cascade Crossing will allow us to reliably deliver our existing and future generation resources to meet our customers' load, increase the path rating on the Cross-Cascades South path, improve system reliability, provide transmission price certainty, and reduce our dependence on BPA. In addition, Cascade Crossing will cross a region that has significant potential for new renewable resources. This proximity to potential renewable resources could help us deliver clean, carbon-free electricity to our customers and help us meet our RPS requirements. Therefore, we recommend and seek acknowledgment of Cascade Crossing as a double-circuit 500 kV facility.

8.6 Transmission Sizing

As discussed above, PGET has received a generation interconnection request from a third party to interconnect 500 MW of wind generation near Arlington. If the third party submits a transmission service request to transmit that generating capacity west, then a single-circuit 500 kV facility would not be adequate to meet all of the transmission service requests, nor could PGET satisfy the request using current facilities. In order to accommodate those requests, PGET would need to construct additional transmission facilities, such as a double-circuit 500 kV facility. Even without the additional requests, we believe that it would make sense to design and site the facility as a double-circuit 500 kV facility. If Cascade Crossing were to be sited and built as a single-circuit line it would only be sufficient to meet our current transmission requests for service between northeastern Oregon and our service area. If we were to require additional transmission capacity beyond our current NITS requests, PGET would have to go through the entire design, siting and planning processes to add another line, which would likely cost significantly more and require new rights-of-way.

At a minimum, a conservative estimate for designing, siting and adding another single-circuit at a later date would be equivalent to today's total project costs, inflated to the year that the expansion circuit was built. In addition, the future prices of construction materials such as aluminum and steel may increase faster than inflation, which would drive the cost of adding a second single-circuit at a later date even higher.

We must also consider the viability of permitting a second corridor in the future. Federal and state land and resource management agencies are being increasingly pressed through changes in environmental policy and case law to scrutinize cumulative environmental impacts on sensitive habitats and species. Permitting and siting Cascade Crossing to allow for two circuits will utilize less land for the corridors, require fewer river crossings and reduce the environmental impacts compared to constructing two separate transmission lines. While future policy trends are unknown, there is no question that sensitive habitats, such as late successional reserve forests in the Cascades, are diminishing and that future developments through such habitats may become impossible.

In order to provide for future load growth and transmission needs, we believe that siting, permitting and building Cascade Crossing as a double-circuit facility would be an efficient and prudent investment.

9. Benchmark Resources

Our forecasted load and resource balance indicates a need for additional firm generating resources to meet growing customer demand (see Chapter 3). As described below, we plan to develop and submit for consideration three new facilities (the "benchmark resources") for the purpose of comparing with and evaluating against the responses to energy and capacity request for proposals that we plan to issue pursuant to this IRP. In response to Guideline 13 of Order No. 07-002 addressing resource planning, this chapter contains a description of the proposed benchmark resources. The chapter also assesses the advantages and disadvantages of owning a resource instead of purchasing power from a third party. Natural gas acquisition and supply strategies for the benchmark thermal resources (and all of PGE's gas-fired resources) are addressed in Chapter 5, and transmission is discussed in Chapter 8.

Chapter Highlights

- PGE is proposing three benchmark resources – two natural-gas fired resources and one wind resource – that will be evaluated against the responses to energy and capacity request for proposals to be issued pursuant to this IRP.
- The proposed Port Westward II is an up to 200 MW flexible, natural gas-fired capacity resource located at PGE's existing Port Westward Generating Project site.
- The proposed Carty Generating Station is a CCCT energy resource with nominal capacity in the 300-500 MW range, located near PGE's Boardman Coal Plant.
- A 330- to 385-MW wind farm located in one or more of Sherman, Jefferson or Umatilla Counties.
- Utility-owned resources and contract resources offer different risks and benefits to the Company and our customers. However, PGE believes that ownership offers unique flexibility characteristics. These include extending plant life through repowering, upgrading or modifying with new technology to improve efficiency and performance, and altering plant operations and dispatch to respond to changing external conditions. These flexibility attributes are typically not available with contract resources.

9.1 Port Westward Unit 2

We demonstrate our need for additional capacity resources for reliability purposes in Chapter 3. In addition, as discussed in Chapter 7, our increasing level of intermittent energy resources necessitates that we maintain flexibility and load-following capability in our generation portfolio. As such, PGE is proposing a benchmark resource with a nominal generating capability of up to 200 megawatts (MW) to potentially fill part of our future capacity needs. The resource will be bid into a request for proposals (RFP) to be issued pursuant to this IRP. The proposed benchmark capacity resource is a state-of-the-art, highly efficient and environmentally responsible power plant consisting of multiple natural gas-fired reciprocating engine-generator sets and/or aeroderivative combustion turbine generators and associated equipment in simple-cycle operation. The proposed location is PGE's existing Port Westward Generating Project site.

This location has several advantages when compared to other potential site locations.

1. *Gas supply:* Port Westward has a lateral line from KB Pipeline that was designed for two plants. It is adequately sized to supply gas for the capacity resource being proposed. Long-haul gas transportation alternatives are being evaluated; future gas pipeline expansions being planned for this area should be more than capable of fueling the plant (see Chapter 5). Port Westward also has a pipeline connection to the NW Natural Mist Storage field that could be utilized as part of a combined fueling strategy for both plants.

2. *Transmission*: In order to be counted as a firm network resource, the resource must have firm transmission to PGE load. Firm transmission capacity from the east side to the west side of the Cascades to PGE’s system on BPA is not available due to constraints on the South of Allston path.

   With the addition of the new PGE transmission line from Port Westward to Trojan, PGE now has some additional capacity on our system to integrate Beaver to PGE load and can retain our existing BPA transmission capacity to allow delivery of power from a potential new resource located at Beaver. The Large Generator Interconnection Agreement (LGIA) is in the process of being executed with PGE Transmission. The existing switchyard is capable of being expanded to include connections to the capacity project.

3. *Land*: PGE currently has existing long-term site leases that will be used for developing this site.

4. *Permitting:* The existing Port Westward site certificate allows for building a second unit. PGE will go through the amendment process to secure all the required approvals for the capacity benchmark resource. This is quicker and more economical than starting a new site certificate process for a new green field site. The existing combined Beaver/Port Westward Title V air permit will also be amended to include the capacity project.

5. *Common Facilities:* The new Port Westward Unit 2 will use the existing staff with one or two additions for operations and maintenance. The existing control room, water supply, gas supply, fire water, backup power, communications and security will all be common and will result in lower operating and development costs. The existing wastewater discharge agreement with Port of St. Helens can be amended to accept the wastewater from the capacity resource.

6. *Site Access*. The Port Westward site has existing rail, water and paved road access.

9.2 Carty Generating Station

PGE is proposing a second benchmark resource, the Carty Generating Station, to help meet our future energy and capacity requirements. The resource will also be bid into an RFP to be issued pursuant to this IRP. This resource will be a highly efficient and environmentally responsible natural gas combined-cycle power plant. It will have a nominal capacity in the 300-500 MW range.

The resource is proposed for a site in the vicinity of the Carty reservoir in Morrow County near PGE's Boardman Coal Plant. This location has several economic advantages when compared to other potential site locations:

1. *Natural Gas*: Close proximity to Trans Canada GTN interstate pipeline, which has adequate capacity to supply the plant's fuel requirements.

2. *Transmission*: The existing 500 kV transmission line to the Boardman Plant has adequate capacity for both Boardman and the new Carty Generating Station. The primary transmission path is currently from BPA through the NOS process. In addition, if developed, the Cascade Crossing Project will provide a direct 500 kV link from the Boardman site into PGE's transmission system.

3. *Water*: The existing water rights for Boardman have adequate excess capacity to supply the water requirements for Carty. Raw water will be provided to the Carty Generating Station from Carty Reservoir, utilizing the existing Boardman intake structure. No new water rights will be required.

4. *Land*: Land near Boardman, some of which is already owned by PGE, will be utilized for locating the plant and the substation. The land is geologically sound, reasonably level and close to the existing Boardman Plant. As the area already supports power generation, permitting additional generation in this location is not expected to be an issue. Being in close proximity to Boardman will allow for economic supply of construction power and water. It also allows for the potential to share some common facilities between Boardman and Carty. Although this new plant will be operated by a separate staff, the sharing of some common facilities could result in lower development and operating costs.

5. *Common Facilities*: Existing Boardman facilities could be shared with Carty, and new facilities installed at Carty could provide additional redundancy to Boardman. Potential common facilities could include: potable water, sanitary sewage, fire water, Internet and microwave connections, standby electrical power, and others.

6. *Access*: Tower Road will provide existing paved road access to the site for construction traffic and permanent operating staff. In addition, the existing rail spur to Boardman could be utilized for oversized and overweight deliveries. The site is also reasonably close to barge unloading facilities on the Columbia River should any of the major deliveries come via ocean cargo.

9.3 Wind Benchmark Resource

PGE is proposing a benchmark wind resource to fill part of our overall energy need and to help meet the 2015 Oregon RPS target. The benchmark wind resource will be sized in the 330-385 MW range. The resource will also be bid into an RFP to be issued pursuant to this IRP. The resource is proposed for a site in one or more of Sherman, Jefferson or Umatilla counties[82] and is expected to be on line on or before December 31, 2014.

[82] Because PGE is currently in negotiations with landholders for lease rights, it cannot specify the exact plant location at this time.

9.4 Advantages and Disadvantages of Ownership vs. PPAs

Guideline 13 of Order No. 07-002 instructs electric utilities to assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. Furthermore, the guideline provides that the pros and cons should be evaluated from the perspective of the utility and its customers and the assessment should be rigorous enough to provide a basis for evaluation and scoring criteria in any subsequent RFP.

Some of the advantages of owning a resource include:

1. *Synergies with Existing Resources*: An ownership option may provide the utility with access to existing locations and infrastructure which will save cost and minimize the footprint of a new generating project. For example, the proposed Port Westward Unit 2 project will be built at the existing Port Westward site, and will not require new roads or other infrastructure other than the new plant and some minimal appurtenant facilities.

2. *Financing*: Following the global financial market crisis of 2008, capital has remained both tight and relatively expensive unless the borrower / investor exhibits a strong balance sheet and credit rating. Accordingly, many developers have found that securing capital at a reasonable cost is more challenging for the foreseeable future. Utilities, including PGE, have generally maintained relatively low debt to total capital ratios, and strong credit ratings throughout the financial market crisis. As a result, utilities may be better positioned to raise capital to develop and construct a project in the near-to-mid term. The ability to raise capital at a reasonable cost provides increased certainty that once a good resource is identified the development will go forward to completion.

3. *Cost of Credit*: In response to the energy crisis, and reinforced by the recent turmoil in the financial markets, most long term PPAs come with an imputed debt component and margin requirement costs. Credit rating agencies measure and report Imputed Debt to reflect the future cash flow commitment of the buyer as if it were debt. Once added, credit rating agencies are able to compare the risk of default for different companies normalized for their choices to build or enter into a PPA. As a result PPAs reduce our financial flexibility or increase our borrowing costs.

   Margin requirements are now a standard feature within most fixed price PPAs. This feature is meant to protect both the buyer and the seller from the likelihood of default when market prices move materially from the negotiated fixed price of the PPA. If market prices move up from the negotiated fixed price, the buyer is exposed to higher cost for replacing the energy if the seller defaults, while the seller could default on the lower fixed price contract in order to sell that energy into a higher-priced market. In this case, the margin requirement clause would require the seller to post a cash collateral or letter of credit to the buyer and vice versa if market prices move down.

Both imputed debt and margin requirements further tip the scale in favor of ownership to the detriment of PPAs. PPAs will solely add to the liability side of PGE's Balance Sheet without any of the benefits of ownership, thus artificially raising PGE's cost of debt.

4. *Long-term Access to Resources*: Since much of the value of many types of generation, particularly wind and other renewables, is uniquely tied to the specific project location, longer-term access to these sites can provide important risk mitigation for utility customers. An ownership option provides the utility the opportunity to make life extension improvements, use the site for additional resources in the future, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and pass on to its customers the benefits of these opportunities. While some long-term access could potentially be obtained through negotiated extension rights in a Power Purchase Agreement (PPA), the benefit is clearly attained in a utility-owned project.

Ownership options have some disadvantages as well. Owning a plant potentially exposes the utility and customers to the risk that the cost of ownership and operation exceed available market-priced alternatives, the cost of poor project performance or early retirement, and unknown liabilities associated with reclamation[83] at the end of the project life. However, project performance risk is usually mitigated through equipment selection and siting[84]; a well-developed and managed engineering, procurement and construction plan prior to commercial operation; plant operator experience and knowledge; maintenance plans; and management of the relationship with local distribution and transmission system operators. A utility can also minimize energy output risks to

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[83] However, most power plant developers will price in abandonment costs in their long-term power purchase agreement, and in the final analysis the utility and its customers pay those unknown costs as well.

[84] In the case of wind, turbine micro-siting (the placement of wind turbines at specific sites) is fundamental in capturing energy from a site. Maintaining appropriate turbine spacing parallel and perpendicular to strong directional wind flows or in consideration of forecast wind rose (the expected direction and magnitude of winds on project lands) is also critical. Spacing turbines too close together will cause downwind turbulence and loss of energy, while excessive spacing will result in forgone generation opportunity due to less than an optimal number of turbines on a project site.

it and its customers by negotiating effective performance guarantee, warranty and maintenance provisions in the turbine supply agreement and/or engineering, procurement and construction agreement.

While such provisions may also be available in a PPA, an ownership option enables a utility to better control all of the factors described above. Under a PPA, the utility and its customers may not receive any of the savings that result from management of the project. In the case of contract resources, utility customers also do not receive any of the value that may be associated with a project after the contract has expired (e.g. site lease renewals, generation repowering or capital additions to extend the project life).

The selection of a PPA resource or a utility-owned resource remains situational, depending upon a number of factors including the particular characteristics of the project, the ability to raise financing, as well as the profile and circumstances of the seller and utility at the time of selection. Accordingly, a comprehensive and case-by-case approach should be used to assess the differential risk of utility-owned vs. contracted resources.

10. Modeling Methodology

The goal of the IRP is to identify a mix of new resources that, considered with our existing portfolio, provides the best combination of expected costs and associated risks and uncertainties for PGE and our customers. In order to achieve this goal, we must first examine the relevant types of risk and cost that can be forecast and measured through the IRP process, as well as how those results should be interpreted and applied to resource decision-making. Given the many uncertainties facing the energy industry today, our analysis and risk evaluation approach must be broad and flexible enough to identify and describe the many possible conditions that may be encountered over a long-term planning horizon. In this chapter we provide both a conceptual overview of how we think about and assess risk and value for the IRP, as well as a detailed description of our analytical methods, tools and metrics.

Resource planning analytics primarily involve estimating future expected costs for various potential portfolios of resources along with an assessment of the range of possible variations in outcomes around those expected costs. IRP analysis also requires making point estimates and risk assessments that extend well beyond the current timeframe. Given the potential for significant timing differences between planning and implementation, we must consider the possibility that current circumstances may change, perhaps dramatically, over time. History of the energy markets has consistently demonstrated that supply-demand equilibrium can fluctuate and that structural changes and market evolution with significant impacts on price and availability do occur. Additionally, evolving state and federal energy policy and related legislative requirements must be considered.

As a result, we believe that it is most effective to apply a broad set of tools and techniques to assess resource and portfolio performance across a wide range of potential future environments. In addition, we believe that it would not be wise to rely on any single performance metric or analytical method. There is simply no single right answer when evaluating an uncertain energy supply future. Rather, the collective insights derived from quantitative and qualitative performance measures instruct and guide our business judgment and strategic decision-making with respect to the selection of a preferred future portfolio.

As with our previous IRP, we use AURORAxmp® by EPIS, Inc. to assess Western electricity supply and demand as well as resource dispatch costs and resulting market prices on an hourly basis for the entire WECC region across our planning horizon. In doing so, we gain better insights into the impacts of different potential future resource choices, both by PGE and other regional participants, through advanced sensitivity and scenario-testing capabilities.

We continue to use net present value of revenue requirements (NPVRR) to assess the expected cost of portfolios. We employ a variety of deterministic, stochastic, reliability and diversity metrics to examine the various risk and durability aspects of portfolios. We continue to evaluate risk according to two primary categories: scenario risk, which we describe as “futures”, and stochastic risk.

More detail regarding our specific risk metrics and modeling methods are presented later in this chapter.

Chapter Highlights

- We use AURORAxmp® to conduct fundamental supply-demand analysis in the WECC, dispatch existing and potential new resources, and project hourly wholesale electricity market prices.
- We constructed 15 discrete portfolios representing either predominantly a single resource or a diverse mix of resources. We then calculate the total expected long-term variable power cost and fixed revenue requirement of each portfolio.
- We assess the total expected portfolio cost (measured as the NPVRR) and related risk using various metrics for each portfolio using both deterministic scenario and stochastic analyses.
- We test these portfolios using 21 different futures representing various potential risks and uncertainties.
- Our stochastic analysis includes changes in load, hydro generation, natural gas prices, wind generation availability and unplanned thermal generating resource outages. These in turn directly impact wholesale electric prices.

10.1 Modeling Process Overview

Our modeling process is composed of three primary steps:

1) We conduct fundamental supply-demand analysis in the WECC using AURORAxmp with the goal of projecting hourly wholesale electricity market prices for all areas in the WECC.

2) We then estimate expected variable and fixed costs of our new resource alternatives. This process includes:

   - Dispatching existing and future alternative resources available to PGE in AURORAxmp, using AURORAxmp's projections of hourly electric market prices and resource availability (subject to transmission constraints) for all areas in the WECC;

   - Grouping alternative resource mixes in different portfolios and calculating the total long-term variable power cost of each portfolio in AURORAxmp;

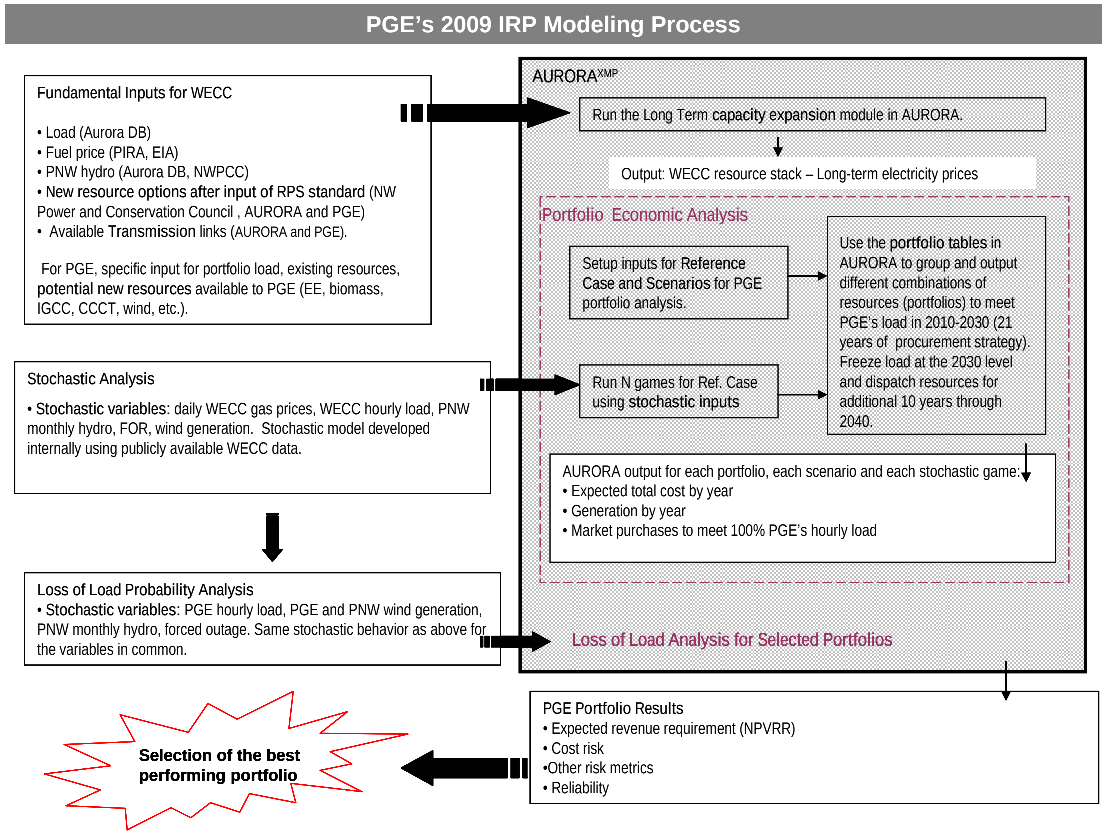
   - Combining the variable power cost from AURORAxmp with the fixed revenue requirement (capital and fixed operating costs), determined using our spreadsheet-based revenue requirement model, for each of the alternative portfolios; and

   - Calculating the NPVRR over the planning horizon (from 2010 to 2040). The NPVRR is our primary long-term cost metric.

3) Using scenario (or deterministic) analysis, we then assess portfolio risk performance for each portfolio based on change in portfolio costs under varying future conditions (i.e., changes in fuel prices, emissions costs, etc). We also consider reliability, emissions profile, diversity and concentration of technology and fuels, financial commitment, and other criteria for each portfolio. We perform stochastic analysis for all portfolios using only the reference case future.

Figure 10-1 summarizes PGE's modeling process.

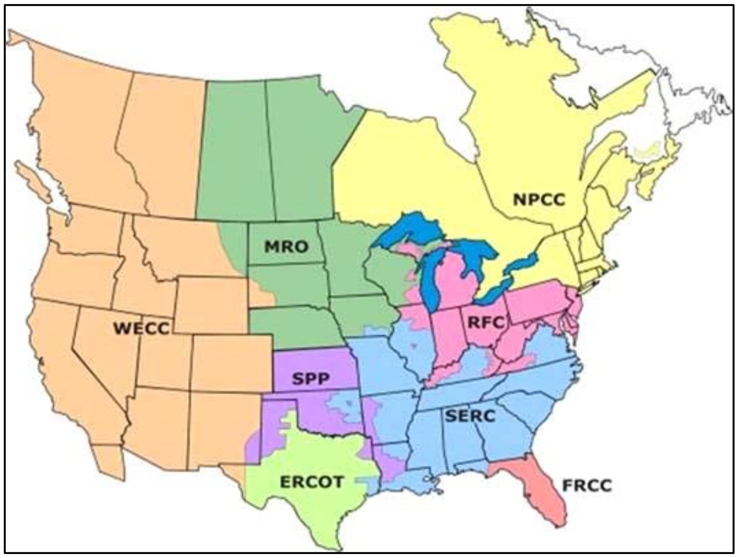
Figure 10-1: Modeling Process for the 2009 IRP



10.2 WECC Topology

We paid particular attention to EPIS-supplied transmission topology and constraints and WECC loads and resources to estimate WECC market prices. The key components of the AURORAxmp topology are areas, zones, and transmission links. AURORAxmp has an extensive database that includes existing resources, new resource costs, electric loads, and fuel costs for North America. Our modeling focused on the WECC region (see Figure 10-2), which includes British Columbia, Alberta, the Pacific Northwest, California, the Southwest, Idaho, Colorado, Utah, Montana and Wyoming.

Figure 10-2: WECC Region Map



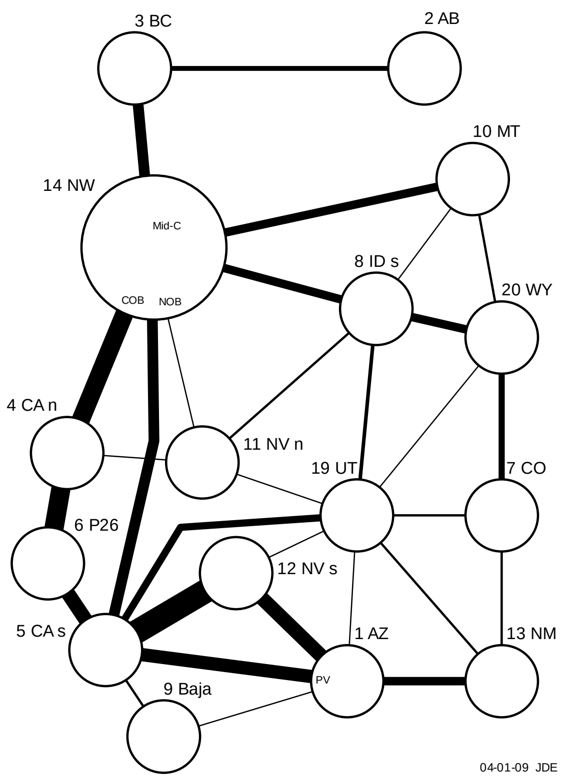
The database is subdivided by region, defined as a geographical area with no internal transmission constraints. Transmission links connect the different areas, define the import-export capability between them, and set related wheeling costs and losses.

AURORAxmp areas are further consolidated into zones, which represent markets. AURORAxmp calculates the dispatch cost of all WECC resources each hour and, for each zone, selects the least-cost incremental resource available to meet load by choosing to generate within the zone or import electricity from other less expensive zones. Intra-zone transmission is ignored in the dispatch logic because AURORAxmp assumes that intra-zone transmission does not constrain plant operations within a zone. Inter-zone transmission sets the maximum import-export capability between zones.

In this IRP, we adopted the default topology of AURORAxmp with the PNW as one zone. We validated transmission capability, expected losses and wheeling to current path ratings, and adjusted default database import/export capability between zones only when we had documentation proving a change in the data base since its release.

The resulting WECC configuration is composed of 16 total zones as shown in Figure 10-3. The thickness of the lines in the figure indicates the relative transfer capability between two zones.

Figure 10-3: WECC Topology



Legend	
1 AZ	Arizona
2 AB	Canada-Alberta
3 BC	Canada-British Columbia
4 CA n	Northern California
5 CA s	Southern California
6 P26	California -ZP26+
7 CO	Colorado
8 IDs	Idaho South
9 Baja	Mexico-Baja California North
10 MT	Montana
11 NV n	Nevada North
12 NV s	Nevada South
13 NM	New Mexico
14 PNW	Pacific Northwest
16 WY	Wyoming

10.3 WECC Long-Term Wholesale Electricity Market

As in the 2007 IRP, we used AURORAxmp to simulate the long-term build-out of WECC resources to meet future electricity demand and generate hourly electricity prices to be used in our portfolio analysis.

The AURORAxmp database specifies load, expected load growth over time, resources, transmission capability, fuel prices, hydro potential and generation, and generation resource emissions for each zone in Figure 10-3. AURORAxmp simulates the WECC markets every hour by calculating the electricity demand of each of the 16 zones and stacking resources to meet demand and reliability standards with the least-cost resource, given operating constraints. The variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period establishes the marginal price.

We used a transparent approach that relies on the default data base in AURORAxmp and validated it using our professional judgment and the advice and expertise of the NWPCC[85]. Following are highlights of the main assumptions we used and a description of the results.

Regional Resource Modeling Assumptions

We imposed the following criteria on the WECC long-term wholesale electricity market:

1. A reliability standard that adds sufficient resources in the WECC to meet the 1-in-2 peak load plus operating reserves of about 6%. Like the NWPCC, we allow utilities within the Northwest Power Pool and California to share their reserves (so that, for example, the west side of the Pacific Northwest takes advantage of the surplus capacity of the east side).

2. A carbon cost of $30 per short ton of CO_2, real levelized in 2009$, starting in 2013[86].

3. We keep fuel costs constant in real dollars after 2025 (because forecasts become increasingly uncertain and speculative beyond that point).

4. Implementation of all approved state RPS targets in place as of year-end 2008.

Table 10-1: RPS Requirements in WECC

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

5. As required by Guideline 1a of Order No. 07-002, we applied PGE's after tax marginal weighted-average cost of capital of 7.59% as a proxy for the

[85] PGE has attended most meetings of the NWPCC on cost assumptions for the Sixth Northwest Electric Power and Conservation Plan and relied on the NWPCC work.

[86] See Chapter 6 for a discussion of how we calculated the carbon tax.

long-term cost of capital in the WECC. Table 10-2 contains our other financial assumptions.

Table 10-2: Financial Assumptions

	Percentage
Income Tax Rate	39.29%
Inflation Rate	1.90%
Capitalization:	
Preferred Stock	-
Common Stock (50% at 10.75%)	5.38%
Debt (50% at 7.31%)	3.66%
Nominal Cost of Capital	9.03%
After-Tax Nominal Cost of Capital	7.59%
After-Tax Real Cost of Capital	5.59%

6. For modeling purposes only, we did not allow AURORAxmp to make plant retirements prior to the end of their original book lives.

Resource adequacy standards and RPS implementation are key drivers of long-term resource additions in the WECC. Figure 10-4 highlights the significant build-out of renewable energy resources due to approved RPS targets in the WECC. After these projected resource additions, the WECC resource mix in 2040 is composed of 34% gas-fueled plants, 32% non-hydro renewable resources, 16% hydro, 9% coal, and 9% nuclear. For more detail, see *Appendix C.*

Figure 10-4: WECC Resource Additions

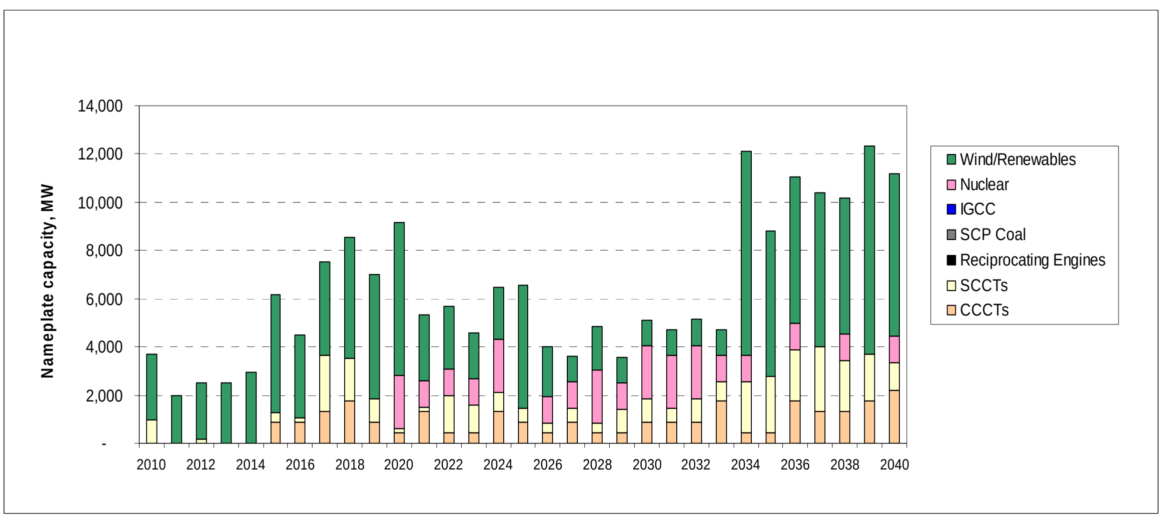
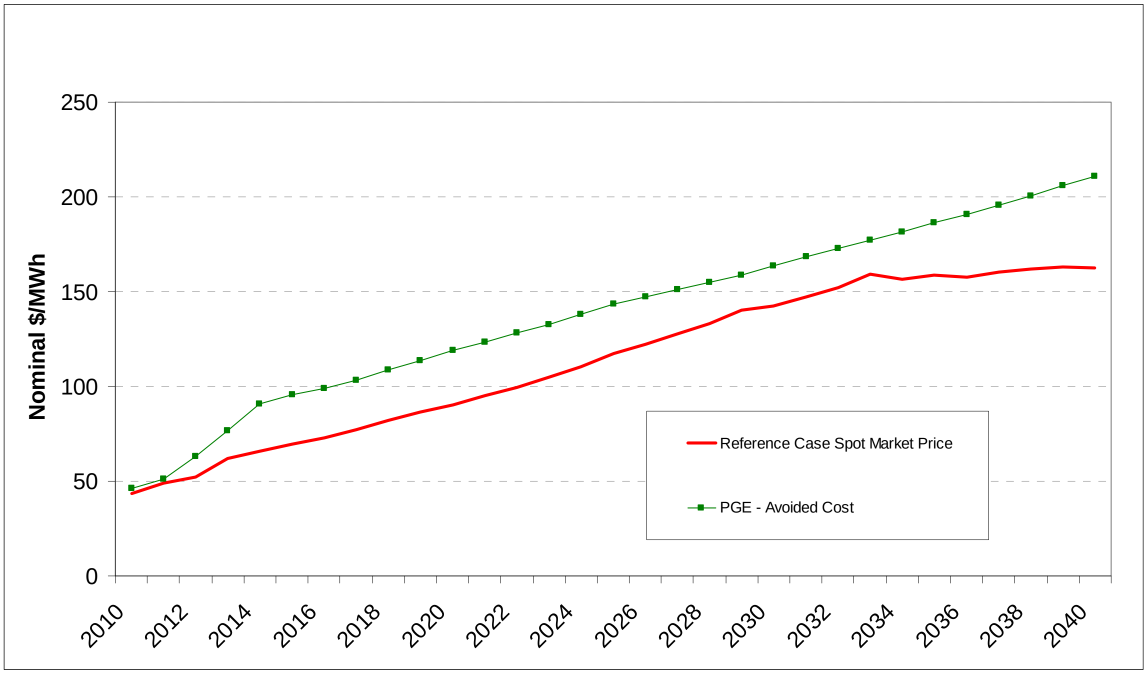


Figure 10-5 shows the resulting average annual electricity market price projection for PGE using the reference case assumptions described in the following paragraphs. For more detail, see *Appendix C.*

Figure 10-5: PGE Projected Electricity Price – Reference Case



Once we developed a forecast reference case market price for electricity in AURORAxmp, we compared it with the fully allocated cost of the avoided resource for PGE, which we currently assume to be a new CCCT G-class plant. We do this to validate AURORAxmp's output and understand the potential consequences of using AURORAxmp's endogenous prices for portfolio analysis. AURORAxmp projects lower prices than the CCCT ($73 vs. $90 per MWh in 2009$, real levelized for the period 2010-40) for the following reasons:

1. AURORAxmp assumes that surplus power will be priced at short-term marginal cost and will be traded, if economic, until transmission limits are reached.

2. Reserve margins imposed to assure reliability and resource adequacy cause the WECC to be in surplus for most hours of the year.

3. New generating plants are added at their typical plant size, which may be larger than the incremental resource need at the time of addition. New resource additions, which are typically large, thus cause temporary over-supply conditions until load growth catches up to new lumpy resource additions.

4. Given these assumptions, the AURORAxmp forecasted electricity price is generally not adequate to achieve a positive return of and return on invested capital for new resources. Therefore, it is assumed that fixed

costs, particularly for capacity, would need to be recovered through regulation or a separate capacity market.

The assumptions we impose on AURORAxmp, while reasonably constraining the model to meet reliability standards over the long haul, do not reflect the discretion of individual utilities and market participants to deviate from these norms, nor do they recognize that, in the short run, supply imbalances have occurred and can cause reserve margins to shrink, causing scarcity and market prices that dramatically exceed marginal and fully allocated costs. A simplified modeling world that always has adequate resources and market prices that are below avoided cost may unwisely suggest a deliberate short-supply strategy in which a utility ignores recommended resource adequacy standards. This simplification ignores real-world supply, price and reliability risks and may also be inconsistent with emerging resource adequacy standards as described in Chapter 3. To offset this potential bias in favor of a deliberately short strategy, we designed scenarios that describe potential market shocks such as high electric prices or higher-than-expected load growth. These scenarios reveal the risks of such a short strategy.

The WECC resource mix and resulting market price forecast created in this step are used in our portfolio and stochastic analyses. Changes in fundamental assumptions for portfolio analysis, such as natural gas prices, potential CO_2 costs, and load growth rates, do not cause any adjustments to the WECC resource mix in our modeling. That is, we do not rerun the AURORAxmp WECC capacity build-out in response to different future scenarios such as a high CO_2 cost. Changes in fundamental assumptions do, however, affect resource dispatch cost and order and lead to differing spot electricity prices.

10.4 Portfolio Analysis

The next step of our analysis is to identify the combination of resources that, when added to the existing PGE portfolio to meet expected future load, achieves the best combination of cost and risk. To avoid confusion we will use the following terminology when discussing portfolios, futures and scenarios. First, portfolios are a mix of resources which will meet our future energy and capacity needs. Futures are a set of input assumptions for the behavior of a set of variables over the planning horizon (31 years). Finally, scenarios are the intersection of a portfolio with a future. Table 10-3 below visually demonstrates this.

Table 10-3: Portfolios, Futures and Scenarios

Future / Portfolio	Future 1	Future 2	Future 3	Future 4
Portfolio 1	Scenario 1,1	Scenario 1,2	Scenario 1,3	Scenario 1,4
Portfolio 2	Scenario 2,1	Scenario 2,2	Scenario 2,3	Scenario 2,4
Portfolio 3	Scenario 3,1	Scenario 3,2	Scenario 3,3	Scenario 3,4
Portfolio 4	Scenario 4,1	Scenario 4,2	Scenario 4,3	Scenario 4,4

In creating, selecting and analyzing our portfolios, we:

1. Identified expected future resource needs based on the load and resource balance reporting theoretical plant availability and capacity by year (see Chapter 3). We identified a few target years for our action plan, when the large gap in energy or capacity suggests procuring long-term resources. The most immediate gap is 2013 for capacity. Additional gaps for both energy and capacity are in 2015, 2017 and 2019.

2. Constructed alternative portfolios with different mixes of resources to meet the expected load-resource gap through 2030 by target year. After 2020, however, we add only those demand-side resources (including EE) that are economic to achieve, renewables to meet RES requirements and spot electricity market purchases for the remaining need.

3. Created each incremental portfolio to contain:

    - Approximately the same amount of energy generating capability on an annual average basis for the target years 2015, 2017 and 2019;

    - An equivalent amount of capacity for the target years 2013, 2015, 2017 and 2019. Once we input demand-side capacity resources, any remaining capacity necessary to meet our 1-hour peak load inclusive of operating reserves is filled by simple-cycle combustion turbines (SCCT, used as proxy for a capacity resource) and/or on-peak purchases. Also, for modeling purposes, we constrained our portfolios to rely on spot market purchases for up to 300 MW of capacity.

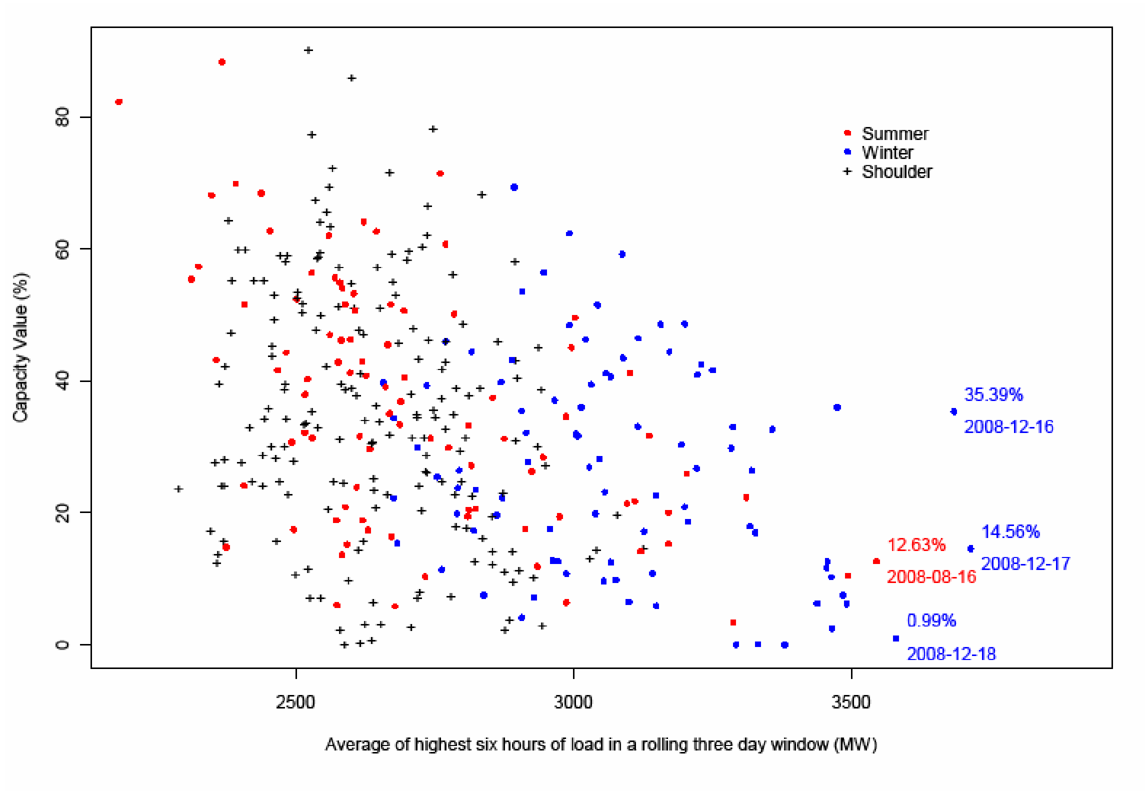
4. Dispatched the portfolios, including existing and new resources, from 2010 to 2040.

5. Added capital and fixed costs for both existing and new resources.

6. Compared the expected cost and risk performance of portfolios across different futures and stochastic iterations. Futures were constructed with input from OPUC staff and other stakeholders. See Section 10.6 for a description of the various futures we used.

For wind, we modeled a capacity value equal to 5% of the nameplate capacity, which is commonly used by the WECC and NWPCC in their regional load resource assessments. The NWPPC has been coordinating a multi-utility effort[87] to estimate a reasonable capacity value for wind to use in the Pacific Northwest for long-term planning purposes. To validate that the Council's number is appropriate for PGE's system, we replicated their methodology using 2008 PGE load and Biglow production data – see Figure 10-6 below[88].

Figure 10-6: Biglow Capacity Value 2008



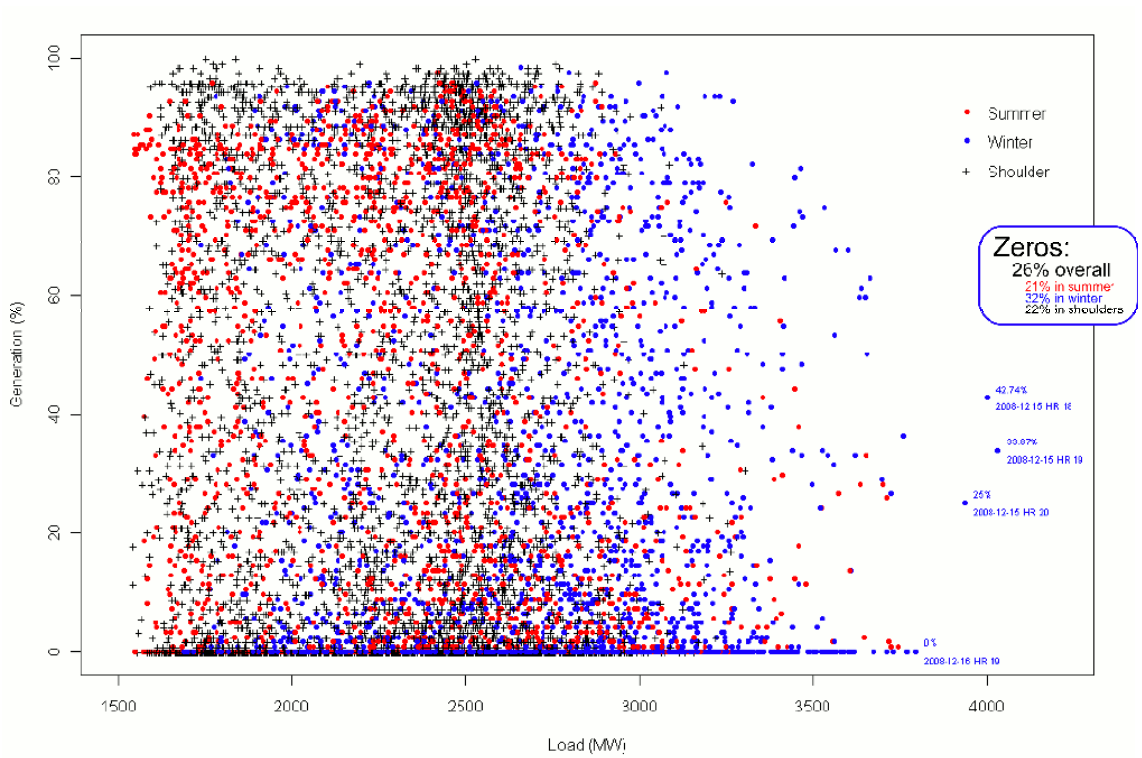
[87] Wind Task Force of the Resource Adequacy Forum

[88] We calculated the sum of the six highest hours in each day across a three-day window that moves across the year and then computed the average load across the 18 hours in each window to provide the x-coordinate for each point on the graph. To produce the y-coordinate, we divided the hourly production of Biglow by the plant capacity, and computed the average plant production across the 18 hours.

The rightmost points on the graph correspond to the highest average load, and provide some indication of how the Biglow wind farm performs in PGE's sustained peak load hours. PGE's highest observed average load corresponds to a capacity value for Biglow of 15% (corresponding to the one number produced by the NWPCC methodology). Examining the collection of points as a whole, however, it becomes difficult to justify choosing this single point for the capacity value, especially in light of the near neighbors at 35% and 1%. In light of the uncertainty of the capacity value for high load hours and the fact that this data represents only one year of data for one plant, the NWPCC's 5%, which is based on a broader set of data for the whole region, can be seen as a reasonable value for the capacity of wind in PGE's system. We consider this assumption a placeholder, subject to revision once we obtain more years of wind data and gain a better understanding of wind behavior in the Pacific Northwest during peak demand events.

It should be understood that this capacity value does not indicate the reliability of wind in any given hour, but rather represents an average availability across many hours. Examining the 2008 Biglow data on an hourly basis (see Figure 10-7) confirms this; while there is a substantial number of high load hours with wind production, 26% of all hours have no wind production at all. The capacity value above is useful for economic purposes, but does not fully characterize the intermittent nature of wind.

Figure 10-7: Production Factor 2008



For solar energy, we also modeled a 5% capacity value. PGE has not yet conducted a solar capacity study and little research has been done in this area for Northwest solar resources. As a result, the 5% value represents a proxy until more specific research is available. PGE is winter peaking, when irradiation is at its minimum. A summer capacity value would probably be much higher.

We included in candidate portfolios those resources that are considered commercially available on a utility scale by 2020, including wind, biomass, solar, geothermal, wave energy, energy efficiency, CHP, nuclear, IGCC, CCCTs and SCCTs. To assess the performance of each resource alternative, we first used a bookend or pure play approach, whereby we created incremental portfolios relying primarily on one long-term resource type (i.e., all wind, CCCT, and all spot market). With input from stakeholders, we then constructed a number of more diverse portfolios to test the performance and risk mitigation potential of various combinations of candidate resources. All portfolios were constructed to meet the 2025 Oregon RPS standard. See Table 10-4 and Table 10-5 for the energy composition of our portfolios, and Table 10-6 for the capacity composition of our portfolios.

All portfolios will have the following in common:

- PGE's existing long-term resources (including additions from the 2008 Renewable RFP).

- Energy efficiency (both embedded and annual increments) – we will use values provided by the ETO. Current estimates show an average annual incremental amount of approximately 28 MWa of cost-effective EE through 2019, declining thereafter. ETO did not include any "emerging" technologies in this study, thus the decline in incremental EE projected in later years.

- Demand-side response of 60 MW. This value is composed of the 50 MW demand-response RFP (DR-RFP) and 10 MW from Schedule 77. The DR-RFP is designed for three peak periods in the calendar year. Peak Periods are 3:00 p.m. to 7:00 p.m. during the summer season (July-September), as well as 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m. during the winter season (December - February). Schedule 77 is a pilot tariff effective July 9, 2009 that allows large nonresidential customers the opportunity to reduce their load in response to PGE request.

- Dispatchable standby generation (DSG) – for modeling we will include our 2008 level of DSG (53 MW), increasing 15 MW annually until we reach 120 MW in 2013 – the current projected maximum available.

- Spot market purchases – as modeled, these are made in hours in which it is either more economic, or to supplement PGE's owned resources.
- Renewables – we will model RPS compliance in all years of the analysis. RPS resources are generally backed up by flexible natural-gas fired resources (377 MW by 2030). For modeling purposes, we used an LMS100 simple-cycle turbine, which has a heat rate of 9165 and can reach full capability within an hour.
- Except for Portfolio 1, all portfolios add 200 MW of flexible natural-gas fired capacity in 2013 and all portfolios are limited to 300 MW of market capacity purchases annually.

All portfolios contain about 100 MWa of short- and mid-term market purchases to provide supply flexibility and responsiveness in serving uncertain commercial and industrial load. As described in Chapter 3, all of our commercial and industrial customers have the option of choosing an alternative energy provider with one year's notice. Large customers can make this election for up to five years. In aggregate, 300 MWa of customer load is eligible for these programs. We are proposing to manage this uncertainty in annual load by meeting about 100 MWa of the expected load in 2020 through a mid-term procurement strategy. An additional 66 MWa is associated with renewal of an expiring hydro contract.

As required under Guideline 8b of Order No. 08-339, we incorporate end-effect considerations as follows. Our portfolio analysis is conducted from 2010 to 2040, over 31 years of dispatch of new resources across all futures. End-of-life effects are addressed by using the real levelized fixed revenue requirement calculated over the life of the plant. For generation projects that have a book life beyond 2040, the net margin in 2040, where margin equals the difference between market revenue and variable costs for the facility, is presumed to equal the marginal profit, escalated at inflation, for plant output for the remaining years of plant life beyond 2040. The total marginal profit for the plant is discounted back to 2040. Similarly, the remaining unrecovered capital and fixed costs are discounted back to 2040 and subtracted from the net marginal profit. This sum is then discounted back to 2009 and included in the NPVRR. Note that if the variable margin in 2040 is negative, then variable margin for the remaining years of life is assumed equal to zero.

For modeling purposes only, existing PGE power plants that expire or reach the end of their original book life before 2040 are not retired, with the exception of Boardman, which is retired in 2011, 2014, 2017 or 2019 in a few portfolios, and Colstrip, which is retired in 2019 in the Oregon CO_2 Goal portfolio. Long-term contracts are generally not extended beyond their term, and are therefore replaced upon expiration. There is only one exception: a long-term hydro contract expiring in 2011, for which we anticipate renewal.

The main differentiating characteristics for the different portfolios are:

1. *Market*. This portfolio does not add any long-term supply-side resources other than those identified above that are added to all portfolios. It is an aggressive "go short" strategy that relies on the regional electricity market to meet load. It does not meet reliability standards.

2. *Natural Gas*. This is a portfolio that tests the impact of using gas technologies to meet all our incremental energy need. We add a 441-MW CCCT in 2015 and 2019 and a 59 MW SCCT in 2017.

3. *Wind*. This portfolio selects exclusively wind to meet our incremental energy need. We add 285 MWa (about 920 MW nameplate capacity) in 2015, 155 MWa (535 MW) in 2017 and 180 MWa (620 MW) in 2019. SCCTs provide capacity and are added in 2015 (120 MW), 2017 (307 MW) and 2019 (256 MW).

4. *Diversified Green*. This portfolio seeks a more diverse set of renewable resources to meet our energy need. We test the addition in 2015, 2017 and 2019 of 17 MWa (20 MW) of biomass, approximately 2 MW of CHP, 26 MWa (30 MW) of geothermal, 1 MWa of PV solar, 3 MWa of central station solar, and 9 MWa of wave energy in 2017 and 2019. Wind fills the remaining need: 220 MWa (about 710 MW) in 2015, 70 MWa (about 240 MW) in 2017 and 115 MWa (about 397 MW) in 2019. SCCTs are added for capacity in 2015 (77 MW), 2017 (259 MW) and 2019 (204 MW).

5. *Diversified Thermal With Wind*. In this portfolio, we pursue a diversified procurement strategy consisting of a 441-MW CCCT in 2015, with a mix of wind (10 MWa in 2017 and 135 MWa in 2019 (approximately 35 MW and 465 MW, respectively) and other renewables (2 MW CHP in 2015, 2017 and 2019; 26 MWa geothermal in 2019; 4 MWa of solar in 2019) filling the remaining energy need. SCCTs are added for capacity in 2017 (53 MW) and 2019 (230 MW).

6. *Bridge (2015) to IGCC in Wyoming (2019)*. This strategy relies on PPAs to fill our energy need in the mid-term until a large scale IGCC plant could potentially be available. For modeling purposes, we assume that the IGCC is a mine-mouth plant in Wyoming, the closest site to PGE that does not have legal constraints to construction of new coal plants. Also for modeling purposes, we assume an investment in the related new transmission line that would be built to connect Wyoming to the PNW. In this portfolio, we add 400 MW of PPA with a four-year duration from

2015 until 2019, when we build a 759-MW IGCC sequestration-ready plant. SCCTs are added in 2017 (96 MW).

7. *Bridge (2015) to Nuclear in Idaho (2019)*. Similar to Portfolio 6 with a 651-MW nuclear plant in Idaho instead of an IGCC. A new transmission line would be built to connect the nuclear plant in Idaho to the PNW and we assign its pro-rata cost to the portfolio. SCCTs are added in 2017 (96 MW) and 2019 (34 MW) for capacity.

8. *Diversified Green with On-Peak Energy Target*. Same as Diversified Green, but adds a CCCT plant in 2015 in lieu of SCCTs to meet most capacity targets. An additional 100 MW of SCCT is added in 2019.

9. *Diversified Thermal with Green*. This portfolio differs from Portfolio 5 in the mix of renewables. This strategy seeks a diversification of renewable sources and a reduction of flexible natural-gas fired resources (SCCT) to meet combined energy and capacity requirements. Here we use wind only for RPS compliance. Biomass is added in 2017 and 2019 (25 MWa in each year); CHP in 2015, 2017 and 2019 (2 MWa); geothermal in 2019 (50 MWa); and solar in 2019 (4 MWa). SCCTs are added in 2017 (26 MW) and 2019 (196 MW).

10. *Boardman through 2014*. Similar to Portfolio 9 (Diversified Thermal with Green) with Boardman running through June 2014. We replace Boardman with a 441-MW CCCT in 2015. SCCTs are added in 2017 (52 MW) and 2019 (196 MW).

11. *Oregon CO_2 Compliance*. Here we model the most aggressive cap on CO_2 emissions in 2020 by limiting the total CO_2 emissions from our portfolios to our 1990 level less 10%. To achieve this goal, Portfolio 4 (Diversified Green) is adjusted to retire the Boardman coal plant and terminate our interest in the Colstrip coal plant in 2019. These plants are replaced by an equivalent amount of energy from a nuclear plant (676 MW) in 2020. This portfolio also adds SCCTs to meet capacity requirements in 2015 (163 MW), 2017 (259 MW) and 2019 (204 MW).

12. *Boardman through 2011, Bridge to 2015*. Similar to Portfolio 9 with Boardman running through 2011. We replace Boardman with a three-year PPA until 2015, when we build a 441-MW CCCT. SCCTs are added in 2017 (52 MW) and 2019 (196 MW).

13. *Diversified Green with Wind in Wyoming*. Similar to Portfolio 4, except that we assume that additional wind is not available in the PNW and we must look to other areas and build transmission to procure resources. For modeling purposes we assume that we access wind sites in Wyoming

(approximately 595 MW, 190 MW, and 310 MW in 2015, 2017, and 2019, respectively.) SCCTs are added in 2015 (83 MW), 2017 (261 MW) and 2019 (209 MW).

14. *Diversified Thermal with Green, no BAL*. Same as Portfolio 9 without the Boardman lease option (15% of Boardman leased 2014-2027). SCCTs are added in 2017 (112 MW) and 2019 (197 MW).

15. *Boardman through 2017*. Same as Portfolio 9, with Boardman running through June 2017. We replace Boardman with a 441-MW CCCT in 2017. SCCTs are added in 2017 (51 MW) and 2019 (197 MW).

Table 10-4: Portfolios Composition through 2020 (Energy in MWa)

	Resource Type	Common to all Portfolios (See Note)	Renewables: Local Wind (Beyond RPS Requirement)	Remote Wind (Beyond RPS Req,)	Biomass	Geothermal	Solar PV - Customer & Central	Wave
	Capacity Contribution (%)*	NA	5%	5%	116%	117%	5%	31%
	Availability (%)	NA	31% --> 29%	37%	86%	86%	11% & 17%	31%
	In-Service Year	2010-2020	2015-2019	2015-2019	2015-2019	2015-2019	2015-2019	2017-2019
	Location	NA	Ore./Wa.	Wyoming	Oregon	Oregon	Customer	Oregon
Portfolios								
1	Market (Do Nothing)	469	0	0	0	0	0	0
	Pure Plays:							
2	Natural Gas	469	0	0	0	0	0	0
3	Wind	469	620	0	0	0	0	0
	Diversified Portfolios:							
4	Diverse Green	469	405	0	52	77	12	19
5	Diversified Thermal w/ Wind	469	145	0	0	26	4	0
6	Bridge (2015) to IGCC in WY (2019)	469	0	0	0	0	0	0
7	Bridge (2015) to Nuclear in ID (2019)	469	0	0	0	0	0	0
8	Div.Green with On-peak Energy Target	469	405	0	52	77	12	19
9	Diversified Thermal w/ Green	469	0	0	50	50	4	0
10	Boardman through 2014	469	0	0	50	50	4	0
11	Oregon CO2 Goal	469	405	0	52	77	12	19
12	Brdmn through 2011, Bridge to 2015	469	0	0	50	50	4	0
13	Div. Green w/ Wind in WY	469	0	405	52	77	12	19
14	Diversified Thermal w/Green, no BAL	469	0	0	50	50	4	0
15	Boardman through 2017	469	0	0	50	50	4	0

* January peak capability: 5% of nameplate capacity for wind and solar; for other resources, capacity contribution is as compared to the average energy contribution.

Table 10-5: Portfolio Composition through 2020 (continued; Energy in MWa)

		Fossil Fueled							Other	Existing Resources			
	Resource Type	CCCT-G (2015)	CCCT-G (2019)	CCCT-G (Replace Brdmn)	Coal - IGCC (Seq. ready)	CHP	PPA Added	PPA Removed	Nuclear	Boardman (Removal)	Colstrip (Removal)	Aquire BoA Lease	Total Energy Actions
	Capacity Contribution (%)*	109%	109%	109%	127%	125%	100%	100%	109%	119%	119%	119%	
	Availability (%)	92%	92%	92%	79%	80%	100%	100%	92%	84%	84%	84%	
	In-Service Year	2015	2019	By Case	2019	2015-2019	By Case	By Case	2019 / 2020	NA	NA	2014	
	Location	Oregon	Oregon	Oregon	Wyoming	Oregon	Unknown	Unknown	Idaho	Oregon	Montana	Oregon	
Portfolios													
1	Market (Do Nothing)	0	0	0	0	0	0	0	0	0	0	72	541
	Pure Plays:												
2	Natural Gas	406	406	0	0	0	0	0	0	0	0	72	1353
3	Wind	0	0	0	0	0	0	0	0	0	0	72	1161
	Diversified Portfolios:												
4	Diverse Green	0	0	0	0	5	0	0	0	0	0	72	1110
5	Diversified Thermal w/ Wind	406	0	0	0	5	0	0	0	0	0	72	1126
6	Bridge (2015) to IGCC in WY (2019)	0	0	0	600	5	400	-400	0	0	0	72	1146
7	Bridge (2015) to Nuclear in ID (2019)	0	0	0	0	5	400	-400	600	0	0	72	1146
8	Div.Green with On-peak Energy Target	406	0	0	0	5	0	0	0	0	0	72	1516
9	Diversified Thermal w/ Green	406	0	0	0	5	0	0	0	0	0	72	1056
10	Boardman through 2014	406	0	406	0	5	0	0	0	-319	0	0	1070
11	Oregon CO2 Goal	0	0	0	0	5	0	0	623	-319	-249	0	1093
12	Brdmn through 2011, Bridge to 2015	406	0	406	0	5	380	-380	0	-319	0	0	1070
13	Div. Green w/ Wind in WY	0	0	0	0	5	0	0	0	0	0	72	1110
14	Diversified Thermal w/Green, no BAL	406	0	0	0	5	0	0	0	0	0	0	984
15	Boardman through 2017	406	0	406	0	5	0	0	0	-319	0	0	1071

* Capacity contribution is as compared to the average energy contribution.

** Oregon Compliance Portfolio required by IRP Guideline 8d. Replaces coal with a like amount of nuclear power.

Notes: For 2021 to 2030, all portfolios add 300 MWa of wind to maintain RPS compliance & 254 MW of SCCTs for wind firming.

Capacity is balanced up to 300 MW each year from the market to always meet our target (1-hour peak plus 6% operating reserves).

For modeling, we have assumed CCCT-Gs are only available as whole units (406 MWa), regardless of ownership -- except for case #8.

Table 10-6: Portfolios Composition through 2020 – Capacity in MW

	Resource Type	Capacity Contrib. from Energy	Common to all Portfolios (See Note)	SCCTs (2013)	SCCTs (2015)	SCCT (2017-2019)	Subtotal: Long-term Cap. Actions	Capacity from all Actions**
	Capacity Contribution (%)*		NA	100%	100%	100%		
	Availability (%)		NA	96%	96%	96%		
	In-Service Year		2010-2020	2013	2015	2017-2019		
	Location		Oregon	Oregon	Oregon	Oregon		
Portfolios								
1	Market (Do Nothing)	576	285	0	0	0	285	861
	Pure Plays:							
2	Natural Gas	1457	285	200		59	543	2001
3	Wind	681	285	200	120	563	1168	1848
	Diversified Portfolios:							
4	Diverse Green	824	285	200	77	463	1025	1849
5	Diversified Thermal w/ Wind	1079	285	200	0	284	768	1847
6	Bridge (2015) to IGCC in WY (2019)	1341	285	200	0	96	580	1922
7	Bridge (2015) to Nuclear in ID (2019)	1233	285	200	0	130	614	1848
8	Div.Green with On-peak Energy Target	1264	285	200	0	100	585	1849
9	Diversified Thermal w/ Green	1141	285	200	0	222	707	1848
10	Boardman through 2014	1115	285	200	0	248	733	1848
11	Oregon CO2 Goal	738	285	200	163	463	1111	1849
12	Brdmn through 2011, Bridge to 2015	1115	285	200	0	248	733	1848
13	Div. Green w/ Wind in WY	810	285	200	83	470	1037	1848
14	Diversified Thermal w/Green, no BAL	1055	285	200	0	309	794	1849
15	Boardman through 2017	1116	285	200	0	249	734	1849

Common to all portfolios for Capacity Actions are a rollout of DR to 95 MW, DSG of 67 MW, & 123 MW of SCCTs in 2016-2019.

** Oregon Compliance Portfolio required by IRP Guideline 8d. Replaces coal with a like amount of nuclear power.

*** Capacity is balanced up to 300 MW each year from the market to always meet our adequacy target.

Figure 10-8: Portfolio Composition through 2020 – Energy Availability by Source

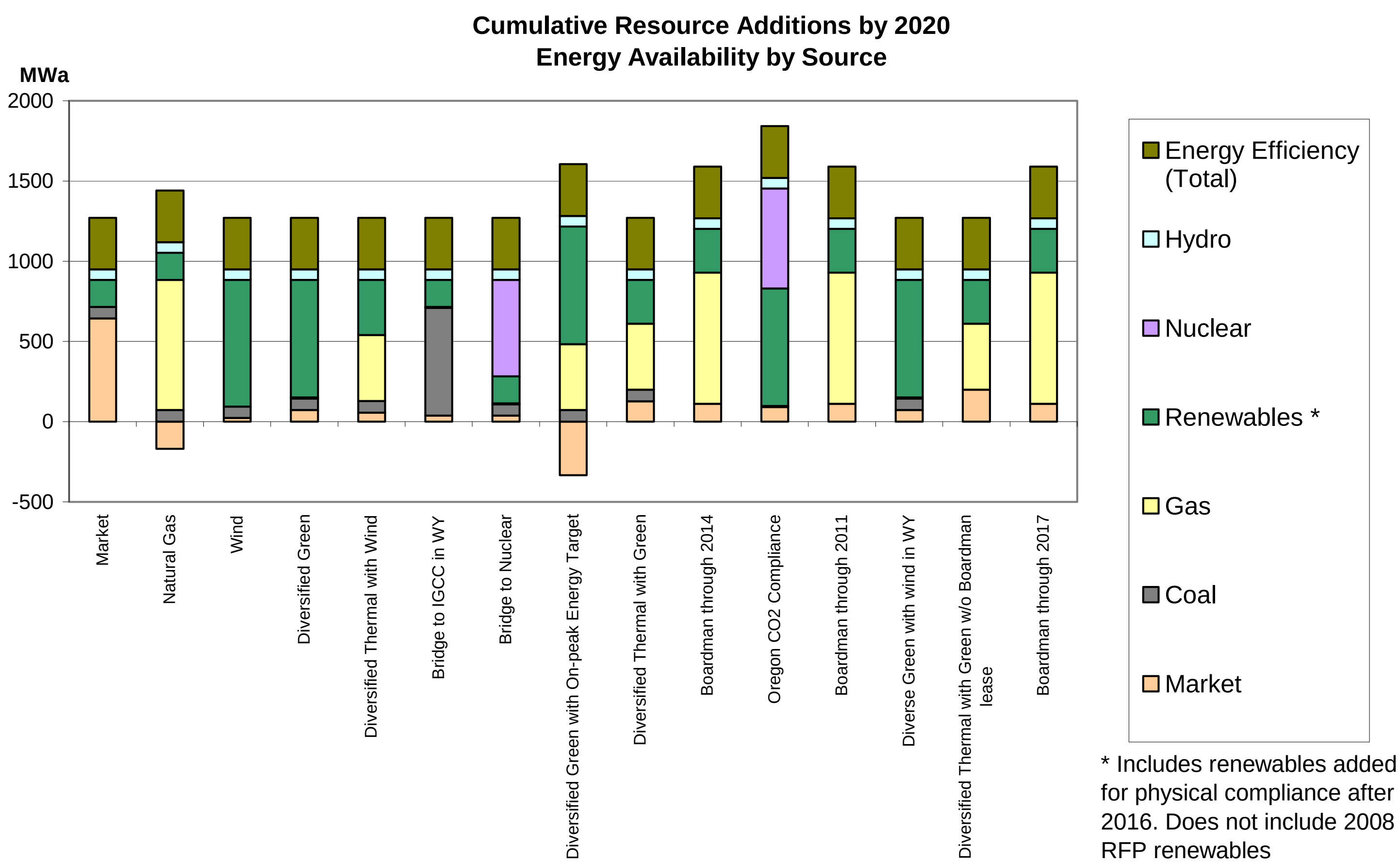
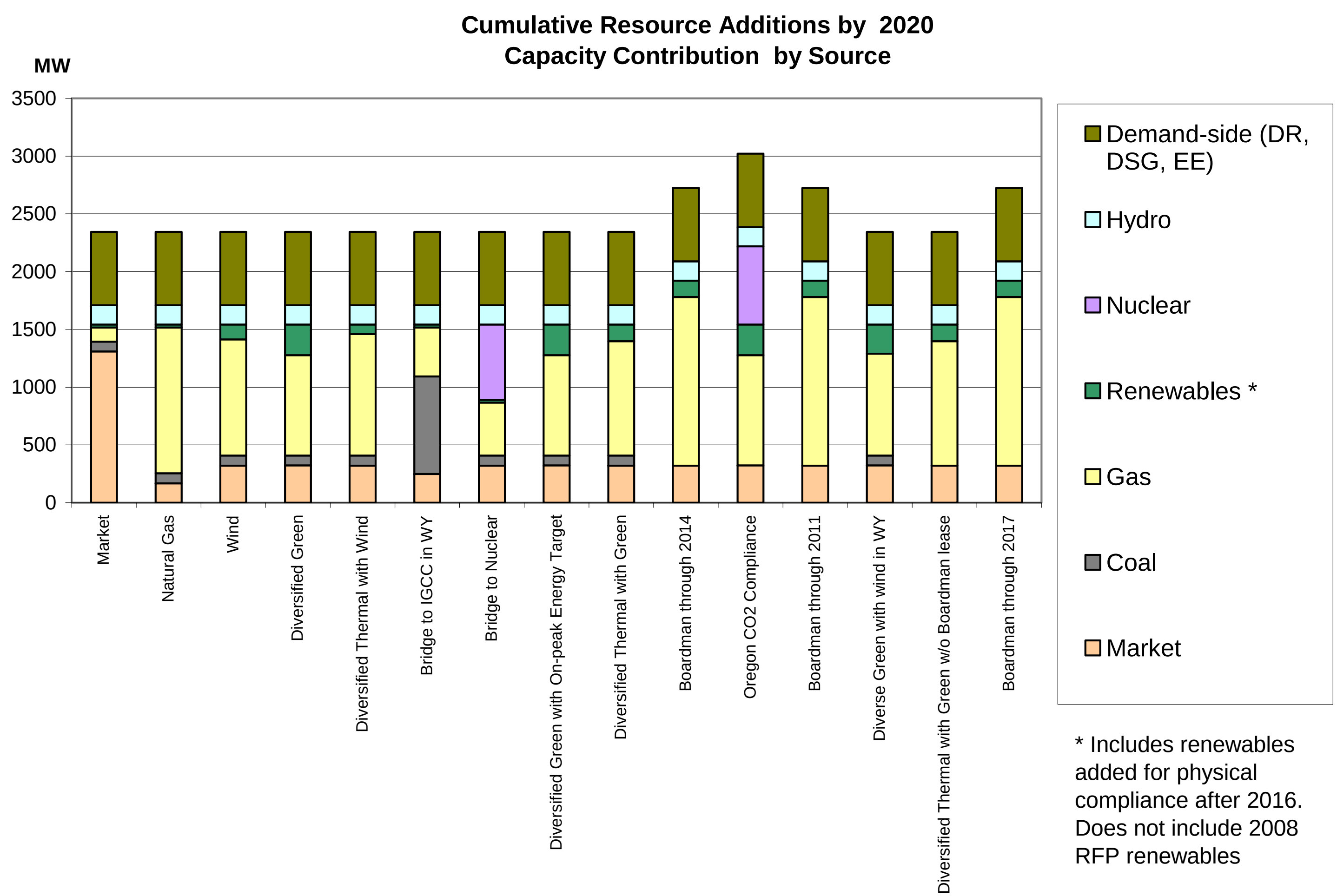


Figure 10-9: Portfolio Composition through 2020 – Capacity Contribution by Source



10.5 Reference Case

The reference case is a deterministic study based on the expected assumptions regarding resource, market, and internal and external conditions associated with the candidate portfolios described earlier. The reference case is also the basis against which we test portfolio performance. The following section summarizes the key inputs used in our reference case.

- **Commodity fuel price** – Natural gas prices are approximately $7.86 per MMBtu (real levelized 2009$ for the period 2010-2040). Our commodity coal price is approximately $49 (real levelized 2009$ for the period 2010-2040) and is based on prices for PRB coal. Both forecasts rely on independent third-party fundamental research and market quotes. More details regarding fuel prices are in Chapter 5. Fuel prices are constant in real dollars after 2025.

- **Fuel transportation cost** – For natural gas, costs are based on current 2009 rates adjusted by approximately 10% for near-term expansion, resulting in $.42 per dekatherm for NW Pipeline and $.48 per dekatherm for GTN. We then assumed escalation at inflation starting in 2010. Coal rail transportation and handling costs are based on PGE's forecasted transportation to Boardman, including any possible surcharges.

- **Resource costs** – We used the cost assumptions detailed in Chapter 7.

- **Renewable Energy Tax Credits** – We use the Production Tax Credit (PTC) in its current form for all wind projects and the Investment Tax Credit (ITC) for solar. We also assume the Business Energy Tax Credit (BETC) for distributed solar.

- **Transmission cost to PGE's system** – We use BPA's transmission tariff rates (escalated at inflation with increases for the NOS in 2013 and 2016) for all new generation resources within the Pacific Northwest. We add transmission losses and wheeling to BPA's system and our expected share of the investment cost of a new transmission line to all resources placed outside the PNW.

- **PGE load** – We used the base case long-term load growth of 1.9% per year in our non-EE adjusted forecast, as described in Chapter 3. The non-EE adjusted reference case load growth varies between 0.7% and 2.0% in the mid-term (2010-2015) with an annual average growth rate for the period of 1.7%. The longer-term growth rate is higher, averaging 2.0% annually from 2015-2030.

- **Environmental assumptions** – We used the assumptions detailed in Chapter 6. A CO_2 cost of $30 per short ton (2009$, real levelized) is imposed on all WECC thermal plants starting in 2013.

- **Renewable portfolio standard (RPS)** – We input an RPS standard in all WECC states that currently have an RPS and impose physical compliance to Oregon's RPS to all our portfolios.

10.6 Futures

In order to stress-test portfolio performance against an unknown future environment, we constructed several discrete futures based on feedback from our stakeholders received throughout our IRP workshops. While the use of these scenarios may not include the full range of possible conditions, we believe that it is possible to develop a broad set of futures that reasonably reflect the types of changing circumstances that could be encountered and the resulting impact to the cost and risk of future portfolio choices. In particular, we wanted to ensure that our futures tested the durability of each candidate portfolio against possible changes in underlying fundamentals that could, if they came to fruition, result in large changes in prevailing energy market prices or significant impacts to the cost or value of the resources within the portfolio. In addition, we wanted to understand the impacts of pursuing portfolios that had more or less exposure to variable costs and prevailing market conditions vs. those candidate portfolios that included higher proportions of fixed costs and would thus be less responsive to changing external factors.

We evaluated all portfolios across the following future scenarios, which we created by modifying the reference case assumptions outlined in Section 10.5 above with input from stakeholders:

- Reference Case – this case includes our base assumptions for load, gas prices, CO_2 price, wholesale electricity prices, capital costs, and government incentives (see section 11.5, above).

- High gas ($12.84 per MMBtu, an increase of $4.98 per MMBtu over the reference case in real levelized 2009$ for the period 2010-2040)

- Low gas ($5.19 per MMBtu, a decrease of $2.67 per MMBtu below the base case in real levelized 2009$ for the period 2010-2040) price futures.

- Potential carbon regulation in accordance with Guideline 8. As required by Guideline 8b of Order No. 08-339, we evaluate the NPVRR costs and risk measures of all portfolios under each of the carbon compliance scenarios.

a. $0
b. $12
c. $20
d. $45
e. $65

We also evaluate certain break-evens, such as the carbon price at which the preferred portfolio containing natural gas is on par with a substantially different alternative on a per MWh basis (see chapter 11 for a description of this trigger points analysis).

- CO_2 compliance cost begins one year earlier (2012)
- CO_2 compliance cost begins one year later (2014).
- High capital costs.
- Low load growth for PGE (non-EE adjusted growth rate is 1.2% per year for low), as required by Order No. 07-002.
- High load growth for PGE (non-EE adjusted growth rate is 2.7% per year for high), as required by Order No. 07-002.
- No renewal of PTC, ITC and BETC
- Renewal of PTC, ITC and BETC at 50% of current.
- High CO_2 cost with high natural gas prices and low coal prices. These factors affect thermal plants.
- High wholesale electricity prices, simulating shortages of resources in the WECC electricity markets caused by a robust load growth combined with sustained poor hydro conditions and increased forced outages of the aging thermal plants.
- Low wholesale electricity prices, simulating a surplus of resources in the WECC combined with low gas prices. The surplus is simulated by imposing a modest growth of WECC loads and the penetration of renewable technologies with very high capacity factors.
- Major resources added one year earlier in each portfolio
- Major resources added one year later in each portfolio.
- Aggressive, higher levels of EE in each portfolio.

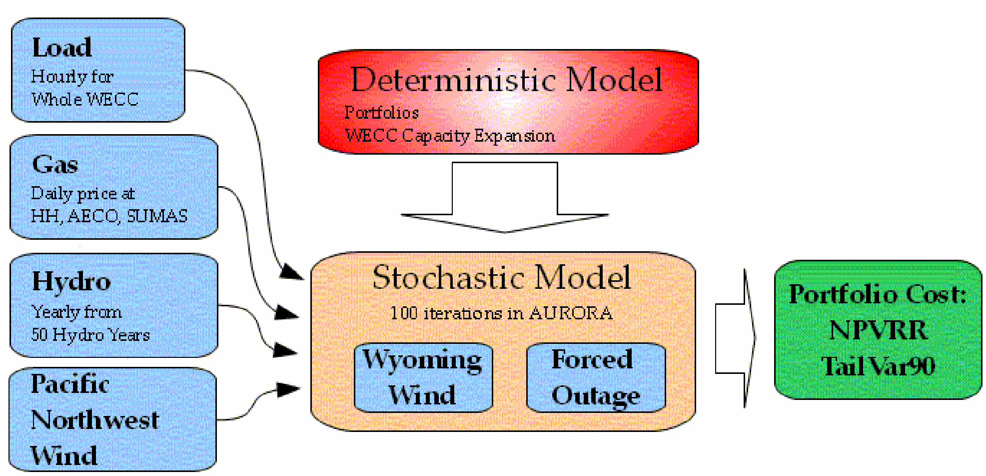
We determined that a higher load growth future is a good proxy for a high plug-in hybrid electric vehicle future.

10.7 Stochastic Modeling Methodology

Stochastic analysis of PGE's portfolios is performed by shocking five input variables: WECC-wide load, natural gas prices, hydroelectric energy, plant forced outage and wind production. Shocking these variables provides insights that scenario analysis cannot provide. Specifically, the stochastic study is geared to examine the cost volatility of a portfolio in a given future, assuming that the input variables will behave in the future according to their random behavior observed in the past. We perform the stochastic study under our reference case future only; running the study under one or more alternate futures would only reproduce the insights of the scenario analysis and is unnecessary.

The stochastic variables modeled in this study supersede those used in the deterministic scenario analysis, but all other inputs are shared between the two simulations; most notably, the portfolios and the WECC-wide capital expansion remain the same. Of the five random variables modeled, PGE and WECC load, natural gas price, hydro generation and Pacific Northwest wind are generated exogenously and imported into AURORA, while plant forced outages and wind outside the Pacific Northwest are addressed by AURORA's internal risk logic. The stochastic analysis is run 100 times to capture the random variations in the input variables, and cost metrics for each portfolio, the Net Present Value of Revenue Requirements (NPVRR) and the average of the worst 10 percent of NPVRR outcomes (TailVar90 of NPVRR) are then calculated. See Figure 10-10 for a diagrammatic representation of this process.

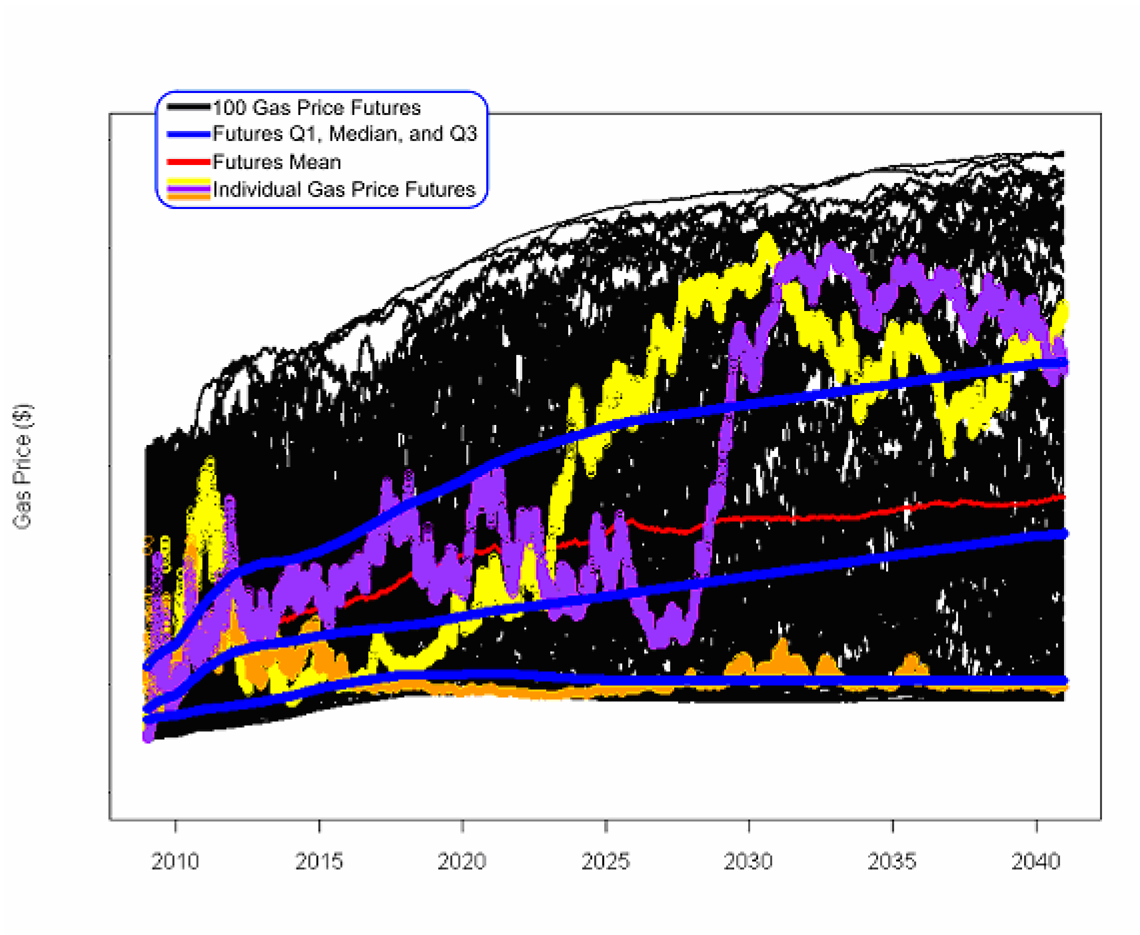
Figure 10-10: Stochastic Inputs



Gas Price

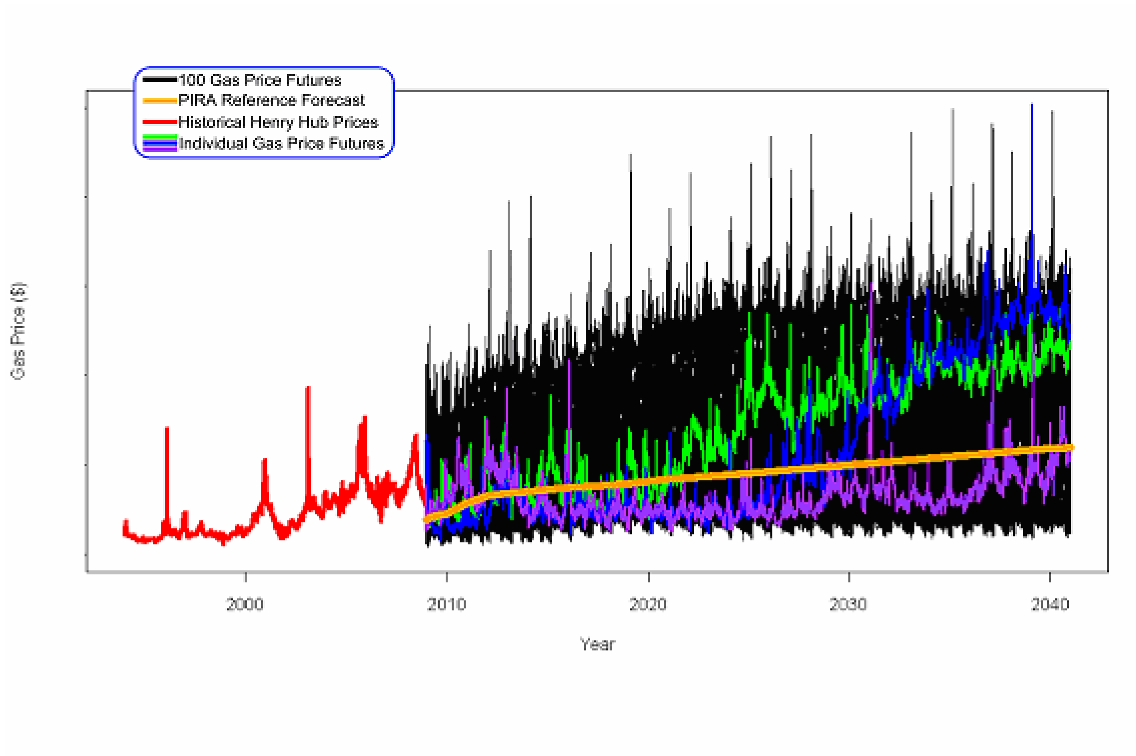
Gas prices are generated on a daily basis for Henry Hub. From this price we calculate the price at AECO and SUMAS as a basis spread from the Henry Hub. These basis spreads are based on the latest PIRA's forecast of future price differentials in the respective hubs and are kept constant over time. Long-term average gas prices follow a random walk between reference future gas prices provided by PIRA, to simulate the entire spectrum of possible gas price futures PGE faces. See Figure 10-11 for an indication of the set of futures explored by the simulation. In this figure, each point represents a long-term annual average gas price at Henry Hub. The blue lines indicate the sample first quartile, median, and third quartile, sourced by the PIRA low, reference and high gas price future. Here, the minimum gas price is taken to be $1 below PIRA's low gas price forecast, and the maximum gas price is assumed to be $10 above PIRA's high gas price. The sample mean is shown in red, and three individual gas price futures are indicated in yellow, purple and orange.

Figure 10-11: Long-term Average Henry Hub Prices



Daily deviations from these long-term gas prices are provided by sampling with autocorrelation from historical deviations from observed long-term gas prices. The gas price as simulated therefore has two components: a slowly moving average gas price, and a more sharply variable daily deviation from this average. The entire set of gas price futures for Henry Hub (in black), with historical data (in red) for comparison, is shown in Figure 10-12. Individual futures are highlighted in green, purple, and blue, with the long-term average gas price shown in orange.

Figure 10-12: Henry Hub Prices



Load

We simulate load on an hourly basis for the entire WECC using a rolling average and sampling methodology. Seasonal and hourly deviations from observed historical mean loads are sampled to provide 100 sets of 31-year load futures for every area in AURORA's WECC topology. Regional cross correlations are calculated from historic hourly load data, which are estimated from the hourly residuals for each AURORA area load net of the seasonal shape. We group the WECC areas into four regions: Pacific Northwest, California, Desert Southwest, and Intermountain. The correlation between any two AURORA areas within a region is 1.0. As a result, all areas within a zone have the same correlation with all areas in a different zone. For example, AURORA Zone 14, which is within the

Pacific Northwest region and includes Oregon, Washington and Northern Idaho, will have the same correlation with Zone 6 and Zone 9 which are both within the California Region.

No correlation with gas or hydro is specified, but among the 100 sets of gas and load data simulated, coincidences of correlation between gas and load are bound to occur.

As an outline of the methodology used in constructing plausible load futures, consider that for each hour in the year we can construct an expected load based on factors such as the hour in the day, the day in the week, and the season (or day number) in the year as a whole by examining similar hours in historical load data for a given region. Of course, expectations based on seasonality and hourly load shape are not always fulfilled, and in order to simulate this in our load futures we sample from observed deviations from the expected load in previous years. In this way, load is simulated as a combination of an expected value which does not vary from year to year (except by deterministic load growth) and a random component which depends on the season and the hour in the day (weekend mornings in the winter being less variable than weekday hours in the summer).

In order to accurately simulate load, we must match two properties of observed historical load data: the distribution of observed load and the autocorrelation of load from hour to hour. Because load grows from year to year, it is actually best to look at *deviations* from long-term average load to verify the goodness of fit. In Figure 10-13 the histogram of deviations from simulated load futures for PGE is plotted together with a histogram of observed historical deviations from long-term average load. In Figure 10-14 the autocorrelation of the two sets is plotted. Note that the histogram of simulated load shapes is much smoother than the observed values due to the sample size of ~28 million future load hours as opposed to the empirically observed ~78 thousand hours of historical load. The autocorrelation of the sampled data is slightly less than that exhibited in the observed data, but the difference is largest in the first 72 hours and diminishes quickly enough to be negligible at greater lag.

Figure 10-13: Histogram of PGE Load

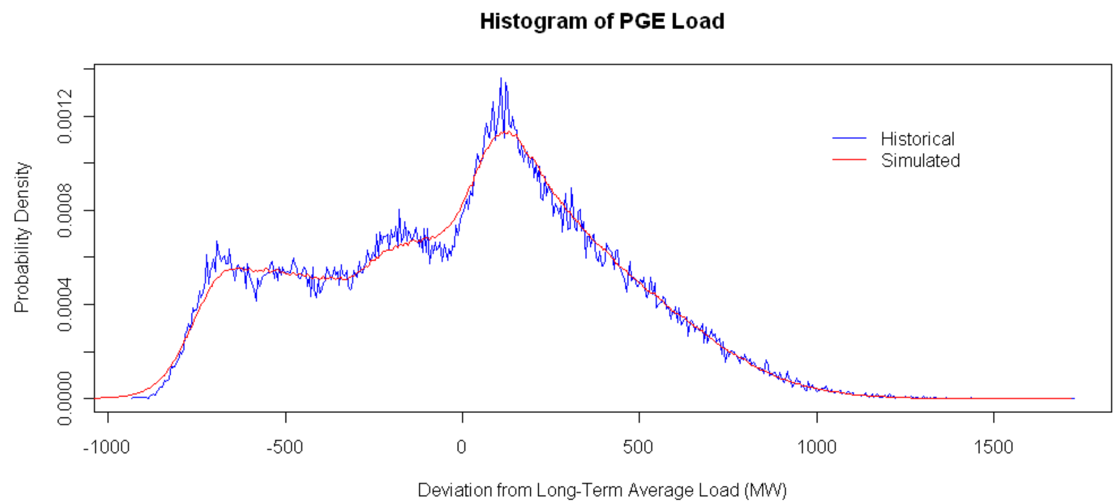
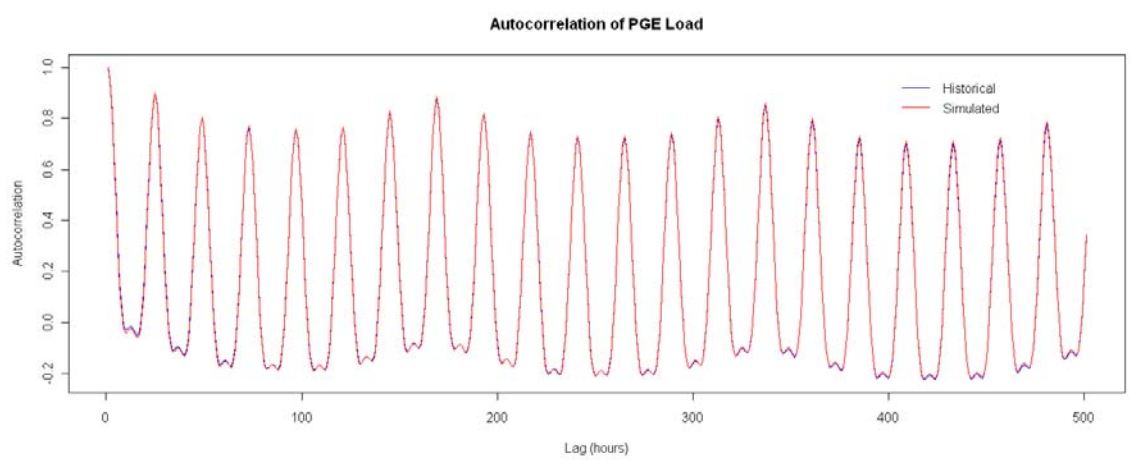


Figure 10-14: Autocorrelation of PGE Load



Hydro Generation

The available energy of hydropower varies from year to year based on changes in water runoff and precipitation. To simulate this we tie Pacific Northwest hydropower to the historical hydro output of the region. Because hydro exhibits significant monthly serial correlation, it is simulated by random sampling of the 50 historic water years starting in 1929[89]. We input these water years into the 12 AURORA areas covering the Pacific Northwest and western Canada. Each area is

[89] In the stochastic analysis we use 50 hydro years to simulate hydro uncertainty in the Pacific Northwest because this data is readily available from the NWPCC and is still commonly used by the NWPCC in its regional studies.

described by 12 monthly factors and one annual factor which describe the hydro condition of one actual year in the past.

The sampling is made independently, and as a result there is no serial correlation across the years. Similarly, the hydro condition is independent within each stochastic iteration and between any two stochastic iterations. As a result, each of the 50 hydro years has an equal chance of being selected. The sampling is made with replacement, so that it is conceivable, though unlikely, that one historic year could be sampled many times within the course of a single iteration. Hydro year has no specified correlation with any other random variable in the study.

Forced Outage

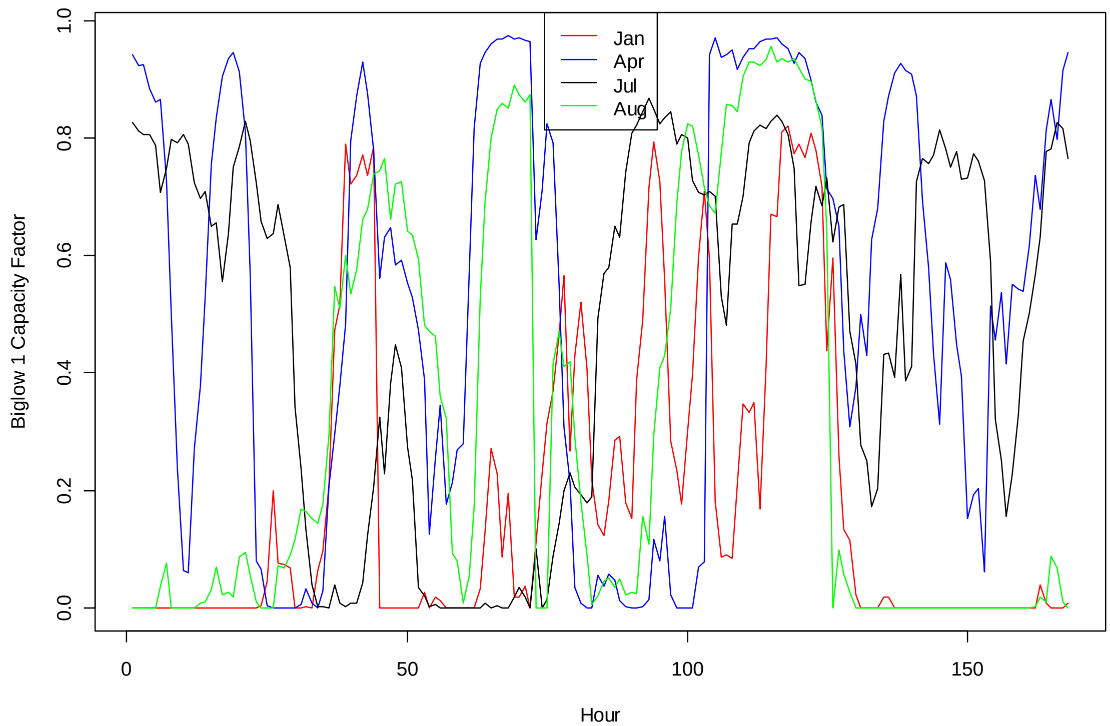
Plant forced outages occur when a plant is forced to shut down outside of regular maintenance and is unable to provide generation. AURORA simulates this internally by sampling from a distribution based on plant- or resource-specific Forced Outage Rates (FOR) and Mean Time to Repair (MTTR). For modeling purposes, we use the same FOR as the deterministic analysis, and specify a MTTR for each of PGE's plants based on the North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS). These data were used to provide a broad base of experience and history for each plant, rather than relying on the relatively small sample of MTTR observed at PGE's plants.

The AURORA forced outage logic assumes that a plant's MTTR and Mean Time To Failure (MTTF) are both exponentially distributed, and chooses the MTTF so that on average the FOR of the plant in the simulation approaches the input FOR. It is our experience that 100 iterations are enough for the output of the process to effectively converge to the input.

Wind

Intermittency of wind is modeled in this IRP by generating plausible wind futures from historical data where such data is available, and by using AURORA's forced outage logic to simulate the intermittency of wind when no data is obtainable. In the first case, we generate plausible wind shapes for the Pacific Northwest for every hour of the 31-year study period on the basis of 2008 data for PGE's Biglow plant. This is done by sampling with autocorrelation from observed production at Biglow and mapping this sample onto wind plants with a specified nameplate capacity and capacity factor using a quadratic mapping. This process accurately reproduces the intermittent nature of wind in the Pacific Northwest given the one-year history of production at Biglow – see Figure 10-15 below. Under this methodology, all plants in the Pacific Northwest are assumed to track Biglow identically, with relative differences in production arising only from plant capacity and capacity factor. In particular, this means that for the purposes of the simulation we assume that there is no diversity of wind shape in the Pacific Northwest.

Figure 10-15: Simulated Hourly Biglow Capacity Factor



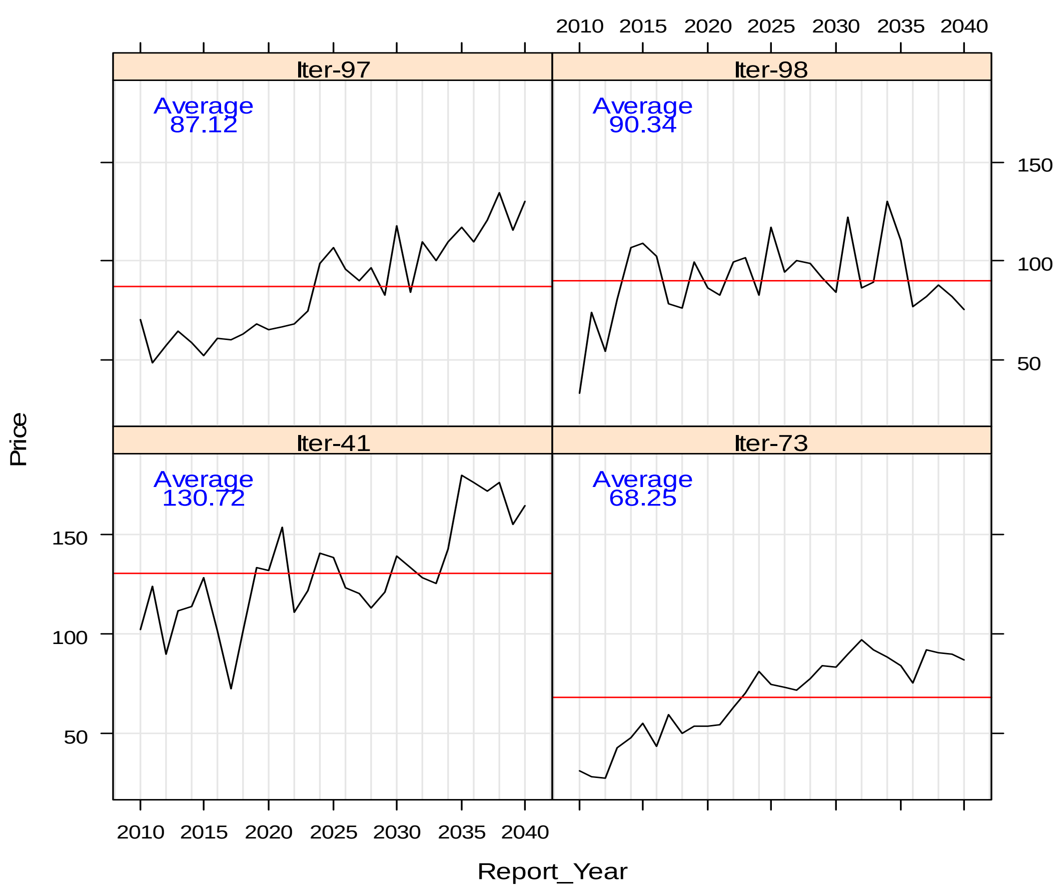
For PGE's potential wind projects outside of the Pacific Northwest, data sufficient to allow the implementation of an hourly wind simulation does not exist. For the purposes of this IRP, wind outside the Pacific Northwest is modeled using monthly capacity factors supplied by the NWPCC. Absent detailed hourly wind shapes, we assume that wind outside the PNW is all-or-nothing; either the plant produces at full capacity or not at all. More detailed data obtained in future studies may allow this assumption to be refined, but in the meantime this approach allows us to simulate wind in a reasonable manner that reflects both its capacity value as indicated by the NWPCC and the intermittent nature of the resource.

To simulate wind outside the Pacific Northwest, we specify an artificial FOR and MTTR to reflect the observed availability of wind at the site. It should be understood that this FOR and MTTR do not in any way indicate an actual FOR at the plant, but are instead specified so that wind in the simulation performs consistent with actual historical wind observations. Thus, the FOR and MTTR here specified represent the availability of wind, *not* the availability of the plant. We take the FOR from NWPCC data for the capacity factor of regional wind in the WECC, and we specify the MTTR as the average time at zero production of PGE's Biglow plant.

Electricity Price

Using the above stochastic input variables and plant outage parameters, AURORA is run to produce a market-clearing electric price in each hour of the year for each zone of the AURORA topology. One hundred iterations are performed, each with a different time series of gas prices, loads, resource availability reflecting plant forced outages, and hydro production, with each leading to a differing series of electric prices. Electric prices are thus determined as a function of the stochastic variables: gas, load, hydro generation and other resource availability reflecting plant forced outages. Figure 10-16: illustrates four iterations of resulting AURORA electric prices.

Figure 10-16: AURORA Electricity Prices for Four Stochastic Iterations



Relative Importance of Stochastic Analysis

While we believe that both stochastic and deterministic scenario analyses provide important insights for assessing the performance and reliability of a portfolio over time, we have found that the most substantial risks in connection with making future resource choices are those associated with large fundamental or structural shifts – the types of risk best described through scenario analysis. As a result, we believe that scenario analysis should be given the primary emphasis in our overall portfolio risk evaluation. However, we do also continue to consider the instructive value from the stochastic analysis.

Ultimately no degree of modeling and analysis can account for all possible future uncertainties. Modeling by its nature only provides an estimate or range of estimates of future results. Nevertheless, we believe that a well-reasoned and complementary application of both scenario and stochastic analysis can provide useful insights about how a candidate portfolio is likely to perform in the future.

10.8 Loss of Load Probability Analysis Methodology

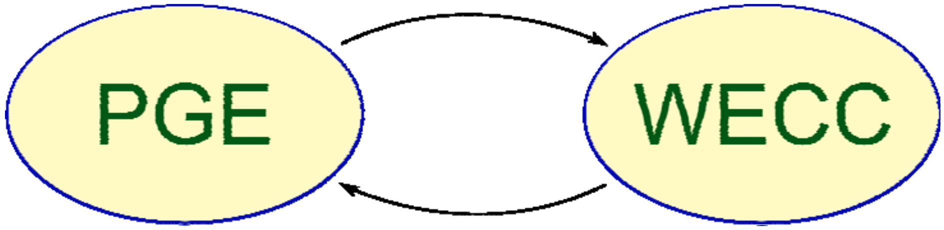
Guideline 11 of OPUC Order No. 07-002 requires PGE to analyze supply reliability within the risk modeling of the supply portfolios we consider. To do this, we use three related metrics for each portfolio with two goals: first, to provide a relative ranking of the portfolios on a reliability basis; second, to assess the resource adequacy of our top-performing portfolios.

Throughout this discussion it should be understood that the loss of load probability metrics calculated are best interpreted as indicators of *market dependence*. Reliability in this IRP is interpreted to mean, “To what extent can PGE rely on its owned and contracted resources to meet load?” Portfolios that are more reliable in this sense are less exposed to fluctuations in market price and hypothetical curtailment events in which PGE would be unable to secure spot market power needed to meet load.

LOLP Modeling Methodology

We use AURORAxmp to assess our risk (probability) of being unable to serve our customer energy needs and the resulting amount of expected unserved energy. For this purpose, we created a new AURORAxmp topology in which we isolated our service area from the rest of the WECC. See Figure 10-17 for a schematic of the topology used, in which PGE’s resources and load are isolated from the remainder of the WECC, which for the purposes of this study is modeled as a single area.

Figure 10-17: LOLP and Expected Unserved Energy



To rank the portfolios by relative market exposure, each portfolio is tested against 10 years of stochastic futures where load, hydro, wind and plant forced outages are shocked identically as they are in the stochastic study. Because the reliability study assesses portfolio reliability rather than economics, a stochastic simulation of gas prices is unnecessary. We test the years 2012 through 2020, plus 2025. Additional years are not necessary because we do not make major resource additions after 2020, with the exception of RPS compliance through 2025. Thus, the years we assess are the relevant years for exploring relative reliability between portfolios.

Another objective of reliability analysis is to assess PGE's reliability of our top portfolios based on maintaining a 6% required operating reserve for all hours. We do this by testing performance for the top portfolios for the years 2015 and 2020 by decreasing and increasing our incremental capacity levels from what the portfolios contain. That is, in addition to assessing resource adequacy of the portfolios as is, we subtract or add capacity to each of the three portfolios in increments of 100 MW and observe the effect of this change on the reliability metrics. These resources are modeled as SCCTs, each with a forced outage rate and a mean time to repair. We run the model 100 times at each level of altered capacity reserve for the portfolios. Because most of our portfolios build to similar capacity levels and portfolio-specific differences do not exist after 2020, performing this analysis over two years provides the adequacy information we seek.

It should be noted that nowhere in the reliability analysis do we make an assumption about the availability of power on the spot market under circumstances of extreme weather or a plant forced outage. Such assumptions are characteristically vague and speculative. To avoid making a specious assumption about the availability of market power, we make no assumption about our ability to purchase replacement power, opting instead to calculate the amount of power we would need to purchase in order to meet our reliability requirements.

LOLP Metrics

We use three metrics to describe our reliability modeling results:

LOLP – We calculate the Loss Of Load Probability (LOLP) as the average (expressed as a percentage across 100 risk iterations) of the ratio between the number of hours of PGE resource insufficiency vs. the total number of hours included in the study.

FORMULA: For each year and risk iteration, let $h_{year,iteration}$ represent the number of hours across the year when PGE must make market purchases in order to meet its load, and y_{year} represent the number of hours in the year (either 8760 or 8784). The LOLP in each year is calculated as

$$\frac{1}{100}\left(\sum_{iteration=1}^{100}\frac{h_{year,iteration}}{y_{year}}\right)$$

This metric measures the percentage of hours that customer load will exceed PGE's owned and contracted generating capacity. For example, a 0.1% LOLP indicates that PGE, on average, would expect to make market purchases in approximately 8 hours of the year in order to meet our customer load. This metric only addresses the likelihood of PGE's resources falling short of customer demand, not the amount that we would need to purchase on the spot market. For this reason, we focus more on the next reliability metric.

Expected Unserved Energy – We calculate the Expected Unserved Energy (EUE) as the average (across 100 risk iterations) of the amount of power PGE must purchase on the spot market in order to meet customer load, expressed in MWa, where the average includes only those hours when spot market purchases are needed.

FORMULA: For each risk iteration i, let $I_{year,iteration}$ represent the total amount of power purchased on the market, and $h_{year,iteration}$ represent the number of hours across the year when PGE must make market purchases in order to meet our load. The expected unserved energy is calculated as

$$\frac{1}{100}\left(\sum_{iteration=1}^{100}\frac{I_{year,iteration}}{h_{year,iteration}}\right)$$

This metric measures the average amount that PGE must purchase on the spot market, when PGE's owned and contracted resources are insufficient to meet customer load. This statistic is a good indicator of the expected magnitude of the resource insufficiency. However, because it is the average of 100 iterations, it does not measure the potential severity of bad outcomes.

TailVar 90 Unserved Energy (TailVar UE) – We calculated this metric, in MW of unserved load, as the average of the worst 10% outcomes across the 100 iterations of the EUE. This metric gives an estimate of the potential severity of our short position, or our dependence on spot market purchases. Because we're interested in portfolios that avoid bad outcomes (or so-called right tail events), we use this metric as the single best indicator of portfolio reliability performance.

Other Quantitative Performance Metrics

A metric designed to test the portfolio diversity is the Herfindahl-Hirschman Index, or HHI. This is a metric commonly employed to test the market concentration; the Department of Justice (DOJ) uses it to analyze mergers for potential anti-competitive impacts. Calculating the HHI is relatively straightforward – it is simply the sum of the square of the market share of all participants. The formula is:

$$HHI = s_1^2 + s_2^2 + s_3^2 + ... + s_n^2$$

A maximum HHI would be 10,000 in the case where a single company had 100% of the market. A minimum HHI would approach zero in the case where there are infinite companies with equal percentages of the market. The DOJ considers markets from 1,000-1,800 to be relatively concentrated, with those over 1,800 concentrated. Thus, the lower the HHI, the lower the market concentration, or in our case, the more diverse is the portfolio.

The HHI was adapted to compare the diversity of each of PGE's portfolios with the assumption that a more diverse portfolio is preferable to a less diverse portfolio, all else being equal. Two HHI measures representing both technological and fuel diversity were examined for each portfolio. Nameplate capacity by fuel type in 2020 (the last year for major resource additions) was the proxy for the portfolio intensity of each technology. The sum of energy generation from 2010 to 2020 by fuel type was used to derive fuel diversity based on actual portfolio dispatch.

Description of Risk Metrics Used in Portfolio Scoring

In addition to expected portfolio cost as measured by NPVRR, we employ risk metrics that examine scenario, stochastic, reliability and diversity risk and durability aspects of the portfolios, much of which has been discussed above. Below we describe the metrics we use in portfolio scoring:

1. *Deterministic Portfolio Robustness*. In this risk metric, we look at the joint probability that a given portfolio does not rank among the four worst outcomes but does rank among the four best cost outcomes when measured against all 15 of our futures. This metric is measured as a percentage. We do not assign weights to our futures, as we have no reliable basis to do so. Hence, they are in effect all equally likely. Our desire is to avoid portfolios that can have a high incidence of bad cost outcomes against all of the futures, while also identifying portfolios that have a high incidence of performing well against all of the futures. The intersection of these two views helps identify portfolios that are more robust and durable in the context of the possible futures they could operate within. For two portfolios with equal expected costs, we expect that the portfolio with a higher score in this metric will be less risky.

2. *Deterministic Portfolio Risk Variability vs. Reference Case*. While the durability metric measures portfolio robustness in terms of frequency, it does not address magnitude of potential adverse outcomes. The risk magnitude metric measures the cost difference, in $NPVRR, between the reference case expected cost for a given portfolio vs. the average performance within the four worst futures for each portfolio. This metric provides insights regarding the cost variability between the reference case future and the futures in which a portfolio would see its worst cost outcomes and is thus analogous to a stochastic TailVar concept. We are thereby able to assess whether a given portfolio is prone to extreme bad outcomes under changing future conditions. For two portfolios with equal expected costs, the one with the lower magnitude of downside variability is deemed to be less risky.

3. *Deterministic Portfolio Risk Magnitude*. This is a variation of the prior metric that was requested by OPUC Staff. This metric provides the average $NPVRR of the worst four futures for a given portfolio without subtracting it from the reference case expected cost. While the former focuses on variability from the reference case NPVRR cost, this metric reflects absolute right tail exposure based on the futures.

4. *Stochastic Portfolio TailVar90 less the Mean*. When considering the impact to portfolios of our stochastic variables described earlier in this chapter, this metric looks at the average of the 10% worst cost outcomes vs. the mean result. It is based on 100 independent iterations of stochastic inputs using the reference case future for each portfolio and is measured in $ NPVRR. It is a measure of the potential for adverse outcomes for each portfolio and is the stochastic equivalent of the deterministic Portfolio Risk Variability metric above. Comparing two portfolios with equal expected

costs, the one with the lower difference between the TailVar90 and the Mean is preferred as less risky.

5. *Stochastic Portfolio TailVar90*. This is a variation of the prior metric which measures the TailVar90 but does not subtract it from the mean value. Where the former focuses on deviations from the mean, this metric focuses instead on absolute right-tail exposure based on the stochastic variables.

6. *Stochastic Portfolio Year-to-Year Risk*. In addition to looking at stochastic right tail risk from a 30 year NPVRR perspective, we also include a metric that looks at year-to-year variance of costs for each portfolio. This metric represents an average across iterations and is in units of squared dollars.

7. *Portfolio Reliability*. Of the three reliability metrics described earlier in this chapter (see Section 10.8), the best metric for reflecting how much load is at risk of not being met is TailVar Unserved Energy (EUE). We use this as our reliability metric for overall portfolio scoring. For this purpose, we take the average TailVar UE from 2010 through 2020, plus 2025[90], for each portfolio. Portfolios with lower TailVar UE will be preferred.

8. *Technology and Fuel Diversity*. All else being equal, it is intuitive that under uncertain futures, greater diversity will hedge against exposure to bad cost outcomes. To measure inherent portfolio resource diversity, we have adapted the HHI by looking at the relative amount of energy provided by different technologies and fuels (coal, natural gas, hydro, wind, market purchases, etc.) from 2010 through 2020[91]. We also look at the HHI based on a snapshot of relative technology concentrations as measured by capacity in the year 2020. Lower values mean less portfolio concentration in any given technology or fuel type over the period. A lower HHI also indicates higher portfolio diversity from either a fuel or technology perspective.

Overall Portfolio Scoring

To integrate the expected cost and each of the above risk metrics, we have developed a scoring matrix approach. In the scoring matrix we take the performance of our portfolios based on expected NPVRR and the various risk metrics, convert the raw performance to a normalized score, apply weighting

[90] Due to long modeling run times and because there are no significant changes after 2020, PGE discussed with OPUC staff totaling the EUE from 2010 through 2020, as well as examining the year 2025 only as a proxy for the remaining years of our planning period.

[91] *ibid*.

factors, and sum them together to arrive at a composite portfolio score. For the conversion of the raw scores, each individual metric score is calibrated based on the highest- and lowest-performing portfolios, so that the worst-performing portfolio receives no points and the best-performing portfolio receives 100 points. Portfolios in between are then scored in direct proportion to their performance against the best and worst portfolios. This approach thus maintains the relative performance spread between portfolios that a simple ordinal ranking would lose.

A scoring matrix approach does not replace prudent utility judgment or the necessity to consider additional quantitative and qualitative performance indicators evaluated through the IRP. Rather, it provides a composite view of the performance of each portfolio based on the primary measures that PGE utilizes to test performance for IRP. The approach also provides insights into the relative importance that we assign to each category when selecting a candidate portfolio for our resource action plan.

Chapter 11 presents the scoring matrix and further illustrates how we turned the raw scores from these metrics into standardized point values and a single score that allows us to evaluate portfolios for multiple criteria.

Metric Weighting

Consistent with how we view scoring for individual projects within an RFP, we have reserved 50% of the total score for expected portfolio NPVRR. We then allocate 20% for the three futures-based deterministic risk metrics described above and 10% for the three stochastic-based risk metrics described above. With these risk measures accounting in total for 30% of the score, the direct portfolio modeling results are highly influential to the total score at a combined 80% weighting, with expected cost accounting for five-eighths of that total. We reserve another 15% for the TailVar UE reliability metric, and 5% total for the HHI diversity metrics.

Some metrics, while not weighted heavily, could in effect wield a “veto” power. For instance, if the portfolio analysis scoring pointed to the Market portfolio as being a top performer, it could still be rejected based on not meeting required operating reserve standards. Some portfolios may be substantially more challenging to implement than others. Our approach is to allow the portfolio modeling of cost and cost risk to dominate the scoring, while still considering reliability and diversity, as well as other quantitative and qualitative risk considerations not captured directly in the portfolio modeling. Ultimately such scoring acts as a guide to inform decision making rather than as a substitute for business judgment.

Other Metrics of Interest

In our portfolio evaluations, we also look at other metrics that are of interest, but that do not enter directly into the scoring. For instance, we report CO_2 emissions for all portfolios. However, because we have included several different levels of CO_2 cost and natural gas prices within our futures, including reasonable high and low limits, the sensitivity of the portfolios to the level of CO_2 cost is incorporated within the expected cost and the deterministic risk metrics. Thus scoring based on CO_2 emissions would be redundant.

Within the deterministic portfolio results, we use the X-Y plots of reference case cost vs. average cost within the four worst futures as a convenient way to provide an initial assessment of portfolio performance. However, both axes of the graph are used directly as scoring metrics above.

In our reliability analysis, we look at LOLP and EUE, but we rely on the TailVar UE as our preferred scoring metric.

Changes from the Draft IRP

Since issuance of the draft IRP in September, we have made various updates and data corrections. The cumulative effect of these changes was to alter a few portfolio rankings, including the relative position of our top two performing portfolios, which had very similar overall performance before and still do now. Overall, the effects of the changes were minor and do not lead to a change in our proposed Action Plan. Changes include:

- Updated commodity costs for gas and coal, as described in Chapter 5;
- Increase in the reference case CO_2 cost from $29 per ton to $30 per ton (real levelized), as described in Chapter 6;
- Correction to post-2025 coal prices in Montana;
- Correction to capital cost escalations for some portfolio resources, which had the effect of lowering the cost of capital-intensive resources

11. Modeling Results

The following chapter presents the results of our analysis and modeling, as well as our conclusions regarding those results. As discussed in Chapter 10 regarding our analytical approach, IRP models do not provide incontrovertible answers to future resource needs, as they merely represent an estimate of future performance or a range of potential results, given a set of assumptions. However, analysis does provide important insights and guidance that enhance business judgment and strategic decision-making with regard to selecting future resources that are more likely to perform well under various conditions. More specifically, the results described in this chapter do not provide a single, clear-cut answer as to which combination of potential resources provides the optimal balance of cost and risk. Rather, the results indicate that the relative performance of various resource alternatives can differ widely depending upon varying future circumstances. Accordingly, our objective is to identify a robust portfolio that performs better than the alternatives under a wide range of credible futures.

To assess the performance of each candidate resource portfolio, we calculated the NPVRR for each portfolio described in Chapter 10 across each distinct, potential future and then examined these scenario results using three views of risk. We also examine portfolio performance based on stochastic variability, reliability, and intrinsic fuel and technology diversity. Taken together, these performance metrics present a fairly comprehensive assessment of portfolio performance under uncertain future conditions.

Chapter Highlights

- To examine expected cost and scenario risk, we construct an X-Y plot of the expected cost and associated cost risk for each portfolio. Results for most portfolios are clustered closely and require further examination.
- We test the potential scenario risk of each portfolio using two measures of risk – the average expected cost of the four worst futures less the reference case expected cost, and average expected cost of the worst four futures. We also examine portfolio performance based on probability of worst performance across futures, stochastic variability, reliability, and intrinsic fuel and technology diversity.
- We assign each metric a weighting and combine the metrics into one portfolio scoring grid. Portfolios that are more diversified generally avoid poor outcomes.
- We identified the CO_2 price that triggers the switch from our preferred portfolio to a substantially different alternative portfolio, and found that the trigger point CO_2 price is $42 per short ton.
- Our Action Plan is based on Diversified Thermal with Green, our second best performing portfolio.

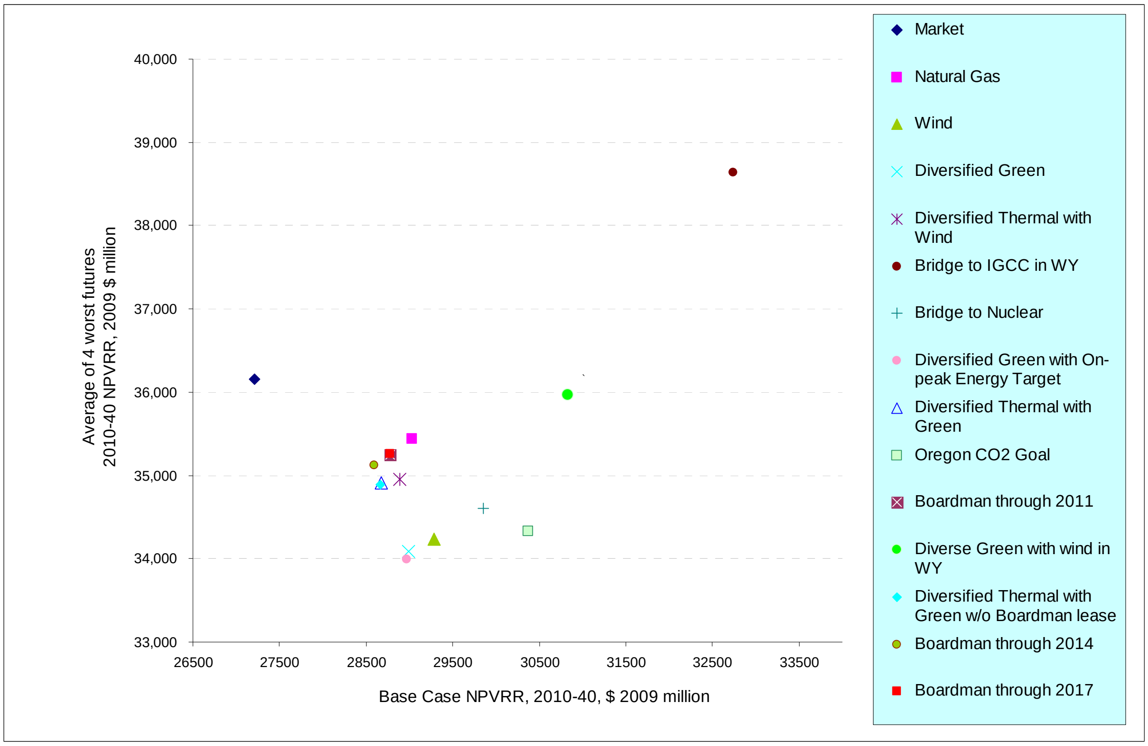
11.1 Deterministic Portfolio Analysis Results

A primary purpose of portfolio analysis is to identify the combination of resources that consistently performs well across different potential future environments. Future scenarios serve as a good proxy for the kinds of risk that we could encounter. To assess the performance of each candidate portfolio, we calculated the NPVRR for each combination of incremental resources described in Chapter 10, along with existing PGE resources, across 21 potential futures described in Chapter 10 (see also *Appendix D*). We then examined portfolio performance using several complementary views of risk and diversity, as described below.

Efficient Portfolios

A helpful initial assessment of portfolio performance is to construct an X-Y plot of the expected cost and associated cost risk for each portfolio. Similar to a financial portfolio efficient frontier, portfolios that lie closer to the origin generally outperform portfolios that are further from the origin. Such portfolios can be thought of as efficient. Figure 11-1 shows on the horizontal axis the expected cost of each of the portfolios in 2009$, defined as the NPVRR of the reference case future, i.e., the future that contains all of our base case assumptions about CO_2 costs, fuel prices, load, capital costs, etc. The vertical axis shows risk, defined as the average NPVRR across the top four most costly futures. Using the average of the top four most costly futures is a deterministic equivalent of a stochastic TailVar – that is, it provides a good proxy for extreme bad outcomes for a given portfolio. While the futures have no likelihood of occurrence weighting assigned to them, this risk metric is basically the average of the worst 20% future outcomes for a given portfolio. Note that in Figure 11-1 we have scaled the X and Y axes the same so as to give visual symmetry to the relative trade-offs of expected cost and risk between portfolios.

Figure 11-1: Efficient Frontier – Risk vs. Cost 2009$



We note the following general insights from Figure 11-1:

- *Risk is generally reduced with higher expected cost.* This is observed via the general downward right slope of the portfolio plots. This demonstrates the inherent trade-off between risk and cost.

- *Diverse portfolios generally outperform the single-resource portfolios*. Most single-resource portfolios are not on the efficient frontier, underscoring the inherent value of diversity.

- *Diverse portfolios are tightly clustered*. The tight clustering demonstrates that the various resource candidates exhibit only modest differences in expected cost. The more diverse portfolios also perform similarly on the risk scale. In the above figure, we only identify four portfolios that are clear outliers (Bridge to IGCC in WY, Bridge to Nuclear, Diverse Green with Wind in WY, and Oregon CO_2 goal), indicating that they are not candidates for an Action Plan. Remaining portfolios merit further examination.

Expected Cost under Reference Case Assumptions

Our first scoring criterion looks solely at the expected cost of the portfolios under the reference case future (the X-axis in the prior graph). This metric receives 50% of our overall score. The graph in Figure 11-2 ranks the portfolios in order of expected cost. Based solely on this metric, Market, Boardman through 2014 and Diversified Thermal with Green (with and without lease) are top-performing portfolios. This graph further demonstrates the fact that most portfolios exhibit relatively small differences in expected cost.

Average of Worst Four Futures

Our next performance measure focuses on the average expected cost of the worst four futures for each portfolio less the reference case expected cost (the Y-axis in the prior graph) – see Figure 11-3. This deterministic risk metric receives 5% of the overall score. The graph ranks the portfolios in order of risk. Here, portfolios with low exposure to natural gas do well, including the Oregon CO_2 goal, the Wind, and the Bridge to Nuclear portfolios. In this metric, early Boardman closure portfolios fare poorly due to their increased gas exposure.

Figure 11-2: Portfolio Reference Case Expected Cost 2009 $

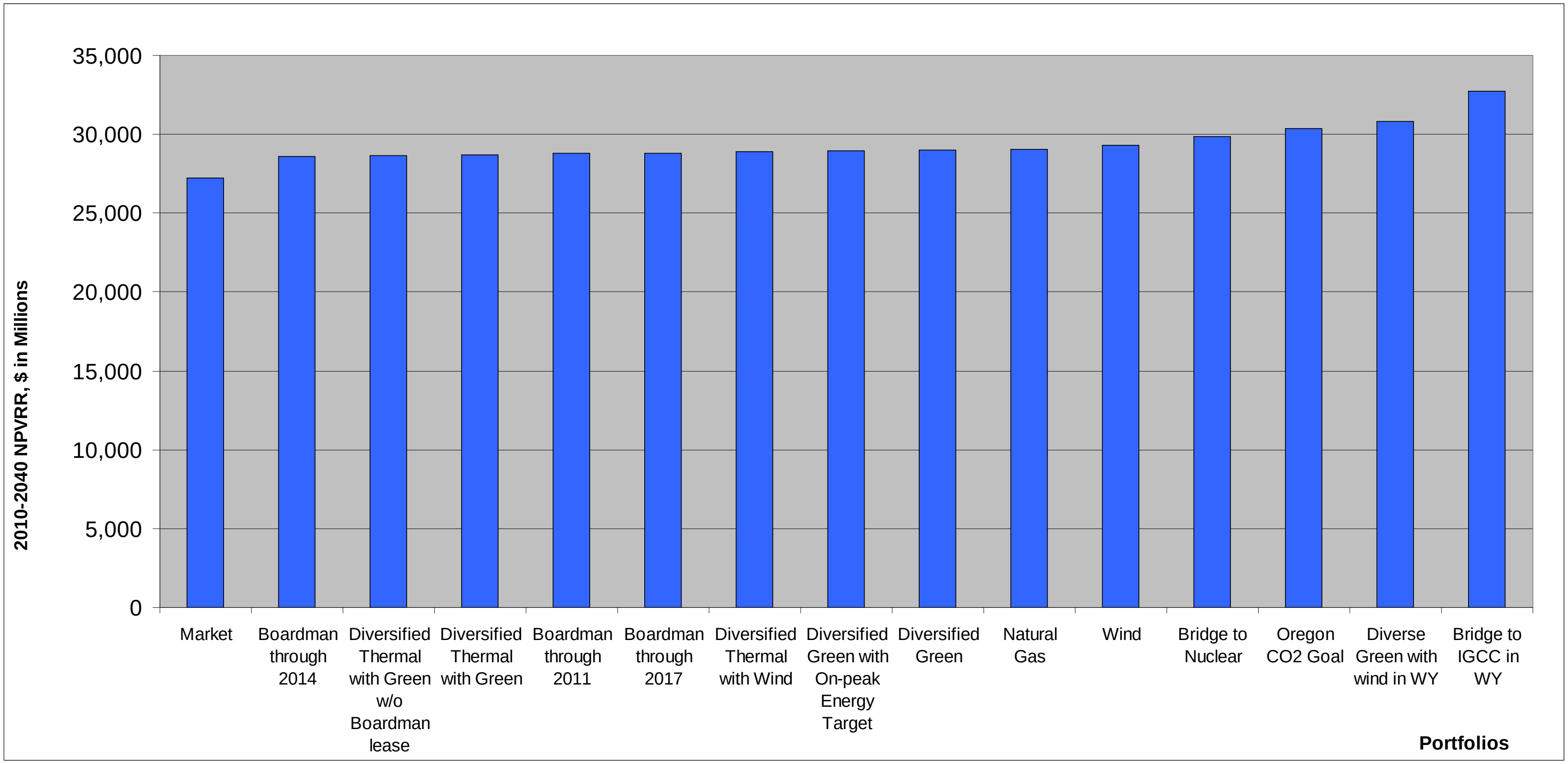


Figure 11-3: Average Cost of Four Worst Futures less Reference Case 2009 $

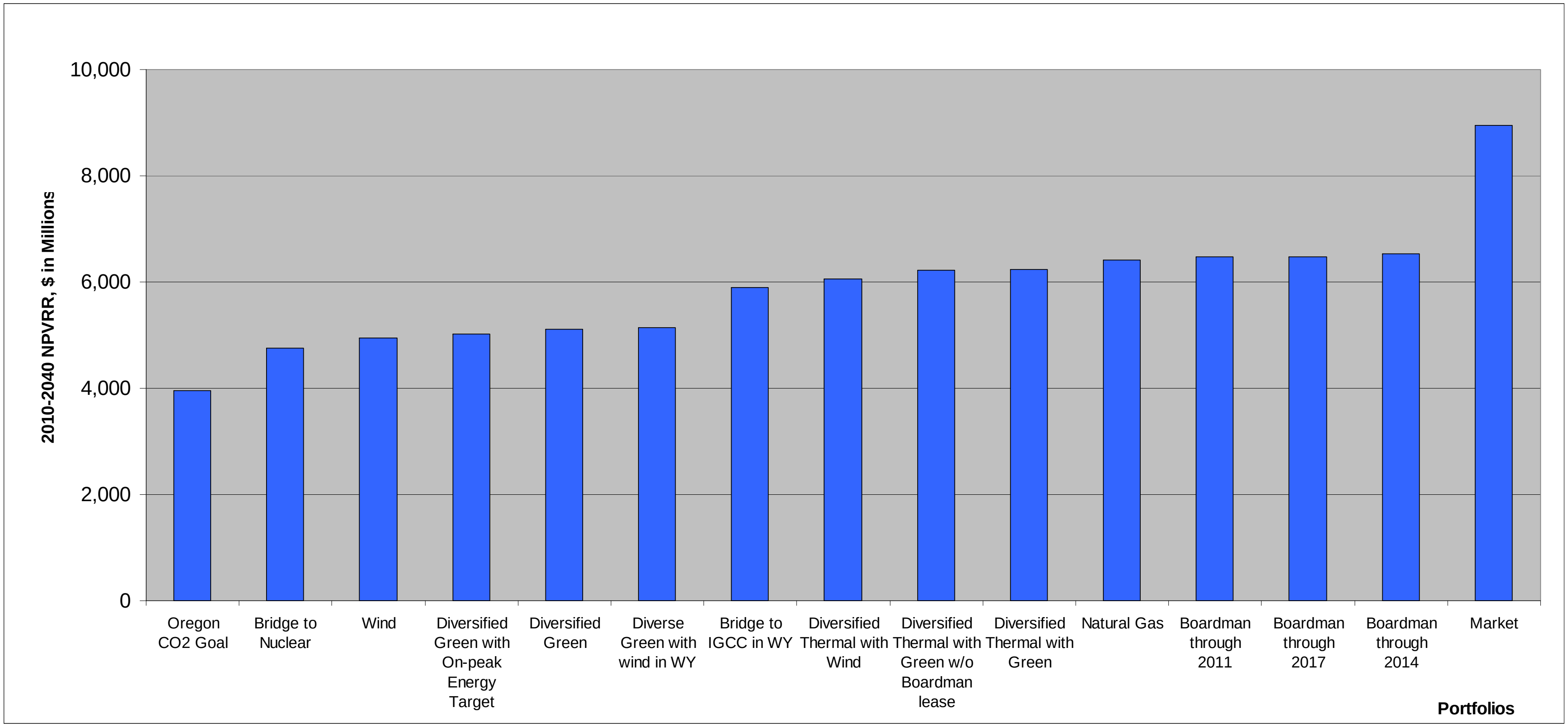
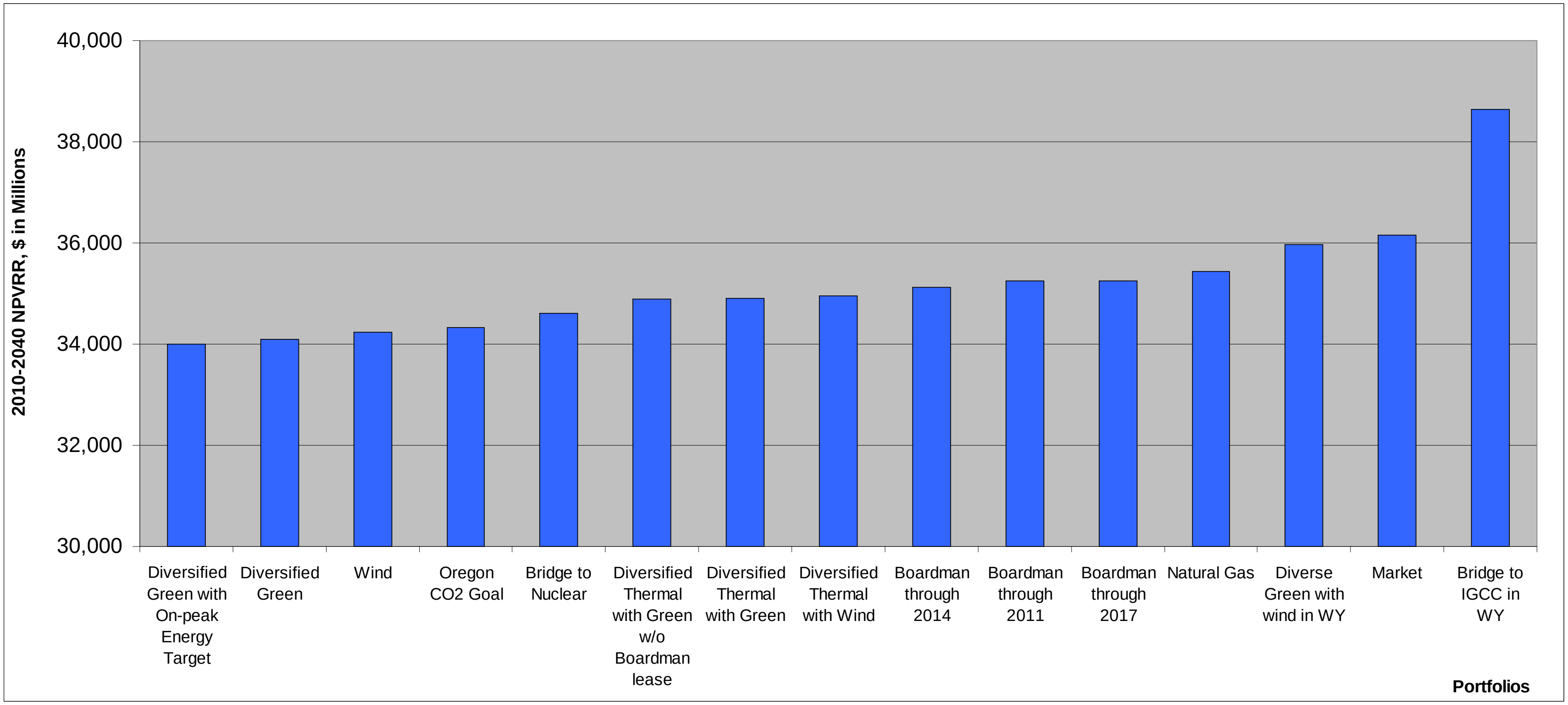


Figure 11-4: Average Cost of Four Worst Futures 2009$



Our third scoring criterion is a variation suggested by OPUC Staff. It uses the same average expected cost of the worst four futures for each portfolio, but does not subtract these results from the reference case expected cost. This variant deterministic risk metric also receives 5% of the overall score. Figure 11-4 above ranks the four worst futures by portfolio.

Where the prior metric seeks to determine the magnitude of the difference between the worst cost outcomes and the reference case expected cost, this metric focuses instead on absolute magnitude of bad outcomes (without regard to the expected cost). As an illustration of why this variation may make a difference, portfolios that are dominated by natural gas may have low reference case expected costs but high cost exposure. Conversely, portfolios dominated by fixed costs (e.g., renewables and nuclear) may have a higher reference case expected cost, but reduced cost exposure. When measuring degree of variation from the expected cost, gas portfolios appear more risky. But when looking at absolute cost exposure, the higher fixed-cost portfolios may actually be riskier. However, it should be noted that the relative performance of most portfolios is unchanged between these two metrics.

Probability of High Expected Costs and Low Expected Costs

One approach to further distinguish portfolio performance against potential futures is to examine each portfolio's probability of being among the worst four performers under the futures with respect to cost. Under this methodology, the probability of poor performance equals the number of times that a given portfolio ranked among the worst four out of the 15 portfolios we tested against all 21 futures. Any portfolio that exhibits a high number of high-cost outcomes may be viewed as more likely to perform poorly under conditions that vary from the reference case.

Figure 11-5 shows the ranking of portfolios based on frequency of poor performance. This graph further suggests that portfolios that are both greener and more diversified are generally better able to avoid bad outcomes. Conversely, Figure 11-6 displays the probability of *best* performance, that is, the probability that a portfolio is among the best four out of the 15 portfolios tested against the 21 futures. In this view, four portfolios emerge as good performers. Finally, Figure 11-7 combines results of the worst and best probabilities – this is the joint probability of both avoiding poor performance and achieving good performance. This deterministic risk scoring metric receives 10% of the total score.

Figure 11-5: Portfolio Probability of High Expected Costs

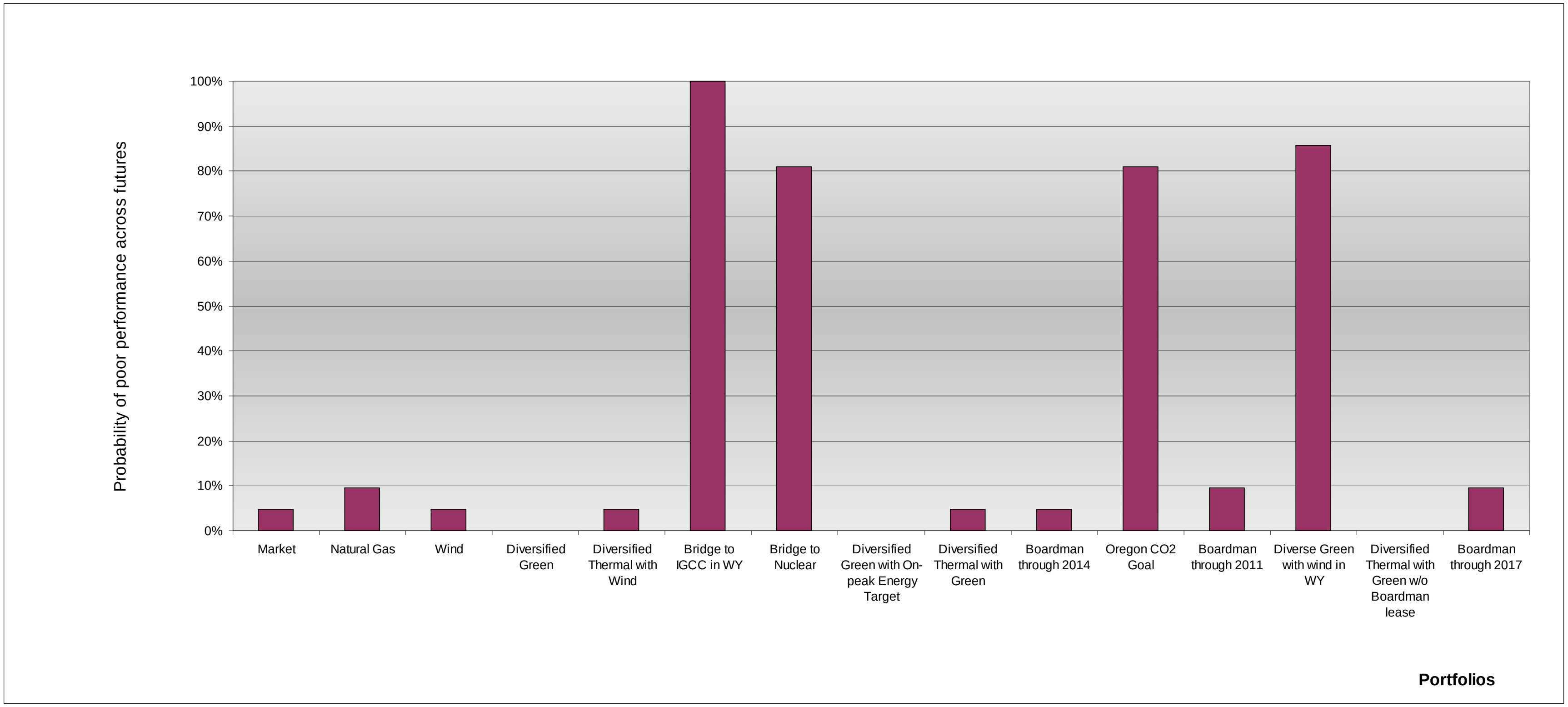


Figure 11-6: Portfolio Probability of Low Expected Costs

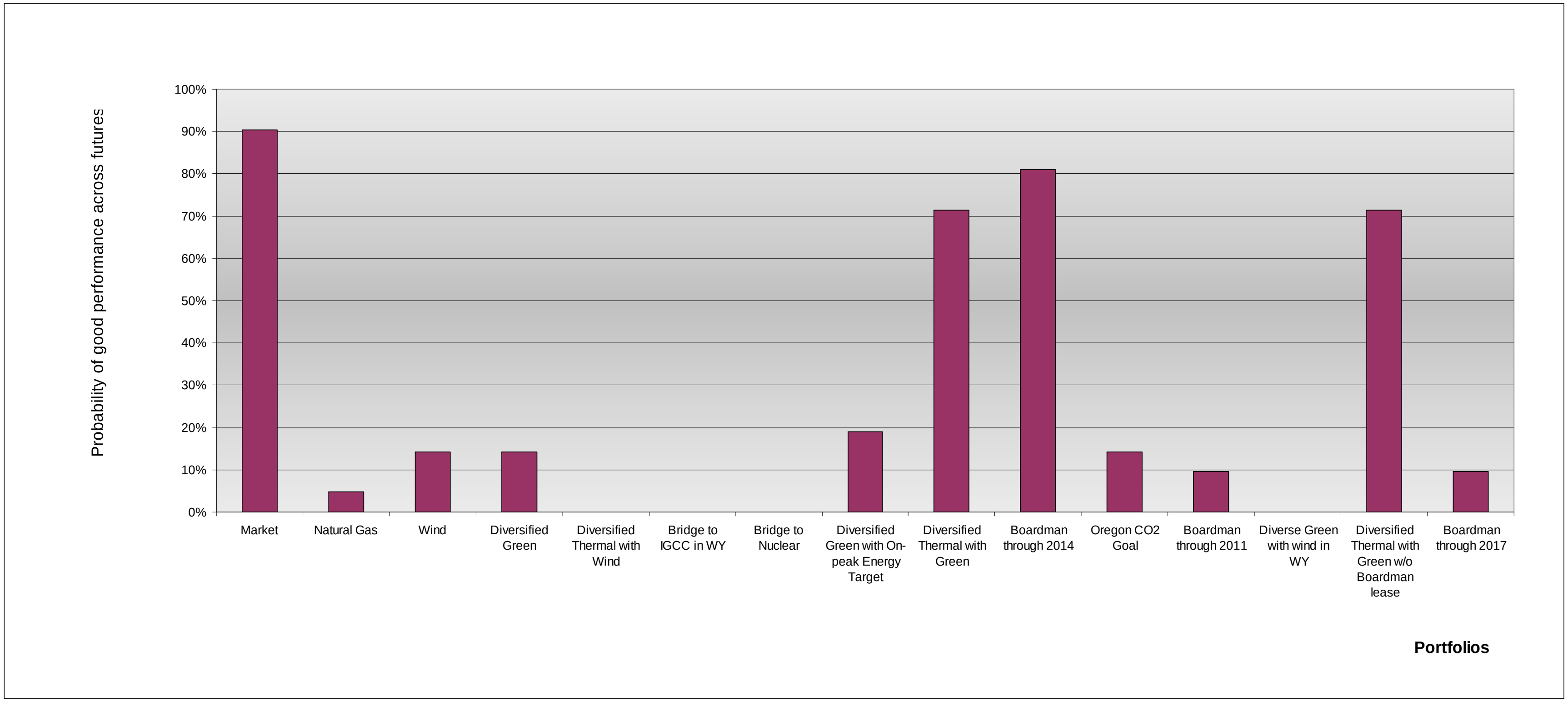
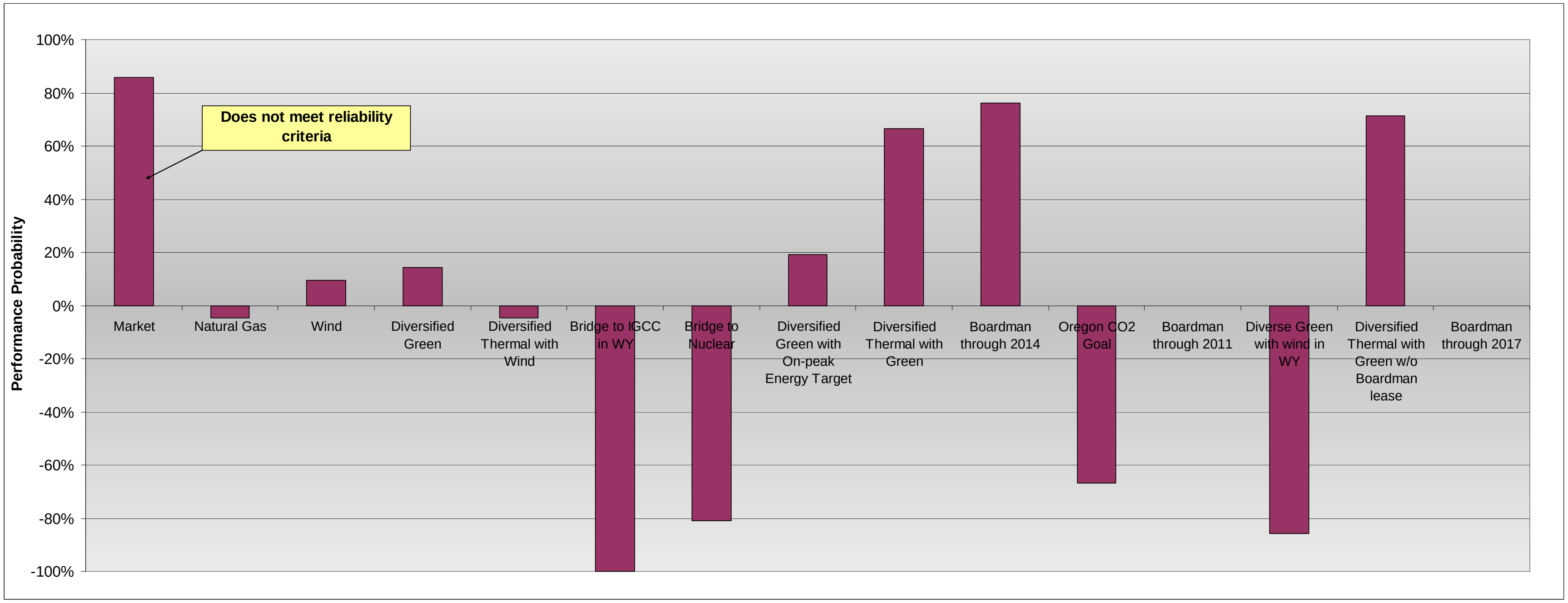


Figure 11-7: Portfolio Probability Combined Results – Achieving Good Outcomes & Avoiding Bad Outcomes



11.2 Stochastic Analysis Results

We now turn our attention from assessing scenario risk, where we look at portfolio performance against a range of potential futures, to stochastic analysis, where we focus on the portfolio performance under reference case assumptions, but with stochastic inputs derived from historical actual data for loads (due to weather deviations from 1-in-2), natural gas prices, PGE generation plant forced outages, wind intermittency and hydro. The preceding chapter set forth the details of how we developed and conducted the stochastic study. Table 11-1 presents a few of the major relationships among the stochastic variables.

Table 11-1: Summary Statistics of Stochastic Analysis 2010-2040 (Nominal$)

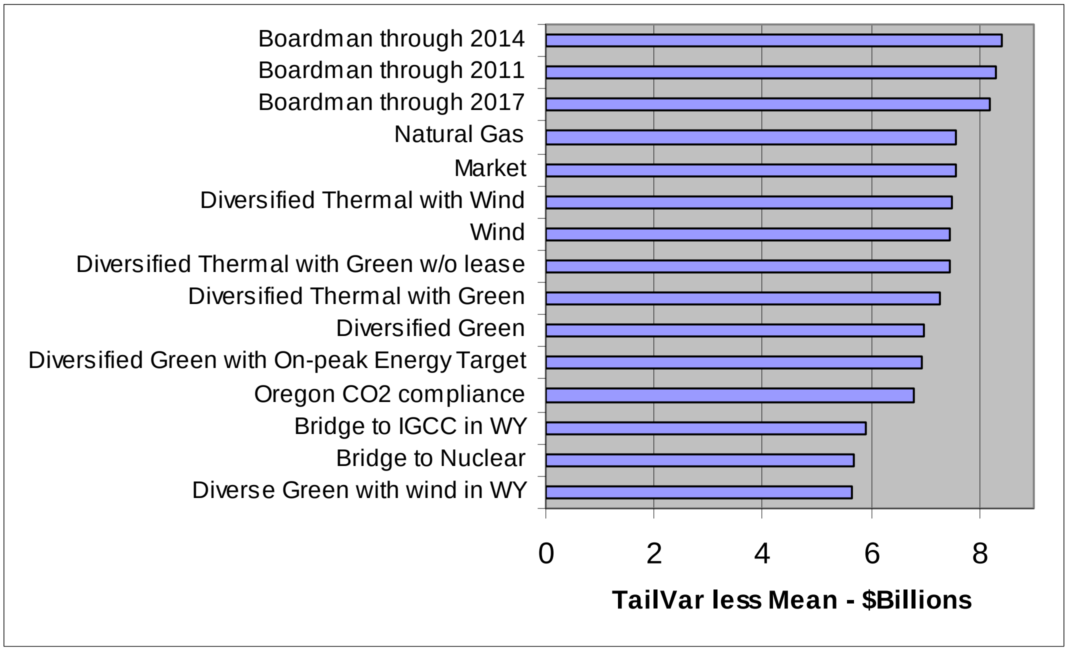
	PGE Electricity Prices Nominal $/MWh			Sumas Gas Prices Nominal $/MMBtu		AECO Gas Prices Nominal $/MMBtu	
	Base Case	**Stochastic**		**Base Case**	**Stochastic**	**Base Case**	**Stochastic**
Mean	$108.8	$95.8		$11.67	$9.53	$11.17	$9.21
Standard Deviation	NA	0.21		NA	0.14	NA	0.14
Annualized Volatility (%)	NA	73.3		NA	49.9	NA	49.9
Correlations :							
		Maximum	Mean	Minimum			
PGE Electricity Prices vs. Henry Hub		0.55	0.38	0.18			

Some participants in our IRP public meetings have correctly observed that long-term future/scenario analysis is more instructive than stochastic analysis, as scenario analysis considers a wider range of risk factors. We agree, and thus the stochastic risk assessment receives only 10% of our total score – half what we give to the scenario/ deterministic risk assessment. Nevertheless, stochastic analysis is valuable in its own right, and both types of modeling methods are necessary to fully examine portfolio performance and durability. They answer different questions, and thus contribute to a broader, more informed set of insights for our decisions. Below are a description of the metrics we used and the results of our stochastic analysis.

TailVar 90

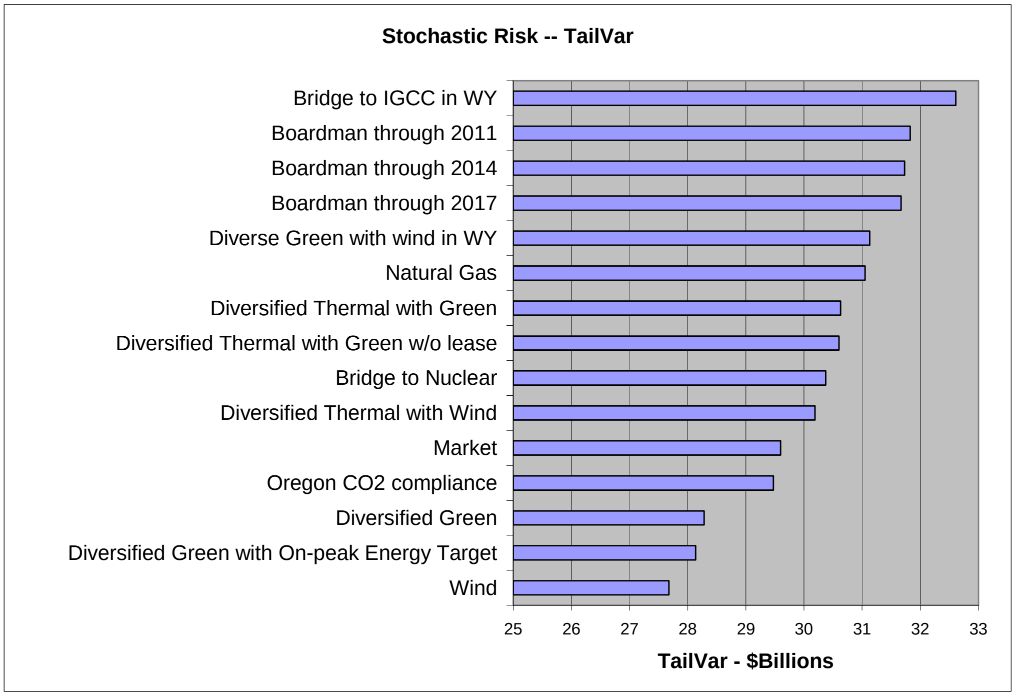
The first stochastic metric looks at the performance of the portfolios using stochastic inputs for the five risk variables described above. Based on 100 iterations, we take the TailVar90 of the 31-year NPVRR cost distribution less its mean. The metric receives 3.33% of our total score. Portfolios with larger natural gas concentrations fare poorly, while portfolios with reduced exposure to natural gas and electricity market prices generally perform better. Figure 11-8 shows portfolio performance. With this metric, portfolios with a lower dollar amount for the TailVar 90 score higher.

Figure 11-8: TailVar 90 less the Mean



In a variation of this metric suggested by OPUC Staff we look at the absolute result of the 31-year NPVRR TailVar90 without subtracting the mean. This metric also receives 3.33% of the total score. As with the two deterministic variants described earlier, the TailVar less Mean metric describes the potential variation between the expected cost and the worst 10% of outcomes, whereas this metric focuses instead on the absolute magnitude of the worst outcomes. Both are legitimate risk exposure considerations. Figure 11-9 below is a graphical representation of the portfolio TailVar results.

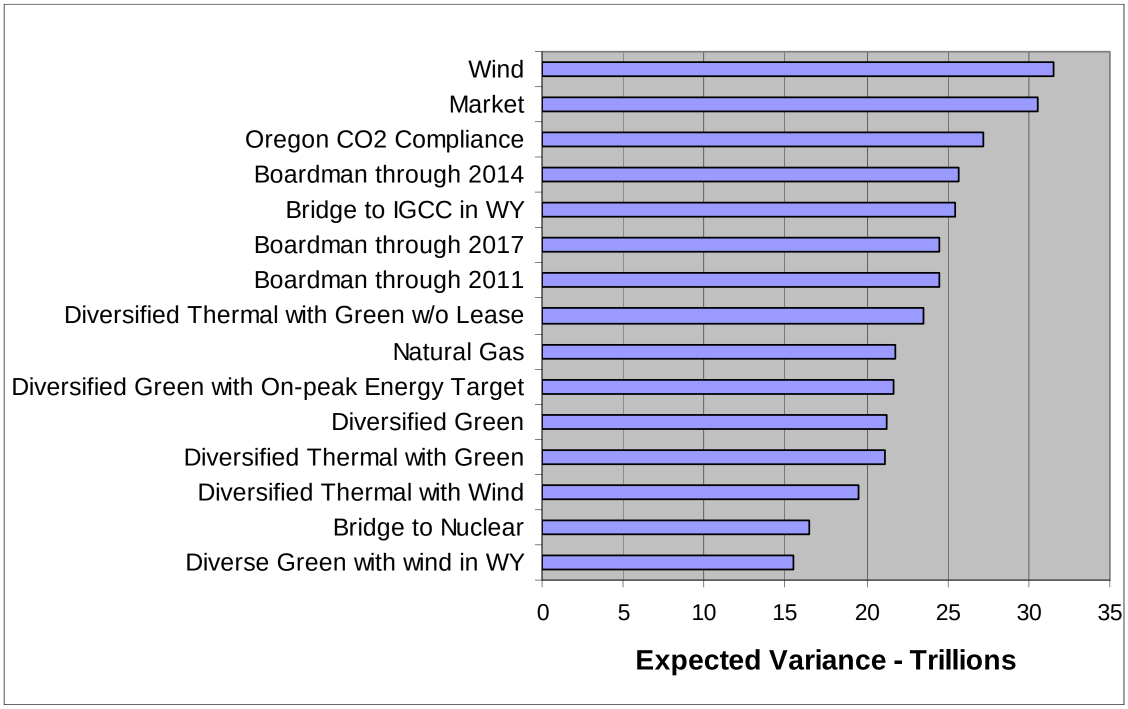
Figure 11-9: TailVar 90



Year-to-Year Variability

Where the metrics above focus on total NPVRR cost change over the modeling period, we use a final stochastic metric that looks at year-to-year variability of portfolios. Here we expect portfolios with lower exposure to the stochastic variables to perform better. As with the prior stochastic metrics, portfolios with higher fixed costs and less exposure to gas and power market prices generally perform well. This metric receives the final 3.33% score in our stochastic scoring. See Figure 11-10 below.

Figure 11-10: Year-to-Year Portfolio Average Variation



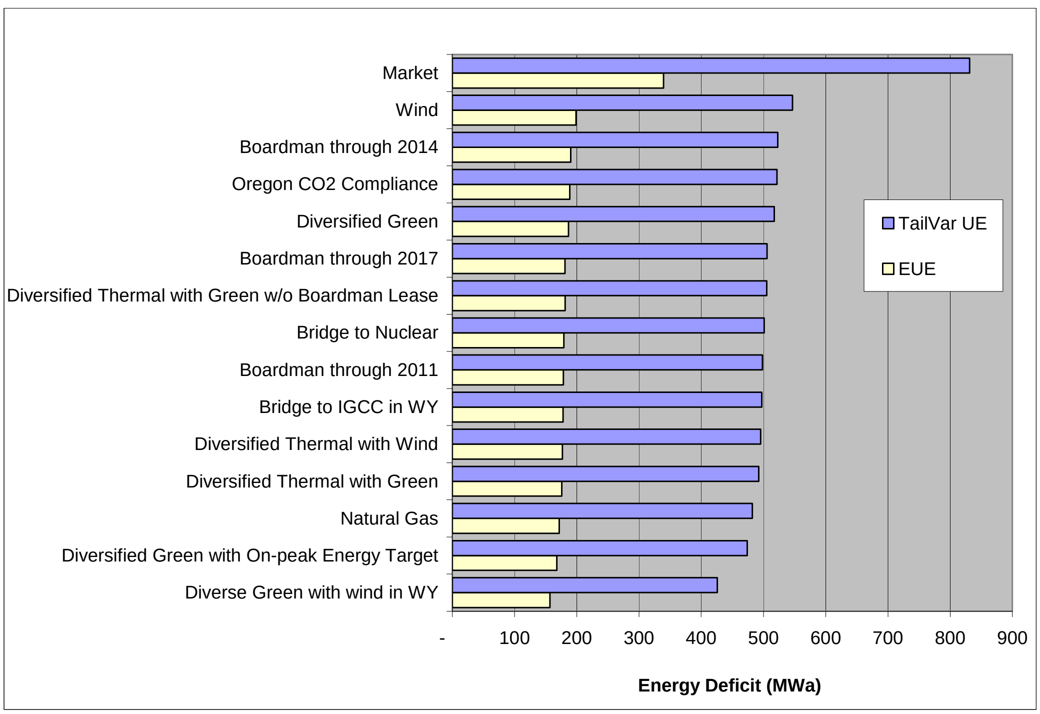
11.3 Reliability and Diversity Analysis Results

To this point, we have focused on portfolio expected cost under reference case assumptions (50% of total score) and variations from expected costs using several deterministic and stochastic risk metrics (30% of total score). Our final criteria for portfolio performance are portfolio reliability performance and intrinsic diversity. The former receives 15% of our total score and the latter the remaining 5%. A portfolio that might otherwise perform well in terms of expected cost and cost risk may be substantially more risky in terms of reliability. Portfolios dominated by a few large generation shafts are a possible example. Likewise, as in financial portfolio theory, it is true that regardless of specific market characteristics, the best way to hedge portfolio risk is to diversify. A portfolio that is balanced with investments in assets that are not equally exposed to the same risks provides a composite risk profile that can actually be lower than the risk of the individual assets in the portfolio. Avoiding portfolio concentration in specific fuels and technologies can also prevent extreme bad outcomes if a significant, fundamental change occurs relative to future legislative policy or supply-demand equilibrium.

Reliability

A description of how we modeled reliability risk is found in Chapter 10. Our preferred metric to assess portfolio performance is Tailvar Unserved Energy (Tailvar UE). What we measure with this analysis is the degree of reliance that PGE's portfolios might have on emergency supply from the spot market. To the extent that the market supply was not available during adverse conditions, the Tailvar UE measure would also reflect the degree of PGE customer demand that would not be met by each portfolio. The higher the expected energy obtained from the market, the poorer the performance for this metric. Unlike loss of load probability, Tailvar UE provides a measure of how big a reliability shortfall might be. Tailvar UE is measured as the average of the worst 10% market exposures for the years from 2012 to 2020, plus 2025. After 2020, the portfolios do not have major resource additions, so Tailvar UE should not change between portfolios. To verify that this was the case, we included and reviewed results for 2025. As expected, relative portfolio performance between 2020 and 2025 does not change. Figure 11-11 shows portfolio performance for the metric.

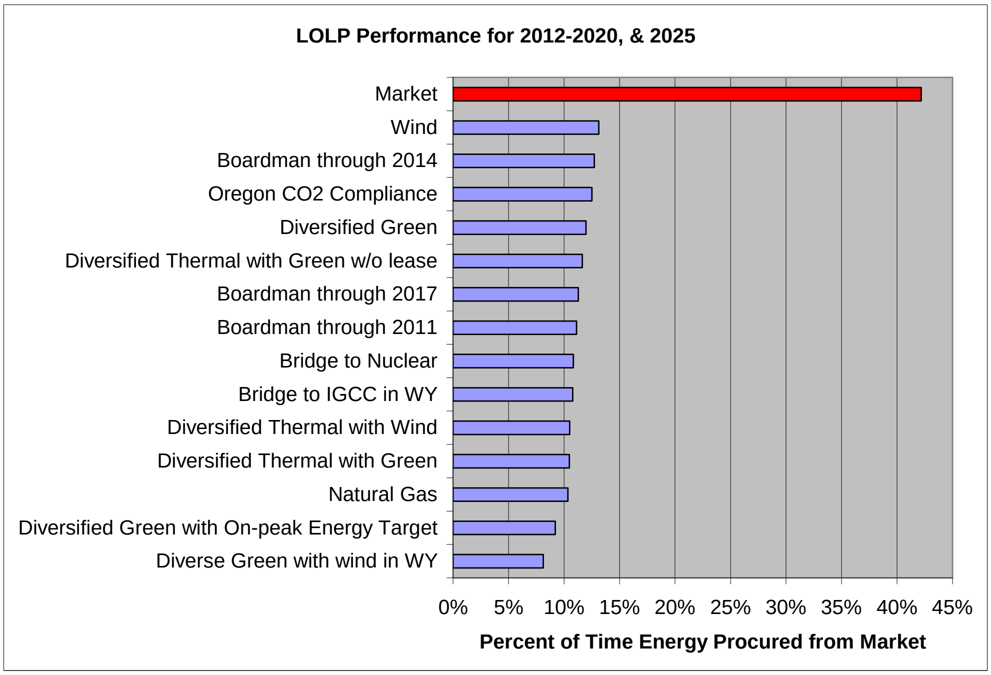
Figure 11-11: Portfolio Reliability - Unserved Energy Metrics for 2012-2020 & 2025



The loss of load probability is an additional reliability metric we calculated. This metric represents the percent of hours that a market purchase is made to cover PGE's load. Figure 11-12 below shows the results, which vary slightly from the

EUE analysis, but are consistent overall. LOLP examines market dependence by number of hours, while EUE and Tailvar UE presents the energy amount need from the market for those hours of shortfall. For consistency with the other Tailvar metrics, we score based on the Tailvar UE metric.

Figure 11-12: Portfolio Reliability - LOLP

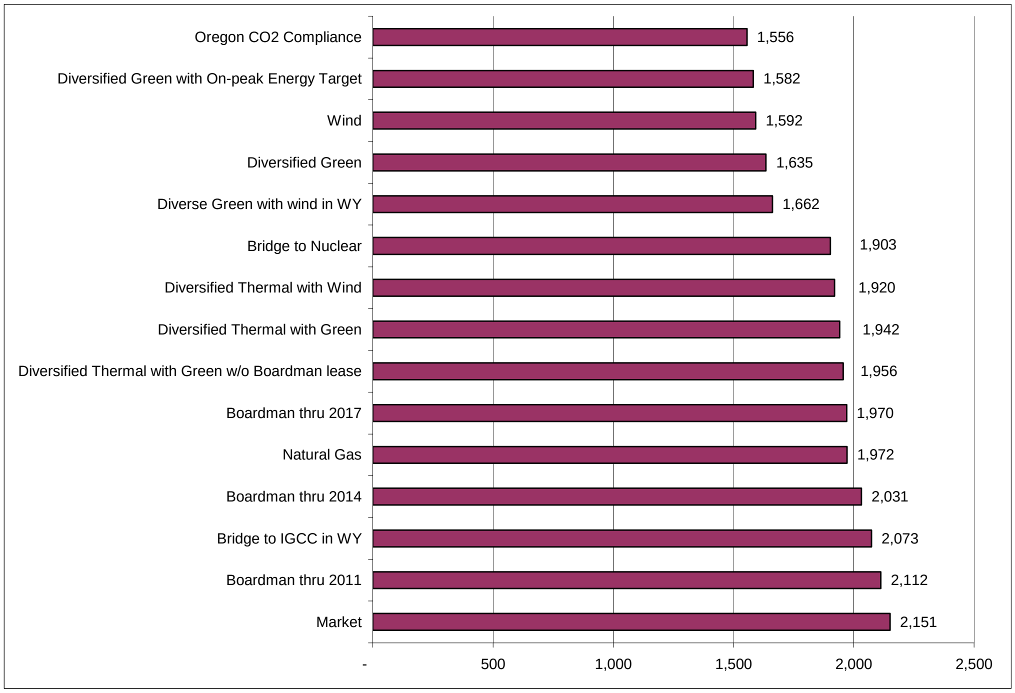


Diversity

To measure diversity we adopted the Herfindahl-Hirschman Index or HHI, as set forth in the preceding chapter. HHI has historically been used in competition and anti-trust law to measure market concentration / power in a given industry. Since the measure was designed to measure concentration (or lack of diversity), it can also be used to assess if an industry (or in this case a portfolio) is diversified, or less balanced. In the HHI, lower numbers indicate greater diversity. Further, we examined both fuel diversity and technology diversity separately, using both in portfolio scoring.

Fuel diversity was measured using MWh of energy as a proxy. Here we totaled the amount of energy provided from actual portfolio dispatch by each fuel type for the period 2010-2020. Figure 11-13 below shows the results.

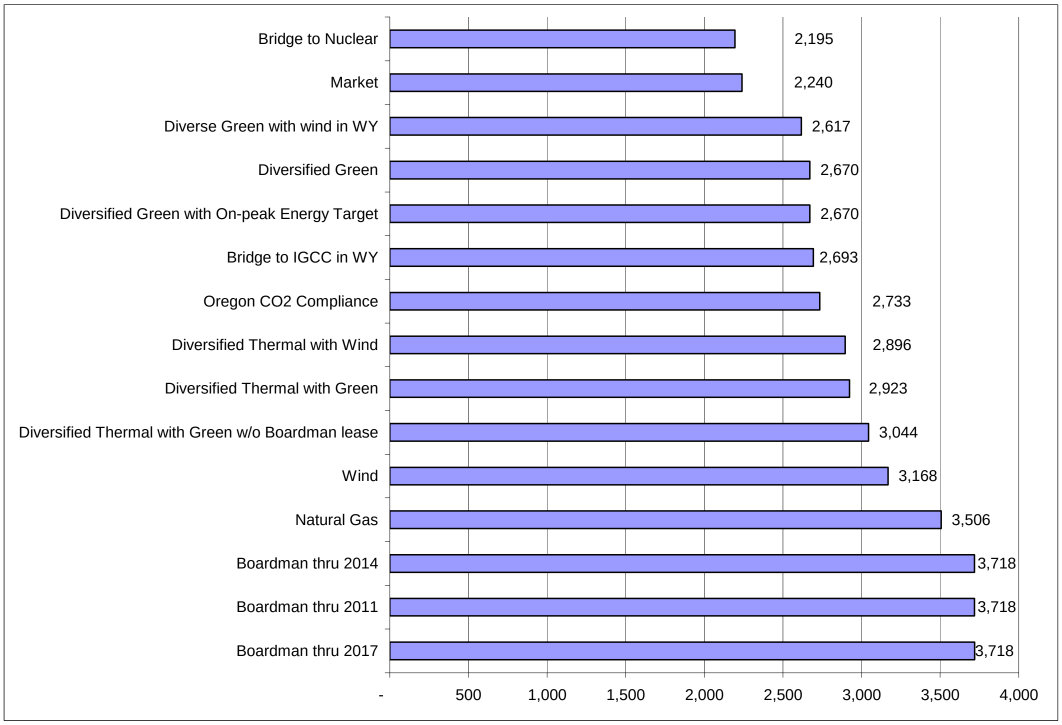
Figure 11-13: Fuel HHI



The figure above shows that from a fuel diversity perspective, the Oregon CO_2 compliance portfolio is the most diverse, with Market being the least diverse. For the CO_2 compliance portfolio, fuel diversity is increased due to the contributions of wind and nuclear, while the Market portfolio is overexposed to market purchases. Increased reliance on natural gas and market purchases also negatively impacts early Boardman closure portfolios, thus their lower ranking.

We used nameplate capacity by fuel type in 2020 (the last year for major resource additions) for the proxy for the technological diversity measure. The results of this analysis are shown in Figure 11-14.

Figure 11-14: Technological HHI



For the technological HHI, Bridge to Nuclear is the best-performing portfolio while the Boardman closure portfolios perform worst. Bridge to Nuclear benefits from the addition of a new resource type, a nuclear plant representing 14% of the capacity in 2020. Market also shows a higher level of diversity due to 27% of the capacity coming from the market, which is an additional resource, as compared to approximately 5-6% for the other portfolios (in which one resource is more dominant). The Boardman closure scenarios perform badly due to a relative decreased use of coal, and dramatically increased reliance on natural gas.

For the overall diversity measure, we gave the technological and fuel HHI metrics equal weightings of 2.5% each.

11.4 CO_2 Analysis

Emissions and CO_2 Intensity

We also look at sensitivity analysis on a few portfolio performance metrics which are not directly included in our portfolio scoring. In most cases the following portfolio attributes have already been assessed in the previously discussed cost and risk measures. The first two of these metrics are total CO_2 emissions by portfolio and *CO_2 intensity*, which is defined by the carbon content per MWh of electricity generated and net purchased to meet our load. We assumed a CO_2 content of 900 lb/MWh (a commonly used emission rate, about equal to the carbon content of existing CCCTs) for market purchases, consistent with what the ODOE uses. We do not use this metric in scoring because it would be duplicative of deterministic risk metrics which incorporate CO_2 price futures ranging from $12/short ton (real levelized) to $65/ton.

Figure 11-15 shows the total reference case emissions by portfolio in 2020. Figure 11-16 shows the reference case emissions by year for each portfolio for the planning horizon, and Figure 11-17 shows the reference case CO_2 intensity by year for each portfolio for the planning horizon.

Figure 11-15: Reference Case CO_2 Emissions in Short Tons by Portfolio in 2020

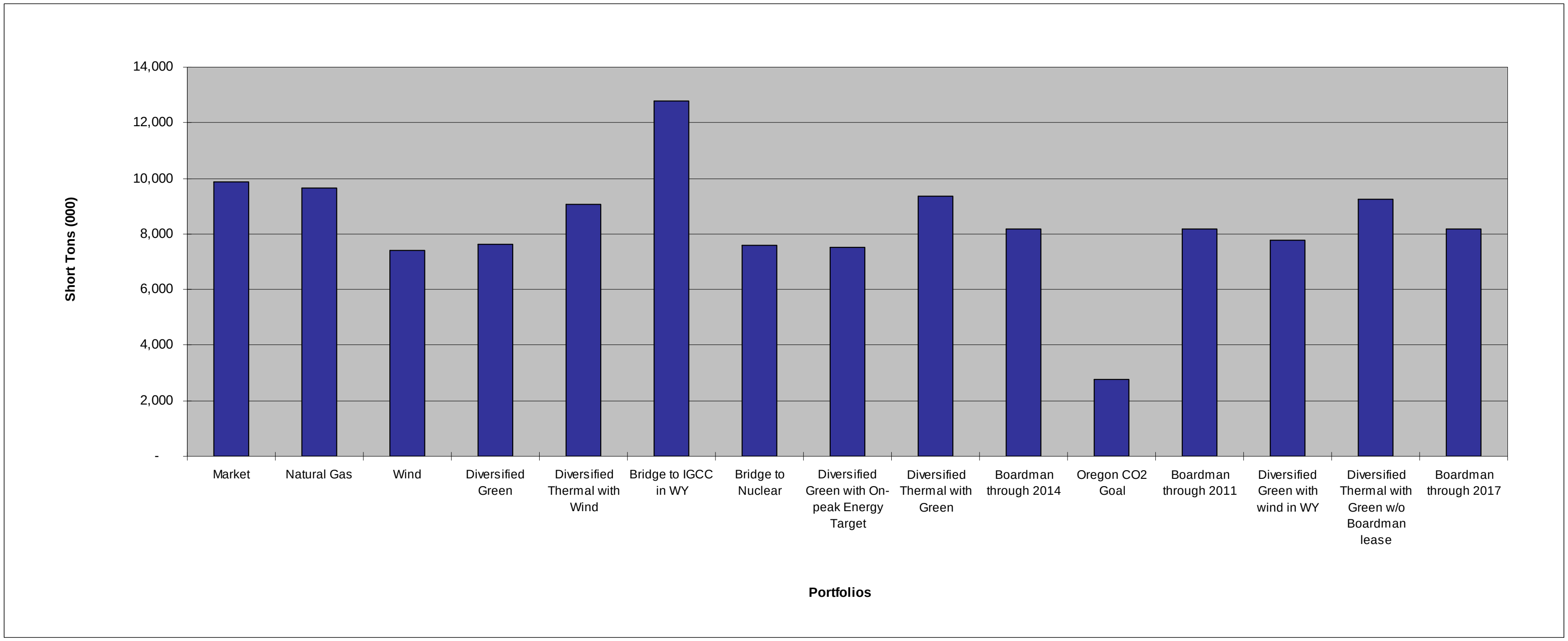


Figure 11-16: 2010-2030 Reference Case CO_2 Emissions in Short Tons by Portfolio

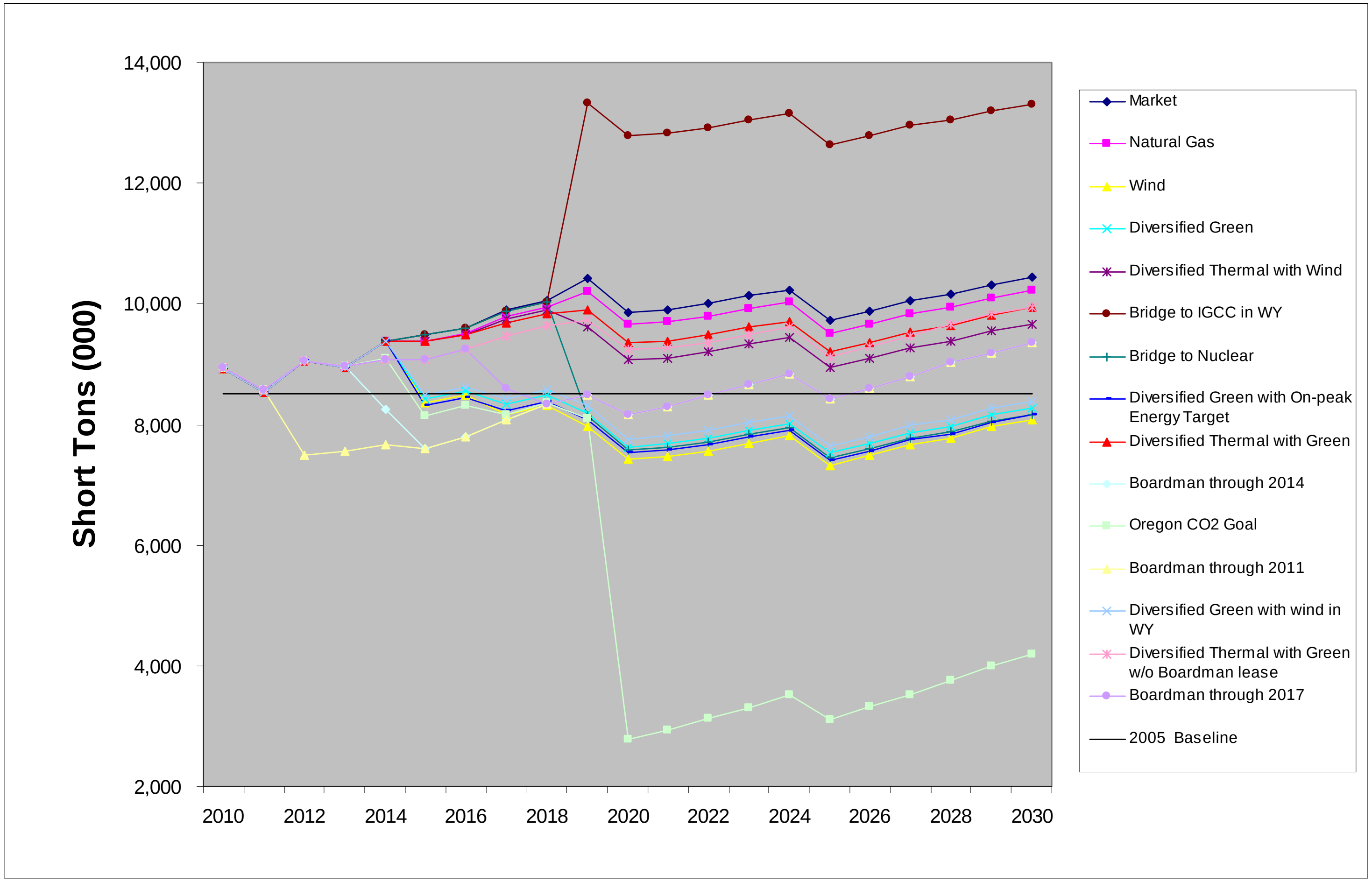
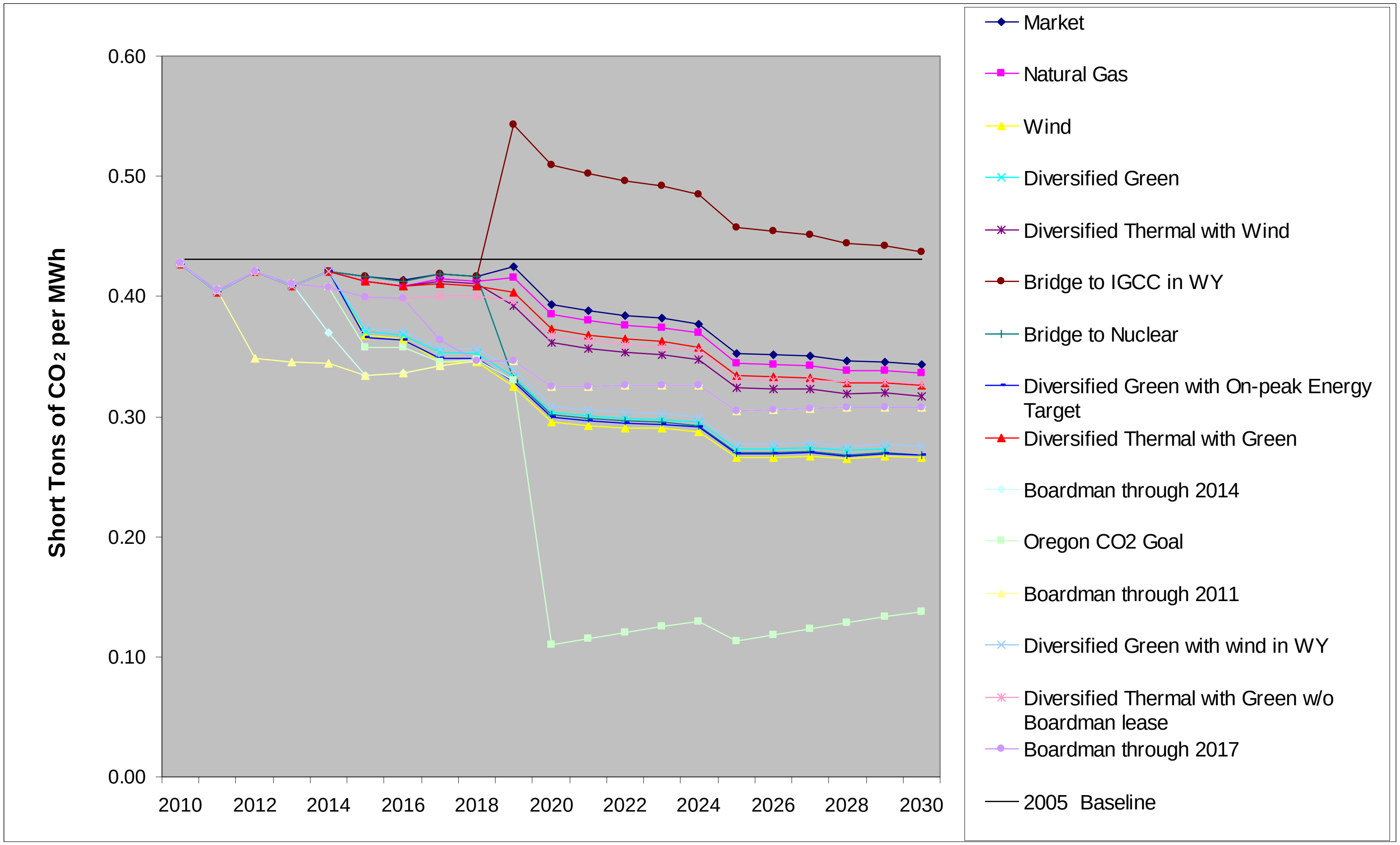
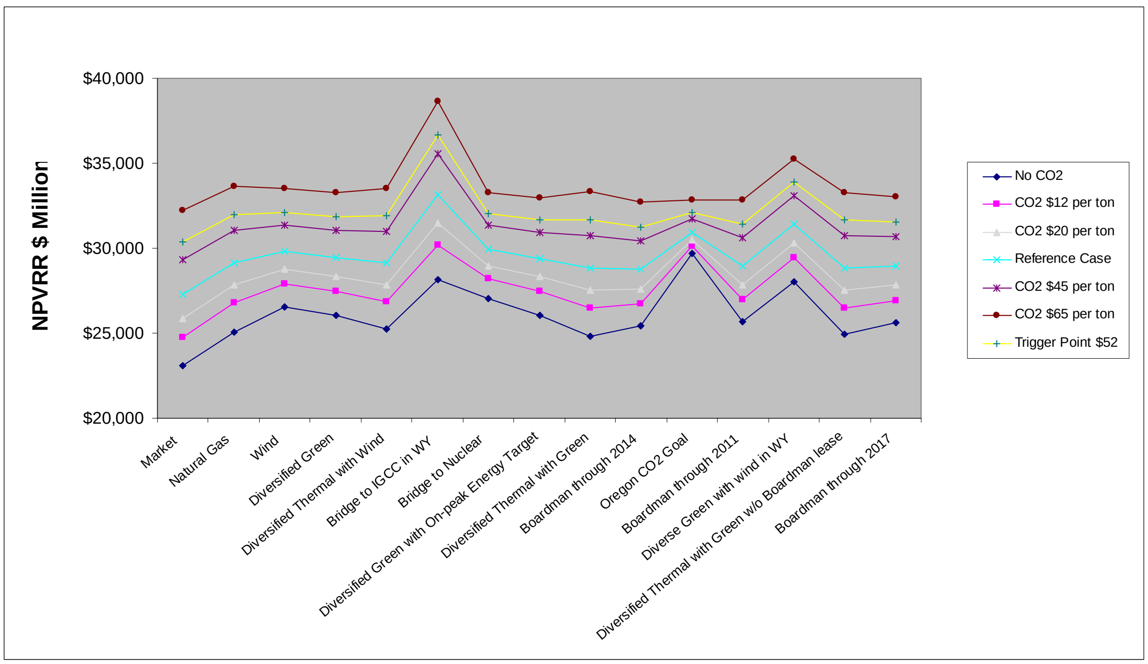


Figure 11-17: 2010-2030 Portfolio Analysis Reference Case CO_2 Intensity by Portfolio



Guideline 8 of Order No. 07-002 calls for a specific analysis of portfolio sensitivity to the impact of potential CO_2 regulation. We analyzed the impact of potential CO_2 regulatory costs from zero to $65 per short ton (in 2009$) on each of our portfolios. Our reference case assumes a CO_2 price of $30 per short ton in 2009$. In Figure 11-18 we assess the NPVRR in 2009$ of each portfolio under different CO_2 price levels. Results show, as expected, that low carbon portfolios hedge against increasing carbon risk. In this analysis, the Market portfolio appears to perform well due to its low expected case cost, not due to its emissions levels.

Figure 11-18: Carbon Price Performance of the Incremental Portfolios



One outcome of this analysis is portrayed in Figure 11-18. As the carbon tax increases, the cost per MWh of power generated by coal plants increases significantly, while the cost per MWh of CCCT generation remains relatively flat, despite the fact that gas also has the same carbon tax based on dollars per ton of CO_2. This is because new CCCTs produce only about 40% of the CO_2 per kWh produced by a new coal plant. As the carbon tax rises, the dispatch cost of a coal plant increases proportionally more than the dispatch cost of other resources, increasing the overall market price of electricity. As a result, the dispatch value of a baseload gas unit goes up, even though it also experiences increased CO_2 costs. In effect, coal and gas swap places in the resource stack at a high enough carbon tax. Where that intersection lies is also a function of the prevailing market price.

Trigger Point Analysis

We identified the CO_2 "turning point" scenario which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. We used the following methodology:

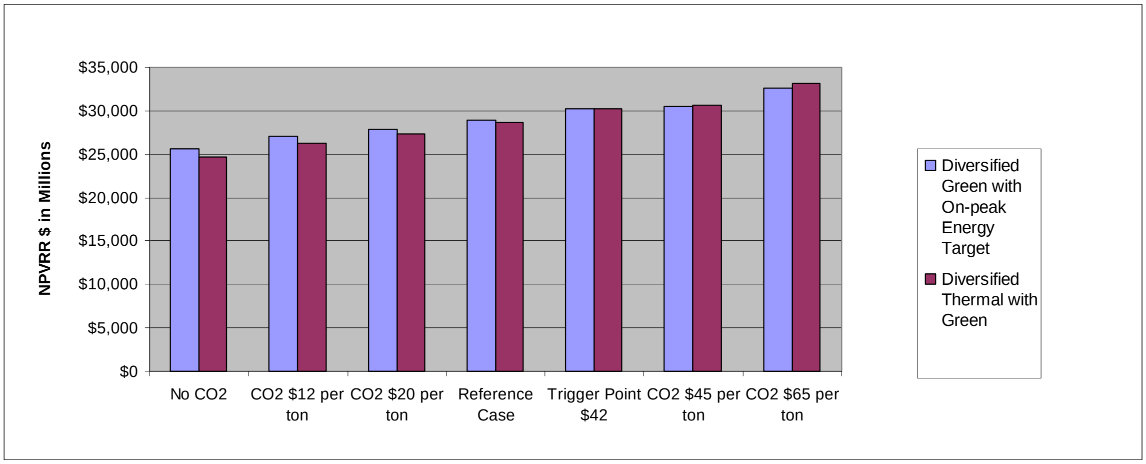
1. In our futures, we have six CO_2 cases (real levelized in 2009$):
   - No carbon price
   - $12/ ton
   - $20/ ton
   - $30/ ton (our reference case)
   - $45/ ton
   - $65/ ton

   From the scenario analysis, we identified if/when a substantially different alternative portfolio becomes the least-cost portfolio in any of the six CO_2 futures identified above.

2. Once we identified the CO_2 price future in which the substantially different alternative portfolio becomes the preferred portfolio, we varied the CO_2 price to find the point at which the preferred portfolio is no longer the least cost. We ran additional CO_2 price futures to identify the CO_2 price that triggers the switch from our preferred portfolio to our substantially different alternative portfolio, and found that the trigger point CO_2 price is $42.

Figure 11-19 below shows when the preferred portfolio is replaced with a different alternative portfolio, Portfolio 8 (Diversified Green with On-peak Energy Target), as the least-cost portfolio.

Figure 11-19: Trigger Point Analysis Results

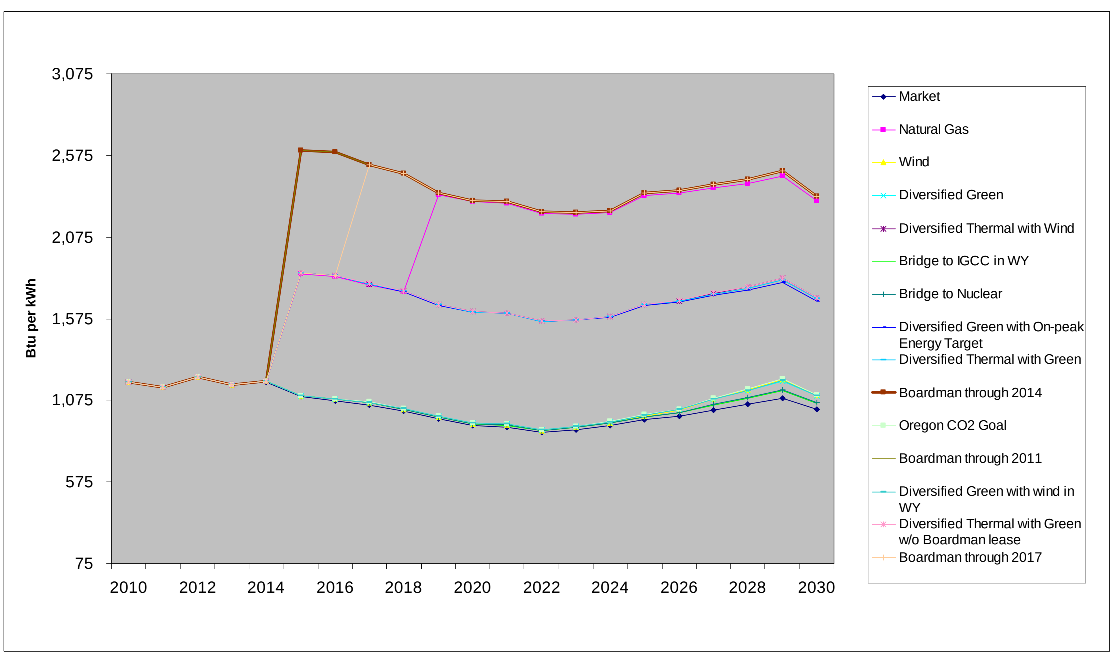


11.5 Other Quantitative Performance Metrics

Natural Gas Intensity

Another metric of interest is the amount of reliance on natural gas in each portfolio. As is shown in Figure 11-20, portfolios cluster into three distinct groups based on the amount of gas resources added in each portfolio. Diversified green portfolios have the lowest gas intensity; portfolios that add mostly gas resources (in addition to existing resources and/or to replace Boardman) have the highest gas intensity (and therefore highest exposure to gas risk), and diversified portfolios that add a mix of gas-fueled and green resources are in the middle.

Figure 11-20: Natural Gas Intensity by Portfolio



Fixed vs. Variable Costs

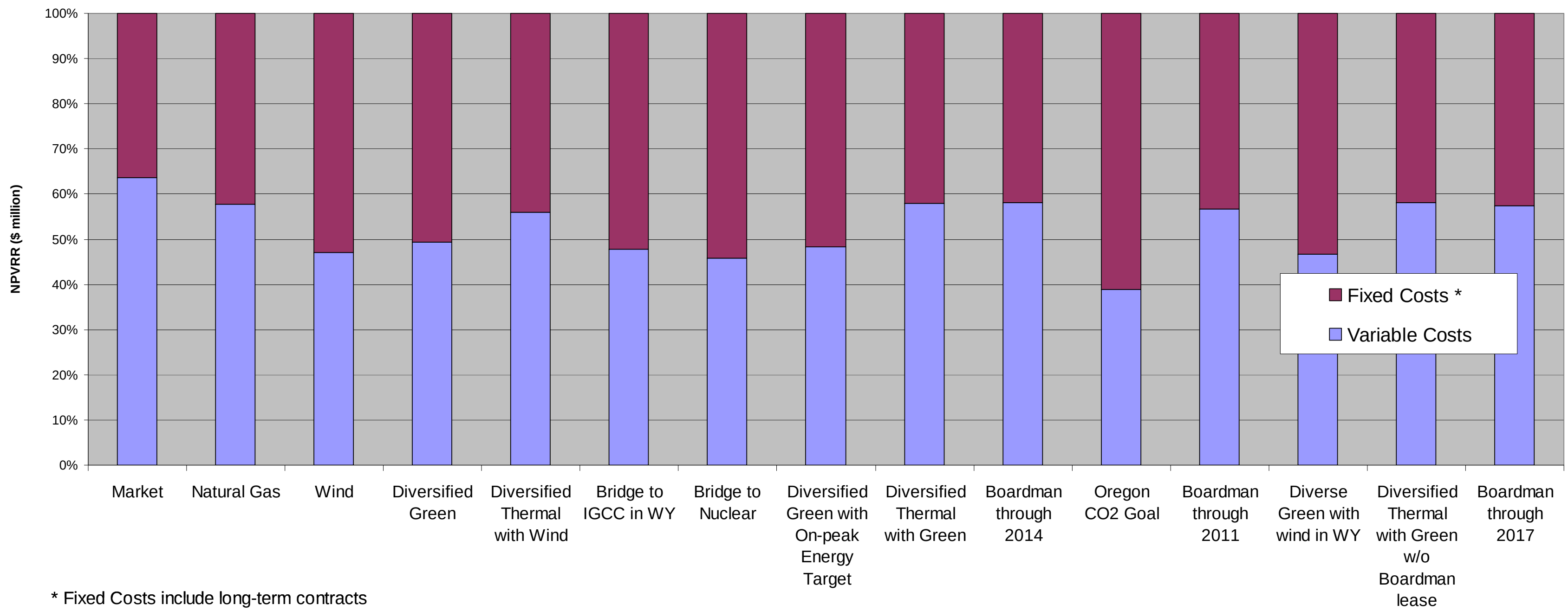
Another metric of interest is the mix of fixed vs. variable costs in our portfolios. We defined as fixed the total cost of long-term power purchase agreements and the fixed component of the revenue requirement. New wind resources are very capital intensive, as are IGCC and nuclear. However, high fixed-cost resources (such as wind or nuclear) typically have low variable and fuel costs. While this metric is of interest in understanding what drives various portfolio costs, we do not use it in scoring because, depending on what futures unfold, it is difficult to know whether high fixed costs or high variable costs are preferable. Perhaps the most useful insight from Figure 11-21 is that due to PGE's embedded portfolio, the overall relative split between fixed and variable costs does not change significantly between portfolios.

Load Growth Stress Testing

Guideline 4b of Order No. 07-002 requires an analysis of high and low load growth scenarios. The analysis provides insights into the potential impacts of fundamental shifts driven by the economy, population growth, or unforeseen changes to electric end uses. In addition, the order requires a stochastic load risk analysis with an explanation of major assumptions. Stochastic load risk in our analysis is driven purely by weather.

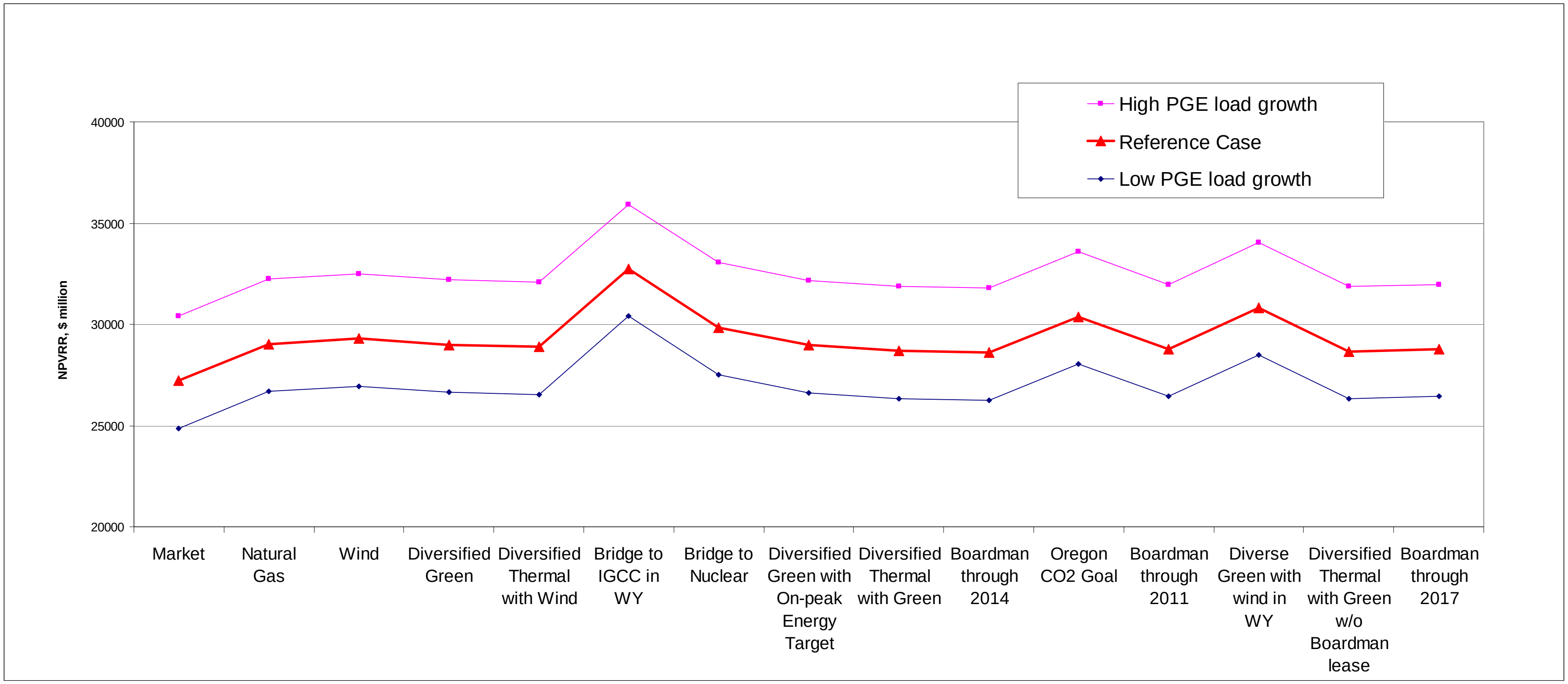
Figure 11-22 shows portfolio performance under the reference case load growth (2.22% per year), high load growth (2.98%), and low load growth (1.57%). All portfolios are affected similarly: they all add the same amount of market purchases when load is systematically higher than forecasted. When PGE load is lower than forecasted, all portfolios reduced market purchases by the same amount. The resulting risk is being overly long with commitments to longer-term resources when loads do not meet expectations, or conversely, of being too market-dependent in the instance where load growth exceeds expectations.

Figure 11-21: Portfolio Fixed and Variable Costs as a Percentage of NPVRR $2009



* Fixed Costs include long-term contracts

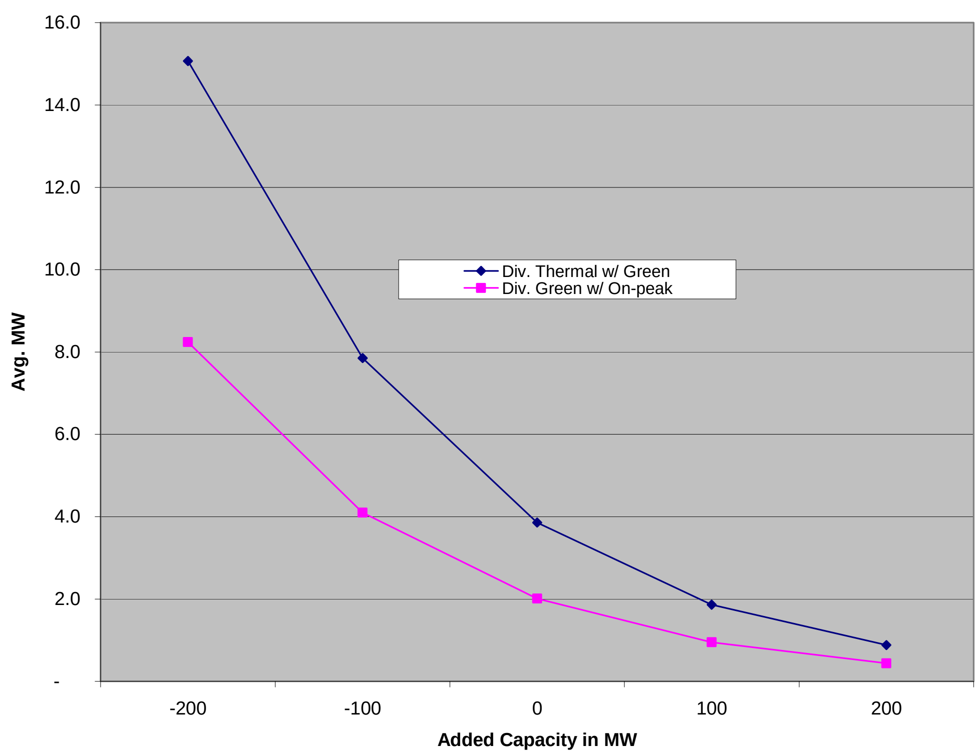
Figure 11-22: Incremental Portfolio Performance under Load Growth Stress Testing



Capacity Adequacy Sensitivity

All of our portfolios, except Market, build to essentially the same capacity capability by 2020. Based on our 2015 stochastic load shape, variable hydro and wind, scheduled plant maintenance outages, and probabilistic forced outage rates with associated stochastic mean- times-to-repair, the following graph displays the impact to reliability in the year 2015 of varying the amount of flexible gas generation additions to our top-performing portfolios. These portfolios include our proposal to add 200 MW of flexible gas generation. We show the annual mean or expected unserved energy (EUE) metric (base on 100 iterations) assuming our Action Plan recommendation of adding 200 MW of such generation. We then show the impact of decrementing gas generation by 200 MW and the impact of acquiring an additional 200 MW. The additional flexible gas generation is also subject to maintenance and forced outages – we do not treat it as firm capacity.

Figure 11-23: Annual Mean Unserved Energy as a Function of Incremental/ Decremental Capacity



The results of the graph confirm that we are in the optimal zone with regard to capacity adequacy. As capacity is subtracted, EUE begins to climb rapidly, essentially doubling with every decrement of 100 MW of capacity. Conversely, additional increments of capacity (up to 200 MW) have a beneficial impact to EUE, reducing the amount of expected unserved energy. Capacity additions beyond 200 MW appear to have declining value as the slope of the line for EUE begins to flatten-out. While annual EUE may seem small, it should be remembered that these are outages that have been spread over 8,760 hours. Hence, the TailVar UE graph is a better representation of the potential severity of these limited-duration events. While results may still seem high, they continue to meet the required 6% operating reserve in all hours. These graphs show that, while these flexible gas units may dispatch a limited amount of hours, they are important for reliability, in addition to their more frequent use in helping integrate variable wind.

11.6 Summary of Portfolio Performance and Uncertainties

The deterministic, stochastic, reliability, and diversity portfolio analysis described in this chapter reveal both strengths and weaknesses of the resource alternatives and candidate portfolios. The next step in our evaluation process is to combine the metrics to see which portfolios emerge as better performers when considering both risk and cost.

Table 11-2 (on the following page) shows the raw scores for each metric, based on the actual units they are measured in ($ NPV, %, MWa, etc), for each of the metrics discussed above.

Table 11-3 normalizes these scores by assigning the best-performing portfolio for each metric a score of 100 and the worst performer a score of 0. The remaining portfolios are assigned a score that is prorated relative to how they perform against the best portfolio.

In the final step (Table 11-4), we apply the weights discussed above to each metric to arrive at a composite score. We then give the portfolios an ordinal ranking from best to worst based on their overall performance. As mentioned in the previous chapter, the metrics and scoring approach we use are intended to provide insights into portfolio performance under a variety of circumstances and considerations. Thus, this approach supplements business judgment rather than supplanting it.

Table 11-2: Portfolio Scoring Grid: Raw Scores for Cost and Risk Metrics

	1. Portfolio Evaluation Scoring: Raw Performance Metrics	Screening		Deterministic						Stochastic			Reliability & Diversity		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Zone?	Meets Operating Reserve Req?	Cost: Expected Cost Reference Case	Prob. of Poor Perf.	Prob. of Good Perf.	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variance	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
	Units	Y or N	Y or N	$ NPV Million	%	%	%	$ NPV Million	$ NPV Million	$ NPV Million	$ NPV Million	Trillion	MWa	Points	Points
1	Market	Y	N	$ 27,211	5%	90%	86%	$ 36,155	$ 8,943	$ 29,598	$ 7,563	30.6	831.2	2240	2151
2	Natural Gas	Y	Y	$ 29,027	10%	5%	-5%	$ 35,436	$ 6,410	$ 31,050	$ 7,571	21.8	482.2	3506	1972
3	Wind	Y	Y	$ 29,288	5%	14%	10%	$ 34,238	$ 4,949	$ 27,679	$ 7,466	31.5	546.6	3168	1592
4	Diversified Green	Y	Y	$ 28,987	0%	14%	14%	$ 34,091	$ 5,104	$ 28,285	$ 6,986	21.2	517.3	2670	1635
5	Diversified Thermal with Wind	Y	Y	$ 28,891	5%	0%	-5%	$ 34,949	$ 6,057	$ 30,191	$ 7,479	19.5	495.3	2896	1920
6	Bridge to IGCC in WY	N	Y	$ 32,735	100%	0%	-100%	$ 38,635	$ 5,900	$ 32,609	$ 5,903	25.5	497.3	2693	2073
7	Bridge to Nuclear	Y	Y	$ 29,853	81%	0%	-81%	$ 34,610	$ 4,757	$ 30,373	$ 5,684	16.4	501.0	2195	1903
8	Green w/ On-peak Energy Target	Y	Y	$ 28,971	0%	19%	19%	$ 33,993	$ 5,023	$ 28,136	$ 6,937	21.7	474.0	2670	1582
9	Diversified Thermal with Green	Y	Y	$ 28,674	5%	71%	67%	$ 34,910	$ 6,236	$ 30,631	$ 7,280	21.1	492.3	2923	1942
10	Boardman through 2014	Y	Y	$ 28,593	5%	81%	76%	$ 35,126	$ 6,533	$ 31,727	$ 8,406	25.7	522.7	3718	2031
11	Oregon CO2 Compliance	N	Y	$ 30,375	81%	14%	-67%	$ 34,332	$ 3,958	$ 29,475	$ 6,801	27.2	521.7	2733	1556
12	Boardman through 2011	Y	Y	$ 28,777	10%	10%	0%	$ 35,247	$ 6,470	$ 31,827	$ 8,315	24.4	498.4	3718	2112
13	Diverse Green with wind in WY	N	Y	$ 30,828	86%	0%	-86%	$ 35,962	$ 5,134	$ 31,131	$ 5,638	15.5	426.0	2617	1662
14	Diversified Thermal w/ Green w/o Lease	Y	Y	$ 28,668	0%	71%	71%	$ 34,891	$ 6,223	$ 30,603	$ 7,453	23.6	505.2	3044	1956
15	Boardman through 2017	Y	Y	$ 28,780	10%	10%	0%	$ 35,257	$ 6,477	$ 31,670	$ 8,200	24.5	505.7	3718	1970

Performance Range for Scoring Normalization:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Best Performing Portfolio(s)			$ 27,211			86%	$ 33,993	$ 3,958	$ 27,679	$ 5,638	16	426.0	2,195	1,556
Best Basis			Min			Max	Min	Min	Min	Min	Min	Min	Min	Min
Worst Performing Portfolio(s)			$ 32,735			-100%	$ 38,635	$ 8,943	$ 32,609	$ 8,406	31	831.2	3,718	2,151
Spread Best to Worst			$ 5,524			186%	$ 4,641	$ 4,985	$ 4,930	$ 2,768	16	405.3	1,523	595
% Difference			20.3%				13.7%	126.0%	17.8%	49.1%	103.0%	95.1%	69.4%	38.2%

Table 11-3: Portfolio Scoring Grid: Normalized Scores for Cost and Risk Metrics

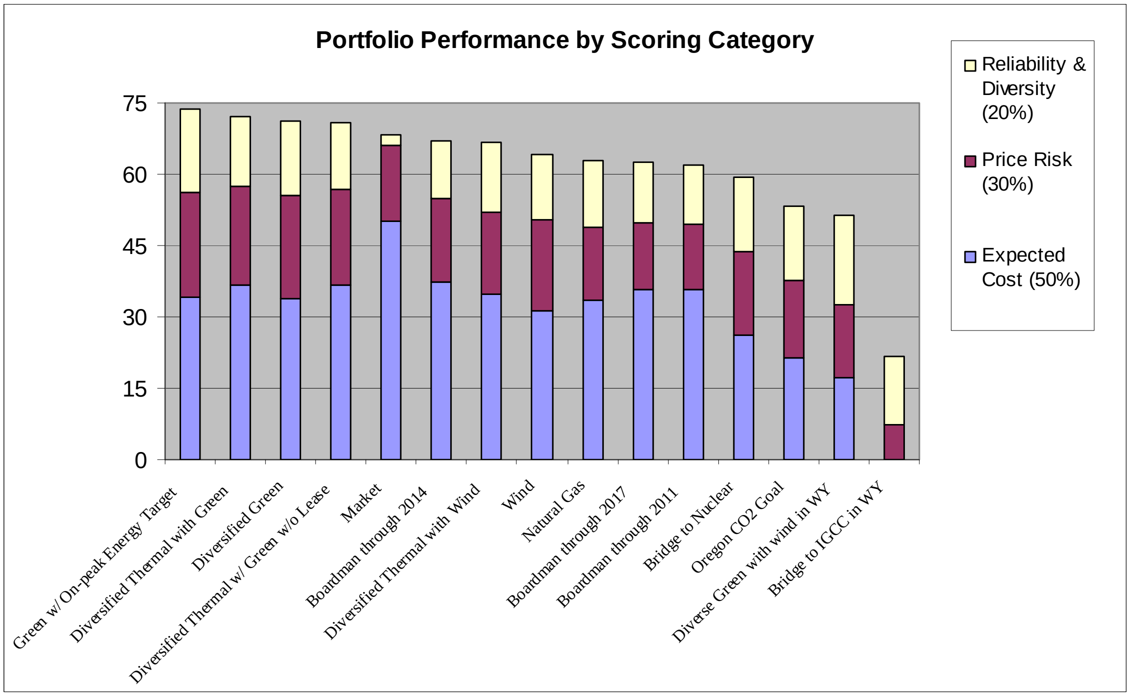
	2. Portfolio Evaluation Scoring: Normalized Scores (0 to 100)	Screening		Deterministic				Stochastic			Reliability & Diversity		
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	**Within Efficient Zone?**	**Meets Operating Reserve Req?**	**Cost: Expected Cost**	**Risk Durability: Good minus Bad**	**Risk Magnitude: Avg. Worst 4**	**Risk Magnitude: Avg. Worst 4 vs. Reference Case**	**Risk: TailVar**	**Risk: TailVar less Mean**	**Risk: Year-to-Year Variance**	**Reliability: TailVar Unserved Energy 2012 2020 & 2025**	**Diversity: Technology HHI**	**Diversity: Fuel HHI**
1	Market	Y	**N**	100.0	100.0	53.4	0.0	61.1	30.5	5.5	0.0	97.1	0.0
2	Natural Gas	Y	Y	67.1	51.3	68.9	50.8	31.6	30.2	60.6	86.1	13.9	30.1
3	Wind	Y	Y	62.4	59.0	94.7	80.1	100.0	34.0	0.0	70.2	36.1	94.0
4	Diversified Green	Y	Y	67.9	61.5	97.9	77.0	87.7	51.3	64.1	77.5	68.8	86.8
5	Diversified Thermal with Wind	Y	Y	69.6	51.3	79.4	57.9	49.0	33.5	75.2	82.9	54.0	38.8
6	Bridge to IGCC in WY	**N**	Y	0.0	0.0	0.0	61.1	0.0	90.4	37.5	82.4	67.3	13.0
7	Bridge to Nuclear	Y	Y	52.2	10.3	86.7	84.0	45.3	98.4	94.2	81.5	100.0	41.8
8	Green w/ On-peak Energy Target	Y	Y	68.1	64.1	100.0	78.6	90.7	53.1	61.2	88.1	68.8	95.7
9	Diversified Thermal with Green	Y	Y	73.5	89.7	80.3	54.3	40.1	40.7	64.9	83.6	52.2	35.2
10	Boardman through 2014	Y	Y	75.0	94.9	75.6	48.3	17.9	0.0	36.4	76.1	0.1	20.1
11	Oregon CO2 Goal	**N**	Y	42.7	17.9	92.7	100.0	63.6	58.0	27.1	76.4	64.7	100.0
12	Boardman through 2011	Y	Y	71.7	53.8	73.0	49.6	15.9	3.3	44.1	82.1	0.1	6.5
13	Diverse Green with wind in WY	**N**	Y	34.5	7.7	57.6	76.4	30.0	100.0	100.0	100.0	72.3	82.2
14	Diversified Thermal w/ Green w/o Lease	Y	Y	73.6	92.3	80.7	54.6	40.7	34.4	49.6	80.4	44.3	32.9
15	Boardman through 2017	Y	Y	71.6	53.8	72.8	49.5	19.0	7.5	44.0	80.3	0.0	30.4

Table 11-4: Portfolio Scoring Grid: Weighted Scores and Ranked Results

	3. Portfolio Evaluation Scoring: Total Weighted Scores	Screening		Deterministic				Stochastic			Reliability & Diversity					
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
	Scoring Consideration	Within Efficient Zone?	Meets Operating Reserve Req?	Cost: Expected Cost	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variance	Reliability: TailVar Unserved Energy 2012 2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI	Weigted Combined Score (0 to 100)	Performance vs. Best (%)	Ordinal Ranking
	Weight			50%	10%	5%	5%	3.3%	3.3%	3.3%	15%	2.5%	2.5%			
1	Market	Y	N	50.0	10.0	2.7	0.0	2.0	1.0	0.2	0.0	2.4	0.0	68.3	92.9%	5
2	Natural Gas	Y	Y	33.6	5.1	3.4	2.5	1.1	1.0	2.0	12.9	0.3	0.8	62.8	85.3%	9
3	Wind	Y	Y	31.2	5.9	4.7	4.0	3.3	1.1	0.0	10.5	0.9	2.4	64.1	87.1%	8
4	Diversified Green	Y	Y	33.9	6.2	4.9	3.9	2.9	1.7	2.1	11.6	1.7	2.2	71.1	96.6%	3
5	Diversified Thermal with Wind	Y	Y	34.8	5.1	4.0	2.9	1.6	1.1	2.5	12.4	1.3	1.0	66.8	90.8%	7
6	Bridge to IGCC in WY	N	Y	0.0	0.0	0.0	3.1	0.0	3.0	1.2	12.4	1.7	0.3	21.7	29.5%	15
7	Bridge to Nuclear	Y	Y	26.1	1.0	4.3	4.2	1.5	3.3	3.1	12.2	2.5	1.0	59.3	80.7%	12
8	Green w/ On-peak Energy Target	Y	Y	34.1	6.4	5.0	3.9	3.0	1.8	2.0	13.2	1.7	2.4	73.6	100.0%	1
9	Diversified Thermal with Green	Y	Y	36.8	9.0	4.0	2.7	1.3	1.4	2.2	12.5	1.3	0.9	72.0	97.9%	2
10	Boardman through 2014	Y	Y	37.5	9.5	3.8	2.4	0.6	0.0	1.2	11.4	0.0	0.5	66.9	90.9%	6
11	Oregon CO2 Goal	N	Y	21.4	1.8	4.6	5.0	2.1	1.9	0.9	11.5	1.6	2.5	53.3	72.5%	13
12	Boardman through 2011	Y	Y	35.8	5.4	3.6	2.5	0.5	0.1	1.5	12.3	0.0	0.2	61.9	84.2%	11
13	Diverse Green with wind in WY	N	Y	17.3	0.8	2.9	3.8	1.0	3.3	3.3	15.0	1.8	2.1	51.3	69.7%	14
14	Diversified Thermal w/ Green w/o Lease	Y	Y	36.8	9.2	4.0	2.7	1.4	1.1	1.7	12.1	1.1	0.8	71.0	96.4%	4
15	Boardman through 2017	Y	Y	35.8	5.4	3.6	2.5	0.6	0.2	1.5	12.0	0.0	0.8	62.5	84.9%	10

The preceding table may be easier to interpret via Figure 11-24, which presents the same information graphically and with scores color-coded by category. The graph ranks the portfolios from best to worst and shows their performance based on expected cost, the price risk relating to expected cost, and the reliability and diversity performance.

Figure 11-24: Portfolio Scoring Grid: Weighted Scores and Ranked Results



Preferred Portfolio Recommendation

The top-performing portfolios are those which are diversified by fuel and technology and have a mixture of new renewables (generally modeled as wind) and natural gas generation. Portfolios with continued operations of Boardman generally outperform those with an early Boardman closure; see the following chapter for a detailed discussion of our Boardman analysis.

The two top-performing portfolios are Diversified Thermal with Green and Green with On-peak Energy Target. This latter portfolio adds resources to meet our average on-peak load, but is long on energy resources when compared to our average annual load. It should also be noted that through 2015 the two portfolios are similar, with the only difference being the addition of about 220 MWa of renewables. Thus, it is not surprising that these portfolios would yield similar overall scoring results.

In selecting the Diversified Thermal with Green portfolio, we also considered the relative balance between cost performance and risk performance. Green with On-peak Energy Target does not score well when considering solely expected cost

(8^{th} of 15), but excels on the risk metrics (1^{st} of 15). On the other hand, Diversified Thermal with Green scores well with respect to both cost and risk (top 4 in both categories). Our preferred portfolio ranks as the 4^{th} best for expected cost (with a version of the same portfolio that excludes the BAL lease scoring 3^{rd} best), while it scores 3^{rd} best in the combined risk and diversity categories. Hence, our preferred portfolio, Diversified Thermal with Green, has a better balance of cost and risk.

The top scoring portfolios both score well when considering combined cost and risk performance. They appear to exhibit the best overall combination of expected cost and associated cost risk and uncertainties. They are portfolios that are durable (in other words, they perform well under a variety of circumstances) and did not demonstrate acute weaknesses when subjected to stress testing in our analysis.

Market, the fifth ranked portfolio, performs very poorly in the area of annual cost variability (a stochastic price risk) and the reliability/diversity metrics. A portfolio that relies heavily on short-term market supply presents an artificially low expected cost because the portfolio does not provide a prudent level of capacity and thereby avoids the fixed costs associated with deploying or acquiring physical resources to meet customers' electric demand. Given the potential for this portfolio to exhibit extreme bad outcomes for cost variability and reliability, it is not considered a viable candidate for implementation. To improve its performance on these metrics to an acceptable level, we would need to firm the portfolio by adding a material amount of SCCTs (or like capacity resource) over the planning horizon to bring the market portfolio capacity value to an equivalent level to other portfolios tested. This in turn would add significant cost to the portfolio. That is, improving reliability to an acceptable level can only be accomplished via a significant boost in expected cost.

Among the Boardman early closure portfolios, only the Boardman 2014 portfolio exhibits reasonable performance and thus merits consideration. The other two have serious shortcomings and perform poorly compared to other candidates. The Boardman decision is discussed in greater depth in the following chapter.

Out of the top performing portfolios we are recommending the portfolio that scored second highest overall, Diversified Thermal with Green. The two top performing portfolios, Diversified Thermal with Green and Green with On-peak Energy Target are very close together in overall score; however, we believe that Diversified Thermal with Green is more achievable, represents a higher likelihood of being realized in a subsequent procurement process, and offers a good balance between cost performance and risk performance. In addition to exhibiting robust overall performance, Diversified Thermal with Green also presents lower execution risk than the highest scoring portfolio, Green with On-

Peak Energy Target. The Diversified Thermal with Green portfolio uses a planning target (annual average for all hours) previously approved by the Commission, while the Green with On-Peak Energy Target portfolio adds energy resources to a new, higher resource planning target (on-peak hours average) which the Commission has not considered. The Green with On-Peak Energy Target also adds a very high level of new wind by 2015, approximately 650 – 700 MW (depending on net capacity factor). This amount is above and beyond the amount of new renewables that are necessary to meet RPS compliance by 2015. It is not yet clear if such a high amount of additional wind in the Pacific Northwest would be available or what the cost would be to add such an aggressive amount over a relatively short time-frame.

It should be noted that the two top performing portfolios, Diversified Thermal with Green and Green with On-peak Energy Target also scored very close together in our Draft IRP issued in September, 2009. However, at that time their rank order was reversed with Diversified Thermal with Green receiving the highest overall score and the Green with On-peak Energy Target receiving the second highest overall score. Since issuing the Draft IRP, we have made a number of modeling updates, adjustments and corrections, resulting in modest changes to portfolio results, including changing the ordinal ranking of our top two performing portfolios. These updates and changes are summarized in Chapter 10.

Based on our review of both risk and cost performance of the candidate portfolios, as well as consideration of implementation and execution viability, our preferred portfolio is Diversified Thermal with Green. This portfolio is the basis for our Action Plan as presented in Chapter 13.

12. Boardman Analysis

Boardman is a key resource for PGE. It is a low-cost, baseload plant that enables us to provide 15% of our customers' energy needs with a reliable, stable source of power. The plant also contributes to the diversity of our supply mix. Due to efficiency upgrades, Boardman is in the top quintile among U.S. coal plants for efficiency (heat rate) in converting fuel to electricity. Those same upgrades mean that many of the major components of the plant are comparatively new making it likely that Boardman will continue to operate reliably and efficiently for many years into the future.

In this chapter we describe the emissions controls required under the recently approved Oregon Regional Haze Plan and the Oregon Utility Mercury Rules. We also describe how our scenario and stochastic analyses indicate that the best combination of expected costs and associated risks and uncertainties for our customers is achieved in a portfolio in which PGE invests in the required emissions controls and continues to operate Boardman through 2040.

Chapter Highlights

- PGE's Boardman and Beaver generating plants are subject to an assessment of emissions sources pursuant to the Oregon Regional Haze Plan.
- PGE has also developed a cost estimate for the installation of emissions controls at Boardman, as required by the Oregon Regional Haze Plan and the Oregon Utility Mercury Rule.
- Portfolio analysis used in this IRP favors continued operation of Boardman. PGE recommends investment in emissions controls technology as detailed in the Oregon Regional Haze Plan and Oregon Utility Mercury Rule, with operation of Boardman through 2040.

12.1 Boardman Plant Overview

Boardman is a pulverized-coal plant located in north-central Oregon approximately 13 miles southwest of the city of Boardman, and 160 miles east of Portland. It went into service in 1980. Its expected plant life extends through at least 2040. Coal for Boardman is transported by rail from the Powder River Basin (PRB) coal mines of central Wyoming. PGE is the operator of the plant, and we have a 65 percent ownership interest, or 380-MW share of the plant output. Forecasted average annual energy availability for PGE's share is 318 MWa. The 585-MW net capacity output serves the equivalent of about 341,500 residences.

The Boardman area was chosen for the plant's location because it has good access to land, water, transmission and rail transportation. A large cooling pond, Carty reservoir, was built to provide cooling water for the plant. The pond eliminates the need for returning cooling water to natural streams or rivers, thus avoiding discharge that might impact fish and wildlife. It also minimizes the draw on river water.

The fuel is a low-sulfur sub-bituminous coal, primarily from the PRB mines. Coal is transported to the plant by railcar. Boardman can stockpile up to 400,000 tons of PRB coal at the on-site coal yard, the equivalent of 55 days at full operations.

Boardman typically shuts down once a year in the spring to perform its annual planned maintenance. The plant is primarily a base-load resource, but is economically dispatched during some periods where regional loads and prices are low. Economic dispatch and load cycling generally occurs only in the spring.

12.2 Oregon Regional Haze Plan

Section 169A of the Federal Clean Air Act (as implemented through 40 CFR 51.308) requires that Oregon adopt and implement a plan to reduce visibility impacts in designated areas (referred to as Class I areas) to background levels by 2064. Oregon's plan to achieve this visibility goal is referred to as the Oregon Regional Haze Plan or the Plan. The Oregon Department of Environmental Quality (DEQ) issued a draft Oregon Regional Haze Plan for public comment in December 2008. The Plan included rules that would require specific emission reductions at the Boardman plant by dates identified in the proposed rules. During the public comment period PGE proposed an alternative approach whereby PGE would have to decide, at dates certain, to either proceed with the next phase of controls or cease operations at the Boardman plant by a specific date after the date that controls were otherwise required. This plan would have provided PGE the flexibility to address the general uncertainty associated with future electric prices and potential changes in legislation impacting generation.

Specifically, it would have allowed PGE to consider through future IRP processes the cost-effectiveness of implementing the controls in light of changes to natural gas and coal prices, as well as CO_2 allowance prices.

The added flexibility would have enabled PGE to have access to better information about gas, coal and carbon prices at the time the investment decision would be made, thus reducing the financial risk to customers. PGE's proposal recognized that time is the only effective hedge against the uncertainty surrounding upcoming carbon legislation as well as the commodities markets.

On June 19, 2009 the Environmental Quality Commission (EQC) adopted DEQ's proposed Oregon Regional Haze Plan, as modified in response to public comment. The Oregon Regional Haze Plan, as adopted, did not include PGE's proposal and largely consisted of the approach DEQ proposed for public comment. The Oregon Regional Haze Plan requires the installation of environmental controls at the Boardman plant for the purpose of reducing visibility-impairing emissions.

The Plan calls for a two-phase approach identified as Phase 1 – Best Available Retrofit Technology and Phase 2 – Reasonable Progress. Phase 1 (OAR 340-223-0030) requires compliance with a reduced nitrogen oxides (NOx) limit by 2011 and a reduced sulfur dioxide (SO_2) and particulate matter (PM) limit by 2014. The NOx limit was based on the assumption that PGE would install combustion controls (low-NOx burners and modified over-fired air or LNB/MOFA). If compliance with this limit is not demonstrated by July 1, 2012, then DEQ can grant an extension until July 1, 2014 under the condition that the emissions meet a more restrictive NOx limit. The SO_2 and PM limits are based on the installation of semi-dry flue gas desulfurization (scrubbers) with an associated fabric filter. Phase 2 (OAR 340-223-0040) requires compliance with a further-reduced NOx limit by 2017. This limit was based on the assumption that PGE would install selective catalytic reduction (SCR).

Under these rules, PGE has the following options:

- Install all of the controls: LNB/MOFA by July 2011, scrubbers/fabric filter by July 2014 and SCR by July 2017 and operate Boardman through 2040 or beyond.
- Install LNB/MOFA and scrubbers and cease Boardman operations in 2017; do not make the SCR investment.
- Install LNB/MOFA only and cease Boardman operations in 2014.
- Cease Boardman operations in July 2011 with no obligation to install additional controls.

Non-compliance with the Oregon Regional Haze Plan (and also Oregon Utility Mercury Rule) is, however, not an option. The plant must meet emissions requirements by either installation of controls or by ceasing operations. Failure to comply with the plan can result in significant penalties, equitable remedies, and possibly criminal sanctions.

12.3 Oregon Utility Mercury Rule

In addition to the Oregon Regional Haze Plan, Boardman is also subject to the Oregon Utility Mercury Rule. PGE conducted a detailed engineering cost analysis as well as a study on the impact these modifications will have on operating and maintenance costs once installed. When the Oregon Utility Mercury Rule was first adopted, DEQ, PGE and the public anticipated that the mercury limits would take effect at the same time as the Oregon Regional Haze Plan requirements. This expectation arose from the Department's intent to establish a multi-pollutant strategy whereby mercury, SO_2, and particulate matter (PM) would all be addressed by an integrated control system. However, delays in the development of the Oregon Regional Haze Plan have resulted in the SO_2 scrubber and PM control compliance date being extended to July 1, 2014—two years after the date that the mercury emission standards take effect. The mercury rule revisions adopted by the Environmental Quality Commission (EQC) on June 19, 2009, authorize a two-year compliance extension in the event that it is not practical for PGE to install mercury controls by July 1, 2012, due to supply limitations, electrostatic precipitator (ESP) fly ash contamination or other circumstances beyond PGE's control.

However, based on pilot testing results, PGE determined that the injection of activated carbon upstream of the existing ESP is most likely to result in the capture of at least 90 percent of the mercury contained in the coal. While this control approach is not optimal on a long-term basis, as there is material risk of rendering the ash unsellable, the approach enables PGE to substantially decrease mercury emissions prior to the time when a fabric filter can be installed. Therefore, PGE is submitting for DEQ approval a mercury reduction plan in accordance with OAR 340-228-0606(1). PGE believes that this plan complies with all rule requirements and will enable a high level of mercury control in reliance on the existing ESP until such time that the scrubbers and associated fabric filter is installed consistent with the Oregon Regional Haze Plan. At that time, the activated carbon injection point will be moved to enable collection of the carbon (and mercury) in the fabric filter. The costs of this approach were included in our modeling.

12.4 Boardman Portfolio Analysis

As part of the IRP overall economic analysis, each of the Boardman-related controls technologies and associated deadlines were modeled in AURORAxmp as distinct portfolios. Boardman-specific assumptions in these portfolios are listed below by the following assumed plant run-through dates:

- 2040: Install all of the controls: LNB/MOFA by July 2011, scrubbers by July 2014 and SCR by July 2017 and operate Boardman through 2040 (the "Diversified Thermal with Green" and "Diversified Green with on-peak Energy Target" portfolios).

- 2017: Install LNB/MOFA and scrubbers; cease Boardman operations in mid-2017; no SCR investment. Assumes the addition of a CCCT for energy replacement in 2017 ("Boardman through 2017").

- 2014: Install LNB/MOFA; cease Boardman operations in mid-2014; no further emissions controls investment. Assumes a CCCT for energy replacement online in 2015 (earliest online date for a greenfield CCCT), with market power purchases to bridge through remainder of 2014. ("Boardman through 2014").

- 2011: Cease Boardman operations in July 2011 with no obligation to install additional controls. Assumes a fixed price power purchase through 2014 as a bridge strategy, and then the addition of a CCCT in 2015. ("Boardman through 2011").

Except for the above-noted differences, all of these portfolios are built on the "Diversified Thermal with Green" portfolio assumptions as the starting point. PGE used both scenario (deterministic) as well as stochastic analyses in evaluating the Boardman portfolios. For the scenario analysis, PGE uses AURORAxmp to calculate a Net Present Value of Revenue Requirements (NPVRR) for each portfolio under 21 differing potential futures, starting with a reference case. For the stochastic analysis, PGE "shocks" the following five input variables: WECC-wide load, natural gas prices, historic water years (for PGE only), plant forced outages, and the intermittency of wind production. Detailed descriptions of our portfolios and analytical approach are in Chapter 10.

12.5 Results of Portfolio Analysis

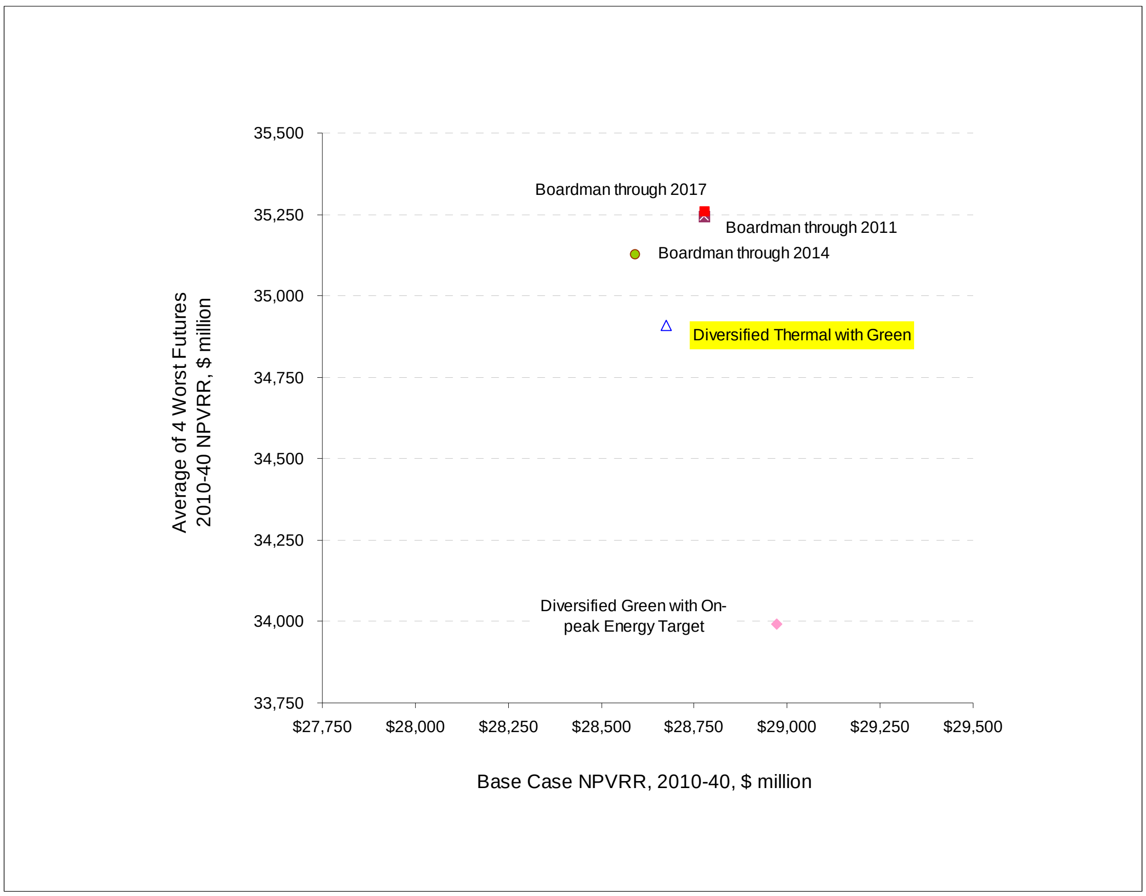
Please refer to Chapter 10 for a detailed description of our portfolio analysis approach.

Deterministic Portfolio Analysis Results

The Trade-off between Expected Cost and Associated Risk

The relationship between expected costs and the associated risk of each portfolio provides a good way to quickly assess the relative performance of portfolios. In this IRP, for each portfolio PGE uses the expected NPVRR from the reference case future as the measure for expected cost (plotted on the X-axis in Figure 12-1) and the average NPVRR of the four worst futures as the measure for portfolio cost risk (plotted on the Y-axis in Figure 12-1). Portfolios that for a given level of risk have the lowest cost, or for a given cost have the lowest risk, are deemed to be efficient.[92] Visually, portfolios that plot closer to the origin generally outperform portfolios located further from the origin.

Figure 12-1: Efficient Frontier for Boardman Portfolios



[92] While this is not the same as an efficient frontier as defined in financial portfolio theory, the concept of looking at the trade-off between a return (or cost in this case) and its associated risk is similar. Thus, at times we refer to a portfolio as being on an efficient frontier, meaning that the portfolio performs better than others when considering both expected cost and risk.

Three of the five Boardman portfolios are efficient. Portfolios titled "Diversified Thermal with Green" and "Boardman through 2014" outperform the third efficient portfolio "Diversified Green with On-peak Energy Target" based on expected cost. As a result, we focus on them. The remaining portfolios "Boardman through 2011" and "Boardman through 2017" proved to be both more costly and risky, and therefore are not efficient. When compared to "Diversified Thermal with Green," these two portfolios are both more costly and more risky (by more than $100 million and $300 million respectively). When compared to "Boardman through 2014", expected costs for these two portfolios are almost $200 million greater. These portfolios also have a higher risk by more than $100 million.

The "Diversified Thermal with Green" and "Boardman through 2014" both outperform the other Boardman choices. Between these two choices, "Boardman through 2014" has a lower expected cost by $81 million, while performing worse on the risk measurement by approximately $200 million. For every dollar of expected cost incurred by choosing "Diversified Thermal with Green" over "Boardman through 2014", risk exposure can be reduced by roughly $2.20. In other words the risk differential is more than two times the cost differential.

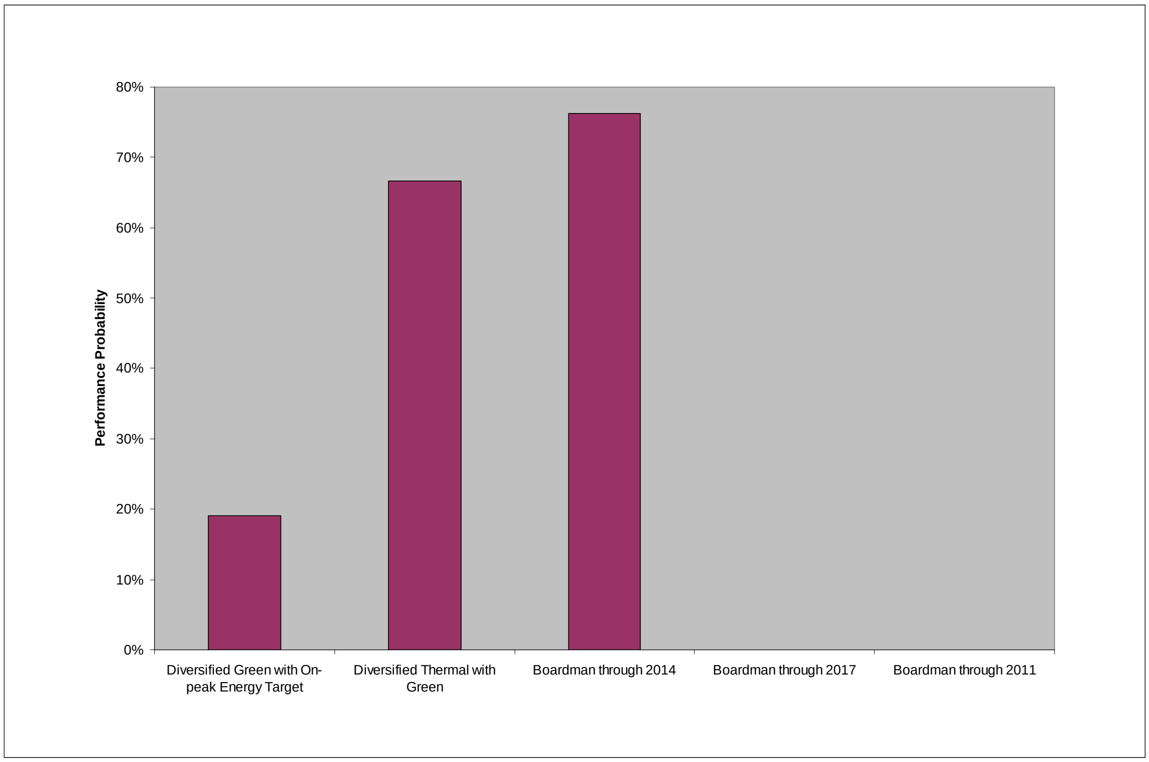
On the graphs in this section, for comparison, we also show our two top-performing portfolios with Boardman operating through 2040, "Diversified Green with On-Peak Energy Target" and "Diversified Thermal with Green".

Portfolio Durability: Combined Probability of Achieving Good and Avoiding Bad Outcomes

Although the deterministic approach to portfolio analysis does not assign probabilities to the likelihood of a particular future taking place, one way to look at portfolio durability is to count the frequency of good outcomes vs. bad outcomes. A bad outcome is defined as the number of times that a given portfolio ranks among the worst four out of the 15 portfolios we tested against all 21 futures. And conversely, a good outcome is defined as the number of times that a given portfolio ranked among the best four out of the 15 portfolios we tested against all 21 futures. The goal is to avoid bad outcomes while seeking good outcomes.

Better portfolios have a high probability of *combined* good vs. bad outcomes. In our scoring, a portfolio that always ranked in the top four would get a 100% score, a portfolio that always ranked in the bottom four would get a -100%. Mediocre portfolios that had mixed results would score 0%. The same two portfolios that lie on the efficient frontier ("Diversified Thermal with Green" and "Boardman through 2014") also outperform all other Boardman options in this metric – see Figure 12-2. "Boardman through 2014" and "Diversified Thermal with Green" resulted in scores of 67% and 76% respectively, meaning that these portfolios are comparatively durable when evaluated against most futures. On the other hand, "Boardman through 2011" and "Boardman through 2017" both resulted in a score of 0%.

Figure 12-2: Combined Probability of Good and Bad Outcomes for Boardman Portfolios



Scenario Risk Magnitude

This metric addresses the magnitude of adverse outcomes. It is the cost difference between the reference case performance of a given portfolio vs. the average performance within the four worst futures for each portfolio. The best portfolio would have the lowest score for this metric. "Diversified Green with On-Peak Energy Target" performs best when compared to other Boardman alternatives with a portfolio risk magnitude of $5 billion. Second best is "Diversified Thermal with Green" with a risk magnitute of $6.2 billion, "Boardman through 2014", "Boardman through 2011" and "Boardman through 2017"have a similar risk magnitude of approximately $6.5 billion.

Summary of Results from Deterministic Measures:

Our portfolio scoring includes three measurement categories from the deterministic portfolio analysis: Expected Cost, Risk Durability and Risk Magnitude (Risk Magnitude includes Average of the four worst cases, as well as Average of the four worst cases vs. Reference Case). In all, four deterministic measurements comprised 70% of the combined score (see Table 12-2). Both "Diversified Thermal with Green" and "Boardman through 2014" perform materially better than "Boardman through 2011" and "Boardman through 2017" with respect to the deterministic portion of the score. "Boardman through 2014" slightly outperforms "Diversified Thermal with Green" by 1% of the deterministic portion of the score.

Stochastic Portfolio Analysis Results

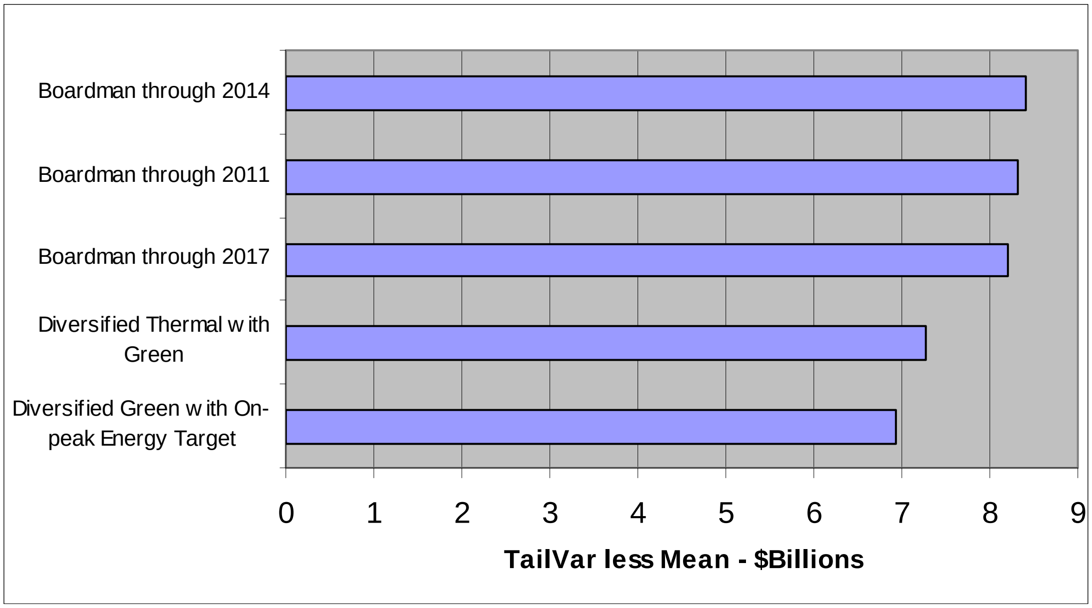
By stochastically modeling WECC-wide load, natural gas prices, historic water years, plant forced outages and the intermittency of wind production, we were able to assess probabilistic metrics of Boardman portfolio risks. As detailed in Chapter 10, the portfolios were run 100 times subject to stochastic variations in the above variables. For stochastic analysis, we employ a NPVRR TailVar less Mean to look at portfolio risk over our dispatch modeling horizon of 2010 to 2040, as well as a year-to-year variability metric.

TailVar 90 less Mean:

This metric measures the right-tail risk or *magnitude* of bad outcomes for each individual portfolio, as measured by averaging the portfolio NPV that resides in the most expensive 10% of the distribution (right tail risk) and subtracting from this the portfolio mean NPV (i.e., expected cost). The result is a measure of how widely a portfolio can deviate from its expected cost.

The "Diversified Thermal with Green" portfolio has a TailVar 90 less Mean amount of $7.2 billion compared to $8.4 billion, $8.3 billion and $8.2 for "Boardman through 2014", "Boardman through 2011" and "Boardman through 2017" respectively – see Figure 12-3. "Diversified Thermal with Green" outperforms the other Boardman alternatives by more than $1 billion on average. These results show the increased risk exposure when moving from coal as a fuel to a greater concentration of natural gas, which has more volatile prices.

Figure 12-3: Stochastic Risk – TailVar less Mean for Boardman Portfolios

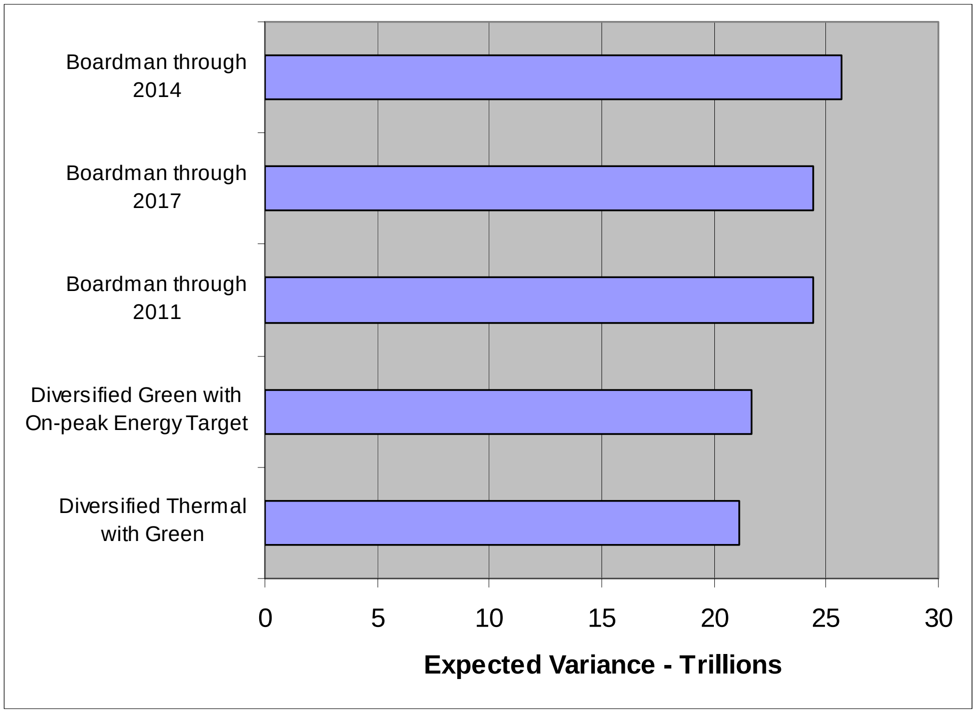


Stochastic Year-to-Year Variation

This metric addresses the innate volatility of a given portfolio. It measures the average year-over-year variation, based on 100 independent iterations of the stochastic inputs. While the "TailVar less mean" measures the worst 10% possible outcome of the expected portfolio costs over the 31 forecast years, the "Year-to-Year Variation" metric measures changes in year-to-year portfolio costs. In other words, "TailVar less Mean" measures "how bad can the worst outcomes be?" over the life of the portfolio while "Year-to-Year Variation" measures "how bumpy is the road?" for a particular portfolio.

The best portfolio would have the lowest year-to-year variation. As shown in Figure 12-4 below, "Diversified Thermal with Green" outperforms the other Boardman portfolios with an expected variation of 21 trillion compared to "Boardman through 2014", "Boardman through 2011" and "Boardman through 2017" all with expected variations exceeding 24 trillion.

Figure 12-4: Stochastic Risk – Year-to-Year Variation for Boardman Portfolios



Summary of Results from Stochastic Measures

We included in scoring three measurement categories from the stochastic portfolio analysis: TailVar, TailVar less Mean and Year to Year Variation. Stochastic measurements comprised 10% of the total weighed combined score (see Table 12-2). Diversified Thermal with Green performs materially better than the other three Boardman portfolios by an average of 31% of the stochastic portion of the score.

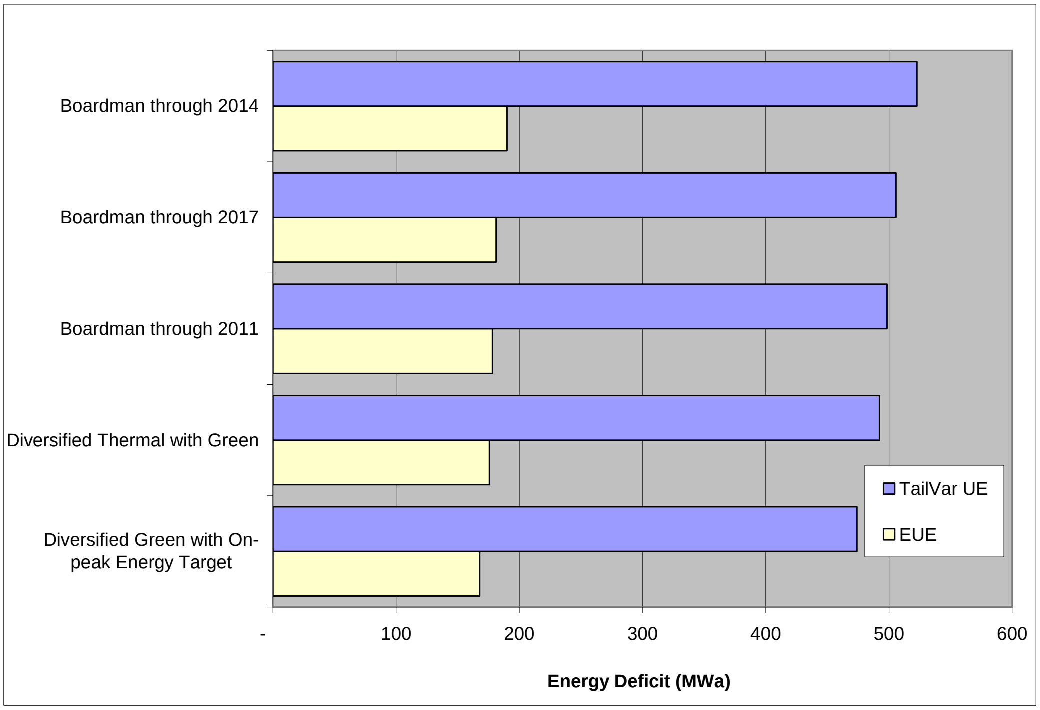
Reliability and Diversity Analysis Results

Tailvar Unserved Energy

We calculate the Tailvar Unserved Energy (Tailvar UE) as the average of the worst 10% of outcomes (across 100 iterations where PGE's plants are subject to random forced outages and associated mean times to repair) of the amount of power PGE must purchase on the spot market in order to meet customer load. Expressed in MWa, market purchases are required when PGE's owned and contracted resources are insufficient to meet customer load. This metric is calculated as the average for all years from 2010 through 2020, plus 2025. The higher the amount, the less reliable that portfolio is relative to the other portfolios.

"Diversified Green with On-peak Energy Target" is the most reliable based on the Tailvar and EUE metrics – see Figure 12-5. In our inputs, we assume that the Boardman plant has a higher forced outage rate compared to a CCCT replacement. The "Boardman through 2014" portfolio, fares somewhat worse than the "Boardman through 2011" portfolio because the 2014 closure assumes that PGE must rely on spot market purchases until a replacement resource can be brought on-line.

Figure 12-5: Unserved Energy Metrics for Boardman Portfolios, 2012-2020 & 2025



Technology and Fuel Diversity

PGE has applied the Herfindahl-Hirschman Index (HHI), which has traditionally been used to measure concentration of commercial market power. In this case, the HHI is used to measure the portfolio concentration in technologies and fuels (coal, natural gas, hydro, wind, market purchases, etc.) from 2010 through 2020.

A lower value means less portfolio concentration in any given technology or fuel type over the period. A lower HHI value is preferred as it indicates higher portfolio diversity and thus less exposure to fuel and generation technology driven risks. The diversified portfolios outperform all of the early Boardman closure portfolios from fuel and technological perspectives. See Figure 12-6 and Figure 12-7 below respectively. While the early Boardman closure portfolios are equivalent on a technological basis, the later closures perform better from a fuel diversity perspective.

Figure 12-6: Herfindahl-Hirschman Index Boardman Fuel Results

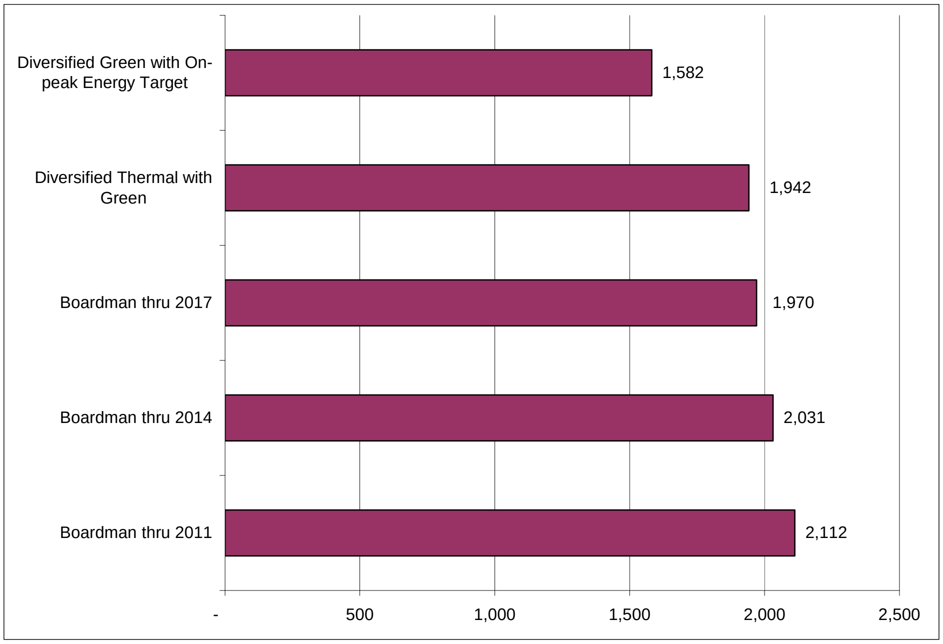
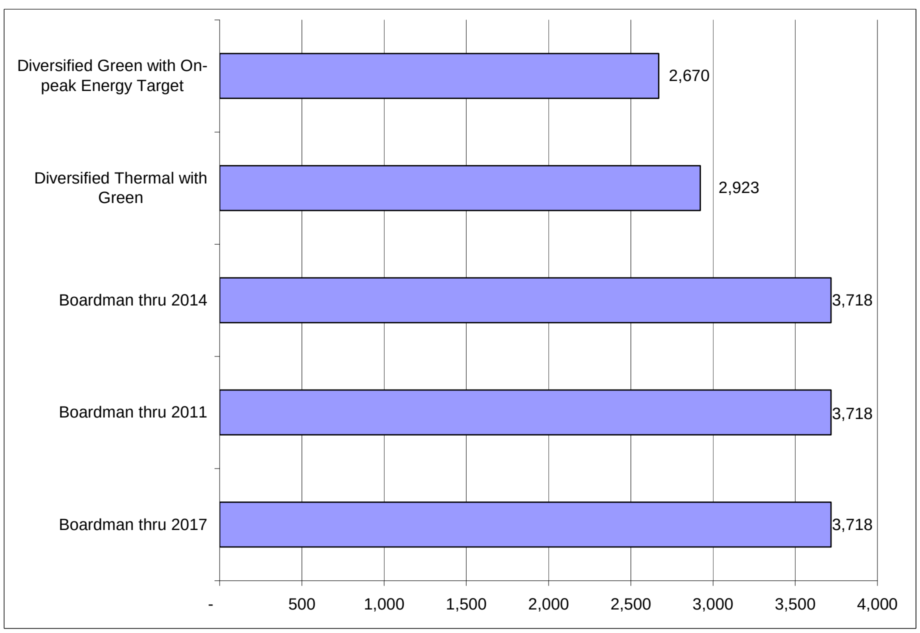


Figure 12-7: Herfindahl-Hirschman Index - Boardman Technological Results



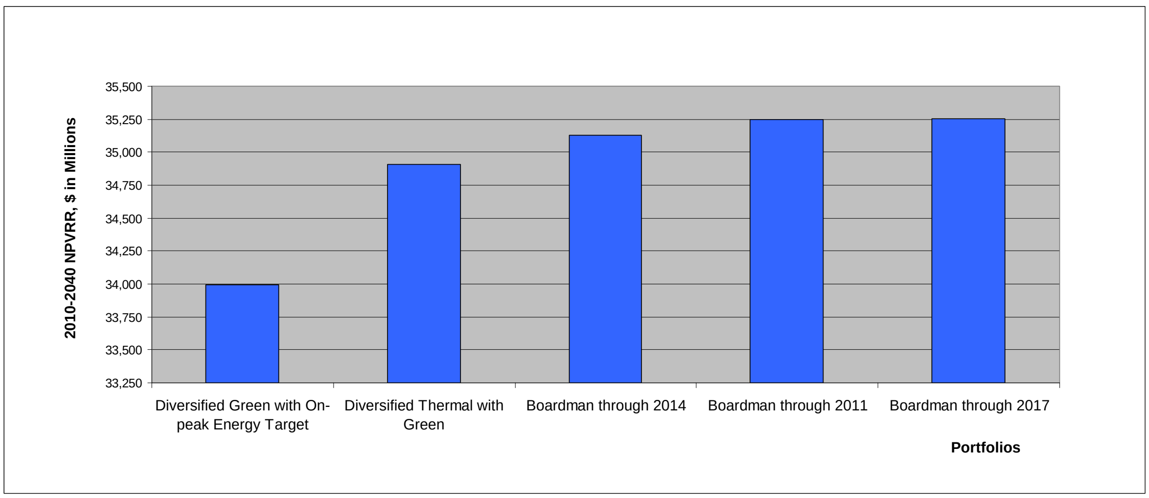
Summary of Results from Reliability and Diversity Measures

We included in scoring three measurement categories from the reliability and diversity portfolio analysis: Tailvar UE, Technology HHI and Fuel HHI. Reliability and Diversity measures comprised 20% of the total weighed combined score (see Table 12-1). Diversified Thermal with Green performs materially better than the other three Boardman portfolios.

Other Metrics

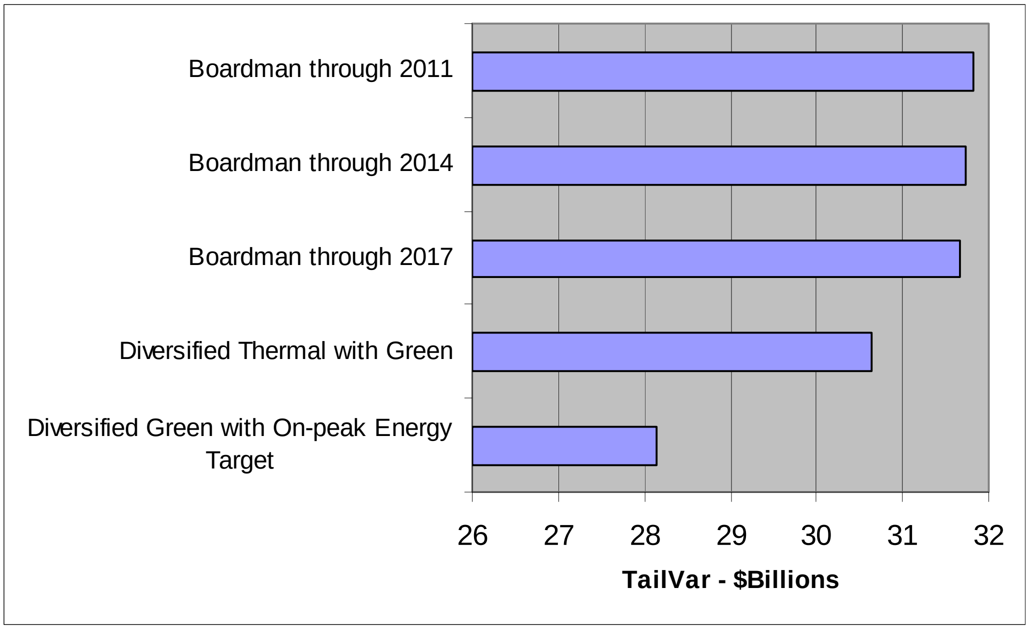
At the recent suggestion of OPUC Staff, PGE has added a variation of two metrics described above to its scoring. Rather than look solely at the deterministic average of the worst four futures less the reference case expected cost and the similar stochastic metric of TailVar 90 less the Mean, we have added these two right-tail metrics as absolute measurements without subtracting from a mean value. This allows for an absolute look at risk exposure without being influenced by distance from the mean. These metrics do not have a significant impact on the top-performing portfolios, particularly given the relatively small weights they have been assigned in the scoring matrix. Figure 12-8 shows the average NPVRR for the four worst future outcomes. “Diversified Green with On-peak Energy” has the lowest NPVRR of the five cases, while “Boardman 2017” shows the highest worst-case average.

Figure 12-8: Average NPVRR of Four Worst Futures



Similar results are shown in Figure 12-9 for the selected portfolios when looking at the TailVar analysis. Here again “Diversified Green with On-peak Energy” shows the lowest value, just over $28 billion. The early Boardman closure portfolios all have higher TailVar scores – with the earlier the closing, the worse the outcome.

Figure 12-9: Stochastic Risk - TailVar

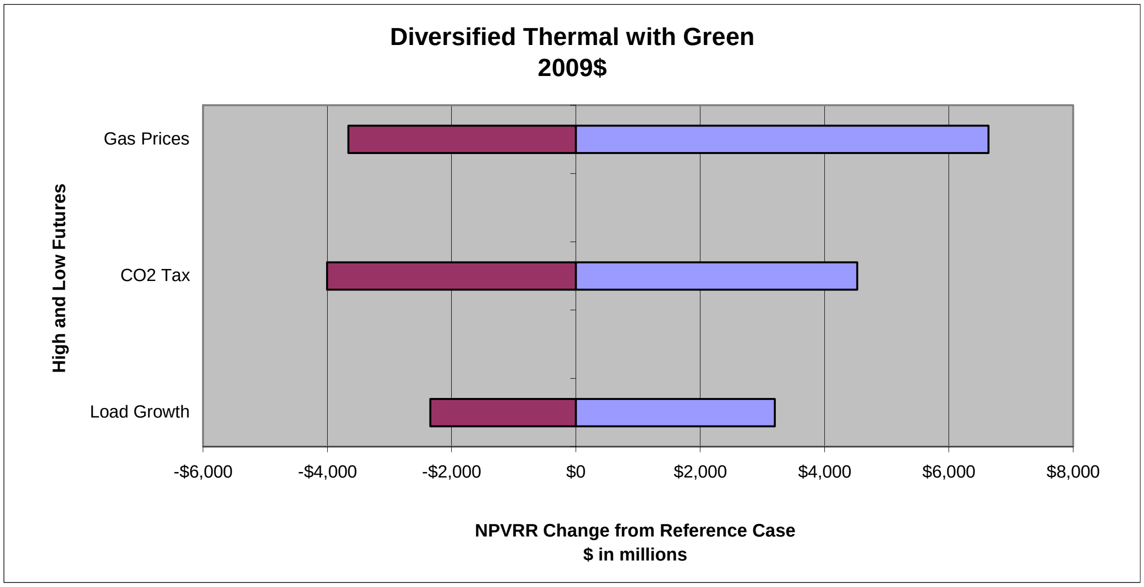


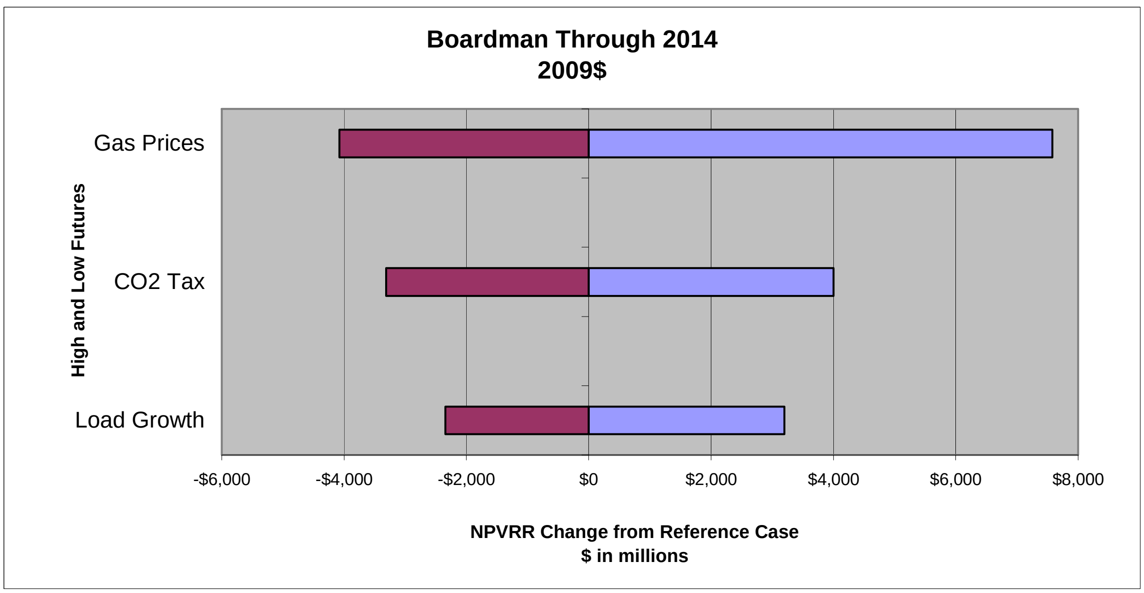
Primary Drivers of Uncertainty

Portfolios were stress-tested with several discrete futures. Of all the futures tested, variation in natural gas price, CO_2 price and load growth had the most impact on our portfolio NPVRR. Natural gas price was modeled with low, reference and high price futures at $5.19, $7.86 and $12.84 (real levelized 2009$) respectively. CO_2 prices ranged from $0 per short ton to $65 per short ton with a reference price at $30 (real levelized 2009$) and non-EE adjusted load growth rates were modeled at 1.21% and 2.72% per year for low and high scenarios with a reference growth rate at 1.91%.

Figure 12-10 shows the "Diversified Thermal with Green" and "Boardman Through 2014" portfolios' sensitivity to these futures. "Boardman Through 2014" is more exposed to gas price risk than "Diversified Thermal with Green." This portfolio assumes a CCCT as the replacement technology for Boardman past 2014. "Boardman Through 2014" has an expected NPVRR change from the reference case gas price of $7.582 billion compared to $6.636 billion for "Diversified Thermal with Green". For the same magnitude of natural gas price increase (from $7.86 to $12.84, both real levelized in 2009$), "Boardman Through 2014" has an NPVRR of $946 million more than "Diversified Thermal with Green."

Figure 12-10: Boardman Portfolios' Sensitivity to Gas Prices





"Diversified Thermal with Green" is more exposed to CO_2 risk. This reflects the higher CO_2 output profile of a coal plant compared to a CCCT. Exposure to CO_2 price is $4.526 billion for "Diversified Thermal with Green" and $4.003 billion for "Boardman Through 2014". Exposures to load growth are identical at $3.199 billion for downside and $2.345 billion on the upside for both portfolios.

Another insight from these graphs is the apparent asymmetry between upside and downside exposure to gas price risk, while CO_2 price and load growth have fairly balanced risk profiles. For "Diversified Thermal with Green" and

"Boardman through 2014," upside and downside of portfolio NPVRR for CO_2 price risk are +$4.526 vs. -$4.002 and +$4.003 vs. -$3.312 billion respectively. But for gas price risk exposure, the range is +$6.636 vs. -$3.662 and +$7.582 vs. -$4.076 respectively for those portfolios. This reflects the asymmetry of the high and low natural gas prices as compared to the reference case price. Most natural gas price forecasts (including PGE's) indicate that there is more risk that prices will rise rather than fall; this is a logical deduction with a log-normally distributed price.

Of the three major cost drivers, natural gas price risk emerges as the greatest driver of the portfolio NPVRR and as a result, the single largest risk factor. CO_2 price is second and load growth is third. Load growth risk magnitude is identical for both portfolios. "Diversified Thermal with Green," though more exposed to CO_2 risk, performs better under a high gas price future than "Boardman Through 2014."

12.6 Assessing Boardman Analytical Results

The portfolio analysis, using both scenario and stochastic approaches, provides a comprehensive look at Boardman's value and risks. PGE's recommendation takes into account expected cost, as well as price and reliability risk. Overall, "Diversified Thermal with Green" scored better than the Boardman 2014 portfolio – see Table 12-1 below. The "Diversified Thermal with Green" portfolio which includes Boardman through 2040 also clearly outperformed the early closure cases with respect to price risk and reliability. In general, although more exposed to CO_2 costs, the "Diversified Thermal with Green" portfolio provides an effective hedge against natural gas price volatility, while maintaining system reliability at a relatively low cost.

Table 12-1: Boardman Portfolio Analysis Scoring Grid

	1. Portfolio Evaluation Scoring: Raw Performance Metrics	Screening		Deterministic						Stochastic			Reliability & Diversity		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Zone?	Meets Operating Reserve Req?	Cost: Expected Cost Reference Case	Prob. of Poor Perf.	Prob. of Good Perf.	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variance	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
	Units	Y or N	Y or N	$ NPV Million	%	%	%	$ NPV Million	$ NPV Million	$ NPV Million	$ NPV Million	Trillion	MWa	Points	Points
8	Green w/ On-peak Energy Target	Y	Y	$ 28,971	0%	19%	19%	$ 33,993	$ 5,023	$ 28,136	$ 6,937	21.7	474.0	2670	1582
9	Diversified Thermal with Green	Y	Y	$ 28,674	5%	71%	67%	$ 34,910	$ 6,236	$ 30,631	$ 7,280	21.1	492.3	2923	1942
10	Boardman through 2014	Y	Y	$ 28,593	5%	81%	76%	$ 35,126	$ 6,533	$ 31,727	$ 8,406	25.7	522.7	3718	2031
12	Boardman through 2011	Y	Y	$ 28,777	10%	10%	0%	$ 35,247	$ 6,470	$ 31,827	$ 8,315	24.4	498.4	3718	2112
15	Boardman through 2017	Y	Y	$ 28,780	10%	10%	0%	$ 35,257	$ 6,477	$ 31,670	$ 8,200	24.5	505.7	3718	1970

	2. Portfolio Evaluation Scoring: Normalized Scores (0 to 100)	Screening		Deterministic				Stochastic			Reliability & Diversity		
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Zone?	Meets Operating Reserve Req?	Cost: Expected Cost	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variance	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
8	Green w/ On-peak Energy Target	Y	Y	68.1	64.1	100.0	78.6	90.7	53.1	61.2	88.1	68.8	95.7
9	Diversified Thermal with Green	Y	Y	73.5	89.7	80.3	54.3	40.1	40.7	64.9	83.6	52.2	35.2
10	Boardman through 2014	Y	Y	75.0	94.9	75.6	48.3	17.9	0.0	36.4	76.1	0.1	20.1
12	Boardman through 2011	Y	Y	71.7	53.8	73.0	49.6	15.9	3.3	44.1	82.1	0.1	6.5
15	Boardman through 2017	Y	Y	71.6	53.8	72.8	49.5	19.0	7.5	44.0	80.3	0.0	30.4

	3. Portfolio Evaluation Scoring: Total Weighted Scores	Screening		Deterministic				Stochastic			Reliability & Diversity					
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
	Scoring Consideration	Within Efficient Zone?	Meets Operating Reserve Req?	Cost: Expected Cost	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variance	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI	Weigted Combined Score (0 to 100)	Performance vs. Best (%)	Ordinal Ranking
	Weight			50%	10%	5%	5%	3.3%	3.3%	3%	15%	3%	3%			
8	Green w/ On-peak Energy Target	Y	Y	34.1	6.4	5.0	3.9	3.0	1.8	2.0	13.2	1.7	2.4	73.6	100%	1
9	Diversified Thermal with Green	Y	Y	36.8	9.0	4.0	2.7	1.3	1.4	2.2	12.5	1.3	0.9	72.0	98%	2
10	Boardman through 2014	Y	Y	37.5	9.5	3.8	2.4	0.6	0.0	1.2	11.4	0.0	0.5	66.9	91%	6
12	Boardman through 2011	Y	Y	35.8	5.4	3.6	2.5	0.5	0.1	1.5	12.3	0.0	0.2	61.9	84%	11
15	Boardman through 2017	Y	Y	35.8	5.4	3.6	2.5	0.6	0.2	1.5	12.0	0.0	0.8	62.5	85%	10

Other Considerations

There are other considerations that are not captured in our IRP portfolio scoring but are relevant to the decision to invest in emissions controls at Boardman. These considerations favor keeping the plant open through 2040.

As of this writing, if and when climate legislation is adopted by the Congress, it appears that the most likely policy outcome is legislation that resembles the Waxman-Markey bill. Legislation introduced in the Senate by Senators Kerry and Boxer (S. 1733) on September 30, 2009 resembles Waxman-Markey in several respects. Preliminary analysis of the September 30 version of S.1733 conducted by EPA (published October 23, 2009) suggests that the economic impacts of the bills will be similar, with S.1733 resulting "sight" or "small" allowance price increases due to differences in the bill provisions affecting the 2020 cap levels, offset limits, strategic reserve, EE and renewable energy provisions and the CCS bonus allowances. However, in order for the Senate to secure 60 votes for cloture, additional negotiation and compromise can be expected including the possibility of adding a firm price collar for allowances.PGE's current reference case price is $30 per short ton. The PGE reference case price is a composite of EPA and EIA studies of legislative proposals and includes the EPA work on Waxman-Markey. PGE's approach to assessing CO_2 risk and selecting a reference case price is described in greater detail in Chapter 6. Although the CO_2 price is unknown at this point, ongoing discussions in the Senate about a price collar mechanism could further diminish the probability of a higher CO_2 price.

In addition, it is reasonable to expect that operational changes and/or technology advancements will affect CO_2 reductions for coal-fired plants. These may include biomass co-firing, biogenic CO_2 capture and recycling, and CO_2 capture with geologic sequestration. PGE's algae sequestration pilot project (described in Chapters 6 and 7) is a promising example. Improvements in CO_2 abatement technology do not need to be specific to Boardman in order to benefit Boardman economics. If development in such technology is accelerated due to an increase in policy-based incentives, even if only available in other parts of the country, PGE's customers will benefit from such incentives since they would likely affect CO_2 prices. Furthermore, the availability of international offsets could put further downward pressure on CO_2 prices.

Boardman Recommendation

With respect to Boardman emissions controls investments and the future operations of the plant, the choices left to us as a result of the Oregon Regional Haze Plan and Utility Mercury Rule are not optimal for our customers compared to the other options that PGE proposed to the DEQ in its Decision Point Plan. In addition, the process of evaluating whether or not to invest in emissions controls is both complex and challenging. As discussed above, however, non-compliance with the Oregon Regional Haze Plan and Oregon Mercury rule is not an alternative. We must also keep in mind that an appropriate course of action for Boardman must be consistent with the objectives of the IRP - that is, to identify a resource action plan, that when considered with our existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for the utility and its customers. Given these goals, we recommend compliance with the Oregon Regional Haze Plan and Oregon Mercury Rules in two phases:

Phase 1

- NOx Controls: install the LNB/MOFA control system which, as proposed, is estimated to reduce NOx by 4,000 tons per year, for a 46% reduction compared to current emission levels. These controls will be installed by July 2011 to meet the 0.28 lb/MMBtu (30-day rolling average) and 0.23 lb/MMBtu (12-month rolling average) emissions limit. The estimated overnight capital cost is $33 million (100% of Boardman plant). Engineering Procurement and Construction (EPC) work will start in early 2010 to support the July 2011 schedule. We anticipate that it will not be necessary to request a compliance extension, thereby changing the dual limits to a single 0.23 lb/MMBtu (30-day rolling average) emissions limit.

- Mercury Controls: install the mercury (Hg) control system by 2012 for an estimated overnight capital cost of $7.7 million (100% of Boardman plant).

- SO_2 Controls: install scrubbers, which will cut SO_2 emissions by 12,000 tons per year for an 80% reduction compared to current emission levels. These controls will be installed by July 2014 to meet the 0.12 lb/MMBtu 30-day average emissions limit.

- Particulate Matter Controls: install a pulse jet fabric filter as part of the scrubber installation to supplement the existing electrostatic precipitator. This installation will cut particulate matter emissions by 122 tons per year for a 29% reduction from current levels. These controls will be installed by July 2014 to meet the 0.012 lb/MMBtu emissions limit. The particulate matter controls, together with the scrubbers, are estimated to have overnight capital cost of $289.9 million (100% Boardman plant).

Phase 2

- NOx Controls: install Selective Catalytic Reduction (SCR), which will cut NOx emissions by an additional 4,000 tons per year for an additional 38% reduction, beyond the Phase I upgrades. These controls will be installed by July 2017 to meet a 0.070 lb/MMBtu emissions limit for an estimated overnight capital cost of $180 million (100% Boardman plant).

Table 12-2 below provides the dates by which equipment must be installed in order for PGE to meet its compliance obligations. An all inclusive engineering, procurement and construction (EPC) approach is preferred, except for the Hg controls. Delay in meeting contract dates will correspondingly delay the date when equipment is operational and the plant can operate in compliance with the Oregon Regional Haze Plan and Oregon Mercury Rule.

Table 12-2: Boardman Engineering Procurement and Construction Schedule

	Controls	**EQC** **Emission Compliance Date**	**EPC** **Contract Date**
1.	LNB/OFA	July 2011	Feb 2010
2.	Mercury	July 2012	Q2-2011
3.	FGD	July 2014	Q1-2011
4.	SCR	July 2017	Q1-2014

Table 12-3 below summarizes the capital costs associated with each of the DEQ's recommended emissions controls; capital costs in this table are for 100% of the Boardman plant output. Installation of the new systems is expected to take place during our normally scheduled spring maintenance outages.

Table 12-3: Boardman Emissions Controls Capital Costs, Nominal $

	LNB/OFA	Hg/FGD	SCR	Total
2007	$ 75	$ 100	$ 75	$ 250
2008	$ 468	$ 624	$ 468	$ 1,560
2009	$ 1,554	$ 376	$ 77	$ 2,007
2010	$ 16,628	$ 3,785	$ 116	$ 20,529
2011	$ 14,123	$ 85,862	$ 94	$ 100,079
2012	$ -	$ 127,146	$ 116	$ 127,262
2013	$ -	$ 58,570	$ 684	$ 59,254
2014	$ -	$ 21,042	$ 38,789	$ 59,831
2015	$ -	$ -	$ 80,564	$ 80,564
2016	$ -	$ -	$ 43,720	$ 43,720
2017	$ -	$ -	$ 15,350	$ 15,350
Overnight Capital	**$ 32,848**	**$ 297,505**	**$ 180,053**	**$ 510,406**
AFDC	$ 3,636	$ 73,627	$ 42,352	$ 119,615
Property Tax	$ 386	$ 9,913	$ 5,727	$ 16,026
Total	**$ 36,870**	**$ 381,045**	**$ 228,132**	**$ 646,047**

With all controls in place in 2017, total fixed and variable O&M for PGE's 65% share of Boardman is projected to increase by approximately $8.1 million in 2009 $. About two-thirds of this amount is variable O&M. At the same time, the net plant heat rate is projected to increase by about 2% and plant output is projected to decrease by the same percentage. The ongoing impacts to the dispatch cost due solely to emissions controls (the variable O&M and change in heat rate) are fairly modest. In 2017, when all controls are in place, the dispatch cost is expected to increase by approximately $3 per MWh in 2009 $ exclusive of CO_2 costs.

This analysis is based on PGE's cost of capital. Tax-favored pollution control bond financing, if available, could improve the economics. Our modeling assumes no extension of the Oregon Pollution Control Facilities Tax Credit program, which currently does not benefit controls that were placed in service after December 31, 2007.

The PGE Power Supply Engineering Services group and the Boardman plant operations team are comfortable in this assessment of expected plant life and believe it may, in fact, be conservative. There are many instances of thermal plants operating well beyond their original book life and Boardman has a number of relatively new major components or upgrades, including steam turbines, pulverizers and boiler tubing. Other scheduled replacements over the next few years include generator components and burners.

In summary, PGE recommends proceeding with the Phase 1 and 2 emissions control upgrades required under the Oregon Regional Haze Plan and the Oregon Utility Mercury Rule, and retaining Boardman in our resource portfolio. This recommendation is based on the results of our portfolio analysis, which indicate that the portfolio which includes the operations through 2040, and the portfolio that ceases plant operations in 2014 yield similar expected cost results. However, the 2040 Boardman portfolio performs better across most risk metrics, including price risk and reliability measures. The Boardman 2040 portfolio also provides for increased fuel and technology diversity when compared to the early shutdown cases. Further details regarding the results of our portfolio analysis can be found in Chapter 11. Because of the importance of Boardman to PGE's resource portfolio and the significant adverse consequences that would result if PGE were not to comply with the Oregon Regional Haze Plan and Oregon Mercury rule, it is imperative that the Commission act promptly in its review of PGE's Integrated Resource Plan.

13. PGE Recommended Action Plans

Based on the combined scoring criteria that accounts for expected cost, deterministic and stochastic risk considerations, reliability, and diversity factors, PGE recommends one of the top-performing portfolios, "Diversified Thermal with Green." Our results indicate that this portfolio provides the second best combination of expected costs and associated risks. The portfolio is durable, performing well under the stress testing we conducted via our analysis. It is also actionable, representing relatively low execution risk when compared to the "Diversified Green with On-peak Energy Target" portfolio.

From our preferred portfolio we have developed a Resource Action Plan – consisting of an Energy Action Plan and Capacity Action Plan – which we believe meets the primary objectives of the IRP to provide the best combination of expected cost and risk for PGE and its customers. Our Action Plan maintains the overall diversity of our existing portfolio and positions us to meet the challenges of an uncertain future. The plan and its diversity of fuels and technologies, and emphasis on increasing levels of renewable resources and energy efficiency, provides a robust platform to respond to changes in fuel and electric prices, new environmental and energy legislation, and uncertainty over the cost and availability of renewable energy to meet RPS requirements.

Chapter Highlights

- Our Energy Action Plan proposes that PGE acquire 873 MWa of additional energy resources by 2015, including a 300- to 500-MW new baseload natural-gas-fired plant, 214 MWa of EE and 122 MWa of renewable resources, in addition to other actions.
- Our Capacity Action Plan proposes that approximately 730 MW of our 1724 MW Winter capacity needs by 2015 be met with thermal resources, including flexible peaking resources, with another 500-600 MW from EE, renewables, demand response and DSG, in addition to other actions.
- To ensure that we can meet our future resource requirements, our preferred portfolio includes the continued operation of the Boardman plant until 2040. Our Action Plan therefore includes investments in new emissions controls at Boardman by early 2014 to meet the Oregon Regional Haze Plan and Oregon Utility Mercury Rule compliance requirements.
- We recommend acquisition of 40,000 dekatherms per day of pipeline transport and/or natural gas storage for flexible capacity needs and 70,000 dekatherms per day for baseload energy, which combined will be able to supply approximately 600 MW of electric generation.
- We also seek acknowledgement of the design, siting and construction of a 500 kV double-circuit transmission line, Cascade Crossing, to enable us to deliver power from significant existing and new resources east of the Cascades, subject to certain milestones and participation agreements.

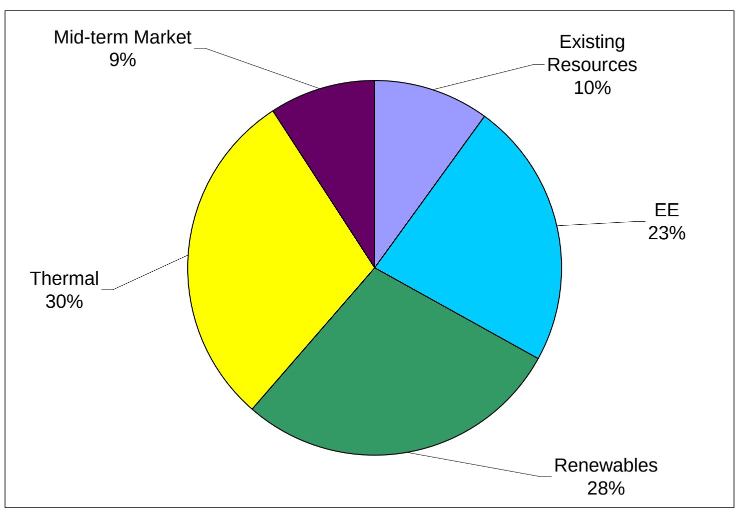
13.1 Resource Actions

Action Plan Resource Mix

Our recommended portfolio seeks to fill up to 873 MWa (including net market activity) with energy actions in the next two to four years, to be in place by 2015. This target is based on the continued operation of the Boardman plant. Of this total, 16% (138 MWa) is expected to come from contract renewals and the exercise of existing contract rights for current hydro and coal resources. Another 24% (214 MWa) will come from EE and 14% (122 MWa) from renewables. A high-efficiency CCCT comprises the remaining almost 50% (406 MWa) of the resource additions.

Through 2020, in addition to ongoing EE, this portfolio continues to add more renewables to the extent they prove to be available and economic. Of the resources that are added between 2011 and 2020, renewal of existing resources comprise 10% (138 MWa), EE meets 23% (322 MWa) of the need, renewables meet 28% (394 MWa), and gas provides 30% (411 MWa). The remainder, approximately 9% (128 MWa), comes from short- to mid-term market purchases. Figure 13-1 illustrates the incremental resource mix of our recommended portfolio through 2020.

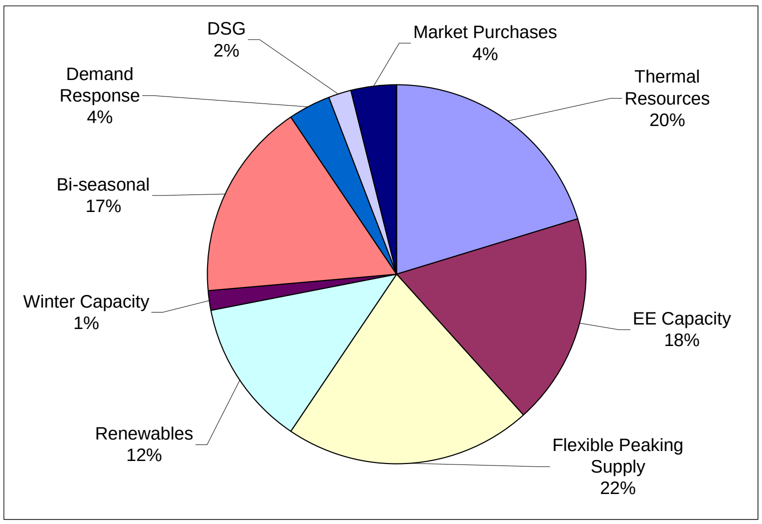
Figure 13-1: Action Plan Incremental Energy Resource Mix – 2020



Our Winter Capacity Action Plan is (in 2015) comprised of 31% (529 MW) thermal resources, 18% (315 MW) EE capacity, 12% (200 MW) flexible peaking resources (2013), 11% (185 MW) renewables, 9% (152 MW) winter-only capacity contracts, 8% (131 MW) bi-seasonal capacity contracts, 3.5% (60 MW) demand response, 3% (52 MW) DSG, and 6% (100 MW) market purchases.

Through 2020 capacity needs continue to grow. The total by resources are 20% (533 MW) thermal resources, 18% (474 MW) EE capacity, 22% (560 MW) flexible peaking resources, 12% renewables (329 MW), 1% (30 MW) winter-only capacity contracts, 17% (458 MW) bi-seasonal capacity contracts, 4% (95 MW) demand response, 2% (52 MW) DSG, and 4% (100 MW) market purchases. Figure 13-2 shows the breakout below.

Figure 13-2: Action Plan Incremental Winter Capacity Resource Mix – 2020

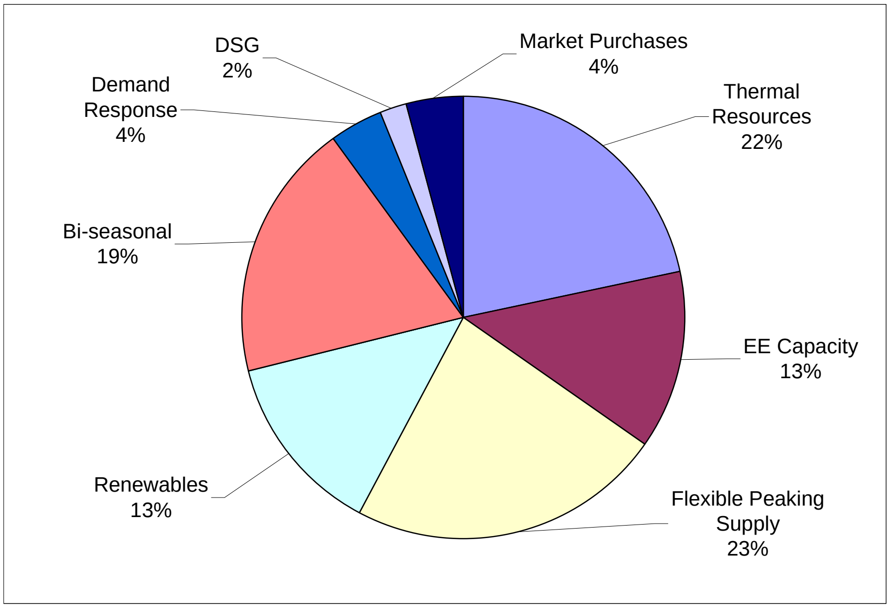


Our Summer Capacity Action Plan is (in 2015) comprised of 36% (529 MW) thermal resources, 14% (210 MW) EE capacity, 14% (200 MW) flexible peaking resources (2013), 13% (185 MW) renewables, 9% (131 MW) bi-seasonal capacity contracts, 4% (60 MW) demand response, 3.5% (52 MW) DSG and 7% (100 MW) market purchases.

Figure 13-3 shows the breakout 2020 summer capacity additions below. The total by resources are 22% (533 MW) thermal resources, 13% (316 MW) EE capacity, 23% (560 MW) flexible peaking resources, 13% renewables (329 MW), 19% (458 MW) bi-seasonal capacity contracts, 4% (95 MW) demand response, 2% (52 MW) DSG, and 4% (100 MW) market purchases.

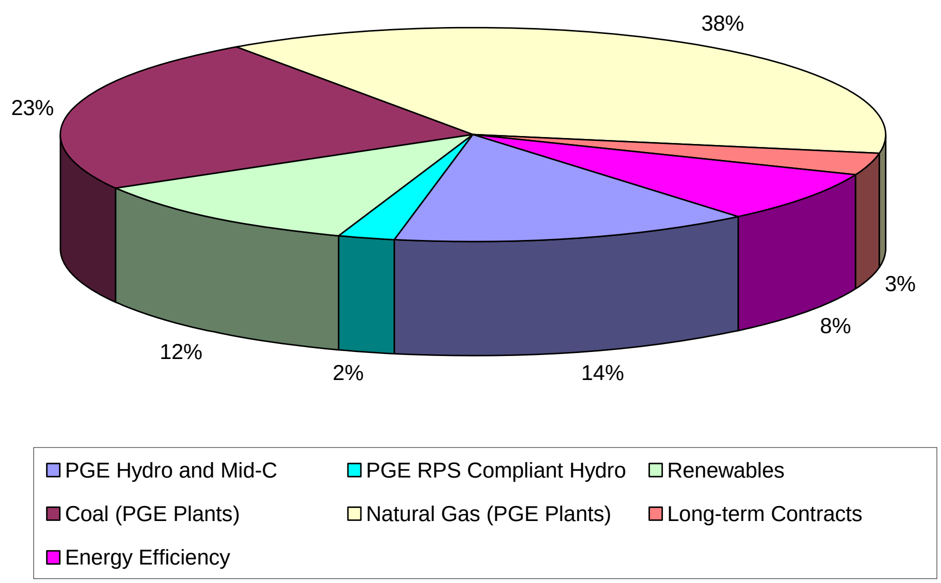
Table 13-1, Table 13-2 and Table 13-3 provide a summary of the recommended year-round energy and bi-seasonal capacity components of our recommended Action Plan (broken into actions to be taken by 2015, which would need to be implemented prior to the next IRP, and cumulative total actions by 2020). The tables show our resource need from the earlier load/resource balance analysis and how the recommended resources fill these needs

Figure 13-3: Action Plan Incremental Summer Capacity Resource Mix



.Figure 13-4 below shows PGE's resource mix following implementation of our Action Plan. For the results shown all plants are at their theoretical availability, with the exception of our Beaver plant. Beaver is dispatched here on an economic basis, approximately 10% of the time.

Figure 13-4: PGE Projected 2015 Energy Resource Mix (After Economic Dispatch)[93]



[93] Total renewable percentage does not equal 15% due to inclusion of EE. Renewables as a percentage of load adjusted for EE will be 15%.

Table 13-1: Energy Action Plan

Energy MWa @ Normal Hydro	Action Plan 2015*	2020
PGE system load at normal weather	2,624	2,886
Remove assumed 5-yr. opt-out load	(28)	(28)
Existing PGE & contract resources	(1,850)	(1,652)
Remove post 2008 cumulative embedded EE	128	187
PGE Resource Target	**873**	**1,393**
Resource Actions		
Thermal Resource Actions:		
Combined Cycle Combustion Turbine (2015)	406	406
Combined Heat & Power (2015, 2017, 2019)	2	5
Boardman Lease Contract (2014)	72	72
Renewable & EE Resource Actions:		
ETO Energy Savings Target (2009-2020)	214	322
Existing Contracts Renewals	66	66
2015 RPS Compliance**	122	122
Biomass (2017, 2019)	-	50
Geothermal (2019)	-	50
Solar PV (2019)	-	4
RPS Compliance (2016-2020)	-	168
To Hedge Load Variability:		
Short- and Mid-term Market Purchases	100	100
Subtotal	**981**	**1,365**
(Surplus) / deficit met by market	(108)	28
Total Resource Actions	**873**	**1,393**

*Actions will be taken, or committed to by end of year 2014 for resources online by 2015

**2015 RPS Compliance is for the 122 MWa necessary for physical compliance in 2015.

Table 13-2: Summer Capacity Action Plan

August Capacity MW @ Normal Hydro	Action Plan 2015*	2020
PGE system peak at normal weather	3,778	4,239
Operating Reserves (approximately 6% of generation)	194	194
Contingency Reserves (6% of Load)	225	252
Remove assumed 5-yr opt outs (w/contingency reserves)	(31)	(31)
Existing PGE & contract resources	(2,822)	(2,396)
Remove post 2008 cumulative embedded EE	126	184
PGE Resource Target	**1,468**	**2,442**
Resource Actions		
Thermal Resource Actions:		
Combined Cycle Combustion Turbine (2015)	441	441
Combined Heat & Power (2015, 2017, 2019)	2	6
Boardman Lease Contract (2014)	86	86
Renewable Resource Actions:		
Existing Contracts Renewals	167	167
2015 RPS Compliance**	18	18
Biomass (2017, 2019)	-	58
Geothermal (2019)	-	58
Solar PV (2019)	-	1
RPS Compliance (2016-2020)	-	25
To Hedge Load Variability:		
Short- and Mid-term Market Purchases	100	100
Capacity only resources:		
Flexible Peaking Supply (2013)	200	560
Customer-Based Solutions (Capacity only):		
Dispatchable Standby Generation (2010-2013)	52	52
Demand Response (2010-2012 and 2017-2020)	60	95
Seasonally Targeted Resources:		
ETO Capacity Savings Target (2009-2020)	210	316
Bi-seasonal Capacity	131	458
Winter-only capacity	-	-
Total incremental resources	**1,468**	**2,442**

*Actions will be taken, or committed to by end of year 2014 for resources online by 2015

**2015 RPS Compliance includes assumed capacity from 122 MWa necessary for physical compliance in 2015. The capacity value is based on filling renewable need with wind resources.

Table 13-3: Winter Capacity Action Plan

January Capacity MW @ Normal Hydro	Action Plan 2015*	2020
PGE system peak at normal weather	4,107	4,478
Operating Reserves (approximately 6% of generation)	205	204
Contingency Reserves (6% of Load)	245	267
Remove assumed 5-yr opt outs (w/contingency reserves)	(31)	(31)
Existing PGE & contract resources	(2,989)	(2,563)
Remove post 2008 cumulative embedded EE	188	275
PGE Resource Target	**1,724**	**2,630**
Resource Actions		
Thermal Resource Actions:		
Combined Cycle Combustion Turbine (2015)	441	441
Combined Heat & Power (2015, 2017, 2019)	2	6
Boardman Lease Contract (2014)	86	86
Renewable Resource Actions:		
Existing Contracts Renewals	167	167
2015 RPS Compliance**	18	18
Biomass (2017, 2019)	-	58
Geothermal (2019)	-	58
Solar PV (2019)	-	1
RPS Compliance (2016-2020)	-	25
To Hedge Load Variability:		
Short- and Mid-term Market Purchases	100	100
Capacity only resources:		
Flexible Peaking Supply (2013)	200	560
Customer-Based Solutions (Capacity only):		
Dispatchable Standby Generation (2010-2013)	52	52
Demand Response (2010-2012 and 2017-2020)	60	95
Seasonally Targeted Resources:		
ETO Capacity Savings Target (2009-2020)	315	474
Bi-seasonal Capacity	131	458
Winter-only capacity	152	30
Total incremental resources	**1,724**	**2,630**

*Actions will be taken, or committed to by end of year 2014 for resources online by 2015

**2015 RPS Compliance includes assumed capacity from 122 MWa necessary for physical compliance in 2015. The capacity value is based on filling renewable need with wind resources.

Resource Actions Common to All Portfolios[94]

1. ***Energy Efficiency (EE).*** We recommend continuation of the ETO EE acquisition programs to provide 322 MWa by 2020, along with continued funding via the twin funding vehicles of the 3% system benefits charge (SBC) and the SB 838 funding mechanism to the maximum degree found to be cost-effective, according to ETO standards. EE not only provides benefits to customers in the form of lower bills and to PGE in the form of

[94] These actions were included in all of our candidate portfolios – see Chapter 11.

a lower load requirement, but, when factoring in its nearly 1.5 MW to 1 annual MWa winter peak reduction benefit, it provides one of the best methods of improving winter load factors.

2. ***Acquisition of Renewables.*** We recommend adding new renewable resources to remain in physical compliance with the Oregon RPS throughout the time frame of this analysis (2029). In this Action Plan, this specifically means acquiring sufficient additional renewables to be in compliance with, at minimum, the 2015 15% portfolio standard. To accomplish this goal, in addition to our existing resource base of approximately 550 MW of wind (by year-end 2010), an additional 122 MWa of new renewables will need to be in service by the end of 2014. This action item was previously found to be reasonable in LC-43, but PGE has not yet fulfilled this renewables need (see Chapter 2). We will consider all forms of renewables with bundled RECs that are Oregon RPS compliant. PGE intends to include a self-build wind benchmark resource in the RFP.

3. ***Distributed Standby Generation (DSG).*** We recommend continuation of PGE's acquisition of all available cost-effective DSG. We have targeted acquisition of 52 MW of new DSG between now and 2013. (We have not identified additional opportunities that may exist beyond 2013, although we expect new opportunities will exist by then). PGE has demonstrated an ongoing need for capacity that can be available for a very limited number of hours per year (normally less than 50 hours per year). DSG is a particularly cost-effective way to meet these peak demand periods.

4. ***Demand Response***. PGE is moving ahead to acquire up to 60 MW of bi-seasonal demand response resources. We have conducted a thorough DR-only RFP and are working with third-party providers for winter and summer peak reduction products that will be offered to residential and commercial customers. Because we have not yet launched these programs, we describe them here as a part of this Action Plan.

5. ***Combined Heat & Power (CHP).*** PGE recommends acquisition of combined heat/power opportunities where they result in overall improved efficiency and where undue risk is not transferred to other customers or PGE shareholders. Our assessment is that such opportunities are comparatively small (5 MWa in the next 10 years).

6. ***Research and Development for Renewables.*** PGE proposes to engage in research and development (R&D) activities related to future acquisition of renewable resources. PGE will be seeking recovery of costs related to R&D activities in subsequent rate proceedings. R&D activities may

include, but are not limited to, research into biomass, solar and wave energy. It may also include external costs related to the integration of renewables such as the costs to develop or acquire modeling and forecasting systems. PGE seeks acknowledgment that such activities are reasonable and consistent with the Commission's resource planning principles.

Actions for Existing Resources

7. ***Oregon Regional Haze Plan and Oregon Utility Mercury Rule Expenditures for Boardman Plant***. Based on PGE's analysis of installing new emissions controls to meet the requirements of the Oregon Regional Haze Plan and the Oregon Utility Mercury Rule, including an assessment of future CO_2, electric and natural gas prices and associated risks, PGE's preferred portfolio includes the continued operation of the Boardman plant through 2040 with all required emissions mitigation actions.

   PGE requests acknowledgement of continuing operations at Boardman, including capital expenditures for Oregon Regional Haze Plan and Oregon Utility Mercury Rule compliance within this Action Plan timeframe. These actions include commitments to low-NOx burners and over-fire air controls by February 2010, with controls installed by July 2011, commitments to purchase scrubbers and mercury control by Q2 2012, with installation by July 2014, followed by commitments in Q1 2014 to install SCR (Selective Catalytic Reduction), with installation by July 2017, for a total estimated installed cost of $510 million (100% plant).

   The current IRP process must necessarily include a comprehensive decision on PGE's proposal to install controls in 2011, 2014 and 2017 as the commitments for the 2011 and 2014 controls must be made before the next IRP will be acknowledged and investments in the 2014 and 2017 emissions controls are mutually dependent.

   Because of the importance of Boardman to PGE's resource portfolio and the significant adverse consequences that would result if PGE were not to comply with the Oregon Regional Haze Plan and Oregon Mercury rule, it is imperative that the Commission act promptly in its review of PGE's proposed Boardman actions.

8. ***Contract Renewal***. In order to maintain fuel diversity, PGE recommends renewal of expiring hydro contracts if they can be renewed cost-effectively. This Action Plan assumes partial renewal of existing contracts.

9. ***Bank of America Lease Option***. We propose exercising one of our options under the BAL leasing agreements to acquire 15% of the Boardman plant output (72 MWa).

New Resource Actions

10. ***Baseload Natural Gas Combustion***. PGE requests acknowledgement of a new high-efficiency combined-cycle, natural gas plant (CCCT) of approximately 300 to 500 MW, to be in service by year-end 2015. This new resource is required to meet continued load growth and existing resource expirations. The CCCT will be included in a future RFP to be issued pursuant to this RFP. PGE intends to submit a self-build alternative, the Carty Generating Station, to be located near Boardman, Oregon.

11. ***Flexible Capacity Resources***. PGE requests acknowledgement of up to 200 MW of flexible capacity resources by year-end 2013 to fill a dual function of providing capacity to maintain supply reliability during peak demand periods and providing needed flexibility to address variable load requirements and increasing levels of intermittent energy resources. PGE intends to submit a self-build alternative to be located near the existing Port Westward site.

12. ***Seasonal Capacity.*** PGE requests acknowledgement to acquire, via contracts, up to 131 MW of bi-seasonal, limited-duration peaking supply and 152 MW of winter-only peaking supply to maintain reliability and meet system contingencies during peak demand periods. These partially replace similar expiring peak seasonal contracts. In the event that we are unable to acquire bi-seasonal, limited-duration peaking supply resources, PGE would need to revisit our procurement plan and may need to consider additional year-round peaking resources as an alternative.

13. ***Shorter-term Resources***. Because new generating resources come in lumpy denominations (e.g., a new CCCT is 400 MW) and take time to develop and acquire, timing of new supply naturally results in a few years of being deficit to our annual supply target, followed by a few years of being modestly long. To balance these short-term deficits or excesses, PGE plans to continue its existing short- and mid-term market activities.

13.2 Natural Gas Transportation Actions

14. ***Gas Transport***. To meet the fueling requirements of the new energy and capacity resources in the proposed Action Plan, as well as to maintain

portfolio flexibility, additional natural gas transport and/or storage is required. In this Action Plan, we recommend acquisition of 40,000 dekatherms per day of pipeline and/or storage for flexible capacity needs and 70,000 dekatherms per day for baseload energy, which combined will be able to supply the generation of about 600 MW of electricity. The actual volumes may be higher or lower depending on (1) the generation resource actions we take as a result of this IRP, (2) the availability of capacity on new pipeline projects and (3) the location and fueling needs of new gas-fired resources acquired through a future RFP.

15. ***Long-term Fuel Acquisition***. To further diversify PGE's procurement strategy for coal and natural gas, we propose adding longer term sources of fuel supply alternatives to our existing short and mid-term purchasing strategy. This will be accomplished by pursuing the acquisition of long-term fuel sources and purchase agreements. The alternatives for long-term fuel supply are further described in Chapter 5.

13.3 Transmission Actions

We propose moving forward with the Cascade Crossing Transmission Project in this Action Plan. When the Commission issued Order 04-375 acknowledging PGE's 2002 IRP, it recognized that the development of new transmission capacity was critical to making new resources, particularly renewable resources on the eastern side of the Cascade Mountains, available to customers. The Commission directed PGE to work with others to develop such transmission capacity. The project we propose in this Action Plan results from this effort.

16. ***Cascade Crossing***. We seek acknowledgment, subject to achieving certain milestones and participation described in Chapter 8, to construct a 500 kV transmission line connecting the southern portion of our service territory near Salem, Oregon, to our Boardman and Coyote Springs plants near Boardman, Oregon. Most of the high-voltage transmission line will be constructed adjacent to or within existing rights-of-way and will enable us to access significant existing and new generation resources east of the Cascade Mountains. We anticipate that the line will be in service by 2015. If we achieve the milestones and participation described in Chapter 8, we will design, site and construct the facility as a double-circuit 500 kV facility. Otherwise, we will construct it as a single-circuit 500 kV facility. We provide a detailed description of the project, including a discussion of the need for the project and a timeline, in Chapter 8.

As mentioned in Chapter 8, Section 8.5, the decision whether to proceed with Cascade Crossing and which option to construct will depend on an updated economic analysis. The results of the economic analysis inherently depend on the path rating, refined cost estimates, the level of equity participation in the project, the transmission service requests submitted to PGE Transmission and PGE's generation facilities that would utilize the project.

13.4 Resource Acquisition Timing

While the timeframe for our portfolios extends to 2020 for major actions and through 2030 for EE and renewable actions to be RPS compliant, PGE's recommended Action Plan is for items that will be implemented or committed to by 2014, for resources in service on or before year-end 2015. Items from the preferred portfolio extending beyond this timeframe will be subject to further review in the next IRP cycle.

In compliance with Guideline 4n of Order No. 07-002, PGE has listed all material resource activities and their key attributes we plan to undertake by 2015. Some of these actions were previously found to be reasonable and are ongoing actions from a previous IRP, RFP or approved acquisition process. One supply action is of short duration and is consistent with PGE's ongoing supply balancing activities in traded energy markets.

13.5 Implementation Considerations

Compliance with State and Federal Energy Policies

Guideline 4m of Order No. 07-002 requires that we identify and explain "any inconsistencies of the selected portfolio with any state and federal energy policies . . . and any barriers to implementation."

We believe our Action Plan is consistent with current state and federal energy policies. Specifically, some of the key ways in which the Plan complies with existing and near-term expected policies include the following:

1. It is in physical compliance with the state of Oregon RPS;
2. It incorporates, at varying levels, an expected compliance cost for potential future federal CO_2 legislation;
3. It includes all required emissions controls to achieve Oregon Regional Haze Plan and Oregon Utility Mercury Rule compliance at the Boardman plant; and

4. It fully utilizes approved funding and acquisition mechanisms to deliver EE savings.

To the extent new requirements are promulgated (e.g., via the next Oregon legislative session), we will make adjustments in our Plan as needed to remain in compliance with the new requirements.

Barriers to Implementation

Potential barriers to implementation tend to be generic and thus are not unique to the recommended Action Plan or even to PGE in most instances. It is difficult to predict the extent to which the barriers listed below may exist and affect implementation of our Action Plan.

1. Lack of quality or cost-competitive bids from third parties in future RFP processes;

2. Access to capital to acquire and build new resources;

3. Need for counterparties with strong balance sheets with which PGE may enter PPAs;

4. Discontinuation or material diminishment of the PTC, ITC or other federal or state credits and incentives for renewables;

5. Inability to find adequate transmission or fuel transport for new generating projects;

6. Inability to acquire or self-provide sufficient cost-effective integration for intermittent resources;

7. Public opposition to specific resource types or locations for generation and transmission;

8. Rates of adoption of EE below expectations;

9. Inability to negotiate acceptable contract renewals for existing resources;

10. Changes in environmental and energy law or policy that would materially change the cost-effectiveness or availability of our Action Plan resources; and

11. Market competition for new resources that adversely impacts availability and cost-effectiveness, particularly for renewables, or

for the primary components to develop and construct new resources.

Regulatory Policy and Support

Successful implementation of our preferred portfolio can be enhanced by state regulatory policies that help reduce barriers to implementation. For example, since our last IRP, passage of SB 838 (the RPS legislation) has removed the prior barrier that limited the amount of EE that could be achieved based on available funds. Now, additional funds can be allocated to assure that all cost-effective EE that customers will adopt is acquired. Examples of other changes or support required that will ultimately help achieve state energy policy objectives while keeping costs to customers reasonable include:

1. ***Build vs. Buy***. PPAs impose increased operating leverage and the risk that debt imputed by rating agencies for contracts will reduce our financial flexibility or increase our borrowing costs. As a result, we advocated for a supportive outcome in the UM 1276 docket, which focuses on build vs. buy decisions. Specifically, we advocated for a structure that recognizes and addresses the risk and potential cost associated with PPAs.

2. ***Renewable Site Acquisition***. Given the very large demand for wind to meet various state RPS goals and the limited supply of good wind sites, it is likely that acquisition of some sites in advance of project development and construction will result in the lowest cost to customers in the long run. This may require a change to ORS 757.355, which exempts customers from paying for an asset that is not yet in service.

3. ***Capacity Contracts***. This Plan calls for bi-seasonal limited-duration capacity contracts to meet customer peaking needs and to maintain prudent reserves for reliability. Because such contracts are only called upon under infrequent circumstances, they cannot be justified strictly on the basis of dispatch economics. Rather, they are needed to assure reliability of service to customers.

4. ***Development of Benchmark Resources***. As noted, PGE intends to submit benchmark resources in the RFP(s) conducted to implement the Action Plan. PGE has found that the inclusion of a benchmark resource in a RFP, regardless of whether it is ultimately selected, benefits the selection process. Not only does it provide an additional price point for comparison purposes but, we believe that parties are likely to submit more competitive bids when they know they will be competing against a utility self-build option. When it submits a bid into a RFP, PGE incurs

certain external costs such as those related to permitting and the identification of sites, which it may not be able to recover if the project is not selected. PGE believes it is important that it be able to recover reasonable external development costs related to unsuccessful benchmark bids.

Conclusion

The recommended Action Plan includes a set of new resources and actions to maintain existing resources, that when considered in PGE's overall portfolio, provides the best combination of cost and risk (including execution risk), when compared to other alternatives that we evaluated. We believe that the proposed actions, and resulting portfolio, are diverse and robust, providing the durability to meet uncertain future conditions. They position PGE to continue to reliably serve our customers' future electricity needs while meeting environmental regulations and renewable energy standards. The Action Plan further enhances the sustainability of our portfolio by increasing the level of renewables, energy efficiency and high-efficiency natural gas. As we move forward to complete our current IRP process, we continue to welcome practical suggestions regarding providing our customers the best possible electricity solutions, while remaining responsive to the interests of our investors and other constituents. Because several major components of this Plan are time-sensitive, we urge expeditious review and acknowledgement.

Appendix A: Compliance with Order No. 07-002

Guideline 1:	Substantive Requirements		Chapter
Guideline 1a	All resources must be evaluated on a consistent and comparable basis.		
	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation and storage – and demand-side options which focus on conservation and demand response.	Consistent with Order 08-246, we consider all known supply-side and demand-side resources that are expected to become available. For energy, we model solar, nuclear, wave and IGCC coal in conjunction with EE, wind, CCCTs, CHP, biomass and geothermal. For capacity, we model reciprocating engines along with SCCTs, DSG and DR. We consider development of new transmission capacity and new gas pipeline contracts.	2, 7
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	We developed portfolios with resource types which inherently exhibit the characteristics identified in the guideline. Refer to our portfolios composition table in Chapter 10.	7, 10
	Consistent assumptions and methods should be used for evaluation of all resources.	PGE used consistent assumptions and methods for evaluating all resources.	10
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	We applied PGE's after tax marginal weighted-average cost of capital of 7.59% as a proxy for the long-term cost of capital in the WECC.	10

Guideline 1b	Risk and uncertainty must be considered.		
	At a minimum, utilities should address the following sources of risk and uncertainty:		
	1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices and costs to comply with any regulation of greenhouse gas emissions.	PGE analyzes the variables specified in this guideline through a combination of deterministic futures, sensitivities and stochastic analysis. Stochastics model volatile behavior for natural gas prices, weather impact to loads, water years, wind intermittency and plant forced outages with mean times to repair. For greenhouse gas, we have a 2020 Oregon CO_2 Goal portfolio.	3,10
	2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.	N/A	N/A
	Utilities should identify in their plans any additional sources of risk and uncertainty.	We include in the risk metrics three measures of scenario/paradigm risk and three measures of stochastic risk. In addition, we look at risk measures including portfolio LOLP risk using EUE, and measures that evaluate portfolio diversity We also look at CO_2 intensity and mix of fixed vs. variable costs. We use futures that reflect a range of CO_2 prices, natural gas prices, capital costs, achievable EE and PGE loads.	10

Guideline 1c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.	PGE used a scoring grid which assigns weightings to cost and risk factors as follows: 50% to expected cost; 20% to scenario risk metrics; 10% to stochastic risk metrics; 15% to reliability performance; 5% to portfolio diversity.	10
	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	Consistent with Order 08-246, we plan for the acquisition of major new resources in the first 10 years, hourly dispatch via Aurora through 2040 with end effects, recovery of life-cycle resource revenue requirements, and end effects for both dispatch benefits and asset fixed costs.	10
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	We use expected NPVRR All other costs over time for gas transport, transmission, fuel, fixed cost recovery, etc. are included within the revenue requirement modeling for all long-lived and short-lived resources. That is, all costs that would actually be incurred to operate the resource are included.	10

	To address risk, the plan should include, at a minimum:		
	1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	We use three measures of NPVRR risk for both the deterministic scenario analysis (portfolio robustness measure and worst four outcomes less the mean) and the stochastic analysis (standard deviation, and TailVar90)	10
	2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	We include a discussion of traditional physical and financial hedging approaches, their purpose and limitations, for wholesale electricity and for natural gas in Chapter 5.	5
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	We explain how we balance cost and risk in Chapter 10 and describe the criteria we use to determine the best cost/risk portfolio.	10
Guideline 1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	We model a portfolio to achieve the Oregon CO_2 goal, RPS compliance in all portfolios, Boardman BART compliance in all portfolios and various scenarios for federal CO_2 regulation.	10

Guideline 2	Procedural Requirements		Chapter
Guideline 2a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	The public has been significantly involved in the development of PGE's IRP. Chapter 1 provides an overview of our public process.	1
Guideline 2b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	PGE's IRP provides non-confidential information used for portfolio evaluation and development of the action plan.	**N/A**
Guideline 2c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PGE distributed a draft IRP for public review and comment on September 4, 2009.	N/A

Guideline 3	Plan Filing, Review and Updates		Chapter
Guideline 3a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	In Order 08-246, the Commission directed PGE to submit a new IRP within 18 months of the effective date of Order No. 08-26, or by November 5, 2009.	N/A
Guideline 3b	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	PGE will comply with this Guideline.	N/A
Guideline 3c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	N/A	N/A
Guideline 3d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	N/A	N/A

Guideline 3e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	N/A	N/A
Guideline 3f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	N/A	N/A
Guideline 3g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:	N/A	N/A
	Describes what actions the utility has taken to implement the plan;		
	Describes what actions the utility has taken to implement the plan;		

	Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and		
	Justifies any deviations from the acknowledged action plan.		
Guideline 4	**Plan Components**		**Chapter**
	At a minimum, the plan must include the following elements:		
Guideline 4a	a. An explanation of how the utility met each of the substantive and procedural requirements;	The purpose of this table is to comply with this Guideline. We include more detailed descriptions and explanations of how we meet the Commission requirements within the body of the IRP filing.	
Guideline 4b	b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;	We include high and low load scenarios for PGE in Chapter 3 We also analyze stochastic load risk which is primarily the result of weather variations based on historical observations of pre-schedule vs. actual loads. We apply stochastic load risk to the entire WECC and include correlations between geographic areas. The primary purpose is to provide realistic volatility to the hourly market price.	3,10

Guideline 4c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;	We perform three related analyses: 1) A load/resource balance on energy and January and August capacity, 2) an LOLP analysis on the benefit of adding additional capacity as well as the comparative reliability performance between portfolios, 3) a portfolio test of the mix between capacity and energy resources. All portfolios model existing transmission costs from the source to our system as well as future transmission additions. We separately evaluated the performance of Cascade Crossing against our top-performing portfolios.	3, 8, 10
Guideline 4d	For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;	N/A	N/A

Guideline 4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;	We develop resource-specific life-cycle revenue requirements. We assume: 1) declining heat rates over time for new thermal units; 2) sharply declining costs for solar PV; and that advances in wind technology are more than offset by declining wind site quality within Oregon/Washington.	7
Guideline 4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;	Each portfolio acquires supply and demand resources to a level that maintains, at minimum, a required 6% operating reserve. Using a loss-of-load analysis, we further examine each portfolio for specific performance given its specific incremental resources with associated shaft risks and market exposure.	10
Guideline 4g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;	We base natural gas prices and CO_2 price on current third-party outlooks and include a range of higher and lower cost outcomes.	5,6, 10

Guideline 4h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;	We use a combination of predominantly single incremental resource and diversified portfolios which acquire various resources in various combinations with varying timing and durations as specified. We represent distributed resources via small amounts of new solar PV, CHP, and DSG within our service territory. Because PGE has a relatively compact service area, location-specificity is not relevant.	10
Guideline 4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;	We have a rigorous and comprehensive scoring system that accounts both for expected portfolio cost and a variety of deterministic scenario and stochastic risks, along with reliability and diversity considerations.	10
Guideline 4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;	We use a 100-point scoring system. Our results are shown in Chapter 12.	12
Guideline 4k	Analysis of the uncertainties associated with each portfolio evaluated;	Our scoring metrics analyze the uncertainties associated with each portfolio evaluated.	10

Guideline 4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;	See 1c above.	10,12,13
Guideline 4m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation;	Our preferred portfolio complies with existing state and energy policies and regulations. We include a portfolio based on the Oregon CO_2 goal. We discuss barriers to implementation in Chapter 13.	13
Guideline 4n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Our Action Plan includes activities that we intend to undertake or commit to in the next two to four years for resource additions that are targeted to be online by 2015.	13

Guideline 5	Transmission		Chapter
	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	Our portfolio analysis includes costs for the fuel transportation and electric transmission required for each resource being considered. We evaluate two transmission builds and acquisition of additional pipeline capacity to support additional gas generation We compare our proposed transmission builds to proxy transmission resources (i.e. transmission from BPA).We also have a portfolio that assumes less costly wind from Wyoming while also adding more transmission cost.	5,8

Guideline 6	Conservation		Chapter
Guideline 6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	We include a study conducted by the Energy Trust of Oregon of technical and achievable potential energy efficiency.	4
Guideline 6b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	N/A	N/A

Guideline 6c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:		
	Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and	We base our portfolios on studies conducted by the ETO which determine the amount of potential energy efficiency without regard to any funding limits.	4
	Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	Our preferred portfolio and action plan are consistent with the ETO's projection of energy efficiency potential.	4, 13
Guideline 7	**Demand Response**		**Chapter**
	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	We evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity and transmission needs	4, 7

Guideline 8 (Order 08-339)	**Environmental Costs**		**Chapter**
Guideline 8a	BASE CASE AND OTHER COMPLIANCE SCENARIOS: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	We construct a reference case based on third-party analysis of federal legislative CO_2 proposals with upper and lower bounds and a year-to-year shape. We assume the compliance comes in the form of a CO_2 price. We assume CO_2 emissions for PGE are regulated at the point of combustion. Our research indicates no reliable correlation between CO_2 price and the cost of natural gas; therefore there is no inconsistency between our CO_2 analysis and other key inputs. Our reference case assumes implementation of emissions controls at Boardman, as required by DEQ, which will achieve regulatory compliance for SO_X, NO_X, and mercury emissions and allow the plant to meet the future compliance requirement. Colstrip is a newer plant with scrubbers and low NO_X burners. At this point, we have no basis to conclude that a reasonably possible regulatory future will require additional controls at Colstrip.	6

Guideline 8b	TESTING ALTERNATIVE PORTFOLIOS AGAINST THE COMPLIANCE SCENARIOS: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	We test our portfolios against futures that incorporate a range of future CO_2 prices and include end effects beyond 2040.	10

Guideline 8c	TRIGGER POINT ANALYSIS. The utility should identify at least one CO_2 compliance "turning point" scenario which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated.	We test the CO_2 price which would trigger the selection of our all-green portfolio over our preferred portfolio (which has new gas). Because our preferred portfolio does not have new coal, we believe no trigger point between coal and gas is needed.	11
Guideline 8d	OREGON COMPLIANCE PORTFOLIO: If none of the above portfolios is consistent with Oregon energy policies (including the state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those of the preferred and alternative portfolios.	We include a portfolio in which Boardman and Colstrip no longer dispatch after 2020 and nuclear generation from Idaho becomes the substitute.	10

Guideline 9	Direct Access Loads		Chapter
	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	We exclude five-year opt-out load.	3
Guideline 10	**Multi-state Utilities**		**Chapter**
	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	N/A	N/A
Guideline 11	**Reliability**		**Chapter**
	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation and storage, along with demand side resources, to reliably meet peak, swing and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	We analyze loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy for all of our portfolios. We assess the tradeoff between higher reliability and higher cost by examining two portfolios – our market portfolio which has few capacity additions and our on-peak energy target portfolio which adds a large amount of capacity.	10, 11

Guideline 12	**Distributed Generation**		**Chapter**
	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	We evaluate distributed generation (including avoided generation technologies, including DSG, DR, EE, distributed solar, and CHP) on par with other supply-side resources. These technologies do not include line losses and transmission costs that burden central station plants.	7
Guideline 13	**Resource Acquisition**		**Chapter**
Guideline 13a	An electric utility should, in its IRP:		
	Identify its proposed acquisition strategy for each resource in its action plan.	Our acquisition strategy includes submitting benchmark energy, capacity and renewables resources in one or more RFPs.	9,13
	Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.	We include an assessment of the advantages and disadvantages of owning a resource instead of purchasing power from another party.	9
	Identify any Benchmark Resources it plans to consider in competitive bidding.	We identify Benchmark Resources in Chapter 9.	9
Guideline 13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	N/A	

Appendix B: Public Meeting Agendas

1st Public Meeting - June 12, 2008

- Renewable RFP Update
- IRP Process Overview
- IRP Resource Mix and Resource Need Update
  - Existing Resources
  - Resource Mix after current RFP
  - Planning Horizon
  - Load Resource Balance / Need for New Supply
- Supply Assumptions & Issues
  - Resources to evaluate in Portfolio Analysis
  - Inclusion of PGE Benchmark Resources
  - Major changes since last IRP
  - Gas prices vs. last IRP
  - Discussion: Environmental Policy
  - Discussion: Planning Horizon
- IRP Study Content and Stakeholder Review
  - Initiatives & studies PGE is undertaking
  - New topics
  - Wind Integration Study status
  - Complying with Order Conditions & Guidelines

2nd Public Meeting – August 21, 2008

- Generation Capital Costs & Technology Updates
  - Capital Cost by Technology
  - PTC, ITC, BETC
  - Technology Updates for Select Technologies
- Updates:
  - Wind Self-Integration Cost Study
  - Renewables RFP
  - Demand Side
  - Boardman BART
- PGE Load Forecast & Uncertainties
- Generation Portfolios and Futures/Scenarios

3rd Public Meeting – December 10, 2008

- Demand Side Topics
  - Energy Efficiency Resource Assessment – Energy Trust of Oregon
  - Demand Response Technical Assessment – Brattle Group
  - Demand Response RFP
  - Load Forecast Update
- Supply Updates
  - Boardman DEQ Emission Control Proposal
  - Renewable Supply RFP
  - Wind Self-Integration Cost Study
- Draft Fuel Forecasts and CO_2 Cost Outlook
- Resources
  - Benchmark Resource Descriptions
  - Draft Generic Generation Revenue Requirements
- Planning
  - Planning Metrics
  - Portfolios/Futures
- Parking Lot Issues from August 21 Meeting

4th Public Meeting: Boardman BART Analysis – April 10, 2009

- Introduction & IRP Basics
- CO_2 Costs / Price Drivers
  - Dr. Mark Trexler – DNV
- Future Technology Options
  - Ellen Petrill – EPRI
- Legislative Environment: Climate Change
- CO_2 Price Approach
- Boardman RH BART
  - RH BART (Regional Haze / Best Available Retro-fit Technology)
- Boardman Economic Analysis
- Wrap-up & Next Steps

5th Public Meeting – May 19, 2009

- Updates
  - PGE's Load/Resource Balance
  - RPS Compliance in 2015
  - Fuel Forecast
  - CO_2 Futures
  - Wind Capacity Contribution
  - Resource Revenue Requirements
- Transmission

  - Regional Situation Assessment
  - PGE's Transmission Balance
  - PGE's Participation in Regional Committees
  - BPA Network Open Season Results
  - Potential Projects
    - South of Allston
    - Overview of Southern Crossing Proposal
- Portfolio Analytical Approach
  - The Aurora Modeling Tool
  - Derivation of Electric Market Price
  - Portfolios & Futures
  - Deterministic Modeling
  - Stochastic Modeling
  - Reliability Risk Modeling
  - Proposed Decision Grid
- Remaining Schedule

6th Public Meeting – July 31, 2009

- EE Update
- CO_2 Update
- Portfolio Analysis
  - Objectives
  - Portfolio Composition
  - Portfolio Analysis Results
- Scoring Grid Results
- Boardman Portfolio Analysis
  - Required Controls & Timing
  - Emissions Controls Update
  - Impact of EQC/ BART Rule
  - Stand Alone vs. Portfolio Analysis
  - Portfolio Analysis Results
  - Primary Drivers of Uncertainty
  - Insights and Conclusions
- Proposed Action Plan
- Gas Transportation & Storage
- Remaining Schedule

7th Public Meeting

- Transmission
  - Situation Assessment
  - Regional Transmission Planning

  - Cascade Crossing Project
  - Treatment in the IRP
- Input Assumption Updates
  - Updated Gas Prices
  - Updated Coal Prices
  - EIA CO_2 Case Study Results
- Scoring Grid Update
  - Additional Metrics -
    - Deterministic: Average of Worst Four Outcomes;
    - Stochastic: TailVar90
  - Changed Metrics - HHI
- Final Proposed Action Plan

Appendix C: WECC Resource Expansion

Table C-1 details the long-term resource additions by area in the Western Electricity Coordinating Council (WECC). The period of the analysis is 2010-2040. All areas with an RPS standard contain a significant percentage of renewable resources in their incremental resource mix. Table C-2 shows resources added in the WECC by technology.

Table C-1: Resource Added by Area (Nameplate MW, 2010-2040)

	AURORA Selection	RPS	Total	RPS %
Arizona	14,305	5,112	19,417	26%
Canada-Alberta	26,955	-	26,955	0%
Canada-British Columbia	1,323		-	1,323
California+	19,697	30,621	50,318	61%
Colorado	11,479	3,118	14,597	21%
Idaho South	11,487	-	11,487	0%
Montana	1,650	641	2,291	28%
Nevada	7,630	3,710	11,340	33%
New Mexico	14,254	1,393	15,647	9%
Pacific Northwest	27,046	10,990	38,036	29%
Utah	3,078	3,978	77%	
Wyoming	1,500	-	1,500	0%
Total	138,226	58,665	196,891	30%

Table C-2: Resources Added by Technology, Nameplate (MW)

	MW	%
RPS	58,665	30%
CCCT-Gas	26,460	13%
SCP Coal	-	-
IGCC Coal	-	-
Nuclear	25,300	13%
Renewable	55,200	28%
Peakers	31,266	16%
	198,891	

Figure C-0-1 shows the WECC resources by technology in 2009 and then by 2040, after the AURORAxmp resource expansion. Capacity by 2040 nearly doubles compared to the current levels.

Figure C-0-1: WECC Resource Mix by Technology, 2009 and 2040

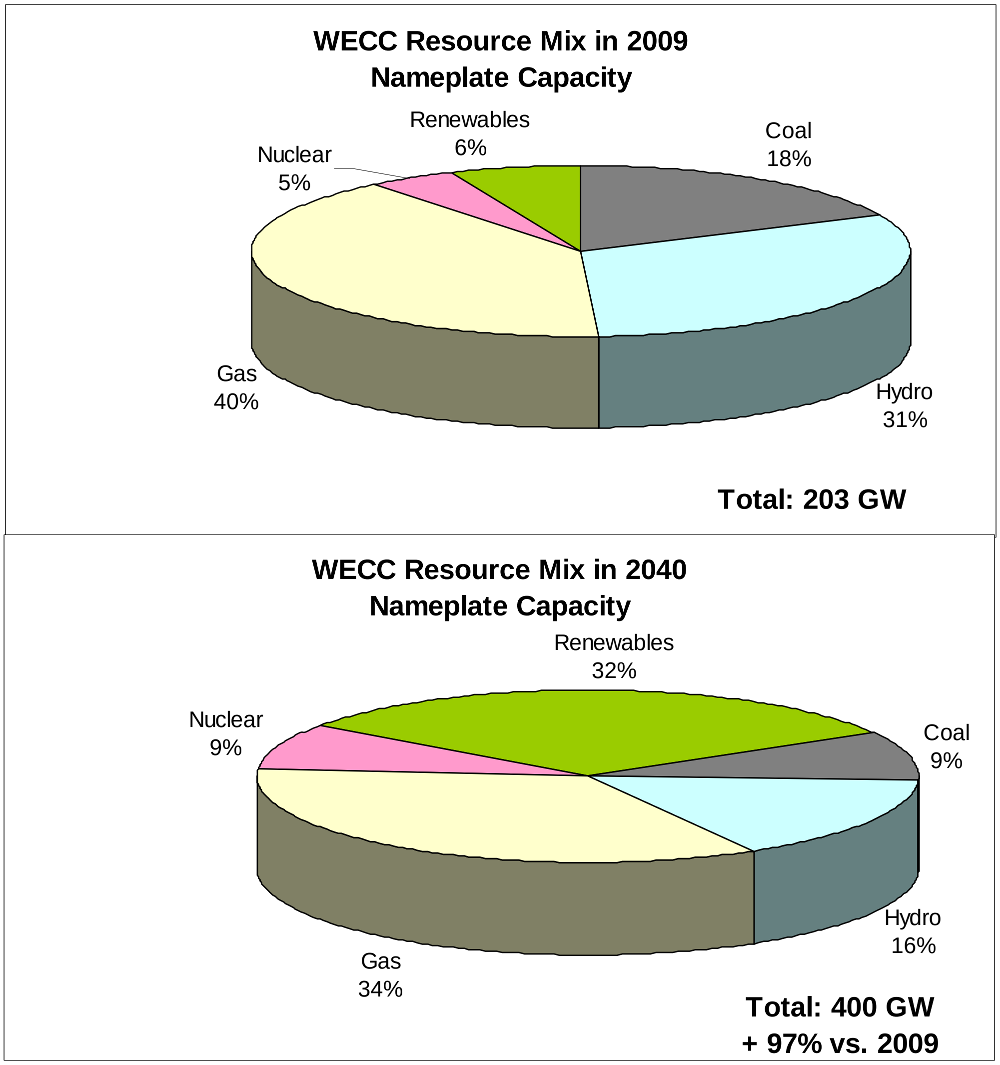


Table C-3 shows the long-term annual average electricity prices resulting from our WECC expansion in AURORAxmp.

Table C-3: WECC–Long-Term Annual Average Electricity Prices (Nominal $ per MWh)

Nominal$/MWh	AZ	AB	BC	CA-NP15	CA-ZP26	CA-SP15	CO	ID S.	Baja CA	MT	NV N	NV S	NM	OWI	UT	WY
2010	44.1	53.9	47.9	48.8	48.0	49.9	43.0	43.8	51.9	41.5	46.7	47.2	41.8	**43.3**	42.8	40.0
2011	49.7	64.3	58.8	54.7	53.9	56.0	48.4	49.4	58.8	47.3	52.8	53.0	47.3	**49.1**	48.6	45.3
2012	52.3	65.6	58.3	57.5	56.7	58.8	51.3	52.3	63.0	50.4	56.0	56.0	49.9	**52.4**	51.5	48.0
2013	62.4	90.3	74.1	67.6	66.8	69.1	61.6	62.2	72.3	60.0	66.4	66.5	60.2	**62.1**	61.5	57.2
2014	85.3	77.6	82.6	88.7	88.0	91.4	87.6	82.3	89.1	78.9	88.5	89.0	81.5	**81.8**	82.7	76.8
2015	65.7	136.9	86.2	71.1	70.2	72.7	65.5	65.8	78.5	63.7	70.3	70.2	63.7	**65.9**	65.1	60.5
2016	71.1	87.1	78.0	76.0	75.2	77.9	69.9	69.6	87.1	67.4	74.8	75.4	68.5	**69.6**	69.7	64.4
2017	75.8	77.2	76.3	79.7	79.0	82.2	74.9	73.1	96.4	70.6	78.8	79.8	73.1	**73.1**	73.8	67.9
2018	80.2	75.5	78.3	84.0	83.3	86.7	80.9	77.5	102.3	74.4	83.4	84.2	76.5	**77.2**	77.9	72.1
2019	90.5	81.8	87.7	93.3	92.5	96.1	94.0	86.9	90.8	83.5	93.6	94.0	86.6	**86.5**	87.5	81.4
2020	94.7	85.4	91.8	97.4	96.5	100.0	87.5	89.9	95.5	86.9	97.3	98.4	88.9	**90.0**	90.6	82.6
2021	99.0	87.3	96.6	102.0	101.1	104.6	93.0	94.9	96.8	91.7	102.6	103.3	92.2	**95.0**	95.2	87.4
2022	105.0	91.0	101.0	107.1	106.2	110.0	98.8	97.9	101.8	95.8	107.4	108.9	97.6	**99.2**	100.2	91.6
2023	110.8	96.3	107.3	112.5	111.4	114.9	106.1	103.8	105.9	101.6	113.5	111.5	103.3	**105.2**	105.7	97.3
2024	115.6	98.3	114.6	117.9	116.7	120.4	105.3	108.8	107.5	106.8	119.1	117.1	108.1	**110.4**	110.6	101.4
2025	122.4	104.9	122.2	123.9	122.7	126.4	112.1	115.0	107.6	113.2	125.3	123.4	114.2	**117.1**	114.4	107.2
2026	125.8	106.2	128.0	128.2	126.9	130.6	118.6	119.9	109.2	118.2	130.3	127.9	118.1	**122.2**	119.0	112.0
2027	130.7	107.0	134.8	132.6	131.1	134.6	125.9	125.2	112.9	123.5	135.5	129.1	122.7	**127.7**	123.8	117.2
2028	134.3	108.0	141.9	137.1	135.6	139.1	123.1	130.0	116.2	128.5	140.7	133.7	126.7	**133.2**	127.6	120.8
2029	139.4	110.7	153.5	141.9	140.2	143.3	130.4	136.1	119.8	134.7	147.4	136.2	131.5	**140.0**	132.8	126.2
2030	143.4	113.0	144.6	146.0	144.3	147.7	137.6	138.5	123.4	137.3	151.6	140.7	135.7	**142.7**	137.4	129.0
2031	147.1	115.4	150.6	150.5	148.8	152.4	145.9	140.5	120.3	141.8	156.3	145.4	140.1	**147.2**	142.1	131.5
2032	151.5	118.2	149.3	155.2	153.4	157.2	141.7	144.8	124.0	146.6	161.2	150.4	141.3	**152.1**	145.4	134.8
2033	154.8	121.2	156.4	160.6	158.7	162.1	150.1	151.6	121.9	154.0	168.0	155.6	141.8	**159.5**	151.5	141.8
2034	159.0	122.8	156.0	162.1	160.4	165.6	149.5	144.2	124.9	150.9	166.3	159.3	145.0	**156.6**	152.2	137.1
2035	165.2	123.8	161.7	166.5	164.7	171.2	155.8	148.5	128.9	153.8	170.9	165.0	149.6	**158.8**	158.2	141.7
2036	168.7	124.3	155.9	168.6	166.9	174.5	155.9	144.9	126.0	153.5	173.4	168.1	152.8	**157.7**	160.9	142.5
2037	173.6	125.5	159.3	172.3	170.5	179.4	158.8	149.1	123.2	157.2	178.5	172.9	157.3	**160.1**	166.6	147.4
2038	177.5	126.4	161.6	175.5	173.6	183.6	157.2	151.8	127.6	159.3	182.8	177.0	159.6	**162.0**	171.1	150.1
2039	181.2	127.9	164.2	177.4	175.7	187.6	159.5	153.5	124.4	160.1	184.3	181.0	162.0	**162.8**	174.6	152.1
2040	184.4	129.1	166.8	178.6	176.9	191.0	158.1	142.7	121.8	160.1	185.4	184.6	161.3	**162.8**	177.2	148.4
Real.lev.2009$	74.9	73.2	77.0	77.7	76.9	79.6	71.9	71.3	73.7	70.2	78.2	77.0	70.4	**72.7**	72.3	66.7

Appendix D: Portfolio Analysis Results

Table D-1 and Table D-2 below show the results of our scenario analysis. We calculated the expected Net Present Value of Revenue Requirement (NPVRR) from 2010 to 2040 for each of the 15 portfolios under each of the 21 futures.

Table D-1: Scenario Analysis Detail ($ Million)

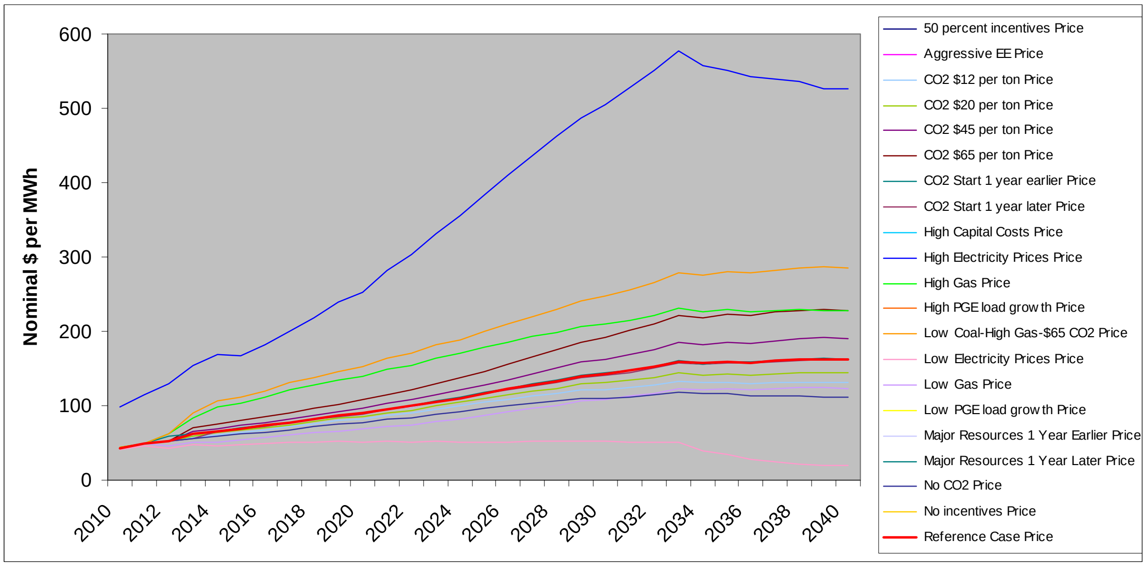
Portfolio -->>	1 Market	2 Natural Gas	3 Wind	4 Diversified Green	5 Diversified Thermal with Wind	6 Bridge to IGCC in WY	7 Bridge to Nuclear	8 Diversified Green with On-peak Energy Target
Reference Case	27,211	29,027	29,288	28,987	28,891	32,735	29,853	28,971
High Gas	34,213	35,970	34,181	34,067	35,312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

Table D-2: Scenario Analysis Detail - Continued ($ Million)

Portfolio -->>	9 Diversified Thermal with Green	10 Boardman through 2014	11 Oregon CO2 Goal	12 Boardman through 2011	13 Diverse Green with wind in WY	14 Diversified Thermal with Green w/o Boardman lease	15 Boardman through 2017
Reference Case	28,674	28,593	30,375	28,777	30,828	28,668	28,780
High Gas	35,310	36,175	35,006	36,297	35,946	35,231	36,191
Low Gas	25,012	24,517	28,141	24,730	28,002	24,958	24,800
CO2 $45 per ton	30,606	30,293	31,150	30,447	32,468	30,575	30,508
CO2 $65 per ton	33,200	32,596	32,296	32,708	34,658	33,142	32,856
No CO2	24,672	25,281	29,107	25,528	27,414	24,755	25,406
CO2 $20 per ton	27,368	27,470	29,917	27,675	29,717	27,369	27,639
High Capital Costs	29,046	29,002	34,993	29,186	31,735	29,053	29,186
High PGE load growth	31,873	31,792	33,574	31,976	34,026	31,867	31,979
Low PGE load growth	26,329	26,248	28,030	26,432	28,483	26,323	26,435
High electricity prices	27,853	26,400	23,541	26,356	26,141	27,477	26,231
Low electricity prices	21,201	21,109	26,914	21,329	24,822	21,147	21,390
No Incentives	29,356	29,275	32,046	29,459	32,488	29,350	29,462
50 percent incentives	29,015	28,934	31,211	29,118	31,658	29,009	29,121
Low Coal-High Gas-$65 CO2	39,257	39,942	36,455	40,007	39,217	39,323	40,003
CO2 Start 1 year later	28,424	28,367	30,206	28,588	30,597	28,423	28,551
CO2 Start 1 year earlier	28,933	28,832	30,560	28,975	31,066	28,923	29,022
CO2 $12 per ton	26,330	26,588	29,574	26,810	28,835	26,340	26,740
Aggressive EE	28,063	27,982	29,764	28,166	30,217	28,057	28,169
Major Resources 1 Year Earlier	28,775	28,741	30,707	28,925	31,102	28,781	28,925
Major Resources 1 Year Later	28,577	28,453	30,079	28,636	30,574	28,562	28,645

Figure D-1 below shows the electricity prices for the Pacific Northwest generated in the different futures and highlights their wide range. Aurora generates a different set of electricity prices for the WECC for the different futures described in sections 10.5 and 10.6 of the IRP.

Figure D-1: PGE Electricity Prices across Futures



Futures and therefore prices are intentionally extreme in order to capture the risk embedded in futures different from our reference case.

PGE

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC _____

In the Matter of Portland General Electric Company 2009 Integrated Resource Plan	) MOTION FOR PROTECTIVE) ORDER))

Pursuant to ORCP 36(C)(7) and OAR 860-12-0035(1)(k), Portland General Electric Company (PGE) moves for entry of the Commission's standard protective order in this proceeding. In support of this Motion, PGE states:

1. The Commission's rules authorize PGE to seek reasonable restrictions on discovery of sensitive commercial information and other confidential business information. *See* OAR 860-11-000(3) (adopting Oregon Rules of Civil Procedure ("ORCP")); ORCP 36(C)(7) (providing protection against unrestricted discovery of "trade secrets or other confidential research, development, or commercial information"). *See also, In re Investigation into the Cost of Providing Telecommunication Service,* Docket UM 351,Order No. 91-500 (1991) (recognizing that protective orders are a reasonable means to protect "the rights of a party to trade secrets and other confidential commercial information" and "to facilitate the communication of information between litigants").

2. PGE is filing a draft 2009 Integrated Resource Plan concurrent with this Motion for Approval of Protective Order. PGE anticipates that discovery in this proceeding may include proprietary cost data and models, information covered by confidentiality agreements, commercially sensitive load and resource projections and other confidential analyses. PGE will be exposed to competitive injury if it is forced to make unrestricted disclosure of its confidential business information.

3. Issuance of a protective order will facilitate the production of relevant information, aid the discovery process and expedite resolution of this case.

THEREFORE, for the reasons stated above, PGE requests entry of the Commission's standard protective order in this proceeding.

Respectfully submitted, this 5th day of November, 2009.

V. DENISE SAUNDERS

V. Denise Saunders

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **PORTLAND GENERAL ELECTRIC COMPANY'S 2009 INTEGRATED RESOURCE PLAN** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No. LC 43.

Dated at Portland, Oregon, this 5th day of November 2009.

Randy Dahlgren
On behalf of Portland General Electric Company

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Docket No: LC 43 **Docket Name:** PORTLAND GENERAL ELECTRIC

Print Sumı

Subject Company: PORTLAND GENERAL ELECTRIC

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2007 Integrated Resource Plan. Filed by Randy Dahlgren.

Filing Date: 6/29/2007 **Public Mtg:** 3/31/2008

Final Order: 08-246 **Order Signed:** 5/6/2008

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ACTIONS **SERVICE LIST (Parties)** SCHEDULE

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