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

April 9, 2010

Via Electronic Filing and U.S. Mail

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

Re: LC 48 - Addendum to PGE's 2009 Integration Resource Plan

Attention Filing Center:

Portland General Electric submits for filing in OPUC Docket LC 48 an original and ten copies of the following:

- ADDENDUM TO THE 2009 INTEGRATED RESOURCE PLAN (IRP). The Addendum includes a new preferred Action Plan based on a proposed portfolio that ceases coal operations at the Boardman plant in 2020. It retains the Action Plan submitted in our original filing as an alternate Action Plan;
- ERRATA containing corrections to spreadsheet and typographical errors identified in certain tables included in our 2009 Integrated Resource Plan; and
- MOTION TO REVISE THE PROCEDURAL SCHEDULE [PGE requests expedited treatment of this Motion.]

This is being filed by electronic mail with the Filing Center. It is also being served on the LC 48 service list.

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

Sincerely,

Randy Dahlgren
Director, Regulatory Policy & Affairs

RD/cm
Enclosures

cc: LC 48 Service List (w/enclosures)

2009 Integrated Resource Plan
Addendum

Portland General Electric Co.

April 9, 2010

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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Table of Contents

Figures

Tables

Executive Summary

PGE is filing this Addendum to its 2009 IRP to seek acknowledgment of a revised Action Plan that is based on a new preferred portfolio – Boardman through 2020.

In response to feedback from IRP stakeholder groups, and after conducting further analysis of the Environmental Quality Commission's (EQC) 2009 Regional Haze Plan for Boardman, we began analyzing a portfolio in which we would cease coal fired operations at the Boardman plant in 2020. This analysis commenced soon after submitting our IRP in November of 2009. The Boardman through 2020 portfolio allows the company to meet new environmental standards by closing the Boardman plant in 2020, twenty years ahead of schedule. As part of the proposal, the company also achieves major emission reductions with new controls and operational changes over the last decade of the plant's life.

The proposal calls for changes to the Oregon's Regional Haze Plan. Under the proposal, PGE will cut haze-causing emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from the Boardman plant by:

- Installing new, state-of-the-art burners by July 1, 2011. The new burners will make it possible to reduce nitrogen oxides the plant is permitted to emit by 50 percent.
- Using coal with a lower sulfur content to fire the plant's boiler. This will be completed in two stages as PGE's current coal supply contracts expire. An initial 20 percent drop in sulfur dioxide the plant is permitted to emit will take effect in 2011. A further reduction in 2014 will cut allowed sulfur emissions by a total of 50 percent from current permit levels.
- Closing the plant entirely in 2020, ending all plant emissions 20 years ahead of schedule and significantly reducing Oregon's greenhouse gas emissions by ending the use of coal to generate electricity in the state.

Under a separate rulemaking procedure with the Department of Environmental Quality (DEQ), PGE already has agreed to install controls that will eliminate 90 percent of the plant's mercury emissions by 2012. Current acquisition and construction schedules should allow PGE to meet this deadline a year early, in 2011.

The proposed emissions control plan for Boardman is outlined in our petition to amend the Oregon Regional Haze Plan filed on April 2, 2010 with DEQ,(BART II Petition) and further detailed in Chapters 12A and 13A of this Addendum.

While we are recommending a change to the installation of emission controls and the operations of Boardman there are no further significant changes to our IRP

Action Plan as previously filed. Our preferred Action Plan still includes significant incremental energy efficiency and new renewables, while providing sufficient energy and capacity resources via the addition of new natural gas-fired, base-load and peaking generation to maintain system reliability. In addition, we still recommend moving forward with new transmission facilities to link generation resources on the east side of the Cascades to PGE's load centers on the west side. The new transmission ("Cascade Crossing") will enable continued reliable delivery of energy from existing and potential future thermal generation. It is also targeted to reach areas where renewable resources are expected to be built, thereby increasing our access to energy which can be used to meet future RPS requirements.

PGE has spent almost two years developing, analyzing and discussing its IRP with stakeholders, including its most recent March 15, 2010 Technical Workshop regarding the Boardman through 2020 portfolio. The result of this analysis demonstrates that the Boardman through 2020 portfolio provides the best combination of cost and risk for PGE and our customers when compared to the other portfolio alternatives that we evaluated. More specifically, the Boardman through 2020 portfolio performs better than portfolios that either retain Boardman through 2040 or those that close Boardman earlier than 2020. Boardman through 2020 provides our customers substantial cost savings over earlier closure alternatives and helps assure continued reliability of supply, while mitigating long-run risks associated with greenhouse gas emissions and related compliance.

While we believe that an Action Plan based on the Boardman through 2020 portfolio provides the best option for PGE and our customers, implementation of the Boardman-related actions will require resolution of the following contingencies (i) EQC approval of our BART II Petition;(ii) resolution of pending litigation related to Boardman operations such that PGE will not be required to install controls at Boardman beyond those required under our BART II Petition; and (iii) reasonable assurance that Boardman will be compliant with forthcoming EPA National Emissions Standards for Hazardous Air Pollutants (NESHAPs) without further requirement to install additional controls at Boardman beyond those required under our BART II Petition.

PGE has been and will continue to work diligently on resolving these contingencies. However, we recognize that despite our best efforts the contingencies may not be resolved in a manner that allows us to implement an Action Plan based on the Boardman through 2020 portfolio. Therefore, we ask the Commission to acknowledge that it is prudent for PGE to move forward with an alternate IRP Action Plan, based on the Diversified Thermal with Green portfolio, should any of the contingencies not be resolved by March 31, 2011. Under the alternate Action Plan, PGE would install all emissions controls at

Boardman currently required under the Oregon Regional Haze Plan and operate the plant through 2040. Other elements of the alternate Action Plan are the same as our preferred Action Plan based on the Boardman through 2020 portfolio. The Diversified Thermal with Green portfolio also performs well considering both cost and risk, and represents the next best option for PGE and its customers if we are not able to resolve the contingencies associated with the Boardman through 2020 portfolio. In Chapter 13A, we discuss the three contingencies and the necessary timing and requirements for their resolution, and the potential costs associated with a temporary plant shut-down in the event of a delay in permitting or in ordering emissions control equipment.

This Addendum is composed of four replacement chapters to the November 2009 IRP filing. Chapters 10-13 are replaced with Chapters 10A-13A, which describe the Boardman through 2020 portfolio, provide performance analysis, and show results against the original 15 candidate portfolios. In the course of preparing this Addendum, we also incorporated various modeling amendments and enhancements for the stochastic and reliability risk analysis, as described more fully in Chapter 10A.

We believe our IRP, as modified by this Addendum, presents a resource Action Plan that provides the best combination of expected costs and associated risks and uncertainties for our customers. In order to continue to reliably meet the needs of our customers, PGE must acquire capacity and energy resource additions as soon as 2013. Given the lead times for construction of new generation and the timelines associated with moving forward with our preferred Action Plan, we request that the Commission issue an order acknowledging our IRP as soon as practical.

10A. Modeling Methodology

Addendum Note: In addition to adding a new "Boardman through 2020" portfolio, a few other analytical refinements and enhancements have been made, primarily with regard to reliability modeling. These changes are described at the end of this chapter.

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 the 2007 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 16 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.

10A.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;

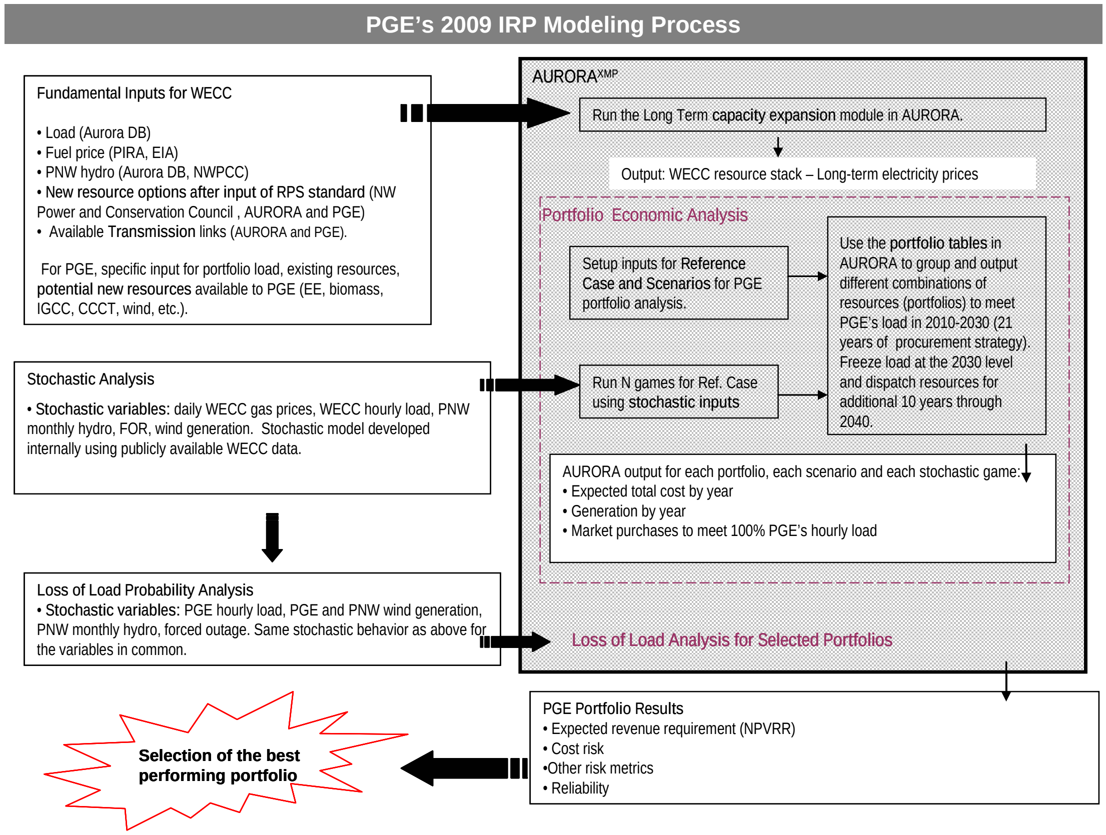
   - Combining the variable power cost from AURORAxmp with the fixed revenue requirement (capital and fixed operating costs), determined using our spreadsheet-based revenue requirement model, for each of the alternative portfolios; and

   - 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 10A-1 summarizes PGE's modeling process.

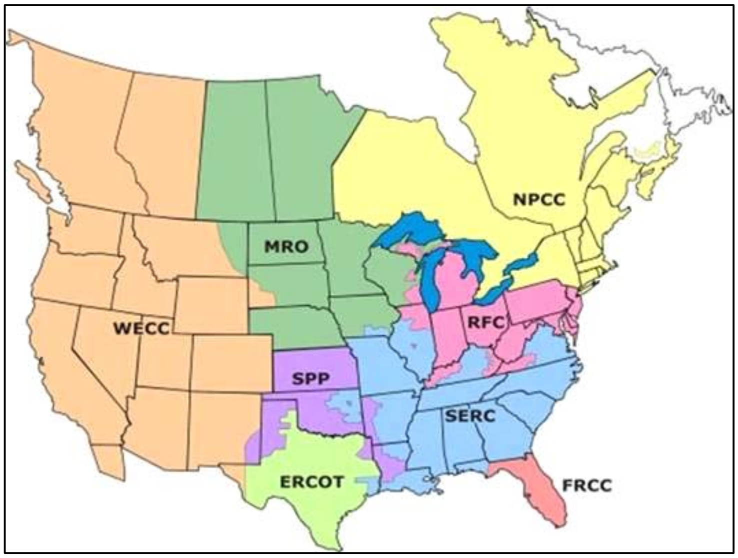
Figure 10A-1: Modeling Process for the 2009 IRP



10A.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 10A-2), which includes British Columbia, Alberta, the Pacific Northwest, California, the Southwest, Idaho, Colorado, Utah, Montana and Wyoming.

Figure 10A-2: WECC Region Map



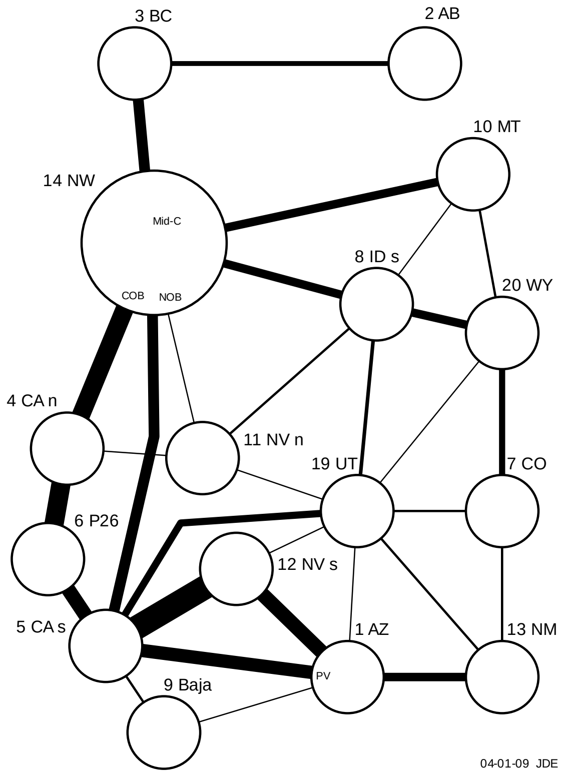
The database is subdivided by region, defined as a geographical area with no internal transmission constraints. Transmission links connect the different areas, define the import-export capability between them, and set related wheeling costs and losses.

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 database since its release.

The resulting WECC configuration is composed of 16 total zones as shown in Figure 10A-3. The thickness of the lines in the figure indicates the relative transfer capability between two zones.

Figure 10A-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 NW	Pacific Northwest
16 WY	Wyoming

10A.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 10A-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 database in AURORAxmp and validated it using our professional judgment and the advice and expertise of the NWPCC[1]. 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[2].

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 10A-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[3]		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

[1] 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.

[2] See Chapter 6 for a discussion of how we calculated the carbon tax.

[3] Oregon's first year of RPS compliance is 2011 with a 5% renewable requirement.

long-term cost of capital in the WECC. Table 10A-2 contains our other financial assumptions.

Table 10A-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 10A-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 10A-4: WECC Resource Additions

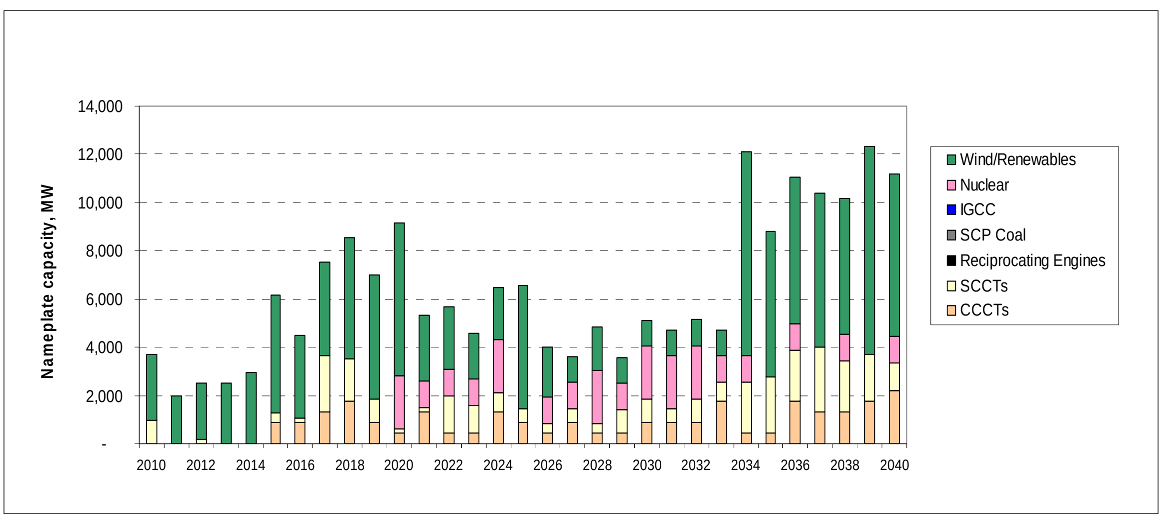
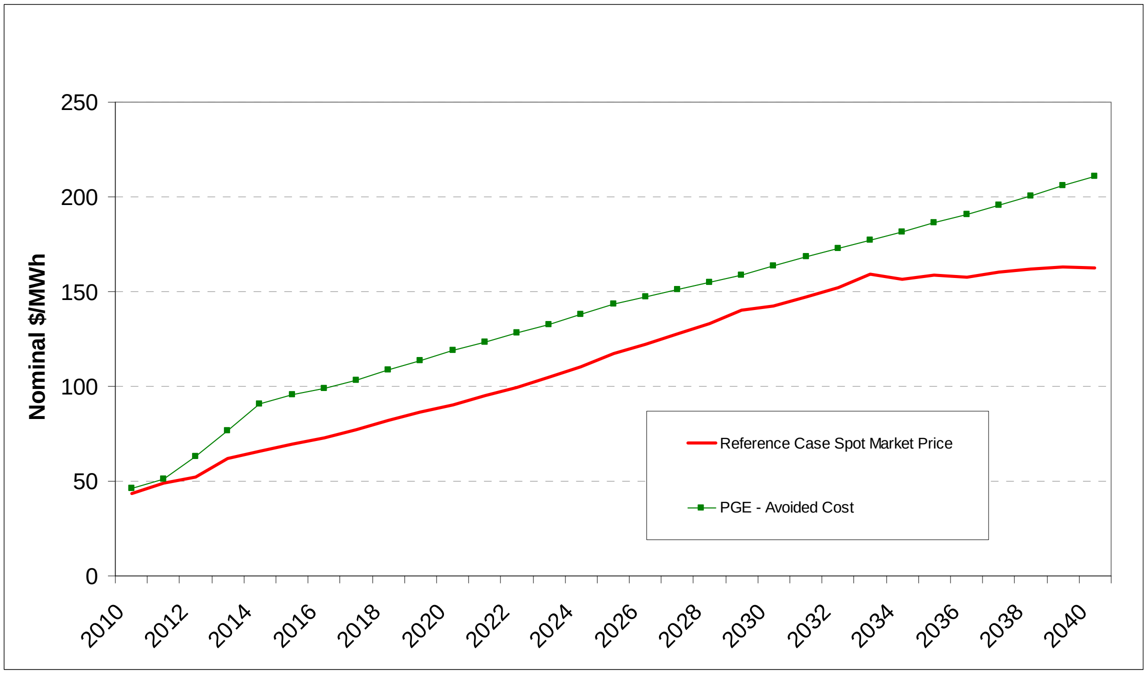


Figure 10A-5 shows the resulting average annual electricity market price projection for PGE using the reference case assumptions described in the following paragraphs. For more detail, see *Appendix C*.

Figure 10A-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.

10A.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 10A-3 below visually demonstrates this.

Table 10A-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 RPS requirements and spot electricity market purchases for the remaining need. The exception is the Boardman through 2020 portfolio. that adds a CCCT in 2021.

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.

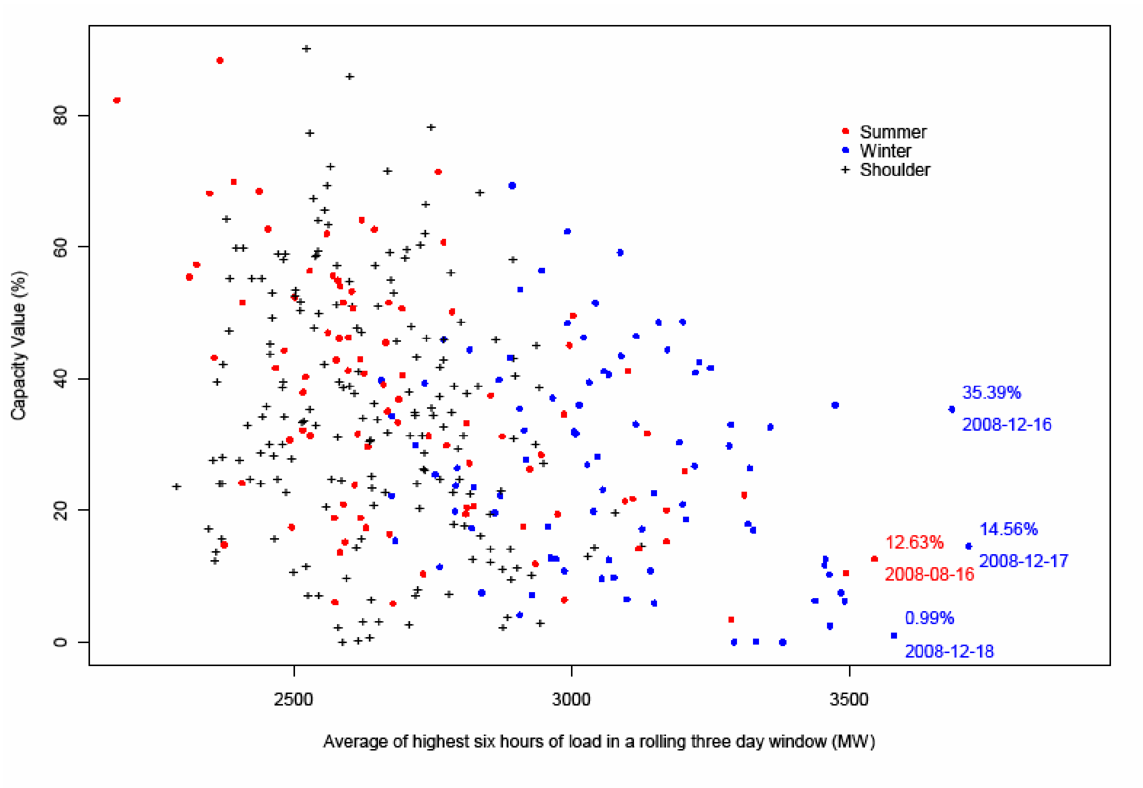
4. Dispatched the portfolios, including existing and new resources, from 2010 to 2040.

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 10A.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[4] 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 10A-6 below[5].

Figure 10A-6: Biglow Capacity Value 2008



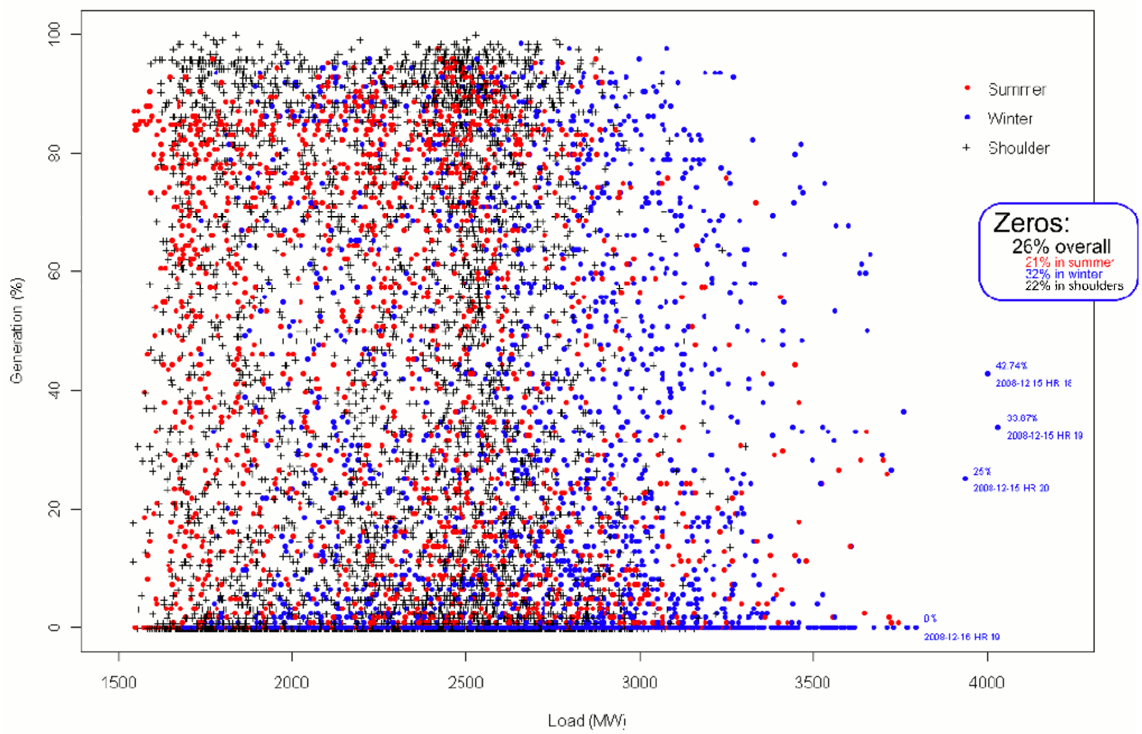
[4] Wind Task Force of the Resource Adequacy Forum

[5] 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 10A-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 10A-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 likely be 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 10A-4 and Table 10A-5 for the energy composition of our portfolios, and Table 10A-6 for the capacity composition of our portfolios.

All portfolios will have the following in common:

- PGE's existing long-term resources (including 122 MWa of Renewable Energy Standard compliant resources by 2015).

- 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 by 2012. 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. All portfolios assume that additional demand-side response starting in 2017 up to 112 MW in winter 2029.

- 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.

Portfolios that include an early closure of Boardman exclude the Boardman Bank of America lease option ("BAL" or "Lease"). These include the following portfolios: Boardman through 2011, Boardman through 2014, Boardman through 2017, Boardman through 2020, and Oregon CO_2 Compliance.

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 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, 2019 or 2020 in some 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 PPAs 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. *Boardman through 2020*. Similar to Portfolio 9, with Boardman running through 2020, (excludes Lease). We replace Boardman with a 441-MW CCCT in 2021. SCCTs are added in 2017 (52 MW) and 2019 (196 MW). A 4-year PPA is added in 2017 to balance capacity with other portfolios until a CCCT is added in 2021.

14. *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).

15. *Diversified Thermal with Green without Lease*. 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).

16. *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 10A-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	Diversified 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 Compliance	469	405	0	52	77	12	19
12	Boardman through 2011, Bridge to 2015	469	0	0	50	50	4	0
13	Boardman through 2020**	469	0	0	50	50	4	0
14	Diversified Green w/Wind in WY	469	0	405	52	77	12	19
15	Diversified Thermal w/Green, no BAL	469	0	0	50	50	4	0
16	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.

**Boardman through 2020 reflects Boardman replacement in 2021

Table 10A-5: Portfolio Composition through 2020 (continued; Energy in MWa)

#	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
		Fossil Fueled							Other	Existing Resources			
	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	Diversified 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 Targe	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 Compliance	0	0	0	0	5	0	0	623	-319	-249	0	1093
12	Boardman through 2011, Bridge to 201	406	0	406	0	5	380	-380	0	-319	0	0	1070
13	Boardman through 2020**	406	0	406	0	5	61	-61	0	-319	0	0	1070
14	Diversified Green w/Wind in WY	0	0	0	0	5	0	0	0	0	0	72	1110
15	Diversified Thermal w/Green, no BAL	406	0	0	0	5	0	0	0	0	0	0	984
16	Boardman through 2017	406	0	406	0	5	0	0	0	-319	0	0	1070

* Capacity contribution is as compared to the average energy contribution.

**Boardman through 2020 reflects Boardman replacement in 2021.

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.

Table 10A-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	0	59	543	2001
3	Wind	681	285	200	120	563	1168	1848
	Diversified Portfolios:							
4	Diversified 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 Compliance	738	285	200	163	463	1111	1849
12	Boardman through 2011, Bridge to 2015	1115	285	200	0	248	733	1848
13	Boardman through 2020**	1115	285	200	0	247	732	1848
14	Diversified Green w/Wind in WY	810	285	200	83	470	1038	1848
15	Diversified Thermal w/Green, no BAL	1055	285	200	0	309	794	1849
16	Boardman through 2017	1116	285	200	0	249	734	1849

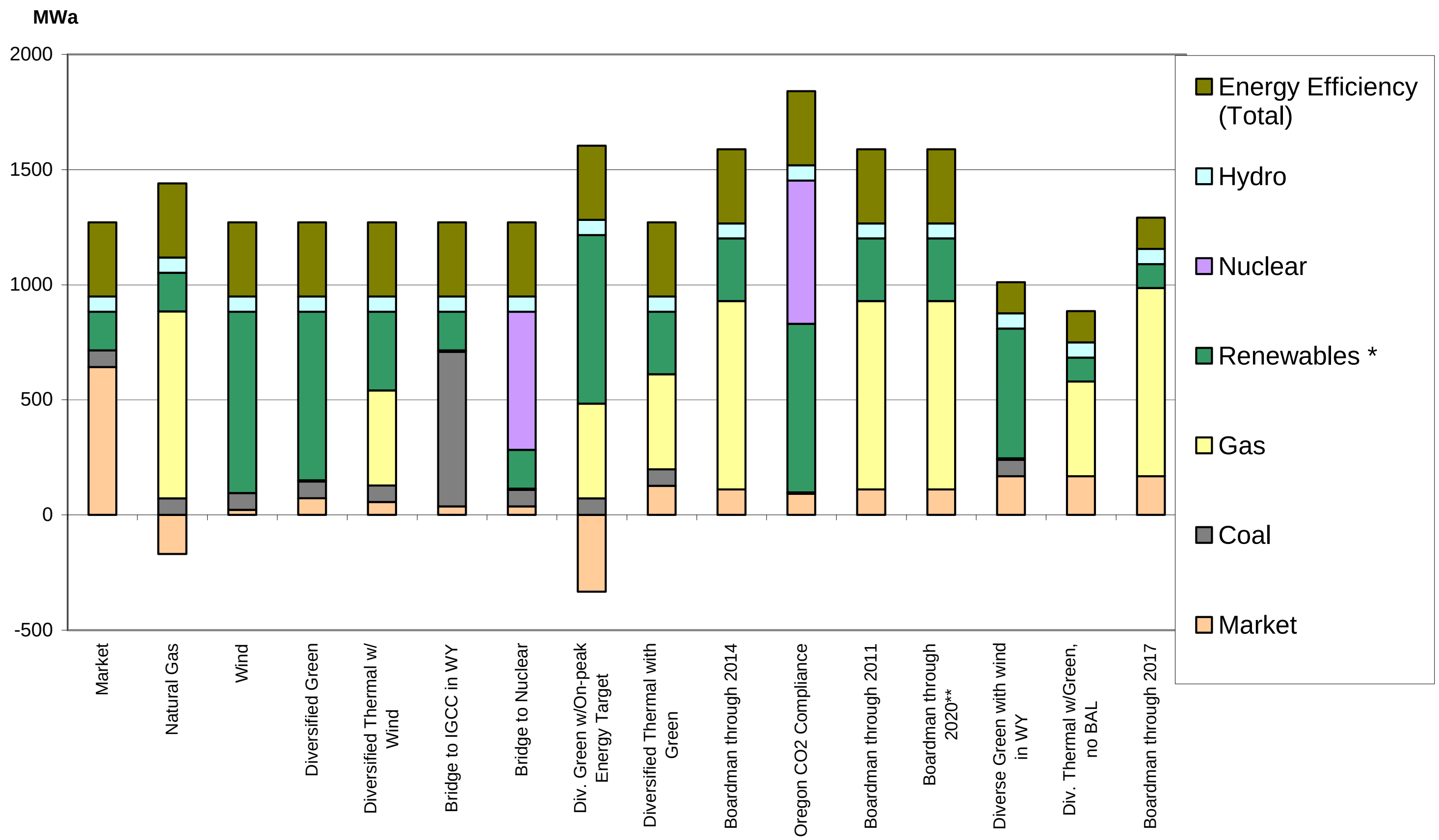
Common to all portfolios for Capacity Actions are a rollout of DR to 95 MW, DSG of 67 MW, & 123 MW of SCCTs in 2016-2019.

* Capacity contribution is as compared to the average energy contribution.

**Boardman through 2020 reflects Boardman replacement in 2021.

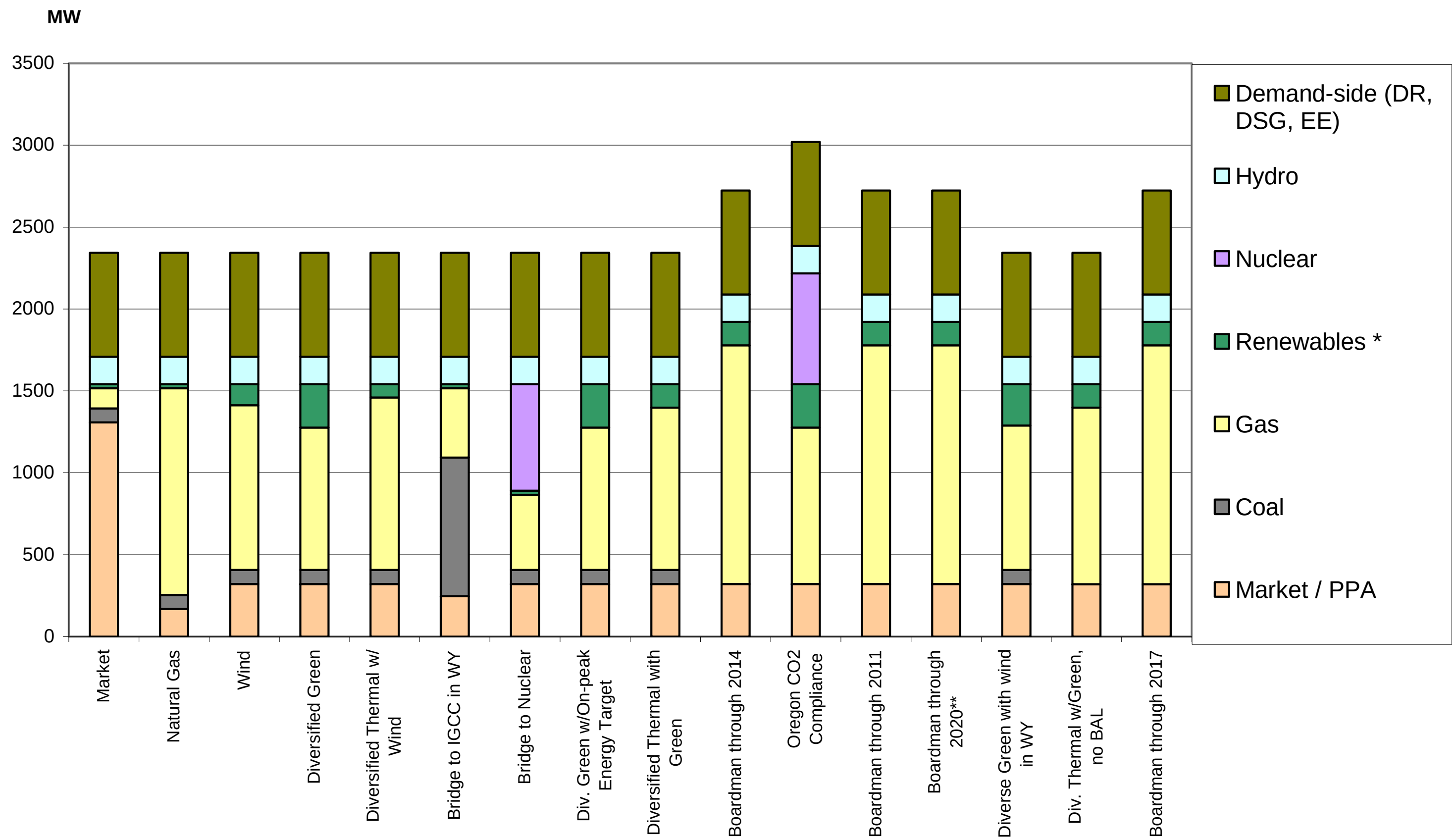
***Capacity is balanced up to 300 MW each year from the market to always meet our adequacy target.

Figure 10A-8: Portfolio Composition in 2020 – Energy Availability by Source



* Includes renewables added for physical compliance after 2016. Does not include 2008 RFP renewables
** Boardman through 2020 reflects Boardman replacement in 2021

Figure 10A-9: Portfolio Composition in 2020 – Capacity Contribution by Source



* Includes renewables added for physical compliance after 2016. Does not include 2008 RFP renewables
** Boardman through 2020 reflects Boardman replacement in 2021

10A.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 $49 per short ton (real levelized 2009$ 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 with Oregon's RPS for all candidate portfolios.

10A.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 10A.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 10A.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

Above CO_2 prices are per short ton, real-levelized in 2009 $. We also evaluate certain break-evens, such as the carbon price at which the preferred portfolio is on par with a substantially different alternative on a per MWh basis (see Chapter 11A for a description of this trigger point 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.

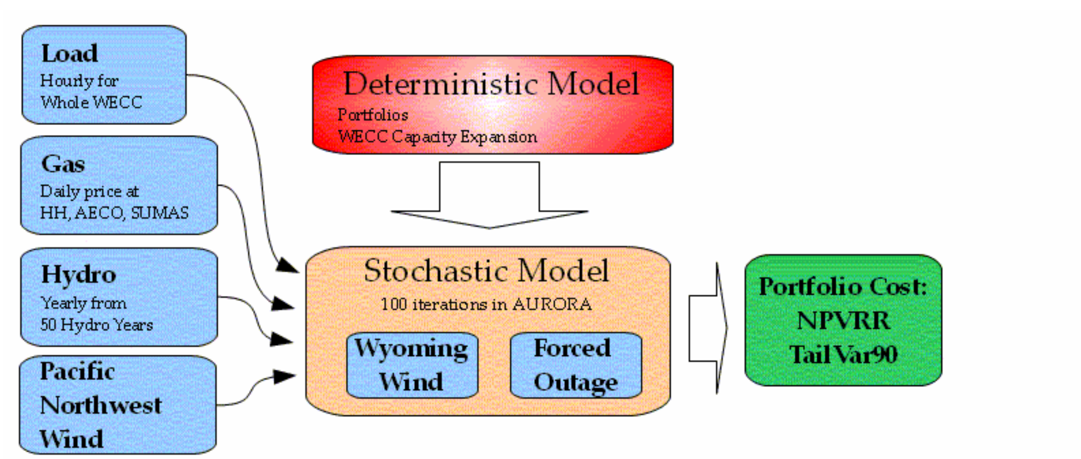
We consider a higher load growth future to be a good proxy for a high plug-in hybrid electric vehicle future.

10A.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 10A-10 for a diagrammatic representation of this process.

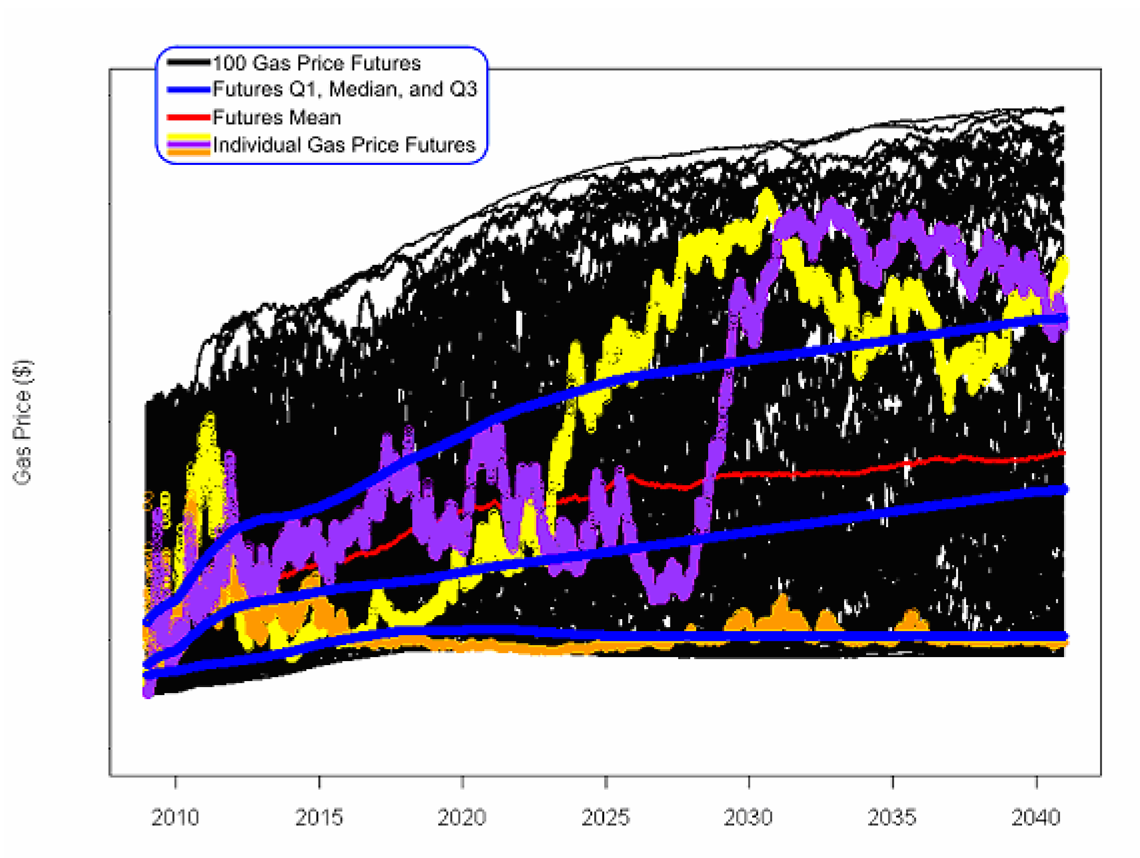
Figure 10A-10: Stochastic Inputs



Gas Price

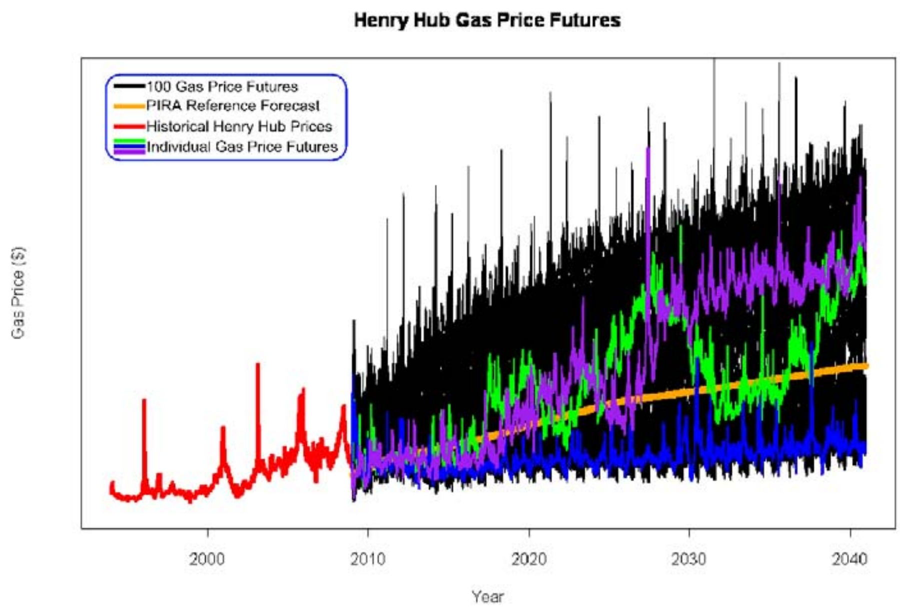
Gas prices are generated on a daily basis for Henry Hub. From this price we calculate the price at AECO and SUMAS as a basis spread from Henry Hub. These basis spreads are based on the latest PIRA forecast of future price differentials in the respective hubs and are kept constant over time. Long-term 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 10A-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 10A-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 10A-12. Individual futures are highlighted in green, purple, and blue, with the long-term average gas price shown in orange.

Figure 10A-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 AURORAxmp 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 AURORAxmp 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, AURORAxmp 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 10A-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 10A-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 10A-13: Histogram of PGE Load

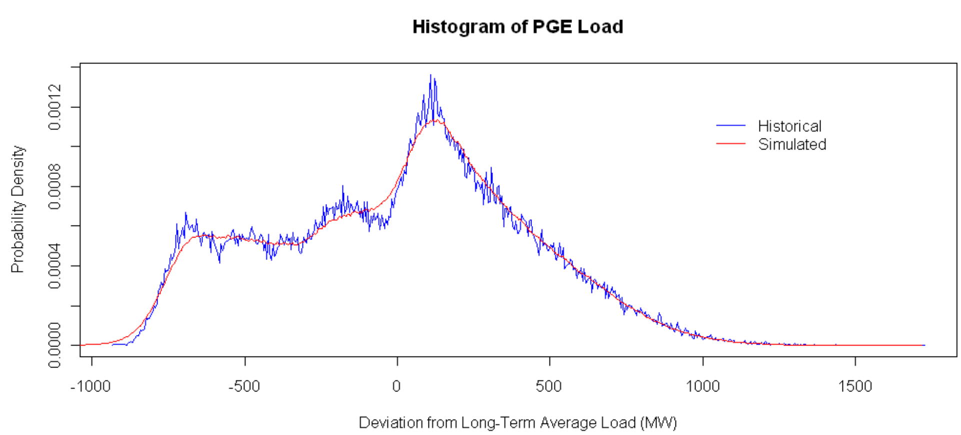
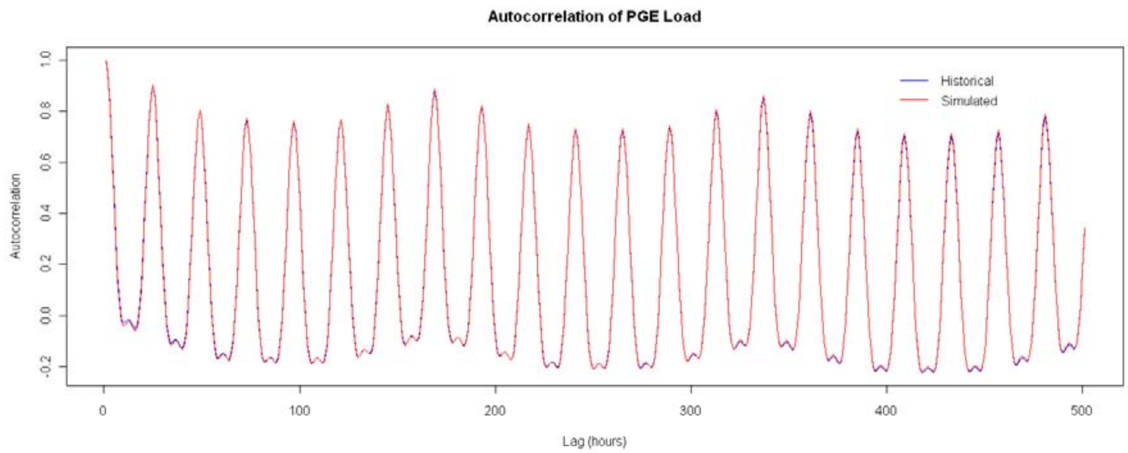


Figure 10A-14: Autocorrelation of PGE Load



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[6]. We input these water years into the 12 AURORAxmp areas covering the Pacific Northwest and western Canada. Each area is 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. AURORAxmp simulates this internally by sampling from a distribution based on plant- or resource-specific Forced Outage Rates (FOR) and Mean Time to Repair (MTTR).

[6] 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.

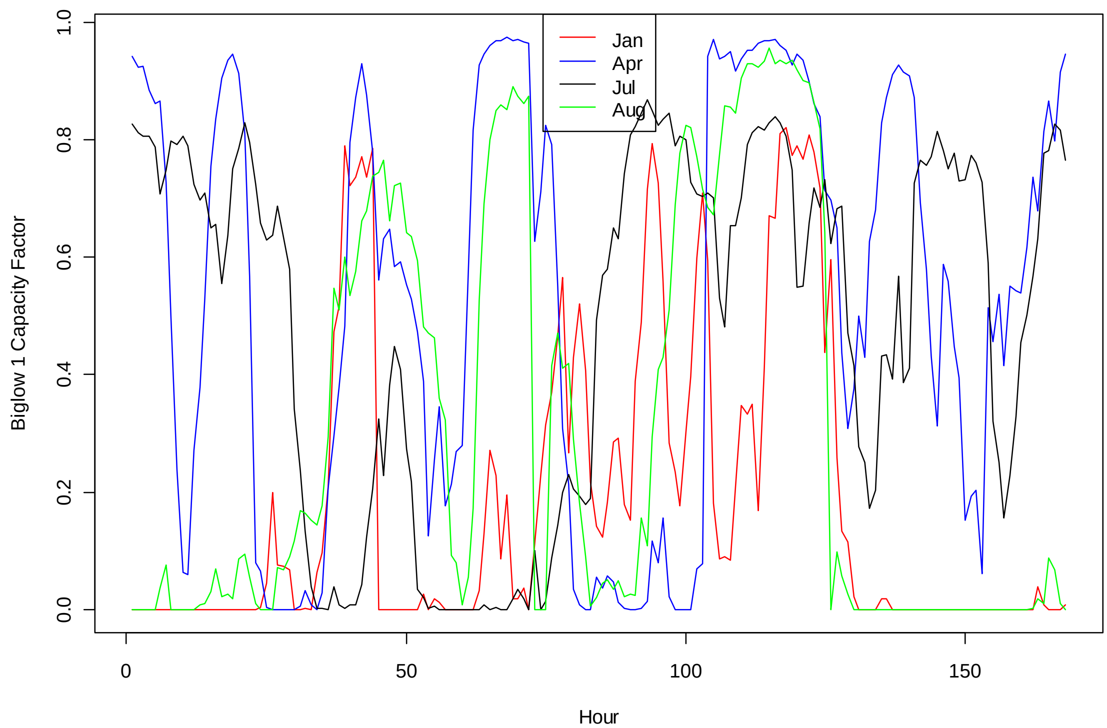
For modeling purposes, we use the same FOR as the deterministic analysis, and specify a MTTR for each of PGE's plants based on the North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS). These data were used to provide a broad base of experience and history for each plant, rather than relying on the relatively small sample of MTTR observed at PGE's plants.

The AURORAxmp 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 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 10A-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 10A-15: Simulated Hourly Biglow Capacity Factor



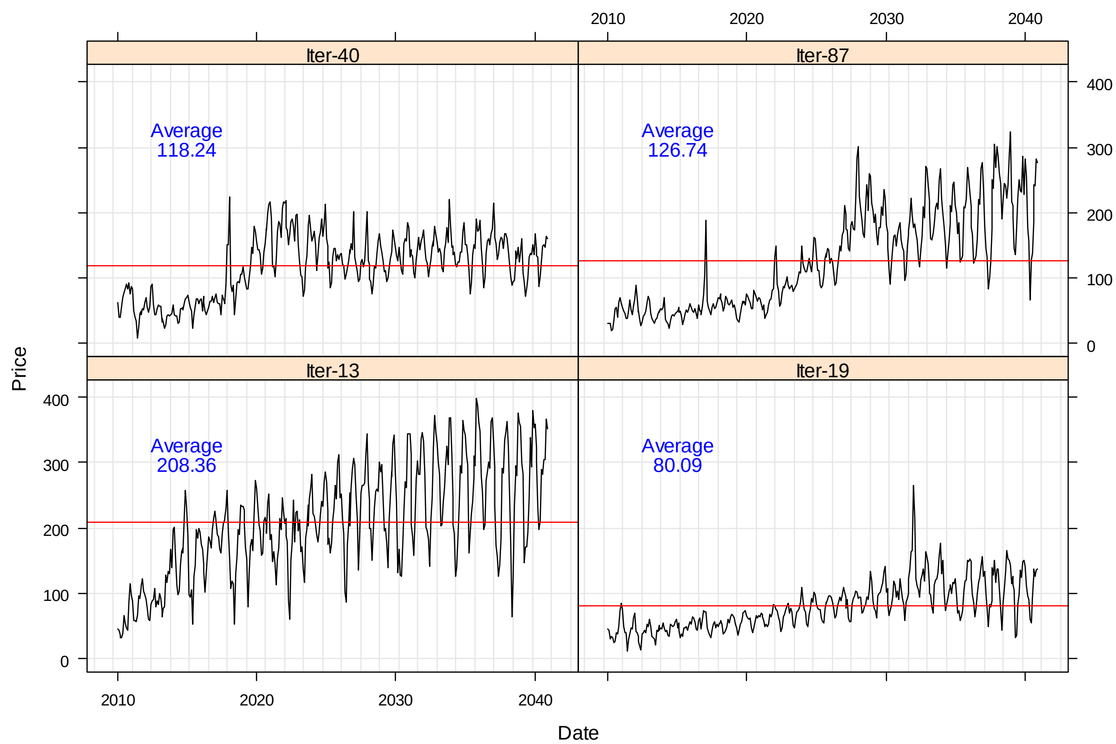
For PGE's potential wind projects outside of the Pacific Northwest, data sufficient to allow the implementation of an hourly wind simulation does not exist. For the purposes of this IRP, wind outside the Pacific Northwest is modeled using monthly capacity factors supplied by the NWPCC. Absent detailed 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, AURORAxmp is run to produce a market-clearing electric price in each hour of the year for each zone of the AURORAxmp 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 10A-16: illustrates four iterations of resulting AURORAxmp electric prices.

Figure 10A-16: AURORAxmp 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.

10A.8 Loss of Load Probability Analysis Methodology

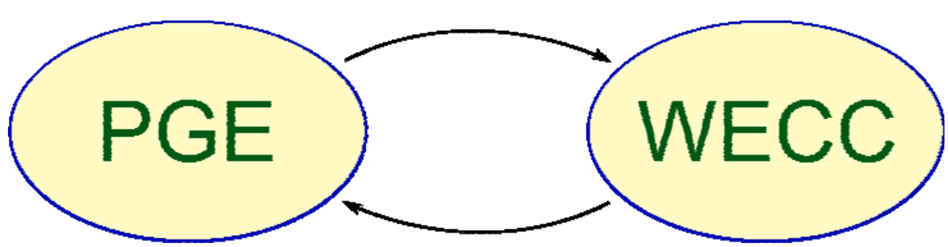
Guideline 11 of OPUC Order No. 07-002 requires PGE to analyze supply reliability within the risk modeling of the supply portfolios we consider. To do this, we use three related metrics for each portfolio with two goals: first, to provide a relative ranking of the portfolios on a reliability basis; second, 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 10A-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 10A-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.

10A.9 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:

$$HHI = s_1^2 + s_2^2 + s_3^2 + \ldots + s_n^2$$

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.

10A.10 Portfolio Scoring

The following sections describe our combined scoring methodology for assessing portfolio performance.

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 21 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 expressed in units of squared dollars.

7. *Portfolio Reliability*. Of the three reliability metrics described earlier in this chapter (see Section 10A.8), the best metric for reflecting how much load is at risk of not being met is TailVar Unserved Energy (UE). 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[7], for each portfolio. Portfolios with lower TailVar UE will be preferred.

8. *Technology and Fuel Diversity*. Diversification is a well studied and practiced method for reducing non-systemic or asset specific risk in a portfolio. For an electric utility resource portfolio, diversification can also reduce exposure to potential extreme adverse outcomes resulting from changes in future circumstances and cost drivers. 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 2021[8]. We also look at the HHI based on a snapshot of relative technology concentrations as measured by capacity in the year 2021. 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 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 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

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[7] 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.

[8] *ibid*.

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 candidate portfolios 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 for identifying top performing portfolios for potential inclusion as part of the resource action plan.

Chapter 11A 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. Since 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.

10A.11 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

10A.12 Changes from the Filed IRP

The primary purpose of this Addendum is to present the results of a new candidate portfolio, "Boardman through 2020", which discontinues coal-fired operations at Boardman after 2020. That portfolio is detailed in section 10A.4 above. We did not update other data inputs (e.g. loads, fuel prices) or modify futures. Hence, the NPVRR and scenario-based deterministic risk results from the original portfolios are unchanged from our original filing. This allows for a straight-forward comparison of the performance of the new Boardman through 2020 portfolio to the pre-existing portfolios.

We also made some changes and corrections to modeling methodology and algorithms. These changes were presented at our March 15, 2010 technical review workshop. Specifically, the following modeling adjustments have been applied:

- For both stochastic and reliability modeling, in addition to treating our Biglow wind generation as a probabilistic variable input, we added similar stochastic treatment for our existing Vansycle and Klondike II plants and for future RPS compliance wind. (Previously, these resources were treated as flat blocks of energy based on expected monthly capacity factors.) This increased wind output variability in all portfolios.

- For stochastic modeling, we changed gas price inputs from real dollars to nominal dollars. For typical AURORAxmp analysis, the model requires price inputs to be in real dollars, however, upon further investigation we determined that the risk engine in AURORAxmp requires nominal dollar inputs. The overall effect within the stochastic analysis was to make gas-intensive portfolios somewhat more volatile.
- Also for stochastic modeling, we changed how we combine variable power costs from the AURORAxmp runs with fixed costs, as the prior approach did not capture all fixed costs. While fixed costs are not treated stochastically, the change allows for a better comparison of deterministic NPVRR results to the mean stochastic NPVRR results, but has very limited impact to stochastic portfolio results.
- For reliability modeling, we improved on earlier results by:
  - Adjusting our Expected Unserved Energy (EUE), TailVar 90 Unserved Energy (TailVar UE) and LOLP calculations (described in Section 10A.8) to capture the forced outages from the AURORAxmp output. (During results validation we realized that the Auorora output we were using overstated the level of forced outages.) The effect was to more consistently rank portfolios dominated by small shafts and/or lower forced outage rates ahead of portfolios dominated by large shafts and /or higher forced outage rates. Thus, for instance Boardman early closure portfolios cluster together and consistently perform well.
  - Assigning Purchased Power Agreements (PPAs) a forced outage rate equivalent to a CCCT, where previously they were treated as always available. This change recognizes that PPAs are often tied to specific generating units and contract delivery terms and conditions vary. The effect is to provide PPAs with the same reliability exposure that CCCTs exhibit.
  - Setting thermal plant scheduled maintenance to zero so that it does not contribute to EUE, as we assume that power will be purchased

well in advance for a planned maintenance outage. (This adjustment is not necessary for multi-shaft generators where maintenance occurs on an ongoing and continuous basis, e.g. wind project.) The effect is to improve the reliability of thermal units.

- Explicitly modeling wind "capacity value" at 5% of nameplate. This was done by setting the output of a wind plant to 5% during the eight "super-peak" hours in the peak load months of December, January, July and August. (Our original approach modeled the wind capacity contribution as though it were 100% of the expected net capacity factor during such super-peak hours.) This change results in a capacity contribution for wind during super-peak periods that is consistent with our overall IRP assumption of 5%.
- Adjusting dispatch parameters on PGE thermal plants to avoid unrealistically frequent cycling of base-load resources. This improves reliability for all portfolios.

Because the new Boardman through 2020 portfolio has a major new resource proposal for January 1, 2021, we also modified scoring metrics and charts that were previously based on year-end 2020 values to 2021 in order to capture the impact of the new portfolio. Because the prior portfolios had no resource addition differences after 2019, changing our look from 2020 to 2021 has no differential impact among the other portfolios.

11A. Modeling Results

The following chapter presents the results of our analysis and modeling, as well as our conclusions. This replacement Chapter 11A incorporates evaluation of the new "Boardman through 2020" portfolio and also includes a limited number of amendments and enhancements to our stochastic and reliability analyses, as described in Chapter 10A.

As discussed in Chapter 10A, 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 the prior chapter 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 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 $67 per short ton.
- Our preferred Action Plan is based on the "Boardman through 2020" portfolio. Our alternate Action Plan is based on the "Diversified Thermal with Green" portfolio.

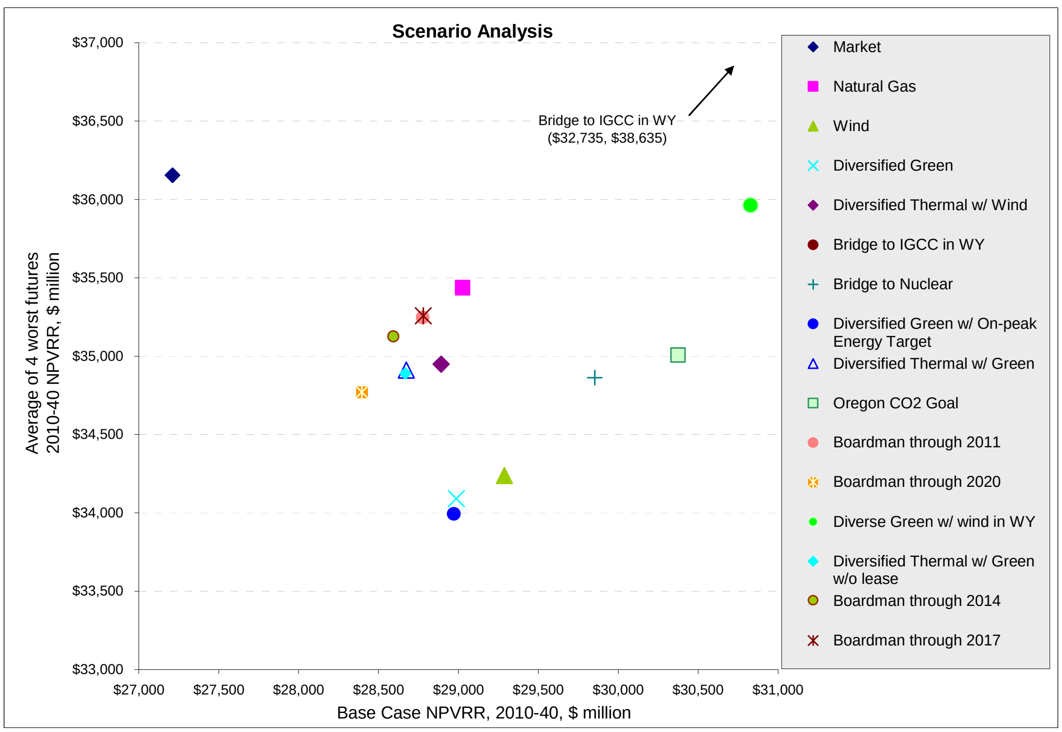
11A.1 Deterministic Portfolio Analysis Results

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 10A, along with existing PGE resources, across 21 potential futures also described in that chapter. (see also *Appendix D- Addendum* for the NPVRR results for each combination of portfolio and future). 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 11A-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 11A-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 11A-1: Efficient Frontier – Risk vs. Cost 2009$



We note the following general insights from Figure 11A-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 11A-2 ranks the portfolios in order of expected cost. Based <u>solely</u> on this cost metric, Market, Boardman through 2020, 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 – see Figure 11A-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, Wind, and the Bridge to Nuclear portfolios. In this metric, early Boardman closure portfolios fare poorly due to their increased gas exposure, although Boardman through 2020 performs best within this group.

Figure 11A-2: Portfolio Reference Case Expected Cost 2009 $

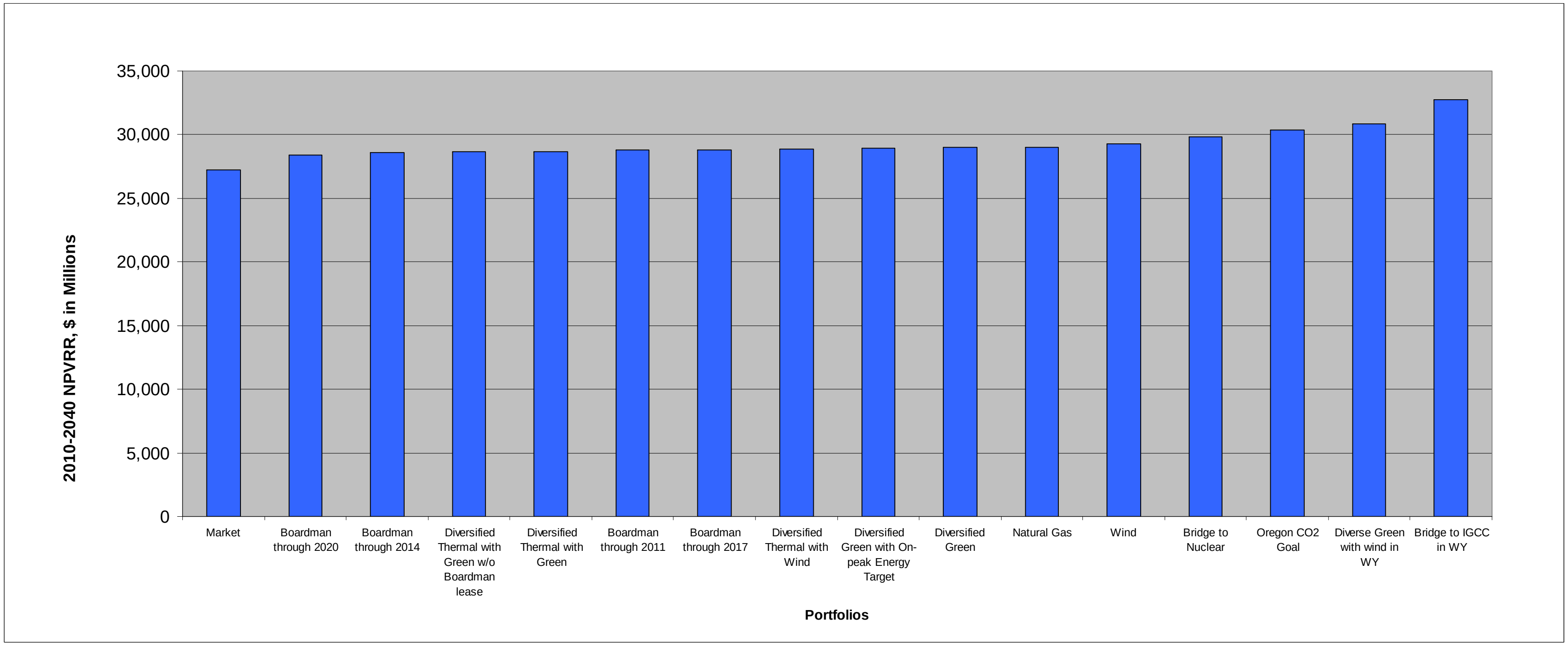


Figure 11A-3: Average Cost of Four Worst Futures less Reference Case 2009 $

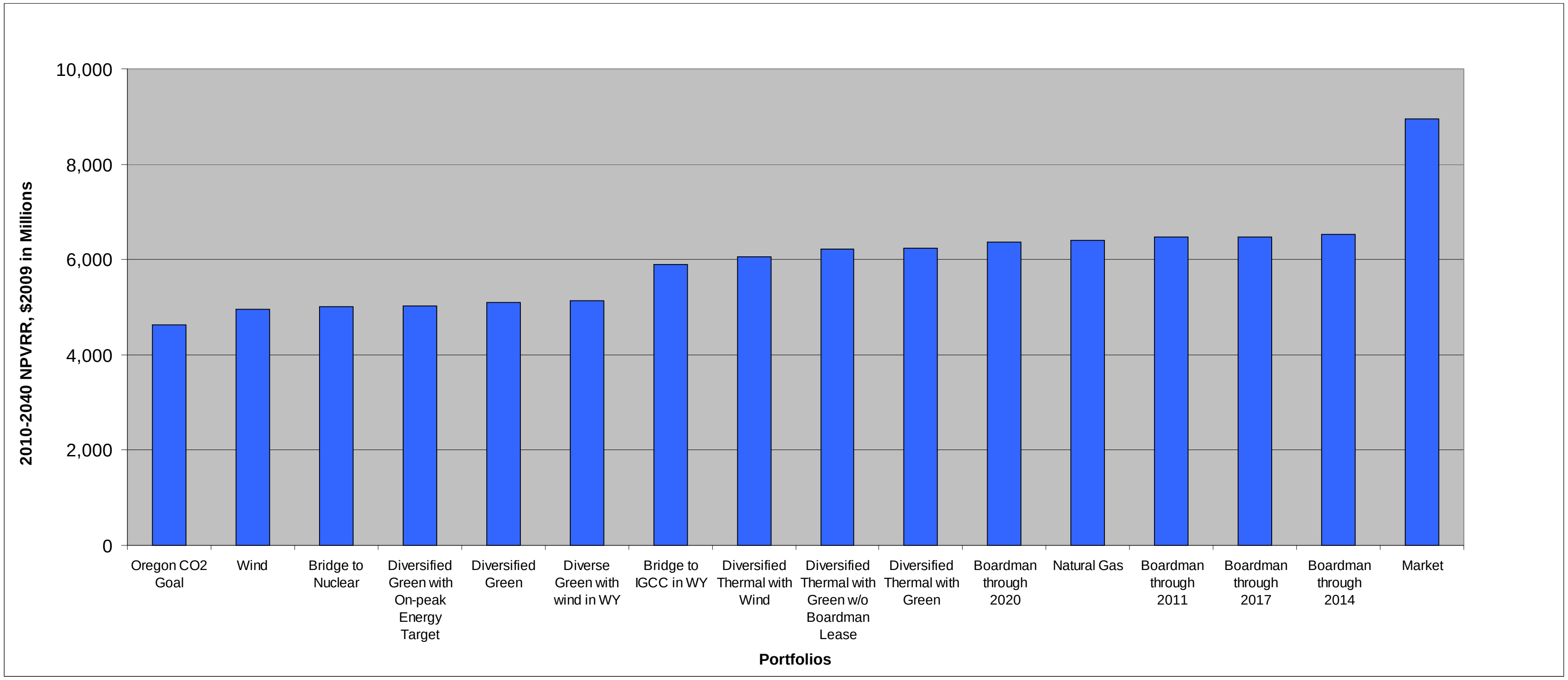
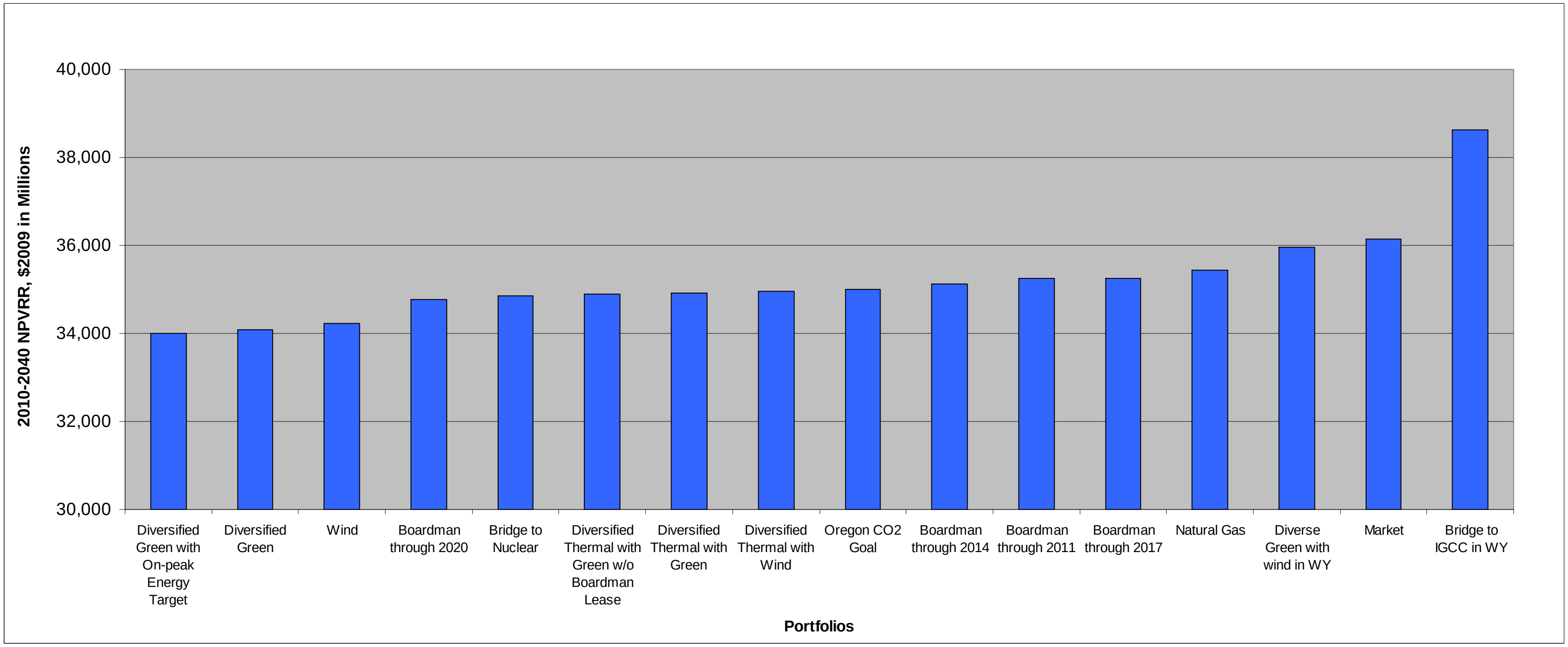


Figure 11A-4: Average Cost of Four Worst Futures 2009$



Our third scoring criterion is a variation suggested by OPUC Staff and is used to plot the Y-axis of the efficient frontier graph (Figure 11A-1). 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.

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, with some exceptions, portfolios that perform well on the first metric score well on the second, and vice-versa. A notable exception is the Boardman through 2020 portfolio, which improves substantially when looking at absolute cost risk rather than potential change in cost from the expected case.

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 16 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 11A-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 11A-6 displays the probability of *best* performance, that is, the probability that a portfolio is among the best four out of the 16 portfolios tested against the 21 futures. Finally, Figure 11A-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. Disregarding the Market portfolio, which performs very poorly on reliability metrics, the top-performing portfolio is Boardman through 2020.

Figure 11A-5: Portfolio Probability of High Expected Costs

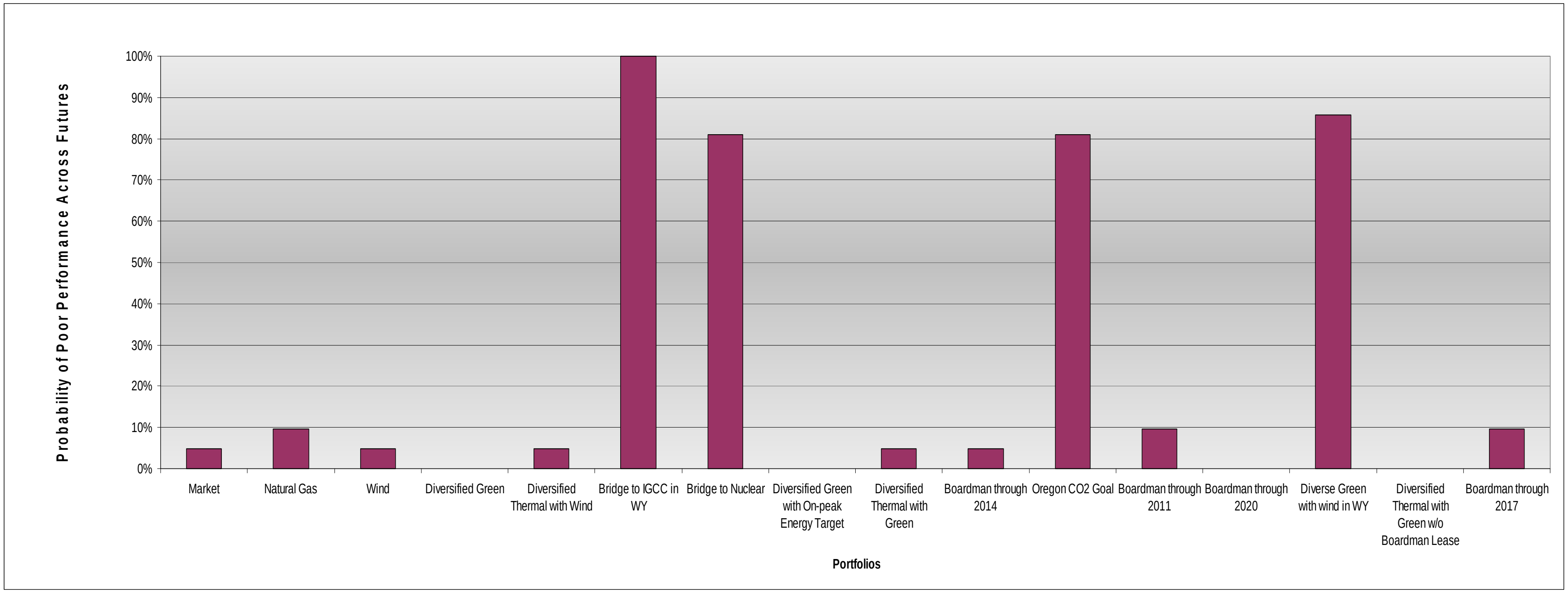


Figure 11A-6: Portfolio Probability of Low Expected Costs

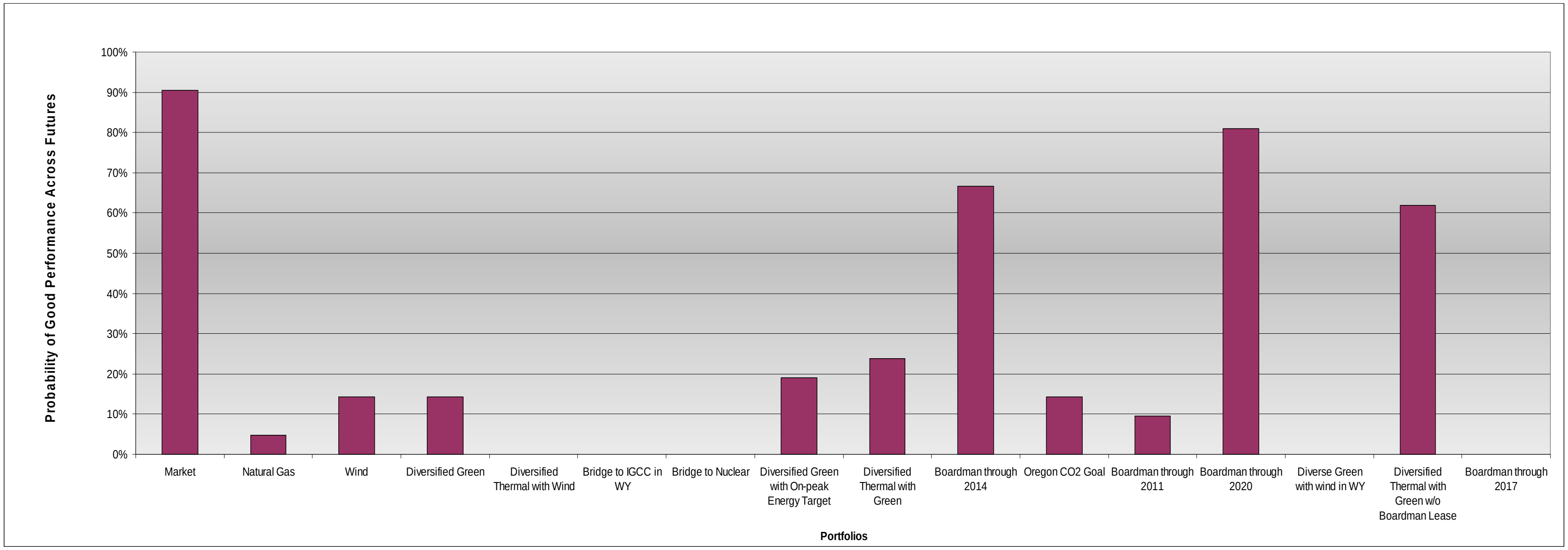
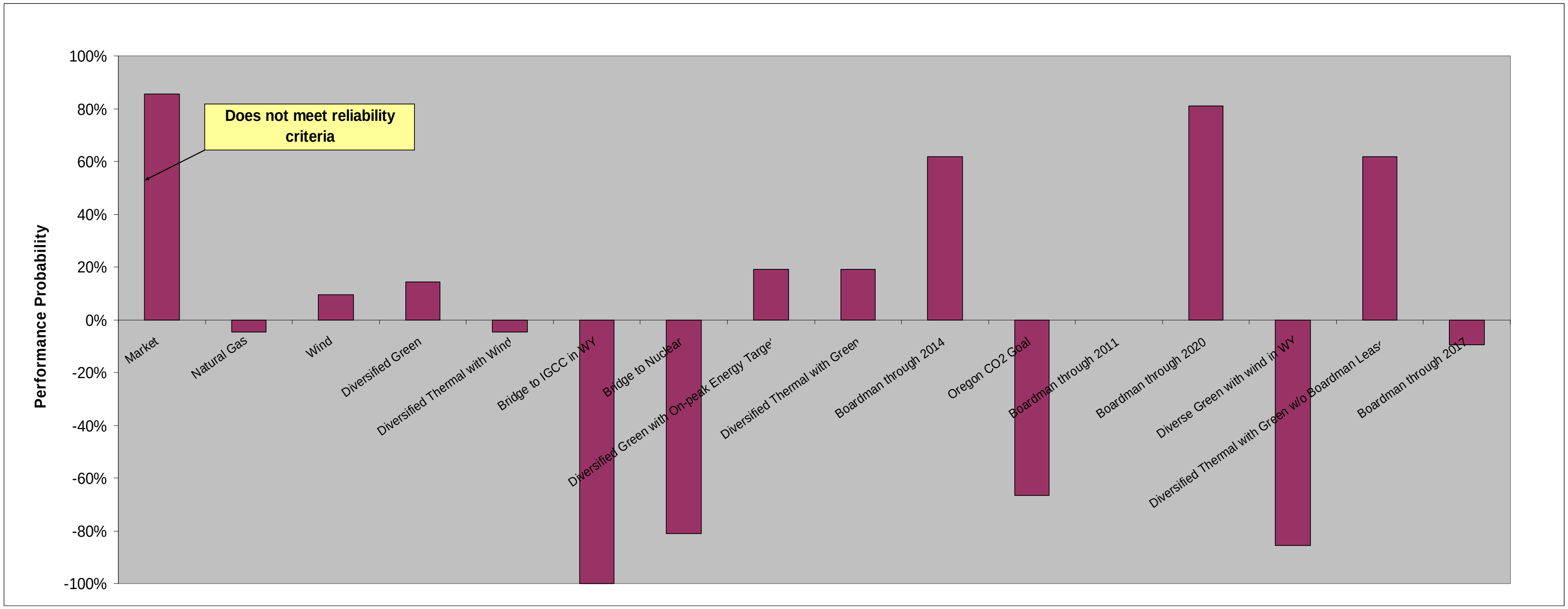


Figure 11A-7: Portfolio Probability Combined Results – Achieving Good Outcomes & Avoiding Bad Outcomes



11A.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 11A-1 presents a few of the major relationships among the stochastic variables.

Table 11A-1: Summary Statistics of Stochastic Analysis 2010-2040 (Nominal$)

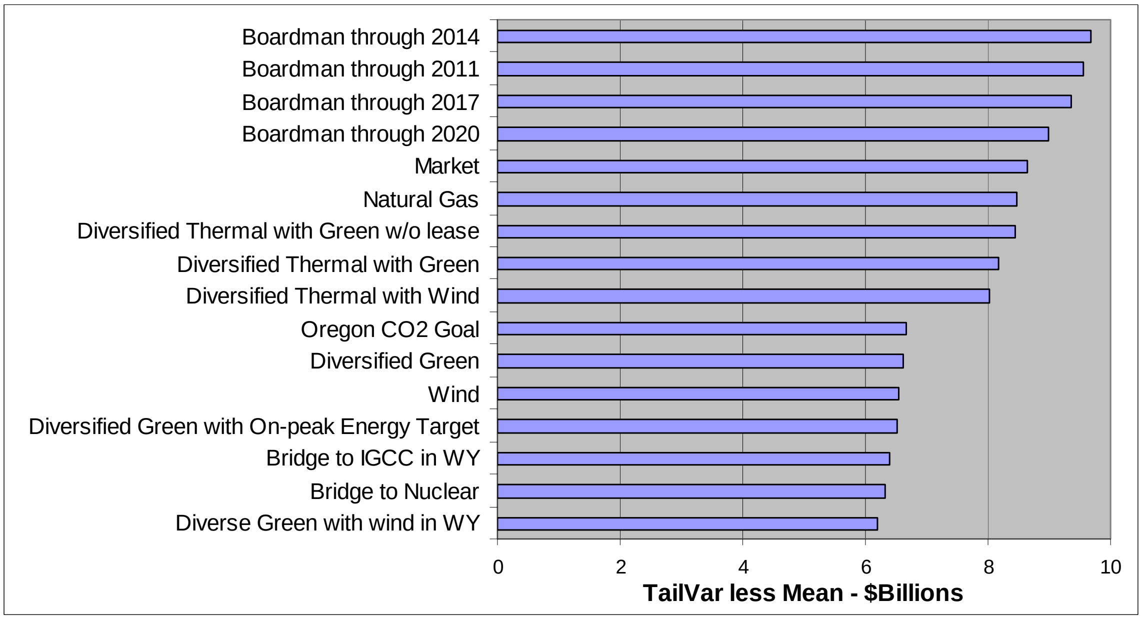
	PGE Electricity Prices Nominal $/MWh			**Sumas Gas Prices Nominal $/MMBtu**		**AECO Gas Prices Nominal $/MMBtu**	
	Base Case	**Stochastic**		**Base Case**	**Stochastic**	**Base Case**	**Stochastic**
Mean	$108.8	$127.8		$12.1	$14.7	$11.6	$14.2
Standard Deviation	NA	0.21		NA	0.11	NA	0.11
Annualized Volatility (%)	NA	72.5		NA	38.9	NA	38.9
Correlations :							
		Maximum	Mean	Minimum			
PGE Electricity Prices vs. Henry Hub		0.54	0.36	0.17			

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

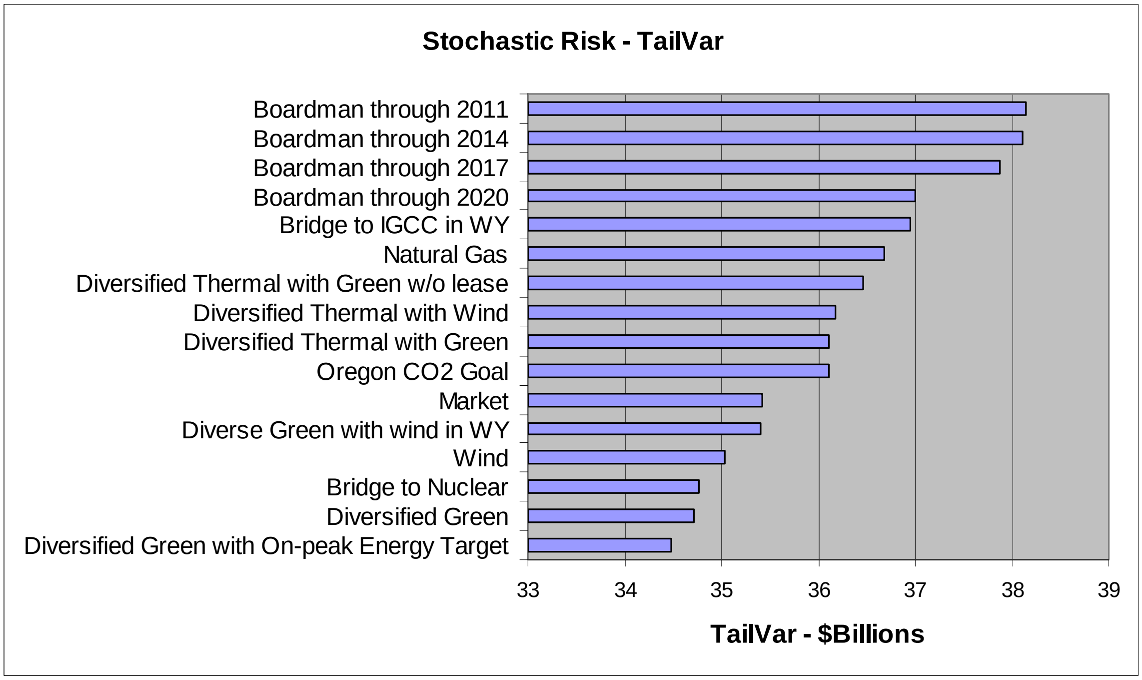
The first stochastic metric looks at the performance of the portfolios using stochastic inputs for the five risk variables described above. Based on 100 iterations, we take the TailVar90 of the 31-year NPVRR cost distribution less its mean. The metric receives 3.33% of our total score. Portfolios with larger natural gas concentrations fare poorly, while portfolios with reduced exposure to natural gas and electricity market prices generally perform better. Figure 11A-8 shows portfolio performance. With this metric, portfolios with a lower dollar amount for the TailVar 90 score higher.

Figure 11A-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 11A-9 below is a graphical representation of the portfolio TailVar results.

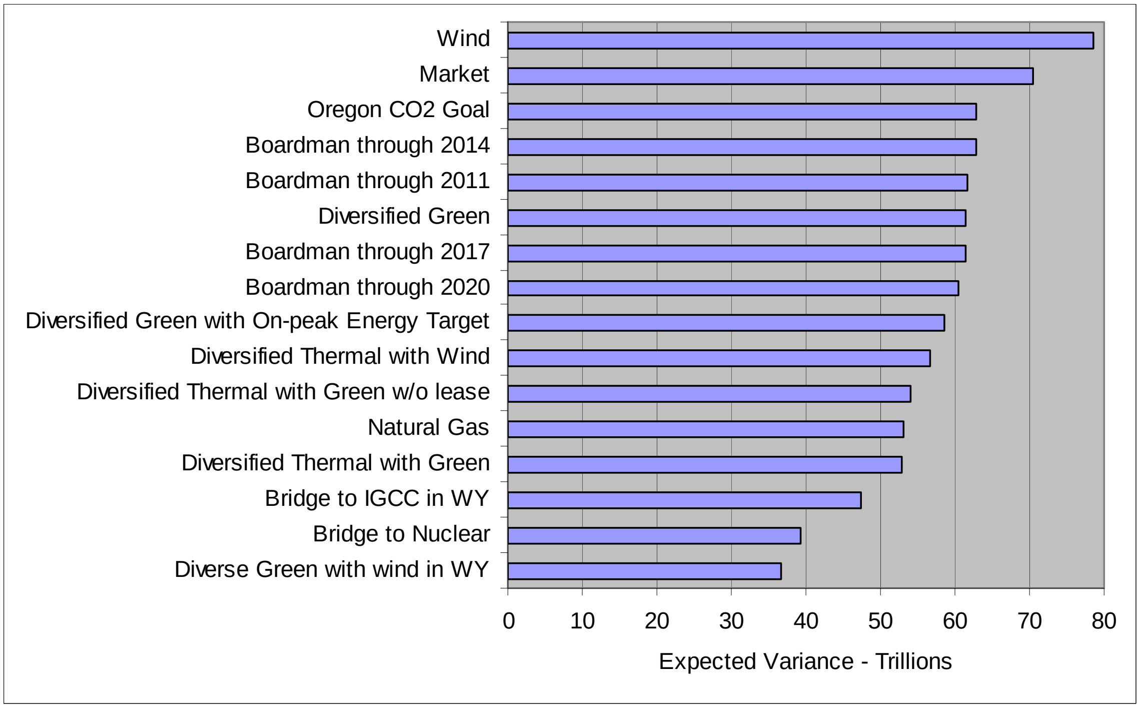
Figure 11A-9: TailVar 90



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 11A-10 below.

Figure 11A-10: Year-to-Year Portfolio Average Variation



Effect of Addendum Enhancements

As discussed in Chapter 10A, the stochastic model results presented in this Addendum reflect changing gas prices from real to nominal dollars, using stochastic wind generation for Klondike II, Vansycle and RPS-compliant Wind, and using fixed costs directly from the deterministic model in the stochastic analysis.

Compared to our November filing, these changes in the stochastic analysis do not materially alter relative portfolio ranking, when combined with the other metrics, of our top portfolios. However, the year-to-year variance for all portfolios increases as a result of changing to nominal gas prices, with gas-intensive portfolios naturally increasing relatively more.

Regarding the two stochastic TailVar metrics, although the absolute values of the metrics have increased, the better and worse portfolios remain largely unaffected, while the portfolios in the middle undergo some generally small ranking shifts.

11A.3 Reliability and Diversity Analysis Results

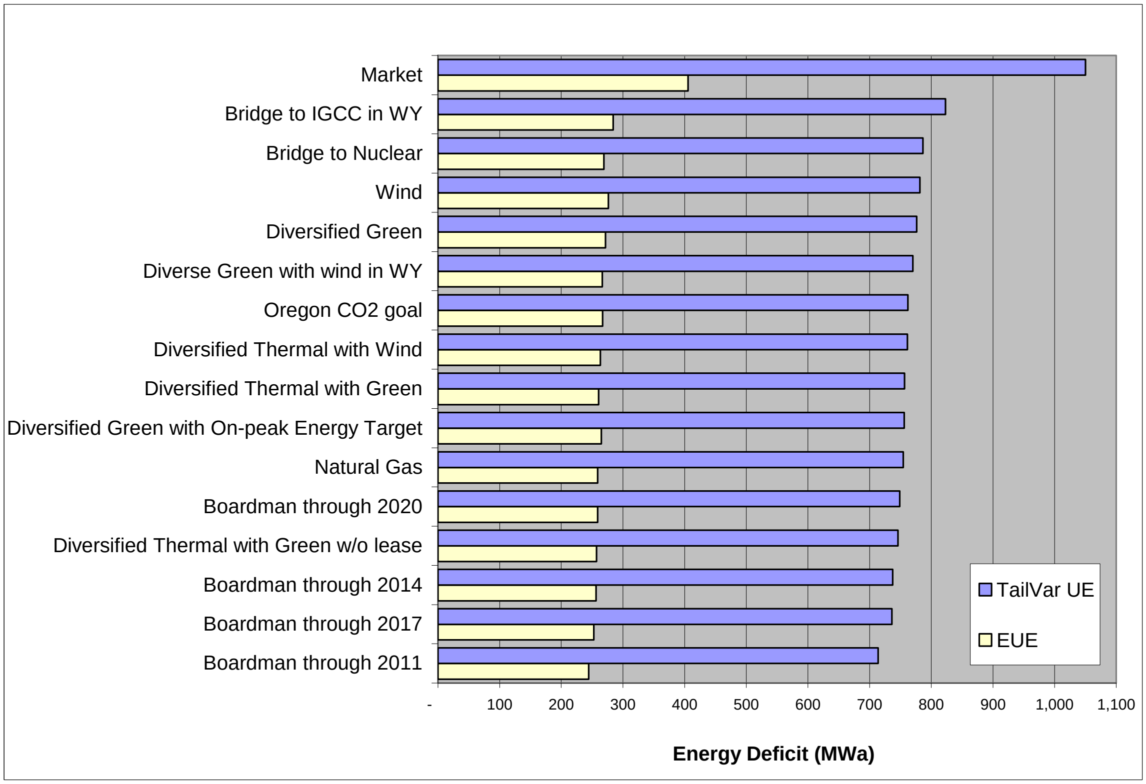
To this point, we have focused on portfolio expected cost under reference case assumptions (50% of total score) and variations from expected costs using several deterministic and stochastic risk metrics (30% of total score). Our final criteria for portfolio performance are portfolio reliability performance 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 10A. 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. With the exception of the Boardman through 2020 portfolio, which requires a new resource at the start of 2021, the portfolios do not have major resource additions after 2020.

Figure 11A-11 shows portfolio performance for the metric.

Figure 11A-11: Portfolio Reliability - Unserved Energy Metrics for 2012-2020 & 2025

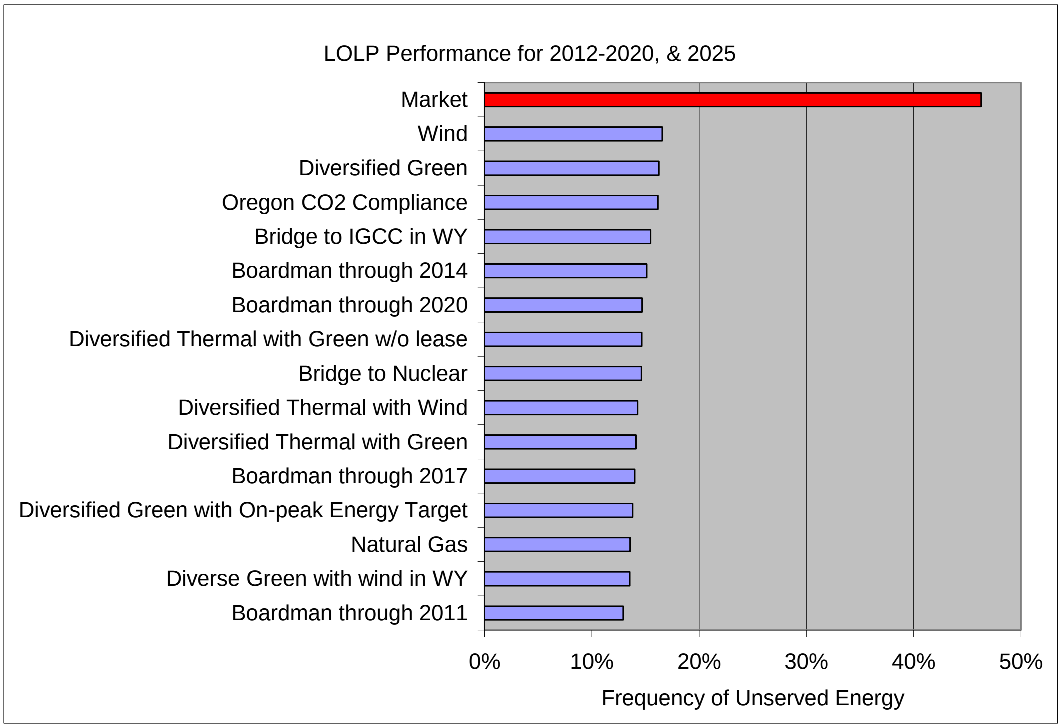


The loss of load probability is an additional reliability metric we calculated. This metric represents the percent of hours that a market purchase is made to cover PGE's load. LOLP examines market dependence by number of hours, while EUE and Tailvar UE present the energy shortfall for those hours. For consistency with the other Tailvar metrics, we score based on the Tailvar UE metric. According to the LOLP metric the Market portfolio clearly represents higher reliability risk.

Effect of Addendum Enhancements

The stochastic modeling changes discussed in Chapter 10A related to reliability analysis result in shifts in portfolio performance and rankings for the reliability metric. A primary impact from the model changes for this area is improved reliability performance, on a relative basis, for portfolios where Boardman closes early and is replaced with a CCCT. Portfolios with “Bridge PPAs” also tend to perform worse as compared to the November filing due to the inclusion of a forced outage rate for contracts. Eliminating thermal plant planned outages from the unserved energy calculation improves the reliability performance for all portfolios.

Figure 11A-12: Portfolio Reliability - LOLP

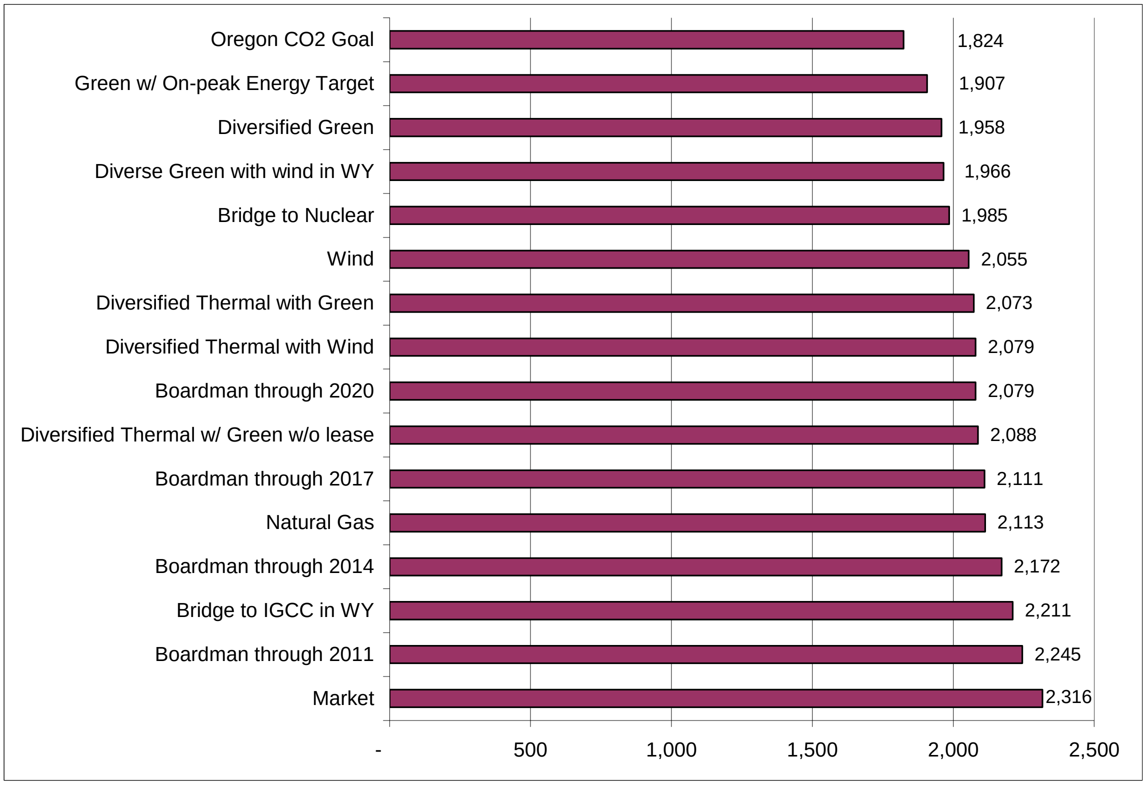


Diversity

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 metric 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 2010-2021. Figure 11A-13 below shows the results.

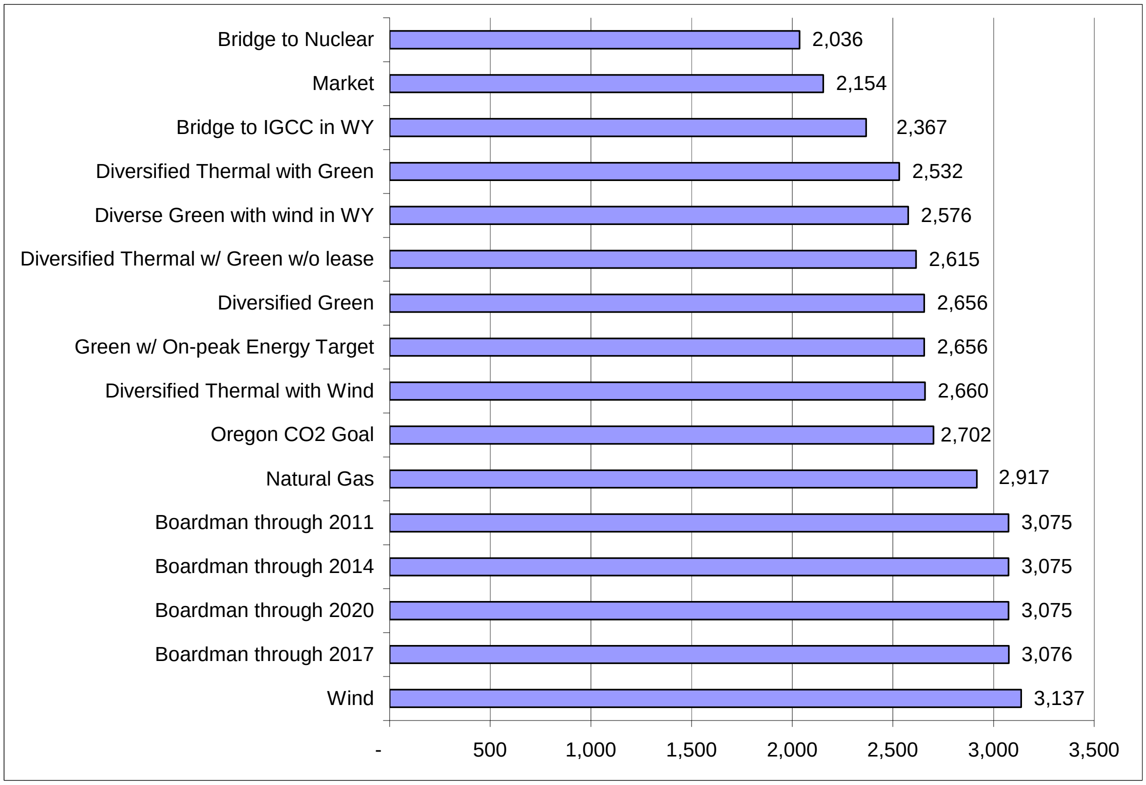
Figure 11A-13: Fuel HHI



The figure above shows that from a fuel diversity perspective, the Oregon CO_2 Goal portfolio is the most diverse, with Market being the least diverse. For the Oregon CO_2 Goal 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 2021 (the last year for major resource additions) for the proxy for the technological diversity measure. The results of this analysis are shown in Figure 11A-14.

Figure 11A-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 11% of the capacity in 2021. From a capacity standpoint, Market shows a higher level of diversity due to 25% of the capacity coming from the market. This compares to approximately 5-8% 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 generation, 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.

11A.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 11A-15 shows the total reference case emissions by portfolio in 2021. Figure 11A-16 shows the reference case emissions by year for each portfolio for the planning horizon, and Figure 11A-17 shows the reference case CO_2 intensity by year for each portfolio for the planning horizon.

Figure 11A-15: Reference Case CO_2 Emissions in Short Tons by Portfolio in 2021

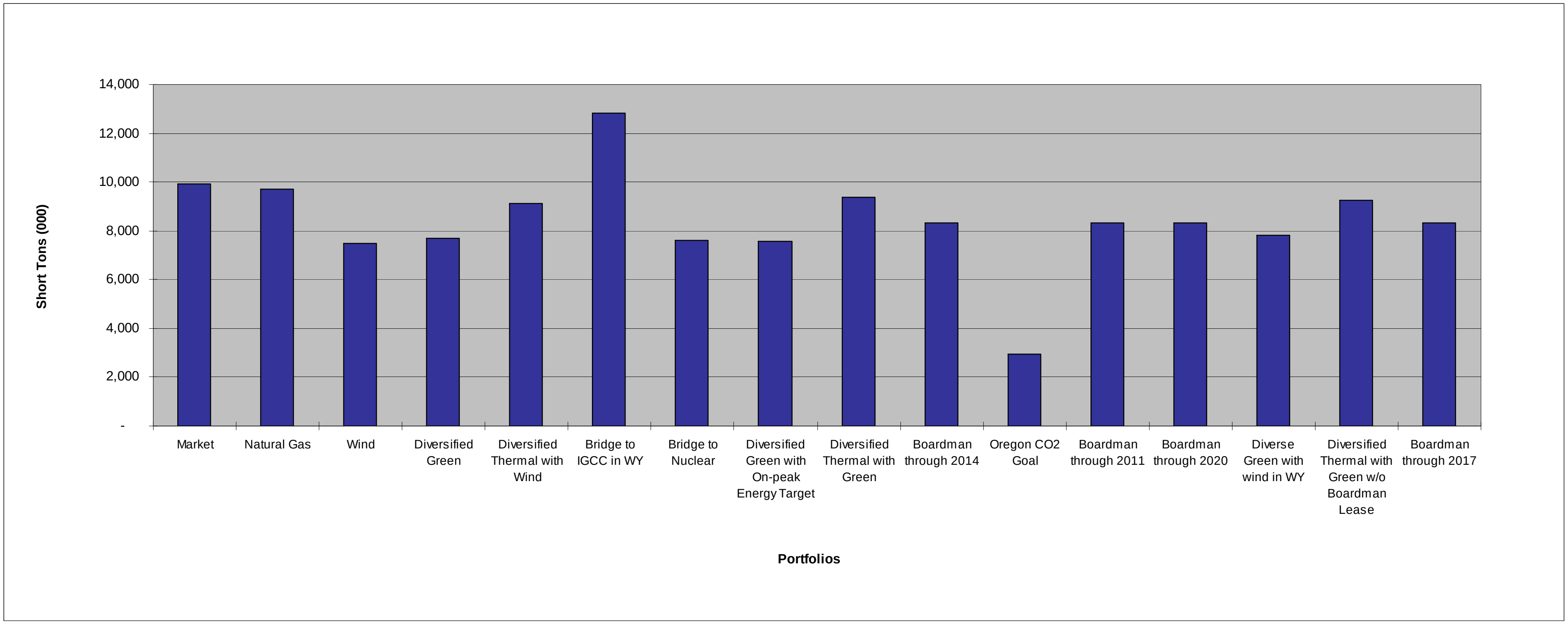


Figure 11A-16: 2010-2030 Reference Case CO_2 Emissions in Short Tons by Portfolio

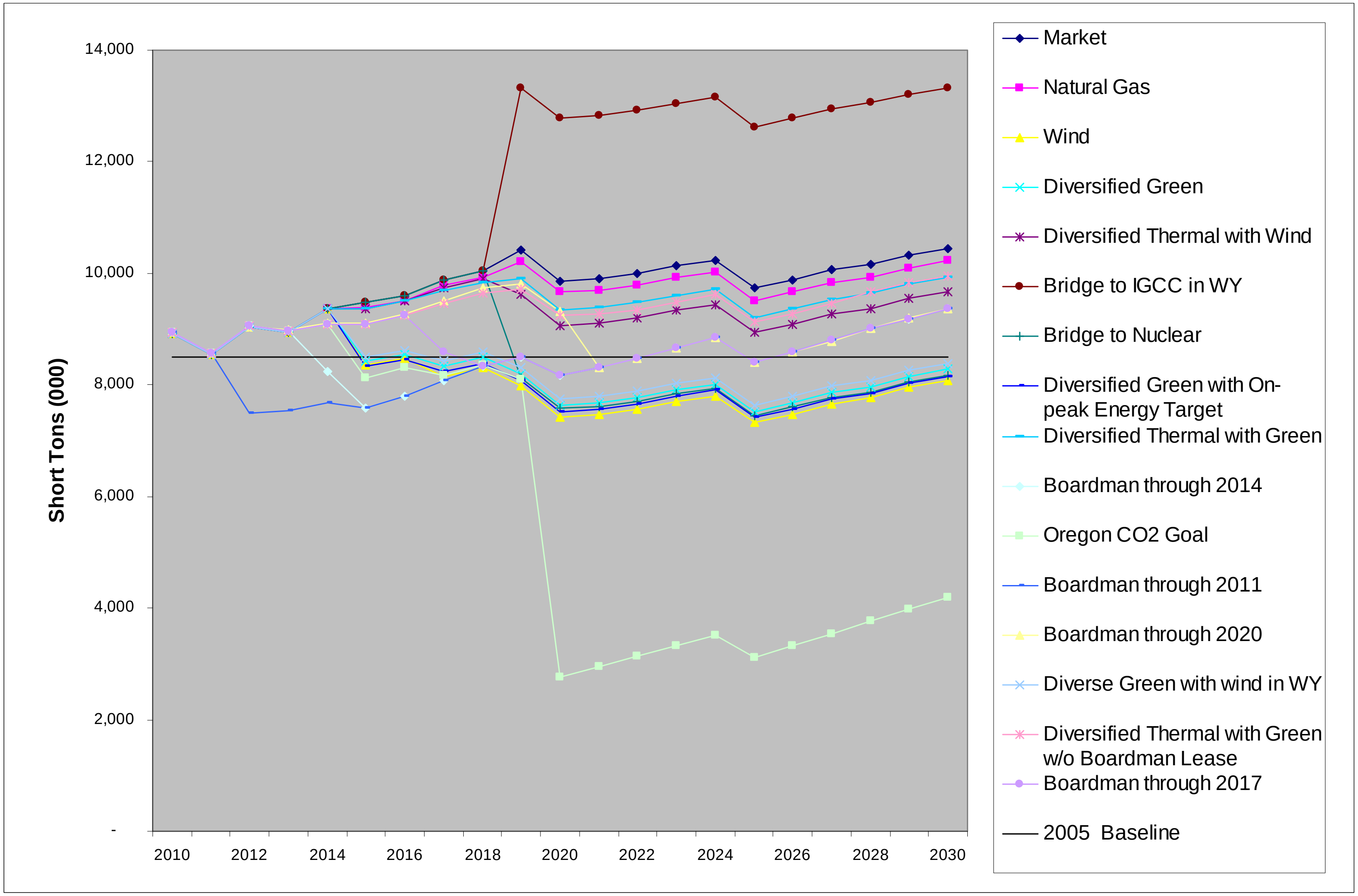
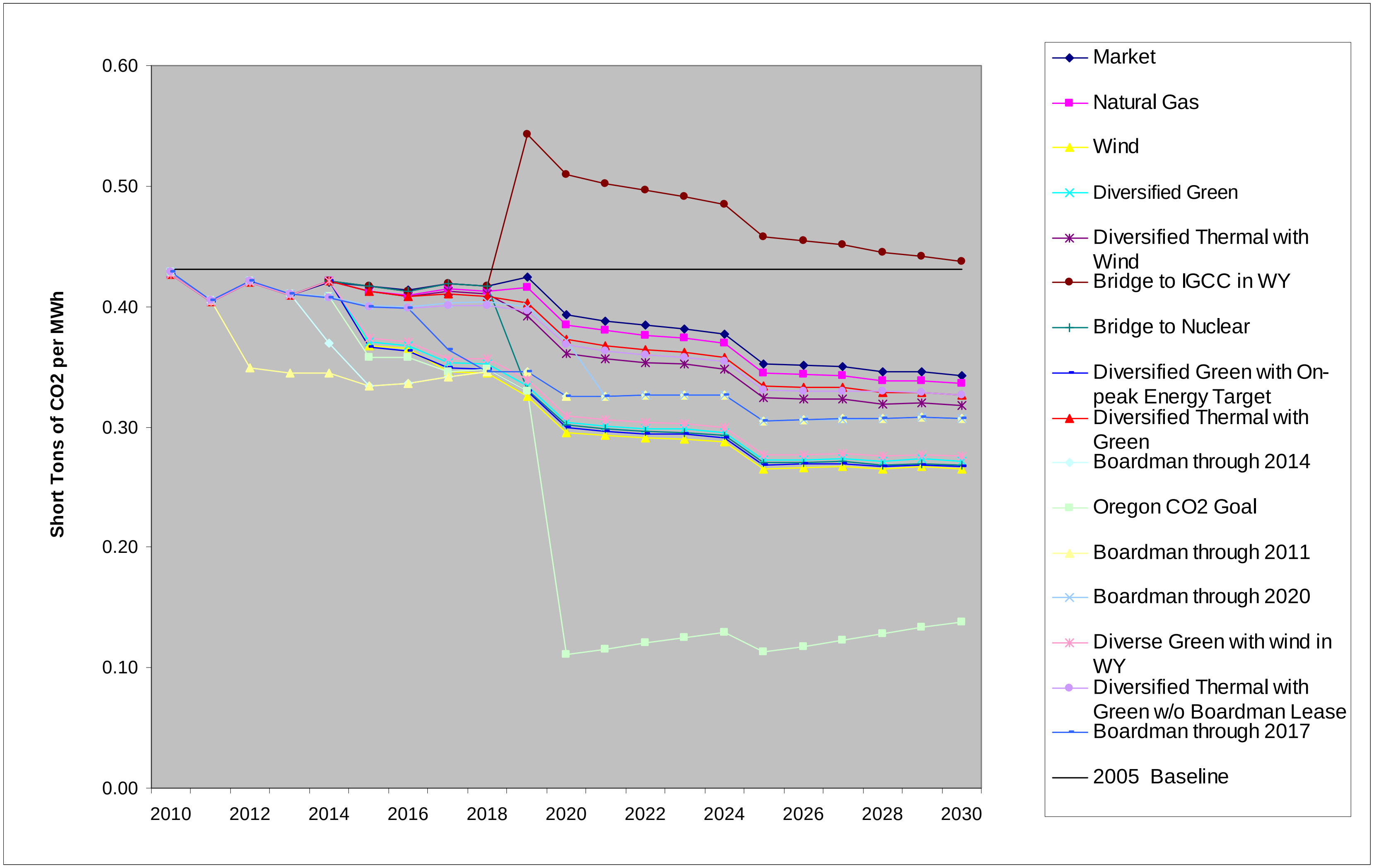
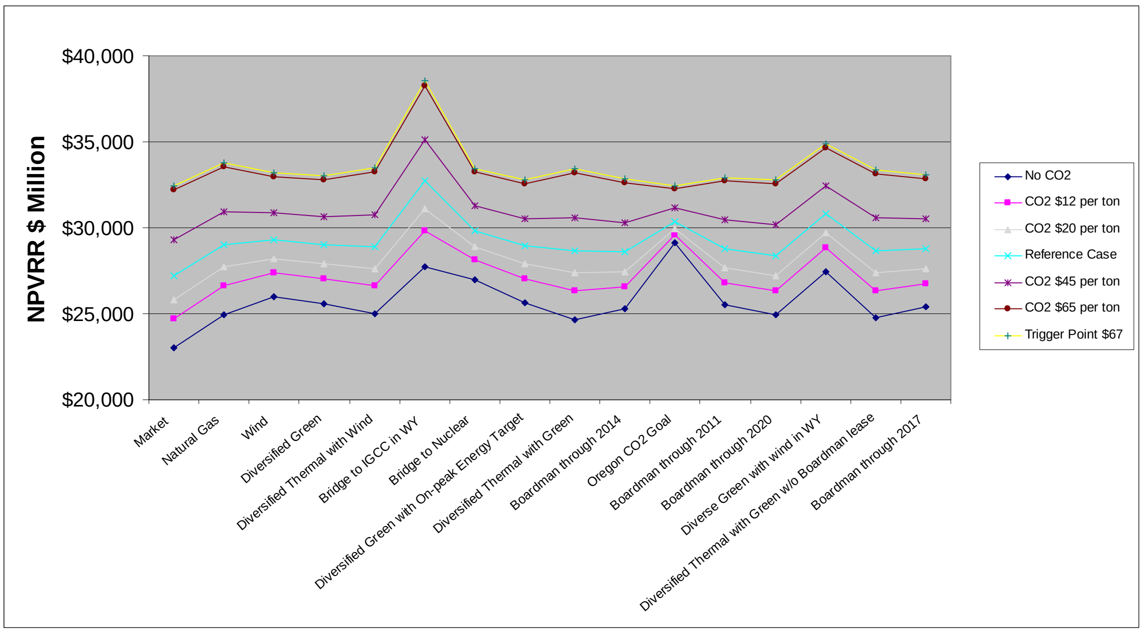


Figure 11A-17: 2010-2030 Portfolio Analysis Reference Case CO2 Intensity by Portfolio



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 11A-18: Carbon Price Performance of the Incremental Portfolios



One outcome of this analysis is portrayed in Figure 11A-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 a substantially different alternative portfolio, and found that the trigger point CO_2 price is $67.

Figure 11A-19: Trigger Point Analysis Results

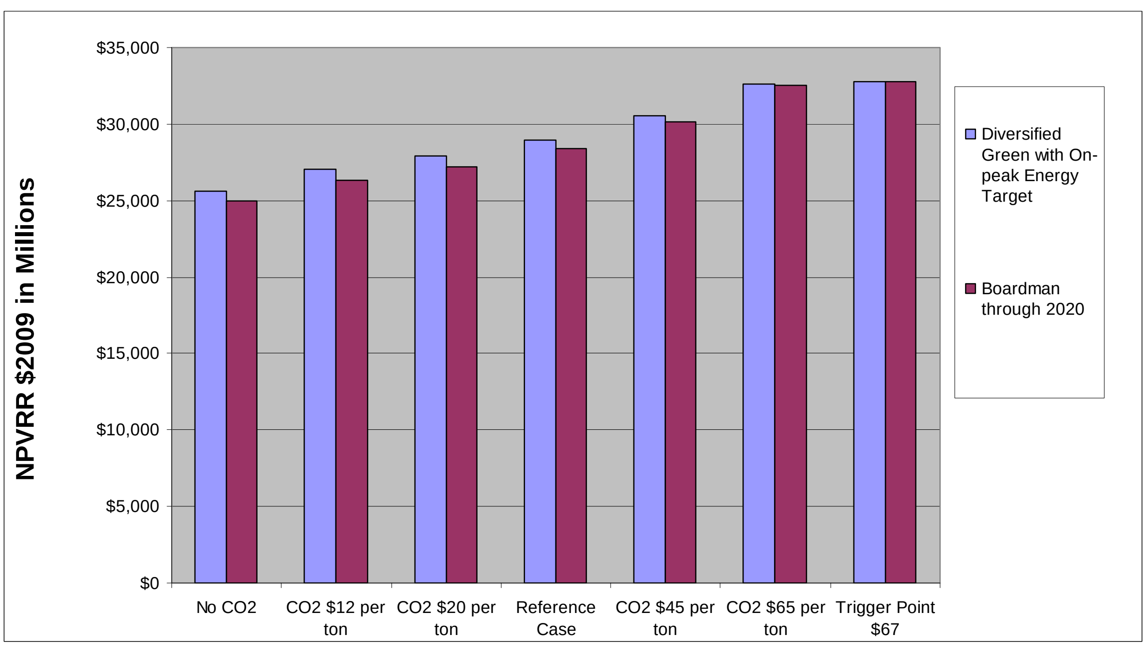


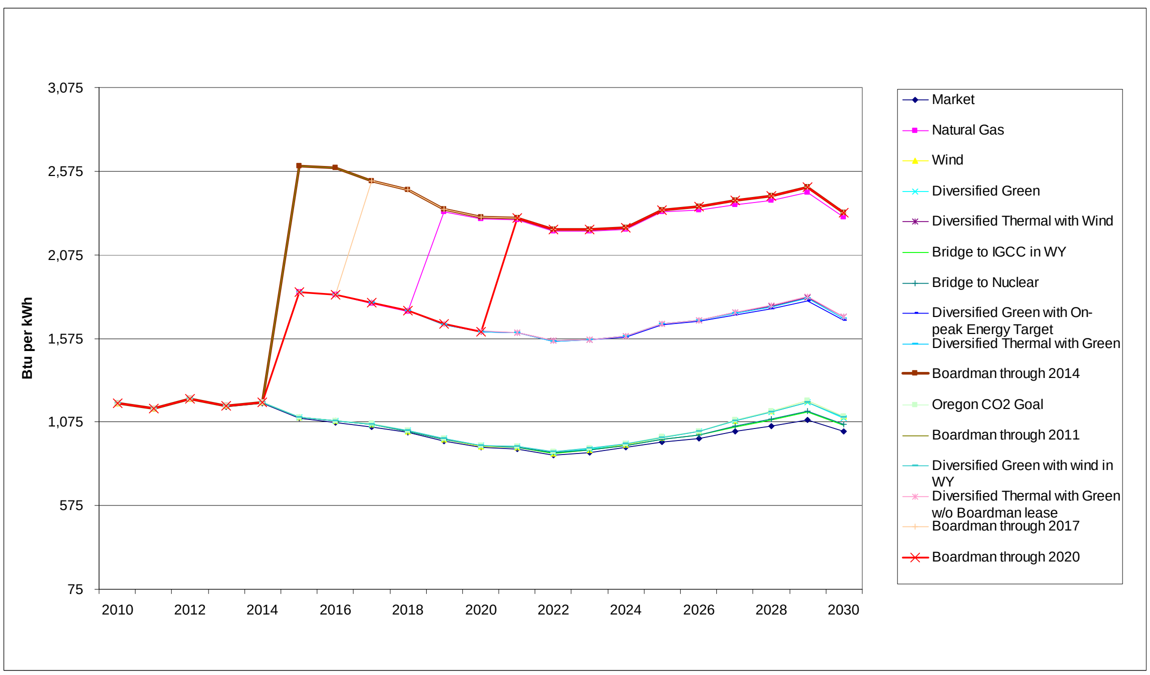
Figure 11A-19 graphically shows this price at which the Boardman through 2020 preferred portfolio is replaced with a different portfolio, Diversified Green with On-peak Energy Target, as the least-cost portfolio.

11A.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 11A-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 11A-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 11A-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 11A-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 11A-21: Portfolio Fixed and Variable Costs as a Percentage of NPVRR $2009

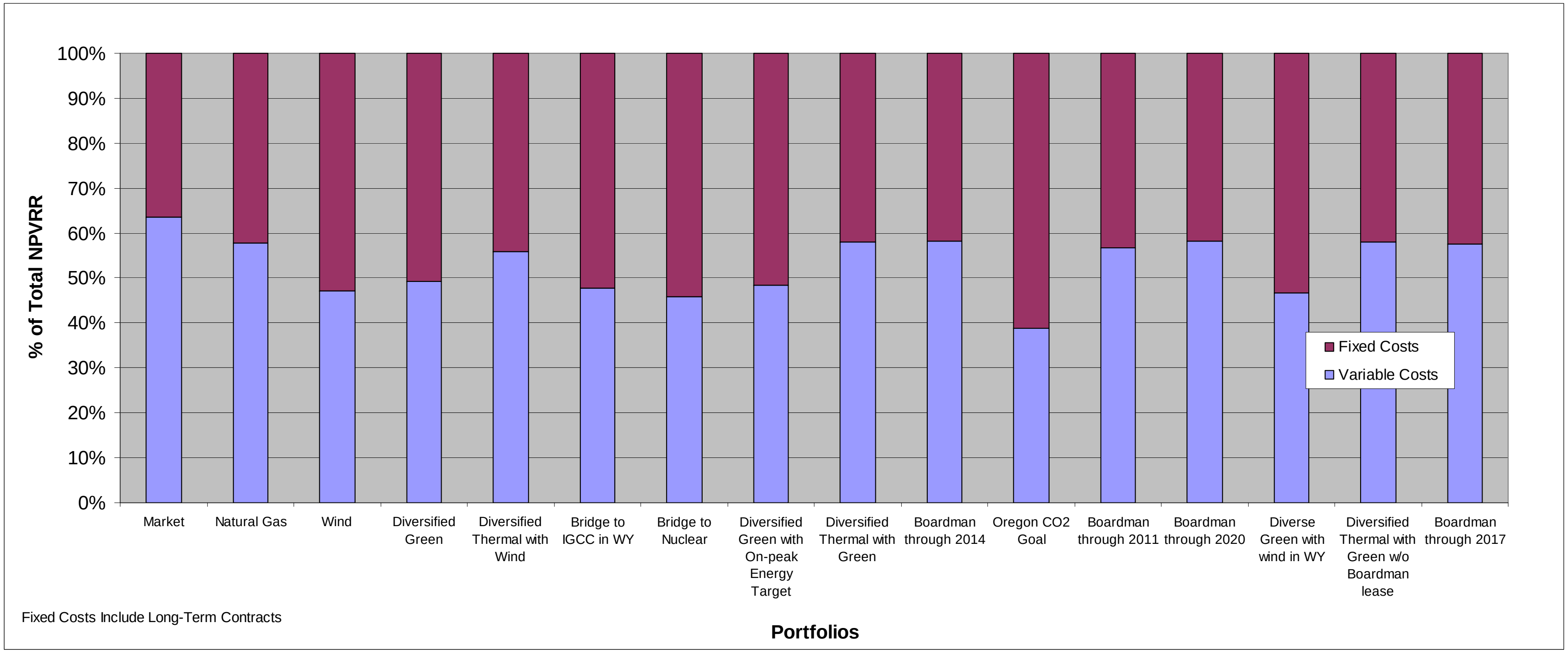
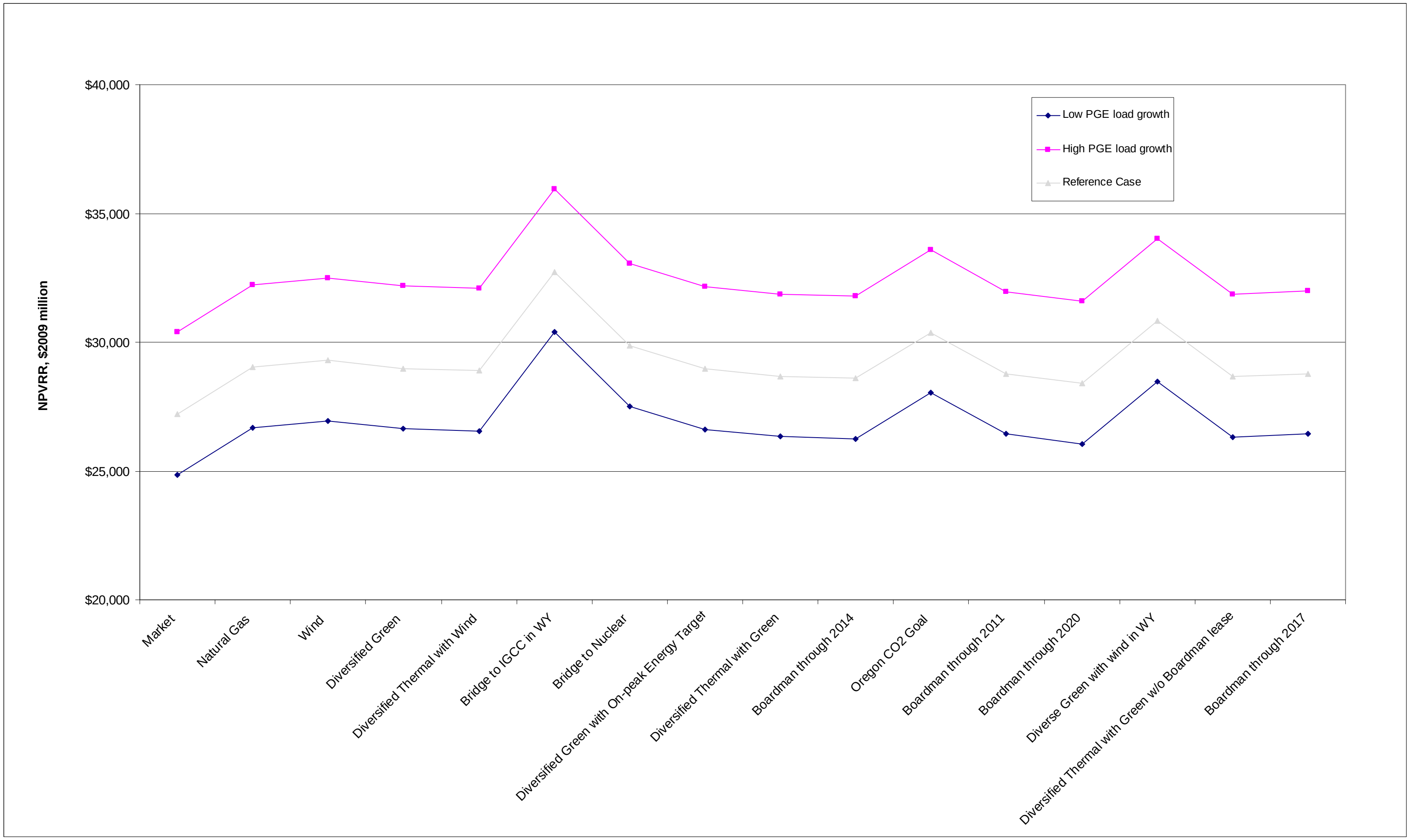


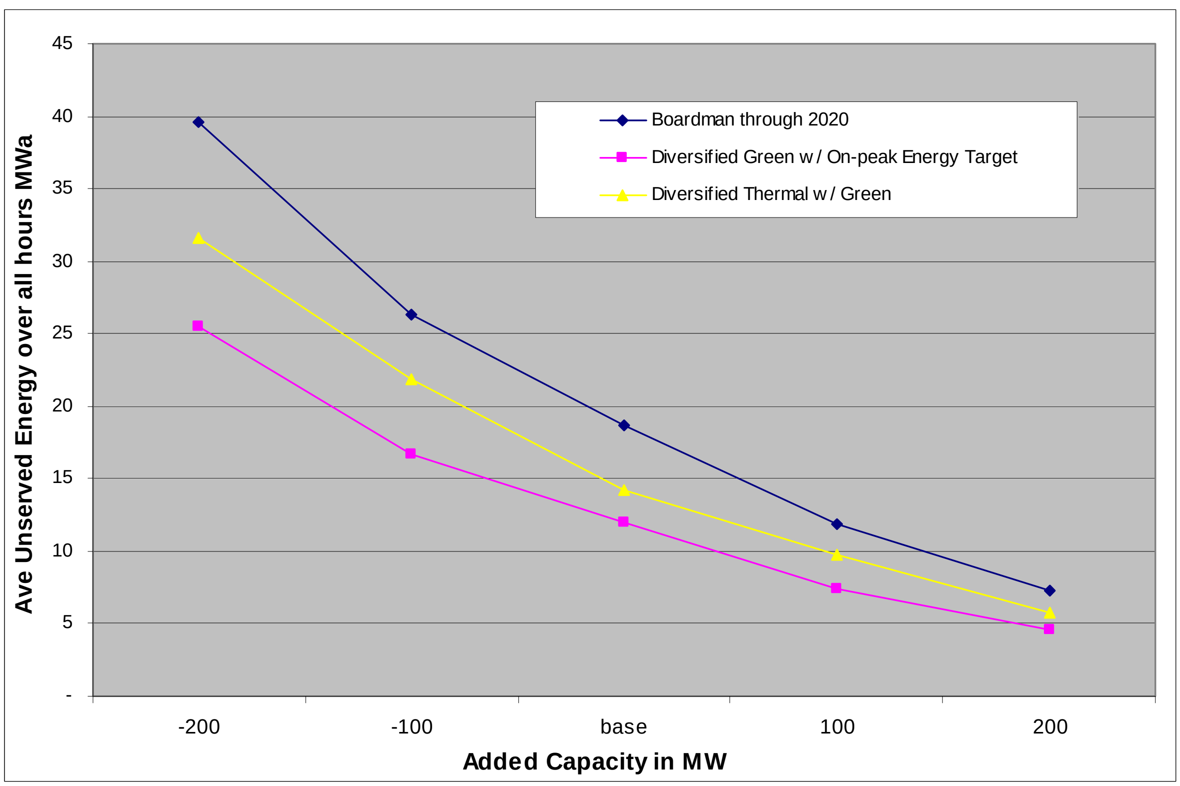
Figure 11A-22: Incremental Portfolio Performance under Load Growth Stress Testing



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. Our top three portfolios all include our Action Plan 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, in 100 MW increments, 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 11A-23: Annual Mean Unserved Energy as a Function of Incremental/ Decremental Capacity



The results of the graph confirm that we are in an acceptable zone with regard to capacity adequacy, if we're able to implement our proposed Action Plan. As capacity is subtracted, EUE begins to climb rapidly, increasing approximately 50 percent 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 have declining value as the slope of the line for EUE begins to flatten-out.

11A.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 11A-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 11A-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 11A-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 11A-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 Frontier 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 Variation	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
	Units	Y or N	Y or N	$ NPV	%	%	%	$ 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	$ 35,414	$ 8,631	70	1050	2154	2316
2	Natural Gas	Y	Y	$ 29,027	10%	5%	-5%	$ 35,436	$ 6,410	$ 36,675	$ 8,458	53	755	2917	2113
3	Wind	Y	Y	$ 29,288	5%	14%	10%	$ 34,238	$ 4,949	$ 35,037	$ 6,547	78	782	3137	2055
4	Diversified Green	Y	Y	$ 28,987	0%	14%	14%	$ 34,091	$ 5,104	$ 34,718	$ 6,624	61	777	2656	1958
5	Diversified Thermal with Wind	Y	Y	$ 28,891	5%	0%	-5%	$ 34,949	$ 6,057	$ 36,175	$ 8,025	57	761	2660	2079
6	Bridge to IGCC in WY	N	Y	$ 32,735	100%	0%	-100%	$ 38,635	$ 5,900	$ 36,950	$ 6,397	47	823	2367	2211
7	Bridge to Nuclear	N	Y	$ 29,853	81%	0%	-81%	$ 34,863	$ 5,010	$ 34,768	$ 6,311	39	787	2036	1985
8	Green w/ On-peak Energy Target	Y	Y	$ 28,971	0%	19%	19%	$ 33,993	$ 5,023	$ 34,481	$ 6,517	58	756	2656	1907
9	Diversified Thermal with Green	Y	Y	$ 28,674	5%	24%	19%	$ 34,910	$ 6,236	$ 36,116	$ 8,171	53	757	2532	2073
10	Boardman through 2014	Y	Y	$ 28,593	5%	67%	62%	$ 35,126	$ 6,533	$ 38,112	$ 9,689	63	737	3075	2172
11	Oregon CO2 Goal	N	Y	$ 30,375	81%	14%	-67%	$ 35,007	$ 4,632	$ 36,112	$ 6,665	63	762	2702	1824
12	Boardman through 2011	Y	Y	$ 28,777	10%	10%	0%	$ 35,247	$ 6,470	$ 38,142	$ 9,551	62	714	3075	2245
13	Boardman through 2020	Y	Y	$ 28,396	0%	81%	81%	$ 34,770	$ 6,374	$ 36,999	$ 8,987	61	749	3075	2079
14	Diverse Green with wind in WY	N	Y	$ 30,828	86%	0%	-86%	$ 35,962	$ 5,134	$ 35,399	$ 6,191	37	770	2576	1966
15	Diversified Thermal w/ Green w/o lease	Y	Y	$ 28,668	0%	62%	62%	$ 34,891	$ 6,223	$ 36,461	$ 8,432	54	746	2615	2088
16	Boardman through 2017	Y	Y	$ 28,780	10%	0%	-10%	$ 35,257	$ 6,477	$ 37,877	$ 9,358	61	736	3076	2111

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	100%	90%	86%	$ 33,993	$ 4,632	$ 34,481	$ 6,191	37	713.9	2,036	1,824
Best Basis			Min	Max	Max	Max	Min	Min	Min	Min	Min	Min	Min	Min
Worst Performing Portfolio(s)			$ 32,735	0%	0%	-100%	$ 38,635	$ 8,943	$ 38,142	$ 9,689	78	1,050.3	3,137	2,316
Spread Best to Worst			$ 5,524	100%	90%	186%	$ 4,641	$ 4,311	$ 3,661	$ 3,498	42	336.4	1,101	492
% Difference			20.3%				13.7%	93.1%	10.6%	56.5%	113.9%	47.1%	54.1%	27.0%

Table 11A-3: Portfolio Scoring Grid: Normalized Scores for Cost and Risk Metrics

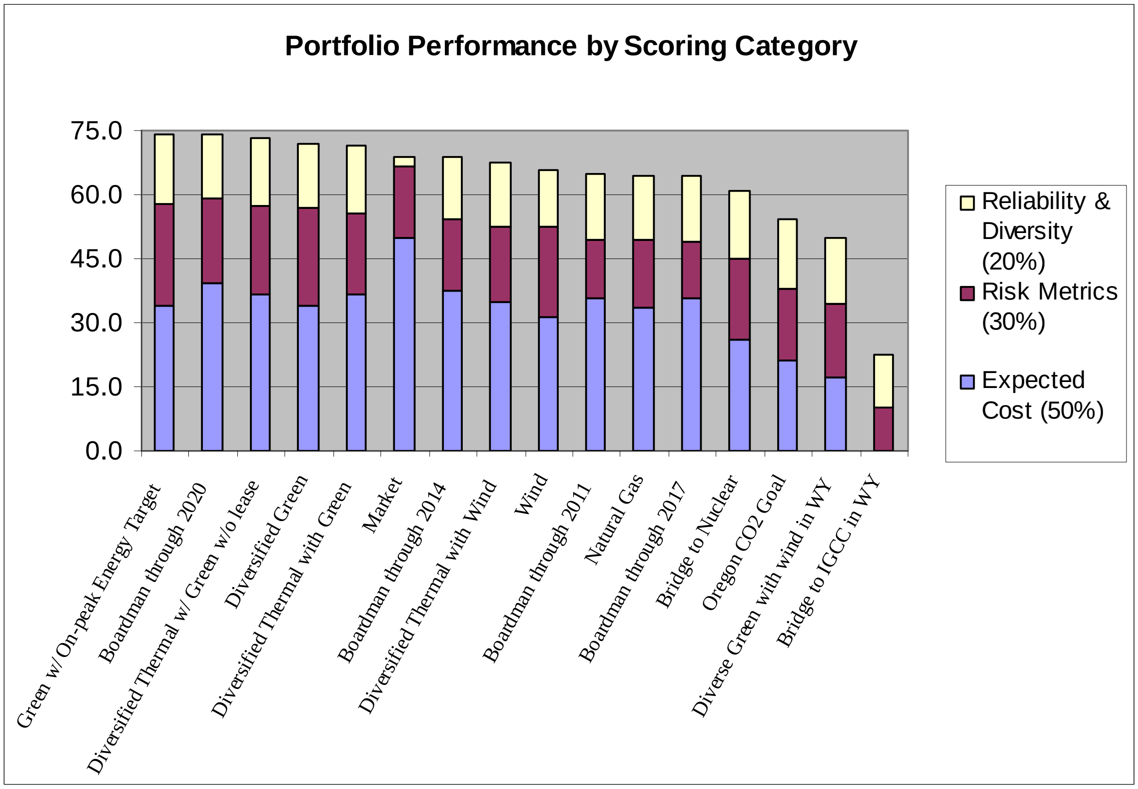
	2. Portfolio Evaluation Scoring: Normalized Scores (0 to 100)	Screening		Deterministic				Stochastic			Reliability & Diversity		
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	**Within Efficient Frontier Zone?**	**Meets Operating Reserve Req?**	**Cost: Expected Cost**	**Risk 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 Variation**	**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	74.5	30.2	19.3	0.0	89.3	0.0
2	Natural Gas	Y	Y	67.1	51.3	68.9	58.8	40.1	35.2	60.8	87.9	20.0	41.3
3	Wind	Y	Y	62.4	59.0	94.7	92.6	84.8	89.8	0.0	79.9	0.0	53.1
4	Diversified Green	Y	Y	67.9	61.5	97.9	89.1	93.5	87.6	40.6	81.4	43.7	72.6
5	Diversified Thermal with Wind	Y	Y	69.6	51.3	79.4	66.9	53.7	47.6	52.3	85.9	43.3	48.2
6	Bridge to IGCC in WY	**N**	Y	0.0	0.0	0.0	70.6	32.6	94.1	74.7	67.5	69.9	21.3
7	Bridge to Nuclear	**N**	Y	52.2	10.3	81.3	91.2	92.2	96.6	93.5	78.3	100.0	67.2
8	Green w/ On-peak Energy Target	Y	Y	68.1	64.1	100.0	90.9	100.0	90.7	47.9	87.4	43.7	83.2
9	Diversified Thermal with Green	Y	Y	73.5	64.1	80.3	62.8	55.3	43.4	61.2	87.3	54.9	49.3
10	Boardman through 2014	Y	Y	75.0	87.2	75.6	55.9	0.8	0.0	37.6	93.0	5.6	29.3
11	Oregon CO2 Goal	**N**	Y	42.7	17.9	78.2	100.0	55.5	86.5	37.4	85.7	39.5	100.0
12	Boardman through 2011	Y	Y	71.7	53.8	73.0	57.4	0.0	4.0	40.0	100.0	5.6	14.3
13	Boardman through 2020	Y	Y	78.6	97.4	83.3	59.6	31.2	20.1	42.9	89.6	5.6	48.0
14	Diverse Green with wind in WY	**N**	Y	34.5	7.7	57.6	88.4	74.9	100.0	100.0	83.3	50.9	71.1
15	Diversified Thermal w/ Green w/o lease	Y	Y	73.6	87.2	80.7	63.1	45.9	35.9	58.3	90.5	47.4	46.3
16	Boardman through 2017	Y	Y	71.6	48.7	72.8	57.2	7.2	9.5	41.0	93.4	5.5	41.7

Table 11A-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)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Frontier 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 Variation	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	2.5	1.0	0.6	0.0	2.2	0.0	69.0	93%	6
2	Natural Gas	Y	Y	33.6	5.1	3.4	2.9	1.3	1.2	2.0	13.2	0.5	1.0	64.3	87%	11
3	Wind	Y	Y	31.2	5.9	4.7	4.6	2.8	3.0	0.0	12.0	0.0	1.3	65.6	88%	9
4	Diversified Green	Y	Y	33.9	6.2	4.9	4.5	3.1	2.9	1.4	12.2	1.1	1.8	71.9	97%	4
5	Diversified Thermal with Wind	Y	Y	34.8	5.1	4.0	3.3	1.8	1.6	1.7	12.9	1.1	1.2	67.5	91%	8
6	Bridge to IGCC in WY	N	Y	0.0	0.0	0.0	3.5	1.1	3.1	2.5	10.1	1.7	0.5	22.7	31%	16
7	Bridge to Nuclear	N	Y	26.1	1.0	4.1	4.6	3.1	3.2	3.1	11.8	2.5	1.7	61.1	82%	13
8	Green w/ On-peak Energy Target	Y	Y	34.1	6.4	5.0	4.5	3.3	3.0	1.6	13.1	1.1	2.1	74.3	100%	1
9	Diversified Thermal with Green	Y	Y	36.8	6.4	4.0	3.1	1.8	1.4	2.0	13.1	1.4	1.2	71.4	96%	5
10	Boardman through 2014	Y	Y	37.5	8.7	3.8	2.8	0.0	0.0	1.3	14.0	0.1	0.7	68.9	93%	7
11	Oregon CO2 Goal	N	Y	21.4	1.8	3.9	5.0	1.8	2.9	1.2	12.9	1.0	2.5	54.4	73%	14
12	Boardman through 2011	Y	Y	35.8	5.4	3.6	2.9	0.0	0.1	1.3	15.0	0.1	0.4	64.7	87%	10
13	Boardman through 2020	Y	Y	39.3	9.7	4.2	3.0	1.0	0.7	1.4	13.4	0.1	1.2	74.1	100%	2
14	Diverse Green with wind in WY	N	Y	17.3	0.8	2.9	4.4	2.5	3.3	3.3	12.5	1.3	1.8	50.0	67%	15
15	Diversified Thermal w/ Green w/o lease	Y	Y	36.8	8.7	4.0	3.2	1.5	1.2	1.9	13.6	1.2	1.2	73.3	99%	3
16	Boardman through 2017	Y	Y	35.8	4.9	3.6	2.9	0.2	0.3	1.4	14.0	0.1	1.0	64.3	87%	12

The preceding table may be easier to interpret via Figure 11A-24, which presents the same information graphically and with scores color-coded by composite 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 11A-24: Portfolio Scoring Grid: Weighted Scores and Ranked Results



Preferred Portfolio Recommendations

Which Portfolios Perform Best? 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 through 2020 or beyond generally outperform those with an earlier closure date. See the following chapter for a detailed discussion of our Boardman analysis.

The top-performing portfolios are Green with On-peak Energy Target, the new Boardman through 2020 portfolio, and Diversified Thermal with Green without Lease. It is significant to note that the Boardman through 2020 portfolio outperforms all candidate portfolios with earlier Boardman closure dates and also outperforms, with a lone exception, the portfolios that continue Boardman operations through 2040. It is also significant to note that the top five portfolios all continue Boardman operations through at least 2020.

Our Preferred Portfolio. We propose Boardman through 2020 as our preferred portfolio. In selecting this portfolio, we considered the relative *balance* between cost performance and risk performance. The Boardman through 2020 portfolio performs well with respect to both cost and risk. It ranks as the 2nd best portfolio for expected cost, while it scores 5th best in the combined risk and diversity categories. By contrast, the other top scoring portfolio, Green with On-peak Energy Target portfolio does not score well when considering expected cost (9th of 16 portfolios), but excels on the risk metrics. (This is, perhaps, not surprising, as it is an energy "long" portfolio, which provides a deliberate trade-off of increased cost for lower risk.) Thus, Boardman through 2020 has a better balance of cost and risk compared to the Green with On-peak Energy Target portfolio.

Our Alternate Portfolio. Diversified Thermal with Green without Lease, which includes Boardman through 2040, ranks 3rd overall. This portfolio also offers a good balance between cost and risk, ranking as 4th best on expected cost and 3rd best with regard to the combined risk and diversity measures. We consider this portfolio to be our next best option in the event that we are not able to implement our preferred portfolio, Boardman through 2020.

Both Diversified Thermal with Green and our preferred portfolio, Boardman through 2020, 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.

Why not Market? Market, the sixth 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 reliably 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 reliability performance to an acceptable level, we would need to firm the portfolio by adding a significant 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 increase in expected cost.

Why not Green with On-Peak Energy Target? The two top performing portfolios, Green with On-peak Energy Target and Boardman through 2020, are virtually identical in overall score; however, both Boardman through 2020 and Diversified Thermal with Green without Lease offer a better balance between cost performance and risk performance, and are more achievable. The Green with On-Peak Energy Target portfolio adds energy resources to a new, higher resource planning target (the average of the on-peak hours) 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 whether assumed costs for smaller volumes would hold for larger amounts over a relatively short time-frame. In short, this portfolio carries higher execution risk.

Summary Portfolio Results. 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 Boardman through 2020. If implementation of Boardman through 2020 is not possible, our next best performing portfolio is Diversified Thermal with Green without Lease.

12A. Boardman Analysis

Boardman, a pulverized-coal plant located in north-central Oregon, is a key resource for PGE and our customers. It is a low-cost, baseload plant that enables us to provide 15% of our customers' energy needs with a stable fuel source and also contributes to the diversity of our supply mix. Boardman is in the top quintile among U.S. coal plants for efficiency (heat rate) in converting fuel to electricity. Because Boardman has been well maintained, it is expected to have continued reliable and efficient operations for the foreseeable future.

In this chapter we describe the emissions controls required under the recently adopted Oregon Regional Haze Plan and the Oregon Utility Mercury Rules. We also present a new emissions control and operating plan which PGE has proposed in a petition to amend the existing Oregon Regional Haze Plan filed with the Oregon Department of Environmental Quality (DEQ) on April 2, 2010 (BART II Petition). This new plan is incorporated via our "Boardman through 2020" portfolio, which forms the basis of our preferred Action Plan. This chapter also provides detailed analysis of the different cases for Boardman emissions controls and operations, including PGE's new proposal to implement a more limited controls package in conjunction with a plan to cease coal-fired operations at the plant in 2020.

Our analysis of the "Boardman through 2020" portfolio balances several important objectives, including cost and risk for customers, system reliability, meeting state and federal emissions standards, and reducing the impact of electric generation on the environment. The portfolio also allows for an orderly transition to replacement supply sources and reduces the impact of a change in plant operations on affected communities and employees. The "Boardman through 2020" portfolio is our preferred portfolio. However, as described in detail in Chapter 13A, implementation of the "Boardman through 2020" portfolio is dependent on the resolution of certain contingencies. Given the reliability and cost risk to customers of a 2014 plant closure, as discussed later in this chapter,[9] we are asking the Commission to acknowledge that is prudent for us to proceed with an alternate Action Plan based on the Diversified Thermal with Green portfolio (with or without lease), which continues Boardman operations through 2040 if contingencies are not resolved by March 31, 2011. The details of both our preferred and alternate plans for Boardman are presented in the balance of this chapter and in Chapter 13A.

[9] In particular, refer to the discussions immediately after Figure 12A-1 and prior to Figure 12A-5.

Chapter Highlights

- PGE proposes a new Boardman BART / Regional Progress plan (BART II). Under the new, proposed plan PGE would install a more limited emissions control upgrade package in conjunction with ceasing coal-fired operations at the plant in 2020.
- This chapter provides comparative analysis of the proposed new Boardman 2020 plan to other potential cases for Boardman.
- Our analysis indicates that a Boardman through 2020 portfolio provides the best combination of cost and risk for customers, when compared to other viable cases. This portfolio is the basis for our preferred Action Plan.
- If we are not able to implement the Boardman through 2020 portfolio, the next best alternative for PGE customers is the Diversified Thermal with Green portfolio. This portfolio is the basis for our alternate Action Plan.
- The detailed elements of our preferred and alternate plans for Boardman are presented below and in Chapter 13A.

12A.1 Oregon Regional Haze Plan

As part of the implementation of the Federal Clean Air Act section 169A, the Oregon Department of Environmental Quality (DEQ) issued a draft Oregon Regional Haze Plan that was later adopted by the Environmental Quality Commission (EQC) on June 19, 2009. The Oregon Regional Haze Plan requires the installation of environmental controls as Best Available Retrofit Technology (BART) at the Boardman plant for the purpose of reducing visibility-impairing emissions and additional environmental controls as Reasonable Progress (RP) towards additional haze causing emissions reductions.

In addition to the Oregon Regional Haze Rule, Boardman is also subject to the Oregon Utility Mercury Rule. PGE has received DEQ approval of a proposed approach whereby activated carbon is injected upstream of the existing electrostatic precipitator in possible combination with calcium halide additive on the coal. This approach is expected to result in the capture of 90 percent of the mercury contained in the flue exhaust gases, enabling the plant to meet the emissions standard under the Utility Mercury Rule. While this control approach increases the risk of rendering the fly ash unsellable, it provides an overall cost benefit to PGE customers by substantially decreasing mercury emissions while avoiding the installation of expensive fabric filter equipment.

12A.2 Current Regional Haze Plan Requirements

The current Regional Haze Plan requirements applicable to Boardman consist of two phases: Phase 1 BART controls; and Phase 2 RP controls. Phase 1 compliance requires installation of Low NOx Burner and Modified Over-Fire Air (LNB/MOFA) and semi-dry flue gas desulfurization (scrubbers) with an associated fabric filter. Phase 2 requires the installation of selective catalytic reduction (SCR). Under the existing Regional Haze Plan, 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 (modeled in the "Diversified Thermal with Green" portfolios).
- Install LNB/MOFA and scrubber/fabric filters and cease Boardman operations in 2017; do not make the SCR investment (modeled in the "Boardman through 2017" portfolio).
- Install LNB/MOFA only and cease Boardman operations in 2014 (modeled in the "Boardman through 2014" portfolio).
- Cease Boardman operations in July 2011 with no obligation to install additional controls (modeled in the "Boardman through 2011" portfolio).

12A.3 BART II

On April 2, 2010, PGE submitted a Petition to amend the Oregon Regional Haze Rule to the DEQ (BART II Petition). This BART II Petition seeks changes to allow Boardman meet BART/RP requirements through an alternate proposal that utilizes a more limited emissions control upgrade package in conjunction with a change in the plant's operation and a commitment to cease coal-fired operations or shut down the plant in 2020. Under this proposed petition, PGE would cut haze-causing emissions of sulfur dioxide and nitrogen oxides from the Boardman plant by:

- Installing new, state-of-the-art LNB/MOFA burners by July 1, 2011. The new burners are expected to reduce nitrogen oxides emitted by the plant by nearly 50 percent.
- Using coal with a lower sulfur content to fire the plant's boiler. This would be completed in two stages as PGE's current coal supply contracts expire. In addition, PGE has recommended an initial 20 percent drop in permitted sulfur dioxide emissions that would take effect in 2011. This is followed by a further reduction in 2014 that would bring allowed sulfur dioxide emissions down by a total of 50 percent from current permit levels.

- Closing the plant in 2020, ending all coal-related emissions at least 20 years ahead of schedule and significantly reducing Oregon's contribution to green house gas emissions.

Under a separate rulemaking procedure with DEQ, PGE already has agreed to install controls that are expected to eliminate 90 percent of the plant's mercury emissions by 2012. Current construction schedules should allow PGE to meet this deadline a year early, in 2011.

Table 12A-1: Comparison of Existing vs. Proposed BART Rule

			Current Rule			Proposed BART II Revision		
Controls	*Constituent*	*2009 Emissions*	*Emissions**	*Cost***	*Schedule*	*Emissions**	*Cost***	*Schedule*
Low NOx Burners / OverFire Air	NOx	0.41	0.23	$32.8 Million	Jul-11	0.23	$32.8 Million	Jul-11
Dry Scrubber with Fabric Filter	SO2	0.70	0.12	$289 Million	Jul-14	Shut Down @ end of 2020		
	PM	0.17	0.012	(Incl. in above)	Jul-14	Shut Down @ end of 2020		
Reduced Sulfur Coal Restriction 1	SO2					0.96	Increased O&M	Dec-11
Reduced Sulfur Coal Restriction 2	SO2					0.60	Increased O&M	Jul-14
Selective Catalytic Reduction (SCR)	NOx		0.07	$180 Million	Jul-17	Shut Down @ end of 2020		
Mercury Controls	Hg		90%	$7.7 Million	Jul-12	90%	$7.7 Million	Jul-12
Aggregate Emissions (tons)			256,815			231,224		
Totals				$509.5 Million			$40.5 Million	
* Lbs/Mmbtu								
**Costs are nominal Capital dollars and do not include AFDC and property taxes								

The concept of potentially closing Boardman early was first introduced by the company in response to a December 1, 2008 DEQ proposed BART determination for the Boardman Plant Boiler. During the public comment period the company requested that DEQ consider allowing PGE to have options to forego certain controls if the company committed to cease operation of the Boardman Plant boiler by dates certain.

On June 19, 2009, the Oregon Environmental Quality Commission (EQC) adopted DEQ's proposed Oregon Regional Haze Plan which included extensive emission controls. Although the EQC did not adopt the company's proposal it did include in its adopted plan an express statement that "Should PGE determine that the impact and cost of carbon regulations will require the closure of the PGE Boardman plant, PGE may submit a written request to the Department for a rule change". In response to feedback from IRP stakeholders and further analysis of the EQC ruling, the company began analyzing a portfolio with a 2020 closure of the Boardman plant. Based on that feedback and analysis, as well as our belief that such a portfolio could meet the emissions standards required under the Regional Haze Program, PGE submitted the BART II request to DEQ.

While a DEQ schedule has not yet been established, the following is from the DEQ press release of April 2, 2010:

DEQ officials will study PGE's proposal and analysis to assess whether it adequately addresses all the factors needed to comply with federal regulations. If so, DEQ will begin a new rulemaking process that will provide the opportunity for the public to review and provide comment. Depending on the outcome of DEQ's review and public process it may be possible to bring a proposed rule revision to the EQC for consideration by the end of the year.

12A.4 Portfolio Analysis

Throughout the remainder of this chapter we focus on a set of portfolios that represent five distinct emission control upgrade and operating plan cases for Boardman. Four of the portfolios, "Boardman through 2011", "Boardman through 2014", "Boardman through 2017" and "Boardman through 2020" represent early closure scenarios. The fifth case, "Diversified Thermal with Green", represents a plan where all emissions controls required under the current DEQ rules are implemented at Boardman and the plant is retained in PGE's portfolio through 2040. Of the above portfolios, only "Boardman through 2020" represents a new case from those presented in PGE's November 2009 IRP filing. This new portfolio provides a Boardman capital and operating plan that is consistent with our BART II Petition. The "Boardman through 2020" portfolio includes the following primary elements:

- Installation of LNB/MOFA in 2011;
- The use of low sulfur coal to meet a 20% reduction in permitted SO_2 emissions by the end of 2011;
- Injection of carbon to eliminate 90 percent of the plant's mercury emissions by 2012;
- The use of low sulfur coal to meet a 50% reduction in permitted SO_2 emissions by July 2014;
- Cessation of coal-fired operations of Boardman at the end of 2020;
- No further emissions control investments;
- Replacement of Boardman with a CCCT at the beginning of 2021.

In addition to the above components, please see Chapter 10A, section 10A.4, for a detailed description of the portfolio composition.

12A.5 Results of Portfolio Analysis

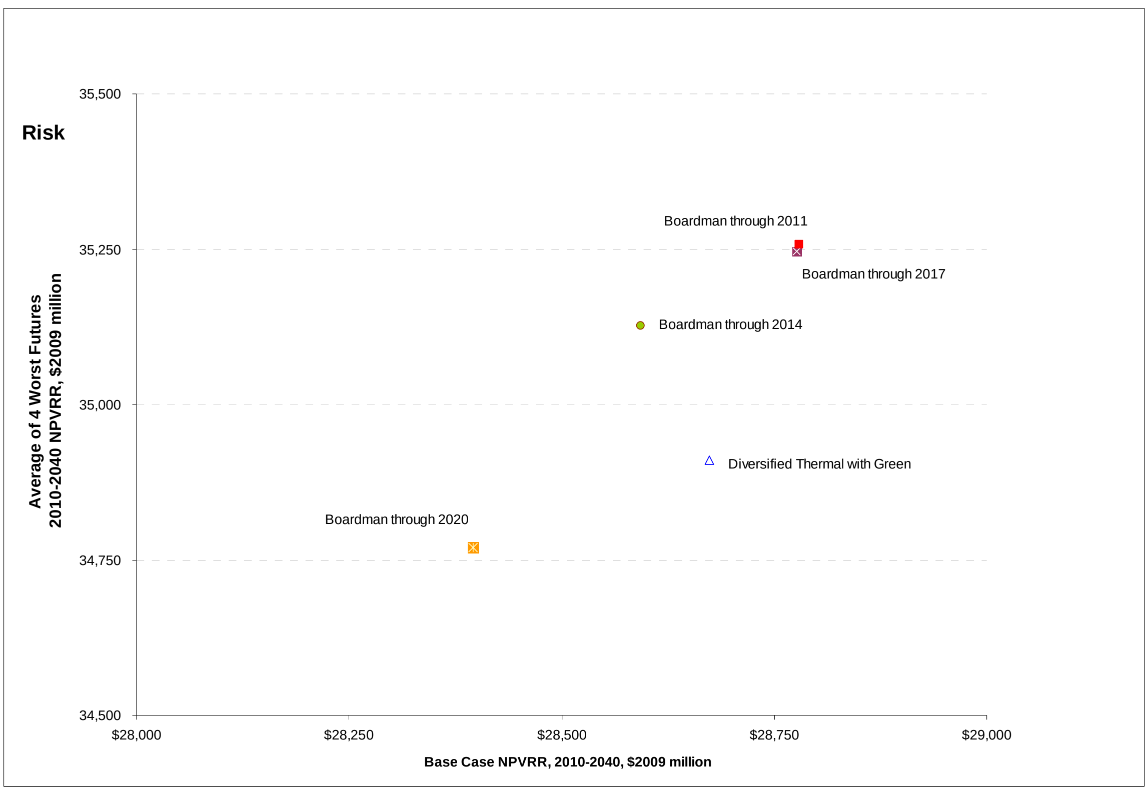
Please refer to Chapter 10A for a detailed description of our portfolio analysis approach.

Deterministic Portfolio Analysis Results

The Trade-off between Expected Cost and Associated Risk

Portfolios with a lower level of risk for a given amount of cost (or vise versa) are deemed to be efficient. This is visually represented on an Efficient Frontier graph where efficient portfolios are closest to the origin when plotting expected costs (plotted on the X-axis) and portfolio risk (plotted on the Y-axis) measured by the average NPVRR of the four worst futures. We originally presented an Efficient Frontier graph in Figure 12.1 of our initial IRP. When the "Boardman through 2020" portfolio is added to the graph, as illustrated in Figure 12A-1, it becomes the best performer. This is a result of the fact that the "Boardman through 2020" provides a better trade-off between cost and risk than any of the other four portfolios. Following "Boardman through 2020", "Diversified Thermal with Green" and "Boardman through 2014" provide the next best cost and cost risk performance. However, "Boardman through 2014" also poses increased implementation and replacement supply risk that is not reflected in the Efficient Frontier Graph.

Figure 12A-1: Efficient Frontier for Boardman Portfolios



This graph also demonstrates that "Boardman through 2020" outperforms the other 4 portfolios on both expected cost and risk, by $197 million in expected cost and $356 million in cost risk compared to the next best early closure portfolio, "Boardman through 2014".

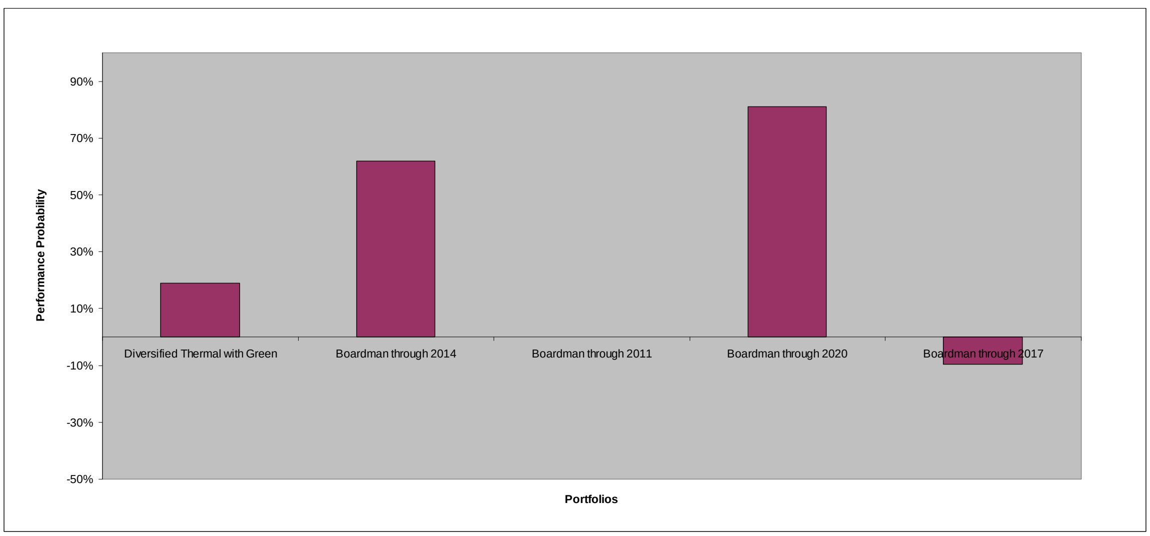
Portfolio Durability: Combined Probability of Achieving Good and Avoiding Bad Outcomes

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. Our IRP analysis defines a bad outcome as the number of times that a given portfolio ranks among the worst four out of the 16 candidate portfolios we tested across 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 16 portfolios we tested across 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 closer to 0%.

"Boardman through 2020" again outperforms the other four portfolios in this metric - 81% of the time it is in the top four performing portfolios through the 21 futures it was tested against.

Figure 12A-2: Combined Probability of Good and Bad Outcomes for Boardman Portfolios



Scenario Risk Magnitude

Scenario (deterministic) risk is measured by two metrics; (1) the average NPVRR of the four worst futures, and (2) the average NPVRR of the four worst futures less the reference case. The first metric addresses the potential magnitude of adverse outcomes. The second metric measures the extent to which performance could adversely change from the expected case. Performance according to the first scenario risk metric is described above under the discussion regarding the trade-off between risk and cost. Looking at the second of these two metrics, "Diversified Thermal with Green", which retains Boardman through 2040, performs best when compared to the other four Boardman alternatives.

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 total, these deterministic risk measures comprise 70% of the overall portfolio score (see Table 12A-2). "Boardman through 2020" performs best according to the combined deterministic risk measures when compared to the other four Boardman alternatives presented in this chapter.

Stochastic Portfolio Analysis Results

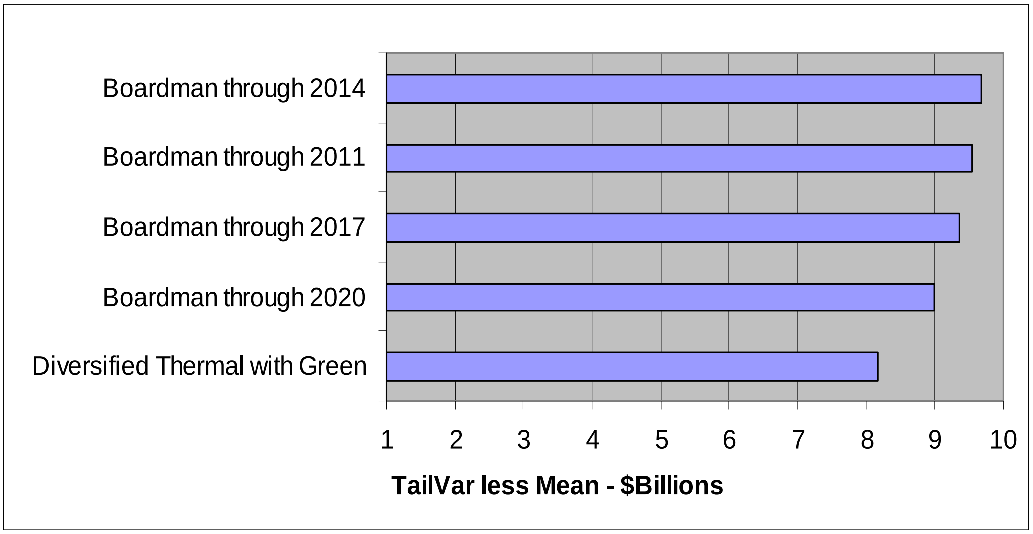
By stochastically modeling WECC-wide load, natural gas prices, historic water years, plant forced outages and the intermittency of wind production, we were able to assess probabilistic metrics of Boardman portfolio risks. As detailed in Chapter 10A, the portfolios were run 100 times subject to stochastic 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 outperforms the other Boardman alternatives by more than $1.2 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 12A-3: Stochastic Risk – TailVar less Mean for Boardman Portfolios

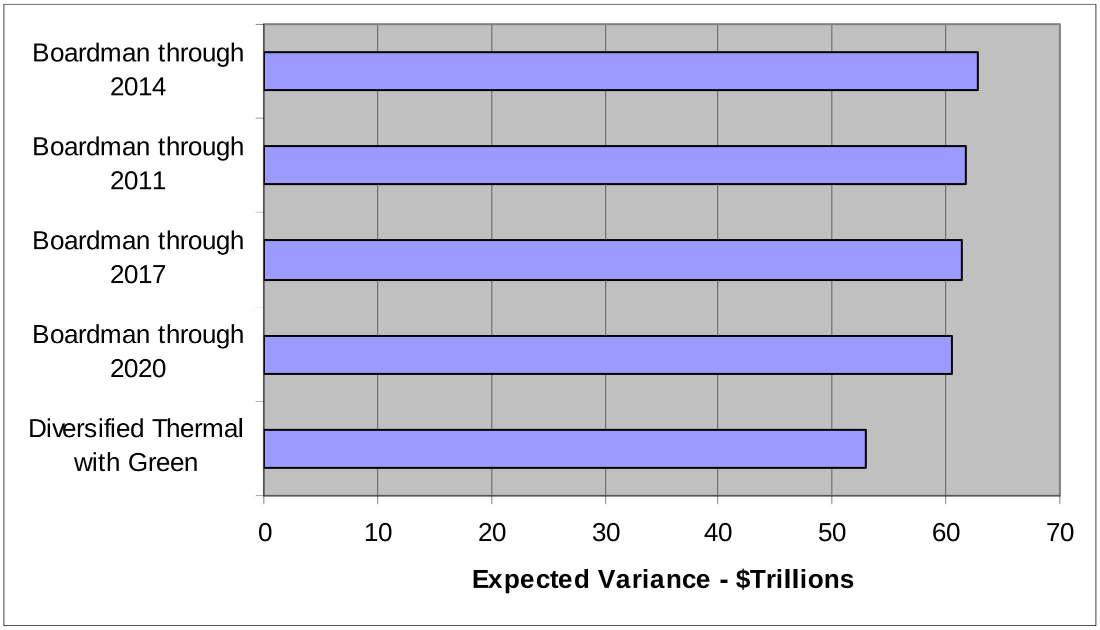


Stochastic Year-to-Year Variation

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 outcomes 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 12A-4 below, "Diversified Thermal with Green" outperforms the other Boardman portfolios. "Boardman through 2020" is the next best performing portfolio according to this risk metric.

Figure 12A-4: Stochastic Risk – Year-to-Year Variation for Boardman Portfolios



Summary of Results from Stochastic Measures

We included three metrics from stochastic analysis in our portfolio scoring methodology: TailVar, TailVar less Mean and Year to Year Variation. Stochastic measurements comprised 10% of the total combined score (see Table 12A-2). Again, the "Diversified Thermal with Green" portfolio performs materially better than the other Boardman cases when considering stochastic cost risk.

Reliability and Diversity Analysis Results

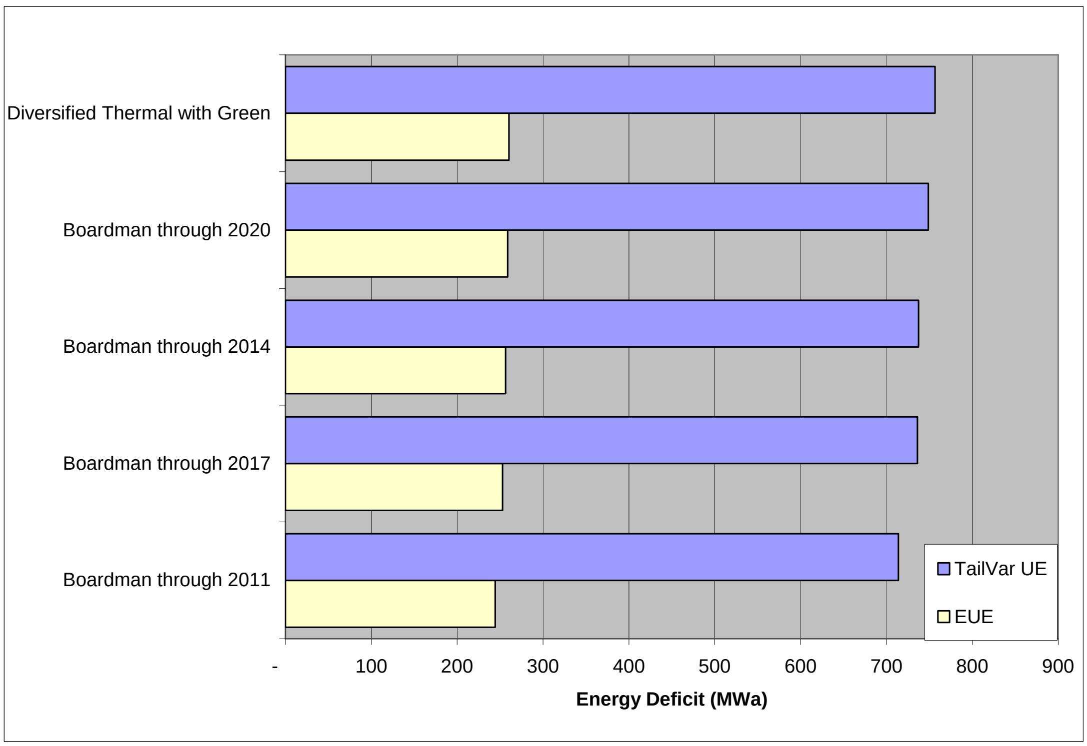
Tailvar Unserved Energy

We calculate the Tailvar of 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) where PGE must purchase power 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 demand. 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.

According to the TailVar UE and EUE metrics "Boardman through 2011" has the highest reliability – see Figure 12A-5. This is largely due to two factors; (1) our model inputs assume a higher forced outage rate for Boardman than a CCCT replacement, and (2) the 2011 portfolio includes a bridge PPA with a forced outage rate equal to a CCCT. However, the TailVar UE and EUE results across the five portfolios presented in Figure 12A-5 are relatively small, with little overall difference in reliability performance for these cases.

It should also be noted that this analysis does not consider reliability risk associated with securing replacement supply sources. It only assesses relative reliability performance of candidate portfolios once all resources are procured and in place. Accordingly, the TailVar UE and EUE metrics do not include uncertainty and potential timing problems with respect to replacing a large current source of baseload energy and capacity such as Boardman. If PGE is unable to secure adequate replacement supply by the time Boardman is closed, our reliability risk would increase. For the earliest Boardman closure portfolios, "Boardman through 2011" and "Boardman through 2014" the replacement supply risk is much higher and more tangible due to the short amount of time that PGE would have to build or procure replacement resources.

Figure 12A-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 2021.

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 specific fuel and generation technology driven risks.

The diversified portfolios outperform all of the early Boardman closure portfolios from fuel and technological perspectives. See Figure 12A-6 and Figure 12A-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 12A-6: Herfindahl-Hirschman Index Boardman Fuel Results

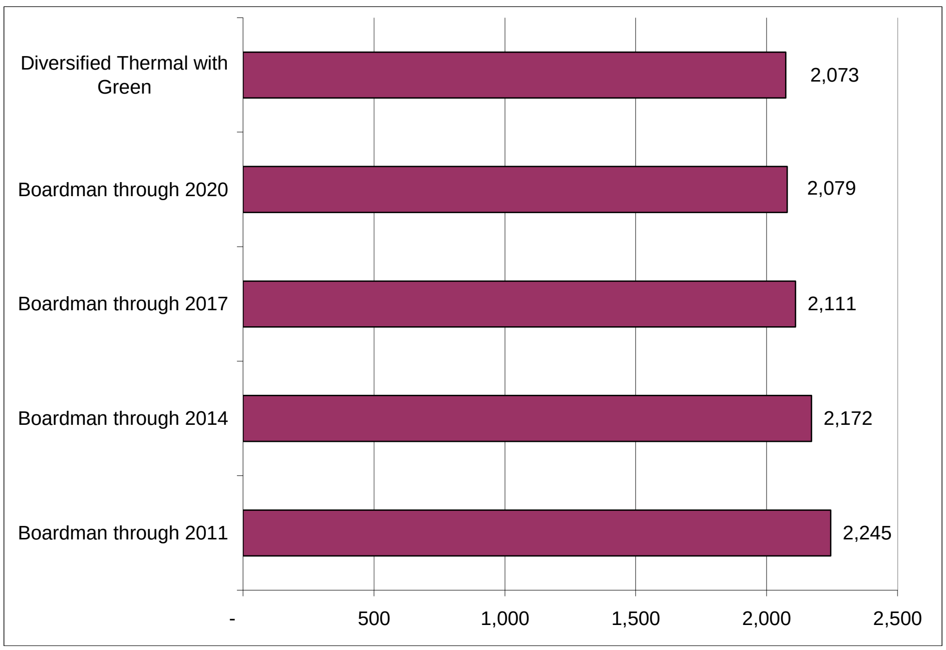
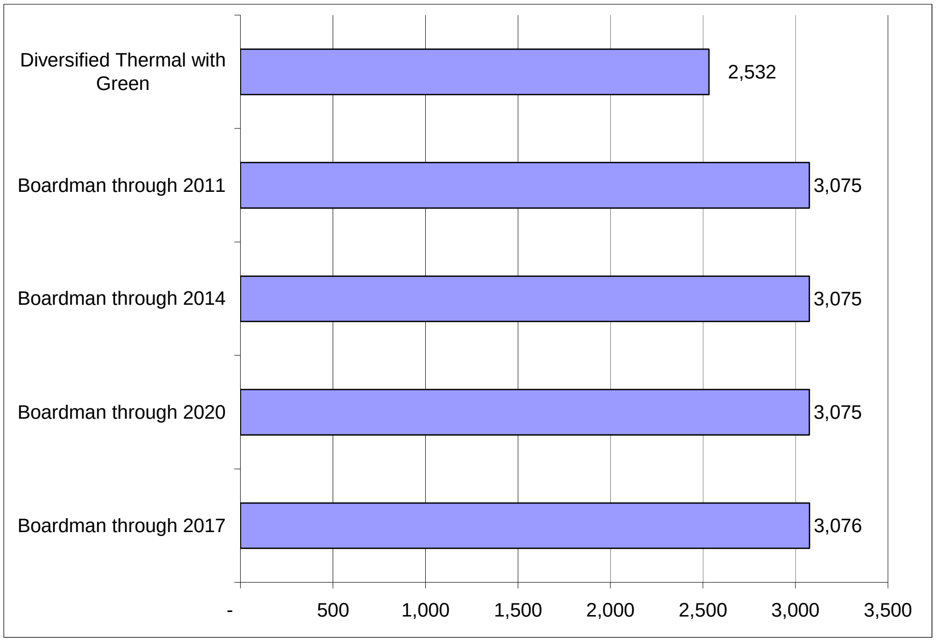


Figure 12A-7: Herfindahl-Hirschman Index - Boardman Technological Results



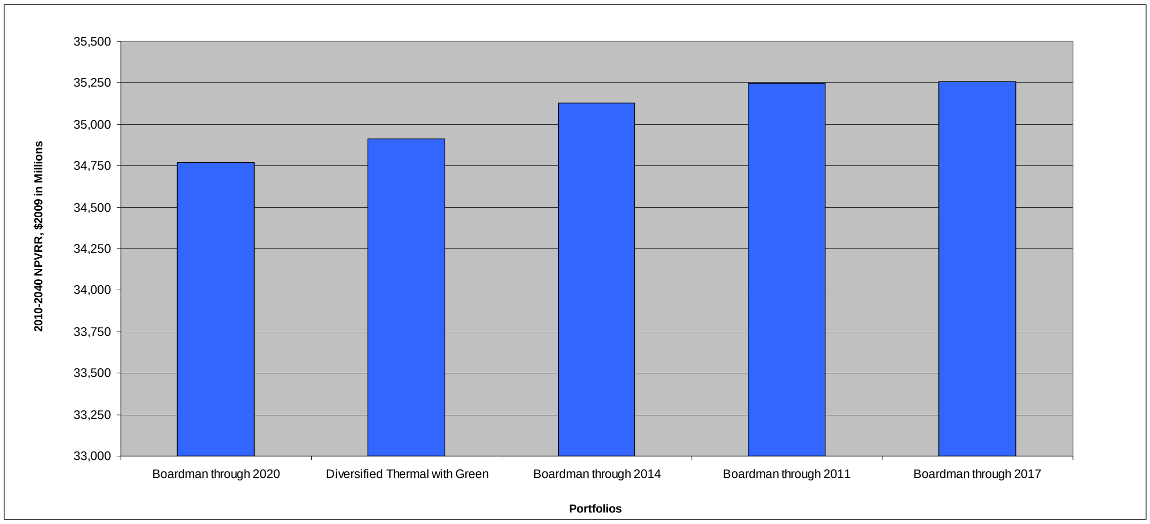
Summary of Results from Reliability and Diversity Measures

Our portfolio scoring includes three measurement categories from the reliability and diversity analysis: Tailvar UE, Technology HHI and Fuel HHI. Reliability and Diversity measures comprise 20% of the total score (see Table 12A-2). "Diversified Thermal with Green", which includes Boardman through 2040, performs better than the other four Boardman portfolios in the combined areas of Reliability and Diversity.

Other Metrics

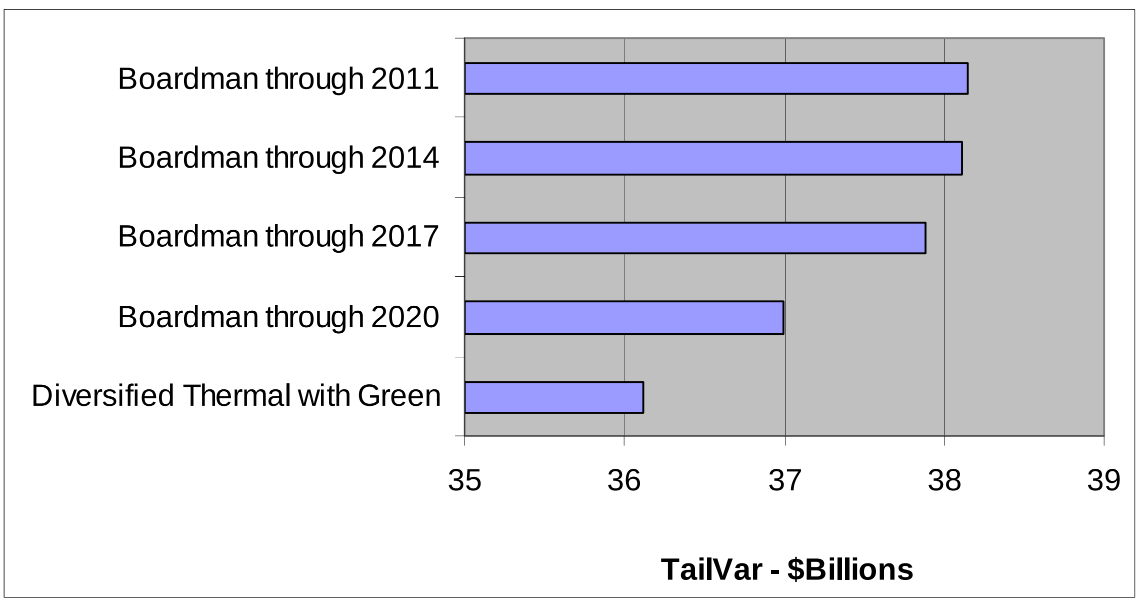
At the suggestion of OPUC Staff, PGE added a variation of two cost risk metrics described above to its scoring. Rather than look solely at the deterministic average of the worst four futures less the reference case cost and the similar stochastic metric of TailVar 90 less the Mean, we have added two right-tail metrics that provide absolute measurements of cost without subtracting a mean or reference case value. This allows for an absolute look at risk exposure without being influenced by distance from the mean. Figure 12A-8 shows the average NPVRR for the four worst future outcomes. "Boardman through 2020" has the lowest NPVRR of the five cases.

Figure 12A-8: Average NPVRR of Four Worst Futures



Similar results are shown in Figure 12A-9 for the selected portfolios when considering TailVar analysis. Here "Diversified Thermal with Green" shows the lowest value. The early Boardman closure portfolios all have higher TailVar scores – with earlier closure dates performing progressively worse.

Figure 12A-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 have the largest impact on portfolio NPVRR. Figure 12A-10 shows the "Diversified Thermal with

Green", "Boardman Through 2014" and "Boardman Through 2020" portfolios' sensitivity to these cost drivers.

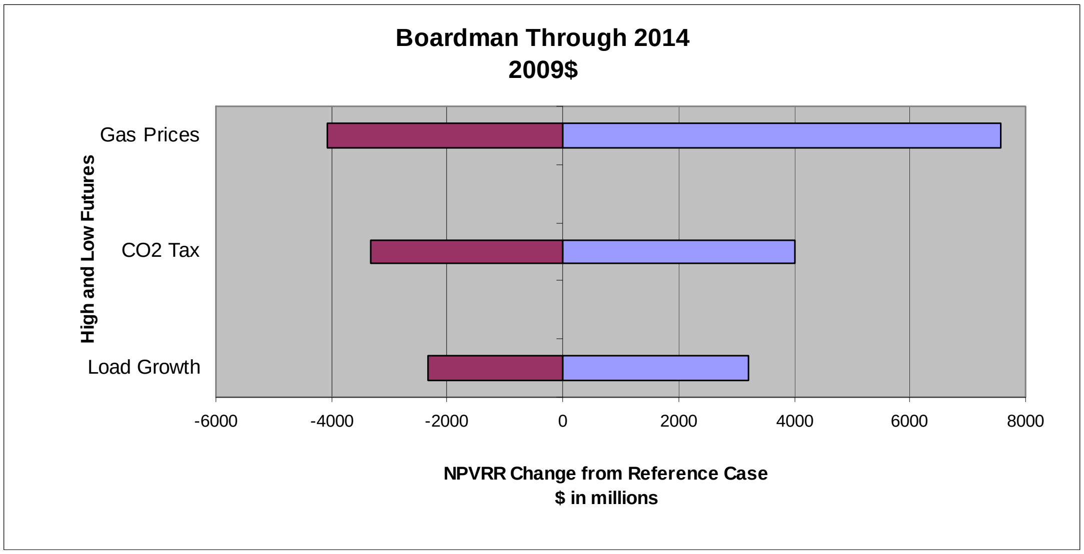
"Boardman Through 2014" and "Boardman Through 2020" are more exposed to gas price risk than "Diversified Thermal with Green", because a gas-fuelled CCCT is the assumed replacement technology for Boardman in these portfolios. However, of these two, "Boardman Through 2020" has less gas price risk than "Boardman Through 2014".

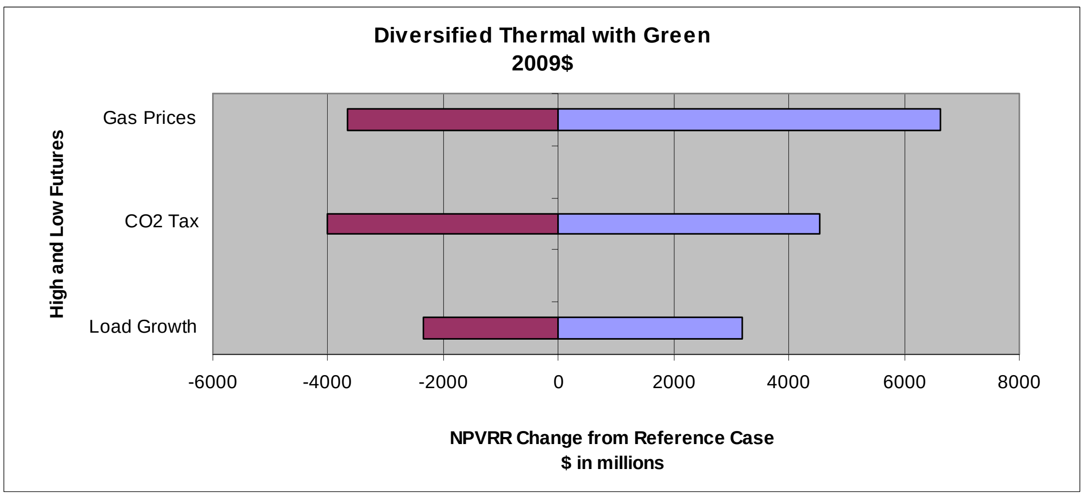
"Diversified Thermal with Green" is more exposed to CO_2 risk. This reflects the higher CO_2 output profile of a coal plant compared to a CCCT. Exposures to load growth are essentially the same for all three portfolios.

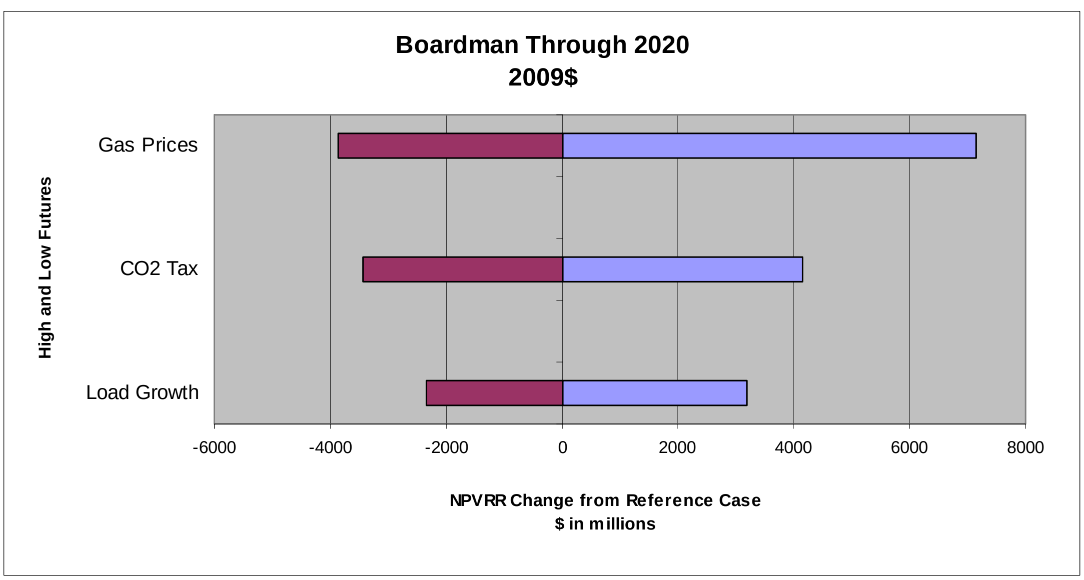
Another insight from these graphs is the apparent asymmetry between upside and downside exposure to gas price risk, while CO_2 cost risk and load growth have fairly balanced risk profiles. This reflects the asymmetry of the high and low natural gas prices as compared to the reference case price, since gas prices can rise higher than they can fall.

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 compliance cost is second and load growth is third. Load growth risk magnitude is equivalent for all three portfolios.

Figure 12A-10: Boardman Portfolios' Sensitivities







12A.6 Assessing Boardman Analytical Results

Our portfolio analysis, using both scenario and stochastic approaches, provides a comprehensive look at Boardman's value and risks. Overall, "Boardman through 2020" performs better than the other Boardman alternatives, when considering the combined portfolio scoring measures – see Table 12A-2 below. The "Boardman through 2020" portfolio clearly outperforms the other early closure cases with respect to both cost and price risk. In general, the "Boardman through 2020" portfolio strikes a good balance between the key risk drivers of natural gas and CO_2 prices, while maintaining system reliability at a relatively low cost. Diversified Thermal with Green also provides a good balance between cost and risk, performing relatively well on expected cost as well most of the risk, durability and diversity measures. Given these results, "Boardman through 2020" is our preferred portfolio, while "Diversified Thermal with Green" represents our next best option when compared to other Boardman alternatives.

Table 12A-2: 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 Frontier 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 Variation	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
	Units	Y or N	Y or N	$ NPV	%	%	%	$ NPV Million	$ NPV Million	$ NPV Million	$ NPV Million	Trillion	MWa	Points	Points
9	Diversified Thermal with Green	Y	Y	$ 28,674	5%	24%	19%	$ 34,910	$ 6,236	$ 36,116	$ 8,171	53	757	2532	2073
10	Boardman through 2014	Y	Y	$ 28,593	5%	67%	62%	$ 35,126	$ 6,533	$ 38,112	$ 9,689	63	737	3075	2172
12	Boardman through 2011	Y	Y	$ 28,777	10%	10%	0%	$ 35,247	$ 6,470	$ 38,142	$ 9,551	62	714	3075	2245
13	Boardman through 2020	Y	Y	$ 28,396	0%	81%	81%	$ 34,770	$ 6,374	$ 36,999	$ 8,987	61	749	3075	2079
16	Boardman through 2017	Y	Y	$ 28,780	10%	0%	-10%	$ 35,257	$ 6,477	$ 37,877	$ 9,358	61	736	3076	2111

Performance Range for Scoring Normalization:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Best Performing Portfolio(s)	0	0	$ 27,211	100%	90%	86%	$ 33,993	$ 4,632	$ 34,481	$ 6,191	$ 37	$ 714	$ 2,036	$ 1,824
Best Basis	0	0	Min	Max	Max	Max	Min	Min	Min	Min	Min	Min	Min	Min
Worst Performing Portfolio(s)	0	0	$ 32,735	0%	0%	-100%	$ 38,635	$ 8,943	$ 38,142	$ 9,689	$ 78	$ 1,050	$ 3,137	$ 2,316
Spread Best to Worst	0	0	$ 5,524	100%	90%	186%	$ 4,641	$ 4,311	$ 3,661	$ 3,498	$ 42	$ 336	$ 1,101	$ 492
% Difference			20.3%				13.7%	93.1%	10.6%	56.5%	113.9%	47.1%	54.1%	27.0%

	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 Frontier 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 Variation	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
9	Diversified Thermal with Green	Y	Y	73.5	64.1	80.3	62.8	55.3	43.4	61.2	87.3	54.9	49.3
10	Boardman through 2014	Y	Y	75.0	87.2	75.6	55.9	0.8	0.0	37.6	93.0	5.6	29.3
12	Boardman through 2011	Y	Y	71.7	53.8	73.0	57.4	0.0	4.0	40.0	100.0	5.6	14.3
13	Boardman through 2020	Y	Y	78.6	97.4	83.3	59.6	31.2	20.1	42.9	89.6	5.6	48.0
16	Boardman through 2017	Y	Y	71.6	48.7	72.8	57.2	7.2	9.5	41.0	93.4	5.5	41.7

	3. Portfolio Evaluation Scoring: Total Weighted Scores	Screening		Deterministic				Stochastic			Reliability & Diversity					
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Frontier 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 Variation	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	0	0	50%	10%	5%	5%	3.3%	3.3%	3.3%	15%	2.5%	2.5%	0	0	0
9	Diversified Thermal with Green	Y	Y	36.8	6.4	4.0	3.1	1.8	1.4	2.0	13.1	1.4	1.2	71.4	96%	5
10	Boardman through 2014	Y	Y	37.5	8.7	3.8	2.8	0.0	0.0	1.3	14.0	0.1	0.7	68.9	93%	7
12	Boardman through 2011	Y	Y	35.8	5.4	3.6	2.9	0.0	0.1	1.3	15.0	0.1	0.4	64.7	87%	10
13	Boardman through 2020	Y	Y	39.3	9.7	4.2	3.0	1.0	0.7	1.4	13.4	0.1	1.2	74.1	100%	2
16	Boardman through 2017	Y	Y	35.8	4.9	3.6	2.9	0.2	0.3	1.4	14.0	0.1	1.0	64.3	87%	12

Other Considerations

The "Boardman through 2020" portfolio has other compelling advantages not captured in our IRP scoring compared to the "Boardman through 2014" and other Boardman alternatives examined here:

- It preserves the near-term economic value of the plant thereby saving customers around $600 million dollars over the next decade compared to the earlier closure alternatives.

- It avoids the acceleration of additional costs and the corresponding customer rate pressure during a time when other IRP resource actions are also being implemented.

- It allows time for other greener technologies beyond wind to develop and economically mature, potentially allowing for a greater range of replacement options by 2020 than are available today for implementation by 2014.

- It provides a hedge against compliance costs of any future greenhouse gas legislation when compared to plans that operate Boardman through 2040

- It allows for an orderly transition for Boardman plant employees and the local community.

Boardman Recommendation

PGE's preferred Action Plan is based on the "Boardman through 2020" portfolio. It includes the following investments in emissions controls:

- <u>NOx Controls</u>: install the LNB/MOFA control system which, as proposed, is estimated to reduce NOx by 4,000 tons per year, for nearly a 50% 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.

- <u>Mercury Controls</u>: install the mercury (Hg) control system by 2012 for an estimated overnight capital cost of approximately $8 million (100% of Boardman plant).

- SO_2 Reductions: procure lower sulfur coal which will reduce SO_2 emissions 20% below current permit levels by the end of 2011 and 50% below current permit levels in 2014. (Incremental costs to procure new, lower sulfur coal supply have not been factored into our portfolio analysis, but any additional costs are not expected to have a material impact on the comparative economics of the candidate portfolios.)

Table 12A-3 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 for the LNB/OFA controls.

Table 12A-3: Boardman Engineering Procurement and Construction Schedule

	Controls	EQC Emission Compliance Date	EPC Contract Date
1.	LNB/OFA	July 2011	March 2010
2.	mercury	July 2012	Q2-Q3 2010

Table 12A-4 below summarizes the capital costs that are modeled in our IRP analysis and are associated with each of PGE's recommended emissions controls. Capital costs in this table are 100% share of the Boardman plant. Installation of the new control systems is expected to take place during our normally scheduled spring maintenance outages.

Table 12A-4: Proposed Boardman Emissions Controls Capital Costs, Nominal $

	LNB/OFA	Hg	Total
2007	75	25	100
2008	468	156	624
2009	1,554	77	1,632
2010	16,628	233	16,861
2011	14,123	4,819	18,943
2012	-	2,345	2,345
2013	-	-	-
2014	-	-	-
2015	-	-	-
2016	-	-	-
2017	-	-	-
	32,849	7,655	40,504
AFDC	3,636	912	4,548
Property Tax	386	108	494
Total	36,872	8,675	45,546

With all proposed BART II controls in place in 2014, variable and fixed non-fuel O&M will not change materially.

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.

Boardman Alternate Recommendation

As discussed in detail in Chapter 13A, if PGE is not able to move forward with its preferred Action Plan by March 31, 2011, then it requests that the Commission acknowledge that it is prudent to move forward with an alternate Action Plan based on the "Diversified Thermal with Green" portfolio (with or without lease). The costs for the emissions control equipment associated with the alternate Action Plan are described in our November, 2009 IRP filing, which for convenience we replicate below.

Phase 1

- <u>NOx Controls</u>: 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 12A-5 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.

Table 12A-5: Boardman Engineering Procurement and Construction Schedule

	Controls	EQC Emission Compliance Date	EPC Contract Date
1.	LNB/OFA	July 2011	March 2010
2.	Mercury	July 2012	Q2-2011
3.	FGD	July 2014	Q1-2011
4.	SCR	July 2017	Q1-2014

Table 12A-6 below summarizes the capital costs associated with each of the emissions controls according to the alternate Action Plan recommendation; 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 12A-6: 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 non-fuel dispatch cost is expected to increase by approximately $3 per MWh in 2009 $ exclusive of CO_2 costs.

As discussed in further detail in Chapter 13A, PGE recommends acknowledgement of our preferred Action Plan based on the Boardman through 2020 portfolio. In the event that the contingencies associated with the preferred Action Plan (as outlined in Chapter 13A) can not be resolved, we recommend proceeding with our alternate Action Plan based on the Diversified Thermal with Green portfolio.

13A. 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 an Action Plan based on the Boardman through 2020 portfolio. Our results indicate that this portfolio provides the best balance of expected costs and associated risks. The portfolio is durable, performing well under the stress testing we conducted via our analysis.

Our recommended Action Plan allows the company to retain the economic and reliability benefits of the Boardman plant for the next decade, avoids expensive plant upgrades and hedges against the long-run risk of green-house gas emissions costs. This Action Plan also includes significant incremental energy efficiency and new renewables, while providing sufficient energy and capacity resources via the addition of new natural gas-fired baseload and peaking generation to maintain system reliability. Finally, the Action Plan includes new transmission facilities ("Cascade Crossing") to link existing and potential future generation resources on the east side of the Cascades to PGE's load centers on the west side. The new transmission is also targeted to reach areas where further renewable resources are expected to be built, thereby increasing access to green energy supply that will be needed to meet future RPS requirements.

As discussed below, the implementation of our preferred Action Plan depends on the resolution of three external contingencies. We are asking the Commission to acknowledge that it is prudent for PGE to move forward with an alternate IRP Action Plan, based on the Diversified Thermal with Green portfolio, should any of the three contingencies not be resolved by March 31, 2011. The Diversified Thermal with Green portfolio also performs well considering both cost and risk, and represents the next best option for PGE and its customers if we are not able to resolve the contingencies associated with the Boardman through 2020 portfolio.

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 650 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 provide our customers with the best combination of supply reliability, near-term cost savings and longer-term risk mitigation, our preferred Action Plan includes cessation of coal operations at the Boardman plant at the end of 2020, with limited investments in new emissions controls at Boardman to meet the requirements of our petition to amend the Oregon Regional Haze Plan, and the existing Oregon Utility Mercury Rule.
- Our preferred Action Plan depends on the resolution of three contingencies. We are requesting acknowledgment of an alternate Action Plan based on the Diversified Thermal with Green Portfolio if we cannot resolve the contingencies by March 31, 2011.
- 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.

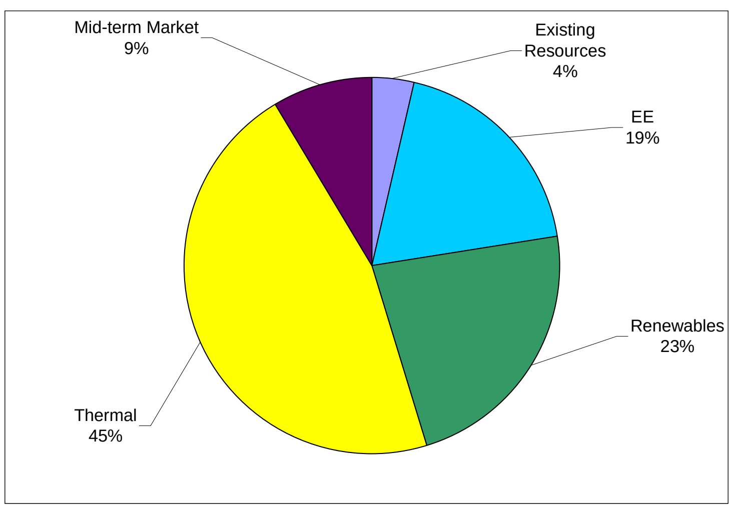
13A.1 Resource Actions

Action Plan Resource Mix

Both our recommended and alternate Action Plans seek to fill up to 873 MWa with energy actions in the next four years, to be in place by 2015. This target is based on the continued operation of the Boardman plant through 2020 for the recommended Action Plan and 2040 for the alternate Action Plan. Among longer-term commitments, 8% (66 MWa) is expected to come from contract renewals and the exercise of existing contract rights for current resources. Another 26% (214 MWa) will come from EE and 15% (122 MWa) from renewables. A high-efficiency CCCT comprises almost 50% (406 MWa) of the resource additions. The remaining need is acquired through short and mid-term market purchases, to hedge against load uncertainty.

Through 2021, in addition to ongoing EE, our preferred 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 2021, renewal of existing resources comprise 4% (66 MWa), EE meets 19% (331 MWa) of the need, renewables meet 23% (405 MWa), and gas provides 45% (817 MWa). The remainder, approximately 9% (151 MWa), comes from short- to mid-term market purchases. Figure 13A-1 illustrates the incremental resource mix of our recommended portfolio through 2021.

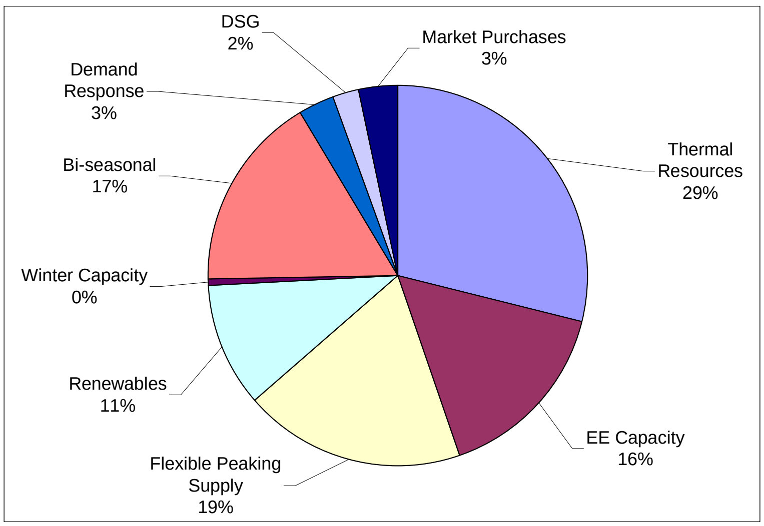
Figure 13A-1: Action Plan Incremental Energy Resource Mix – 2021



Our Winter Capacity Action Plan is, by 2015, comprised of 26% (443 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, 12% (202 MW) bi-seasonal capacity contracts, 3.5% (60 MW) demand response, 4% (67 MW) DSG, and 6% (100 MW) market purchases.

Through 2021 capacity needs continue to grow. Under our preferred portfolio, our capacity by resource type in 2021 is 29% (887 MW) thermal resources, 16% (487 MW) EE capacity, 19% (580 MW) flexible peaking resources, 11% renewables (330 MW), 17% (513 MW) bi-seasonal capacity contracts, 3% (96 MW) demand response, 2% (67 MW) DSG, 3% (100 MW) market purchases and a minor amount (14 MW) of winter-only capacity contracts. Figure 13A-2 shows the breakout below.

Figure 13A-2: Action Plan Incremental Winter Capacity Resource Mix – 2021



Our Summer Capacity Action Plan is, by 2015, comprised of 30% (443 MW) thermal resources, 14% (210 MW) EE capacity, 14% (200 MW) flexible peaking resources (2013), 13% (185 MW) renewables, 14% (202 MW) bi-seasonal capacity contracts, 4% (60 MW) demand response, 5% (67 MW) DSG and 7% (100 MW) market purchases.

Figure 13A-3 below shows a breakout of our 2021 summer capacity resources according to our preferred portfolio below. The total by resources are 31% (887 MW) thermal resources, 11% (325 MW) EE capacity, 20% (580 MW) flexible peaking resources, 11% renewables (330 MW), 18% (513 MW) bi-seasonal capacity contracts, 4% (102 MW) demand response, 2% (67 MW) DSG, and 3% (100 MW) market purchases.

Table 13A-1, Table 13A-2 and Table 13A-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 resource additions by 2021). The tables show our resource need from the earlier load/resource balance analysis and how the recommended resources fill these needs.

Figure 13A-3: Action Plan Incremental Summer Capacity Resource Mix - 2021

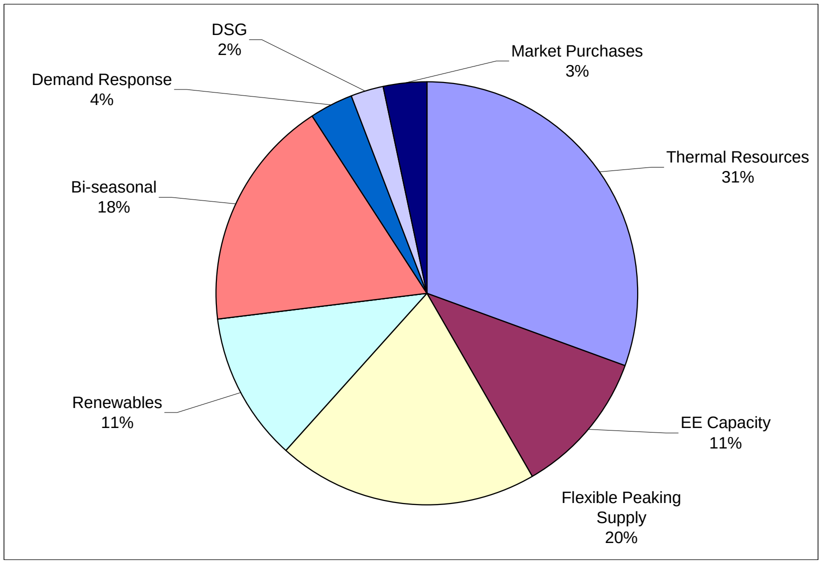


Figure 13A-4 below shows PGE's resource mix following implementation of our Action Plan for 2015.

Figure 13A-5 is the 2021 view. 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 13A-4: PGE Projected 2015 Energy Resource Mix[10]

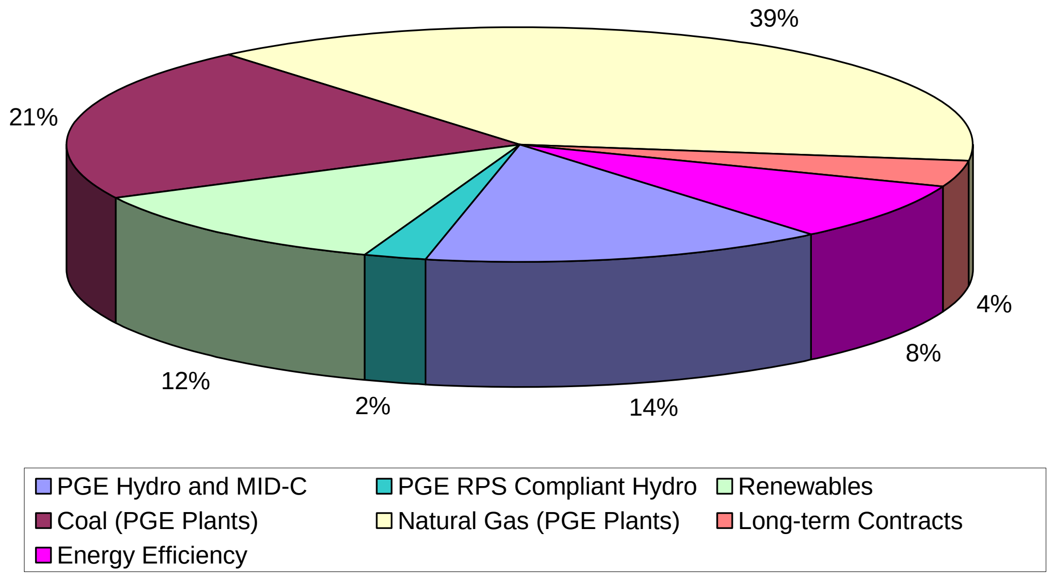
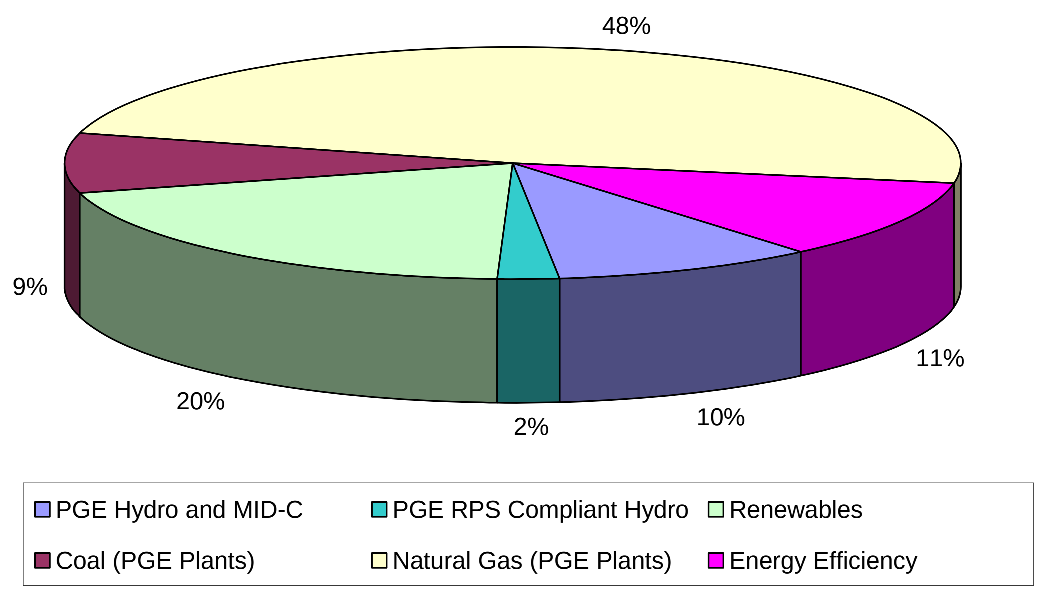


Figure 13A-5: PGE Projected 2021 Energy Resource Mix



[10] 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 13A-1: Energy Action Plan

Energy MWa @ Normal Hydro	**Action Plan**	
	2015*	**2021**
PGE system load at normal weather	2,624	2,942
Remove assumed 5-yr. opt-out load	(28)	(28)
Existing PGE & contract resources	(1,850)	(1,340)
Remove post 2008 cumulative embedded EE	128	196
PGE Resource Target	**873**	**1,769**
Resource Actions		
Thermal Resource Actions:		
Combined Cycle Combustion Turbine (2015)	406	812
Combined Heat & Power (2015, 2017, 2019)	2	5
Renewable & EE Resource Actions:		
ETO Energy Savings Target (2009-2020)	214	331
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)	-	179
To Hedge Load Variability:		
Short- and Mid-term Market Purchases	100	100
Subtotal	**909**	**1,719**
(Surplus) / deficit met by market	(36)	51
Total Resource Actions	**873**	**1,769**
*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 13A-2: Summer Capacity Action Plan

August Capacity MW @ Normal Hydro	Action Plan 2015*	2021
PGE system peak at normal weather	3,778	4,339
Operating Reserves (approximately 6% of generation)	194	168
Contingency Reserves (6% of Load)	225	258
Remove assumed 5-yr opt outs (w/contingency reserves)	(31)	(31)
Existing PGE & contract resources	(2,822)	(2,024)
Remove post 2008 cumulative embedded EE	126	192
PGE Resource Target	**1,468**	**2,903**
Resource Actions		
Thermal Resource Actions:		
Combined Cycle Combustion Turbine (2015)	441	881
Combined Heat & Power (2015, 2017, 2019)	2	6
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)	-	27
To Hedge Load Variability:		
Short- and Mid-term Market Purchases	100	100
Capacity only resources:		
Flexible Peaking Supply (2013)	200	580
Customer-Based Solutions (Capacity only):		
Dispatchable Standby Generation (2010-2013)	67	67
Demand Response (2010-2012 and 2017-2020)	60	102
Seasonally Targeted Resources:		
ETO Capacity Savings Target (2009-2021)	210	325
Bi-seasonal Capacity	202	513
Winter-only capacity	-	-
Total incremental resources	**1,468**	**2,903**

*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 13A-3: Winter Capacity Action Plan

January Capacity MW @ Normal Hydro	Action Plan 2015*	2021
PGE system peak at normal weather	4,107	4,558
Operating Reserves (approximately 6% of generation)	205	178
Contingency Reserves (6% of Load)	245	272
Remove assumed 5-yr opt outs (w/contingency reserves)	(31)	(31)
Existing PGE & contract resources	(2,989)	(2,190)
Remove post 2008 cumulative embedded EE	188	288
PGE Resource Target	**1,724**	**3,074**
Resource Actions		
Thermal Resource Actions:		
Combined Cycle Combustion Turbine (2015)	441	881
Combined Heat & Power (2015, 2017, 2019)	2	6
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)	-	27
To Hedge Load Variability:		
Short- and Mid-term Market Purchases	100	100
Capacity only resources:		
Flexible Peaking Supply (2013)	200	580
Customer-Based Solutions (Capacity only):		
Dispatchable Standby Generation (2010-2013)	67	67
Demand Response (2010-2012 and 2017-2020)	60	96
Seasonally Targeted Resources:		
ETO Capacity Savings Target (2009-2021)	315	487
Bi-seasonal Capacity	202	513
Winter-only capacity	152	14
Total incremental resources	**1,724**	**3,074**

*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[11]

1. ***Energy Efficiency (EE).*** We recommend continuation of the ETO EE acquisition programs to provide 331 MWa by 2021, along with continued funding via the twin funding vehicles of the 3% system benefits charge (SBC) and the SB 838 supplemental funding mechanism, to the maximum degree found to be cost-effective, according to ETO standards. EE not

[11] These actions were included in all of our candidate portfolios – see Chapter 11A.

only provides benefits to customers in the form of lower bills and to PGE in the form of 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 67 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 successfully launched a pilot for large customers who can provide 1MW of load reduction when called upon. Discussions are underway to conduct pilots in the commercial and electric water heat sectors.

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***.

Preferred Action Plan

Our preferred Action Plan includes an emissions control upgrade package for the Boardman Plant, with a cessation of coal-fired operations at the end of 2020. The emissions controls consist of the installation of low-NOx burners and over-fire air ducts by July 2011, which is expected to reduce NOx by approximately 50% and the injection of carbon by 2012 to meet the requirements of the Oregon Utility Mercury Rule (current construction schedules should allow PGE to meet this deadline a year early, in 2011). In addition to new physical controls, our proposal also calls for the use of lower sulfur coal to reduce SO_2 emissions by 20% over current permit limits by the end of 2011 and by 50% over current permit limits by July 2014. We have not conducted a solicitation process for such lower sulfur coal and thus have not modeled any potential corresponding incremental cost within this IRP. However, preliminary estimates indicate that the costs will not have a material impact on the comparative economics of the candidate portfolios.

Contingencies

Our preferred Action Plan is based on the following contingencies:

a. As described in Chapter 12A, on June 19, 2009, the EQC approved an Oregon Regional Haze Plan which provides PGE with limited options for the installation of emissions controls at Boardman. The plan has been submitted, and is currently awaiting approval by EPA. None of the options under the existing Oregon Regional Haze Plan would allow PGE to reduce emissions by installing limited controls and closing the plant twenty years early. Therefore, in order for PGE to implement the preferred Action Plan based on the Boardman through 2020 portfolio, the EQC must approve a change to the Oregon Regional Haze Plan and

PGE must obtain a consistent Title V permit from DEQ. On April 2, 2010, PGE submitted a Petition to amend the Oregon Regional Haze Plan to the DEQ (BART II Petition). If the EQC does not approve the BART II Petition then PGE cannot proceed with the preferred Action Plan and be compliant with federal and state law. We expect a decision on our Bart II Petition from the EQC by December 2010 and issuance of associated permit modifications sometime thereafter. EPA will need to review and approve the revisions to the Oregon Regional Haze Plan. If EPA does not approve the revisions to the Oregon Regional Haze Plan, then PGE cannot proceed with the preferred Action Plan. An EPA decision is expected within a year to 18 months following the EQC decision.

b. A consent decree resolving a recent D.C. Circuit Court case established that the Clean Air Act requires EPA to promulgate National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for Electrical Generating Units (EGUs). The NESHAPs may require plants such as Boardman to control hazardous air pollutants. It is possible controls could be required before 2020 and that they could be similar to the controls required under the current Oregon Regional Haze Plan. Therefore, even if EQC/EPA approves a change to the Oregon Regional Haze Plan, PGE may be required by the EGU NESHAPs requirements to install essentially the same controls that were required under the current Oregon Regional Haze Plan – in which case the Boardman Plant will need to operate through 2040 to recover the costs of the controls. EPA is expected to propose EGU NESHAP in March of 2011, with the final rule in November of 2011. PGE is working to obtain regulatory and legislative resolutions to this contingency. However, if PGE is unable to resolve this contingency then PGE will need to proceed with the alternate Action plan for Boardman.

c. On September 30, 2008, several environmental groups filed a Complaint against PGE in United States District Court for the District of Oregon, Civil No. CV08-1136-HA alleging violations of the federal Clean Air Act (CAA), Oregon's State Implementation Plan (SIP), the Plant's CAA Title V permit and other environmental regulations. The Complaint seeks penalties and injunctive relief, including permanently enjoining PGE from operating Boardman except in accord with the CAA, SIP and the Plant's Title V permit. The parties have agreed to bifurcate the case with a liability trial followed by a separate trial on remedies. The liability trial currently is scheduled for June, 2011. If the court renders an opinion that is adverse to PGE, a remedy trial would follow. We would expect a remedy trial would occur approximately 12 - 14 months following a liability determination. In this case, the Sierra Club has stated that it seeks as a remedy a remand to the Oregon DEQ for a BACT determination in addition to penalties. BACT controls could include substantially similar controls to those required in the current Oregon Regional Haze Plan. If the remand results in a requirement for PGE to install controls at Boardman which are significantly more costly than those proposed under our BART II Petition, then PGE will need to operate through 2040 to recover the costs of the controls.

Timing of Contingencies

The first and third contingencies described above must be resolved by March 31, 2011. This is the date by which we will have to order a scrubber to comply with the Oregon Regional Haze Plan, if it is not amended. In regards to the second contingency – NESHAPs, given reasonable timelines for regulatory or federal legislative resolution, PGE will need to determine by March 31, 2011 if there is reasonable assurance that coal generating facilities that have established shut down dates prior to 2021 will be able to continue operating until that date without installing additional emission control technology beyond those included in our BART II petition. In short, this means that the following 3 events need to occur by March 31, 2011 in order for us to move forward with our preferred Action Plan: (1) EQC must approve our BART II Petition[12]; (2) PGE must have reasonable assurance that Boardman will be subject to a legislative or regulatory resolution to the forthcoming NESHAPs rule or the proposed rule must indicate that installation of controls at Boardman beyond those required under our BART II petition will not be required; (3) the pending litigation must be resolved in such a way that PGE will not be required to install controls at Boardman beyond those required under our BART II Petition. We are seeking acknowledgment to proceed with our alternate Action Plan, based on the Diversified Thermal with Green portfolio (with or without Lease), if any one of these events has not occurred by March 31, 2011.

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[12] DEQ has indicated that it will consult with EPA and include EPA as part of its decision making process regarding BART II. However, there is a risk that after March 31, 2011 EPA may not approve our BART II Petition. There is also a risk that DEQ may not issue a Title V permit that is consistent with its action on our BART II Petition in a timely manner, which could result in temporary closure of the plant until the permit is modified. We want to be clear that Commission acknowledgment of Boardman through 2020 is subject to these risks.

Risk of Delay in Ordering Boardman Emissions Control Equipment

We believe that it is not in the best interests of our customers to delay ordering emissions control equipment beyond the time needed to ensure that we are compliant with state and federal law. Such a delay would likely result in adverse consequences, including: (i) increased costs for emissions control equipment and/or project construction due to a compressed Engineering, Procurement and Construction (EPC) schedule; and (ii) a temporary shut-down of the plant due to an inability to install equipment to timely meet regulatory or legal requirements.

We have evaluated some of the potential cost impacts of a temporary shut-down by estimating the potential cost of replacement power supply for PGE's share of the Boardman plant using a simplified approach based on current production costs for Boardman as compared to current market prices for wholesale electricity purchased at the Mid-Columbia market hub. Using this methodology, the cost of electric supply from Boardman is estimated at $5.4 million per month (on an annual average basis), while the cost for the same amount of electricity from the wholesale market is estimated to be $11.7 million per month (again, on an annual average basis). The resulting incremental cost for replacement supply is approximately $6.4 million per month under current conditions. It should be noted that the cost for replacement supply in the market would be much higher if a temporary shut-down occurred during peak summer or winter months. As an example, if a temporary shut-down were to occur in August or December, the replacement costs would increase by as much as 25 – 40% to a range of roughly $8 - $9 million per month based on current market prices.

Based on this differential monthly cost for replacement power supply we can then estimate the potential cost for various temporary shut-down scenarios. For example, if Boardman were shut-down for a period of six months due to a delay in regulatory approval, a permitting delay or delay in ordering emissions control equipment, the resulting increased cost to PGE customers would be approximately $38.1 million. This compares to actual replacement power costs of roughly $15 million per month during an extended forced maintenance outage for Boardman in late 2005 and early 2006. The current estimate is lower than replacement costs experienced in 2005 – 2006 due to lower prevailing wholesale market power and natural gas prices than those that existed a few years ago. However, current market prices continue to be influenced by lower demand stemming from the "Great Recession", thus an estimate of replacement cost risk based on today's prices likely understates any future exposure.

It should also be noted that there is no certainty that sufficient replacement supply would even be available to offset Boardman's energy production in the event of a temporary shut-down, or what impact a Boardman shut-down would have on prevailing market prices. History has shown that removing large plants from service within the regional power grid typically causes upward pressure on market prices. The degree to which prices would ultimately rise is unknown and depends on many factors, including regional load conditions and generation availability at the time.

We recognize that the above discussion only provides insights into potential replacement power cost impacts for a temporary shut-down based on current conditions, and such conditions and costs could change (perhaps considerably) by the time such closure could occur. However it does provide a sense of magnitude with respect to the risk involved in delaying a decision to proceed with ordering equipment to meet emissions control requirements. Given the magnitude of this risk and the likelihood that other costs will be incurred due to increases in equipment and project costs, we believe that a temporary shut-down of any material duration would result in significant, adverse consequences for our customers.

Alternate Action Plan

As discussed above, our preferred Action Plan can only be implemented upon the resolution of three contingencies. PGE requests acknowledgement to proceed with an alternate Action Plan based on the Diversified Thermal with Green Portfolio (either with or without lease) should any one of the contingencies fail to be resolved. The Diversified Thermal with Green portfolio is the next best option for PGE and its customers, as it provides a good balance between cost and risk and provides lower execution risk when compared to other high scoring candidate portfolios.

Under the alternate Action Plan, PGE would continue operations at Boardman and proceed with capital and operating expenditures to achieve compliance with the existing Oregon Regional Haze Plan and Oregon Utility Mercury Rule within the Action Plan timeframe. These actions include commitments to purchase low-NOx burners and over-fire air controls in Q1 2010, with controls installed by July 2011, commitments to purchase mercury controls in 2010, with installation by 2012, commitments to purchase scrubbers and mercury control in Q2 2011, with installation by July 2014, followed by commitments to purchase SCR (selective catalytic reduction) by Q2 2014 with installation by July 2017, for a total estimated installed cost of $510 million (100% plant).

Boardman is an important resource in PGE's current portfolio. As a result, any decision to change the operating plan for the plant or make significant investments in new equipment will have a major impact on future costs and risks for PGE's customers. Furthermore, these decisions are time-sensitive with significant adverse consequences for failure to act, including ceasing plant operations as soon as July 2014, the beginning of our summer peak load season. As a result, it is imperative that the Commission act promptly in its review of PGE's proposed Action Plan.

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***. Under the above outlined preferred Action Plan, we would not pursue our option to acquire further output from the plant via the BAL arrangements. However, if we proceed with the alternate Action Plan we would evaluate the economics and risks of exercising one of our options under the BAL agreements to acquire an additional 15% of the Boardman plant output (72 MWa) prior to the expiration of those rights. The lease option must be invoked by the end of 2011. Whether PGE would invoke its rights under the lease arrangement will depend on analysis of the economics and risk of exercising such rights prior to the time of expiry, as well as reaching resolution regarding the operating life of the plant. Deferring the decision about exercising the lease option provides value to PGE customers in the form of optionality, and allows further time for risk and value drivers to become more certain.

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 IRP. 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. The Flexible Capacity Resources will be included in a future RFP to be issued pursuant to this IRP. 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 202 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.

13A.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 about 600 MW of electric generation. 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.

13A.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 and other factors. 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. Other factors that could influence which transmission option to pursue include such things as the need for or value of reliability improvements, reducing transmission losses, flexibility to meet future need, the ability to connect to new transmission projects in order to access regional power markets, efficiency of permitting process and any required mitigation of environmental impact.

    Our proposal to construct Cascade Crossing remains the same under both our preferred and alternate Action Plans. If PGE were to cease coal-fired operations at Boardman in 2020, as proposed in our preferred Action Plan, we believe it is likely that Boardman would be replaced with a similarly sized generating facility located near Boardman that could connect to Cascade Crossing. Therefore, a cessation of coal-fired operations at Boardman in 2020 would not alter our recommendation to proceed with the Cascade Crossing project.

13A.4 Resource Acquisition Timing

While the timeframe for our portfolios extends to 2021 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 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.

13A.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."

As described in Section 13A.1, our preferred Action Plan cannot currently be implemented under the existing Oregon Regional Haze Plan. PGE has petitioned the EQC for a rule change to allow us to implement our preferred portfolio. If our BART II petition is not granted we will not be able to implement the Boardman elements of our preferred Action Plan. In addition, as we also describe in Section 13A.1, EPA may issue NESHAPS which will prevent us from implementing our preferred portfolio.

Other than the issues described above, we believe our preferred and alternate Action Plans are consistent with current state and federal energy policies. Specifically, some of the key ways in which the plans comply with existing and near-term expected policies include the following:

1. They are in physical compliance with the state of Oregon RPS;
2. They incorporates, at varying levels, an expected compliance cost for potential future federal CO_2 legislation;

3. The preferred Action Plan includes all required emissions controls to meet the provisions of the new BART II filing for Boardman, subject to such plan being approved by the EQC as a new Oregon Regional Haze Plan; the Alternate Action Plan includes all required emissions controls to meet the provisions of the current Regional Haze Plan; and

4. They fully utilize 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

Beyond the three contingencies to the implementation of our preferred Action Plan described in Section 13A.1, potential barriers to implementation of both our preferred and alternate Action Plans tend to be generic and thus are not unique to those Plans 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 preferred and alternate Action Plans.

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 and alternate Action Plans 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 renewable resources to meet various state RPS goals and the limited supply of good sites (particularly for wind), it is likely that acquisition of some sites in advance of project development and construction would 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***. Our Plans call 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 acknowledged 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 resource bids.

Conclusion

Our preferred and alternate Action Plans include a set of new resources and actions to maintain existing resources that, when considered in PGE's overall portfolio, provide 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 portfolios, 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. Both Action Plans further enhance 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 ways to provide our customers the best possible electricity solutions, while remaining responsive to the interests of our investors and other constituents. Because several major components of our Action Plans are time-sensitive, we urge expeditious review and acknowledgement.

Appendix D Addendum: Portfolio Analysis Results

Table D Addendum-1 and Table D Addendum-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 16 portfolios under each of the 21 futures.

Table D Addendum-1: Scenario Analysis Detail ($ Million)

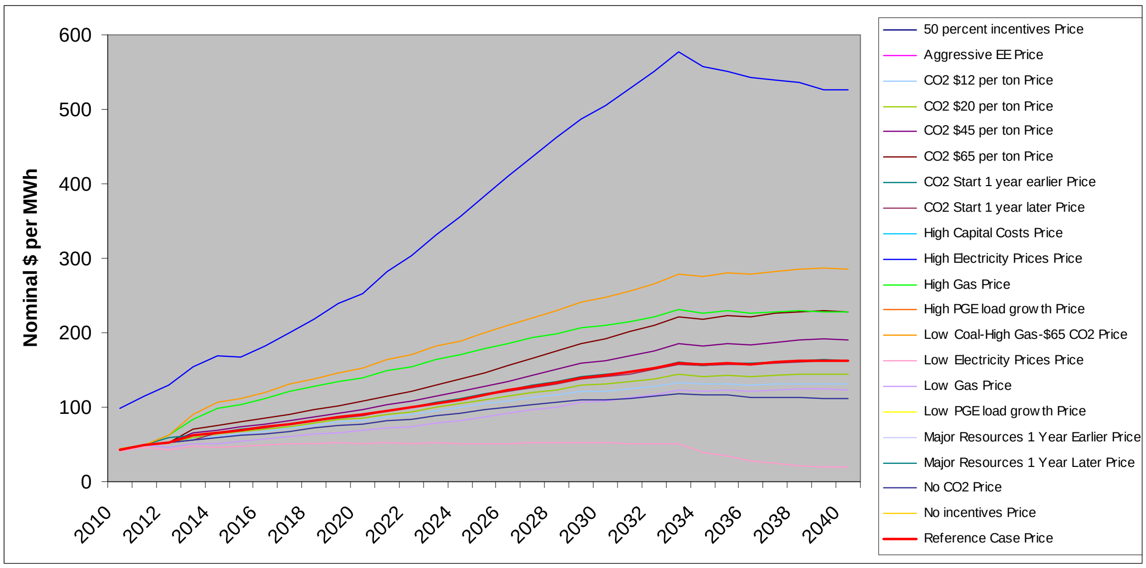
Portfolio -->>	1 Market	2 Natural Gas	3 Wind	4 Diversified Green	5 Diversified Thermal with Wind	6 Bridge to IGCC in WY	7 Bridge to Nuclear	8 Diversified Green with On-peak Energy Target
Reference Case	27,211	29,027	29,288	28,987	28,891	32,735	29,853	28,971
High Gas	34,213	35,970	34,181	34,067	35,312	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 Addendum-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 Boardman through 2020	14 Diverse Green with wind in WY	15 Diversified Thermal with Green w/o Boardman lease	16 Boardman through 2017
Reference Case	28,674	28,593	30,375	28,777	28,396	30,828	28,668	28,780
High Gas	35,310	36,175	35,006	36,297	35,551	35,946	35,231	36,191
Low Gas	25,012	24,517	28,141	24,730	24,532	28,002	24,958	24,800
CO2 $45 per ton	30,606	30,293	31,150	30,447	30,152	32,468	30,575	30,508
CO2 $65 per ton	33,200	32,596	32,296	32,708	32,544	34,658	33,142	32,856
No CO2	24,672	25,281	29,107	25,528	24,952	27,414	24,755	25,406
CO2 $20 per ton	27,368	27,470	29,917	27,675	27,227	29,717	27,369	27,639
High Capital Costs	29,046	29,002	34,993	29,186	28,796	31,735	29,053	29,186
High PGE load growth	31,873	31,792	33,574	31,976	31,595	34,026	31,867	31,979
Low PGE load growth	26,329	26,248	28,030	26,432	26,051	28,483	26,323	26,435
High electricity prices	27,853	26,400	23,541	26,356	25,554	26,141	27,477	26,231
Low electricity prices	21,201	21,109	26,914	21,329	21,120	24,822	21,147	21,390
No Incentives	29,356	29,275	32,046	29,459	29,078	32,488	29,350	29,462
50 percent incentives	29,015	28,934	31,211	29,118	28,737	31,658	29,009	29,121
Low Coal-High Gas-$65 CO2	39,257	39,942	36,455	40,007	39,389	39,217	39,323	40,003
CO2 Start 1 year later	28,424	28,367	30,206	28,588	28,162	30,597	28,423	28,551
CO2 Start 1 year earlier	28,933	28,832	30,560	28,975	28,642	31,066	28,923	29,022
CO2 $12 per ton	26,330	26,588	29,574	26,810	26,309	28,835	26,340	26,740
Aggressive EE	28,063	27,982	29,764	28,166	27,785	30,217	28,057	28,169
Major Resources 1 Year Earlier	28,775	28,741	30,707	28,925	28,493	31,102	28,781	28,925
Major Resources 1 Year Later	28,577	28,453	30,079	28,636	28,268	30,574	28,562	28,645

Figure D Addendum-1 below shows the electricity prices for the Pacific Northwest generated in the different futures and highlights their wide range. AURORAxmp generates a different set of electricity prices for the WECC for the different futures described in sections 10A.5 and 10A.6 of the IRP.

Figure D Addendum-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.

ERRATA

PGE submits the following replacement tables which contain corrections to spreadsheet and typographical errors identified in our 2009 Integrated Resource Plan:

Table 8-2: corrects spreadsheet error which changes values for Cases 4 and 5

Table 8-3: corrects spreadsheet error which changes values for Cases 4 and 5

Table 8-5: corrects spreadsheet error which changes all values in the table

Table C-1: corrects typographical error in the total MW for Utah

Table C-2: corrects typographical error in the total MW

Table C-3: corrects sorting error in the OWI column

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	0.0884	0.0163	0.1032
5	0.1591	0.0870	0.1739

Table 8 3: Cost 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)
(Reference) 3	$11,026	($798)	$25,104
4	$52,543	$32,963	$58,865
5	$73,635	$54,055	$79,957

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	(0.3730)	(0.3875)	(0.3088)
2	(0.2487)	(0.2632)	(0.1846)
3	(0.1328)	(0.1463)	(0.0670)
4	0.1199	0.1073	0.2006
5	0.1907	0.1780	0.2714

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	0%
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	900	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%
	196,891	

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.

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	44.13	53.94	47.90	48.82	47.98	49.86	42.98	43.75	51.86	41.53	46.74	47.20	41.80	43.34	42.82	40.02
2011	49.73	64.25	58.84	54.67	53.88	55.97	48.35	49.42	58.84	47.26	52.76	53.01	47.30	49.13	48.64	45.31
2012	52.30	65.58	58.31	57.52	56.69	58.82	51.30	52.31	63.04	50.39	56.03	55.95	49.85	52.36	51.53	47.95
2013	62.38	90.28	74.08	67.60	66.78	69.05	61.56	62.21	72.25	60.03	66.38	66.46	60.15	62.10	61.54	57.17
2014	65.73	136.85	86.20	71.05	70.22	72.67	65.51	65.75	78.46	63.72	70.25	70.22	63.67	65.92	65.09	60.54
2015	71.08	87.11	78.04	75.98	75.20	77.93	69.91	69.56	87.13	67.35	74.82	75.43	68.47	69.56	69.73	64.40
2016	75.75	77.16	76.34	79.72	78.99	82.19	74.92	73.11	96.43	70.61	78.81	79.75	73.07	73.05	73.79	67.89
2017	80.21	75.54	78.30	84.00	83.28	86.70	80.86	77.45	102.30	74.44	83.38	84.24	76.54	77.15	77.92	72.06
2018	85.32	77.55	82.64	88.68	87.96	91.35	87.63	82.31	89.05	78.87	88.50	89.02	81.47	81.82	82.68	76.84
2019	90.53	81.78	87.72	93.32	92.52	96.11	93.97	86.90	90.79	83.46	93.63	93.97	86.56	86.53	87.48	81.35
2020	94.74	85.35	91.84	97.35	96.52	100.01	87.49	89.86	95.50	86.89	97.34	98.44	88.90	89.95	90.63	82.60
2021	99.04	87.34	96.63	102.03	101.08	104.61	93.03	94.89	96.80	91.73	102.58	103.34	92.21	94.96	95.15	87.41
2022	104.99	91.01	100.96	107.11	106.17	109.97	98.79	97.94	101.78	95.80	107.41	108.94	97.60	99.23	100.22	91.62
2023	110.78	96.29	107.28	112.47	111.41	114.93	106.06	103.84	105.89	101.58	113.47	111.47	103.27	105.16	105.67	97.27
2024	115.61	98.33	114.58	117.86	116.73	120.37	105.34	108.82	107.52	106.84	119.05	117.05	108.09	110.40	110.63	101.41
2025	122.37	104.94	122.19	123.93	122.65	126.39	112.12	114.99	107.58	113.18	125.25	123.41	114.19	117.14	114.42	107.20
2026	125.75	106.17	127.98	128.19	126.90	130.55	118.60	119.87	109.17	118.21	130.31	127.86	118.10	122.23	118.98	112.03
2027	130.65	106.95	134.83	132.55	131.14	134.62	125.87	125.18	112.86	123.45	135.54	129.08	122.73	127.71	123.75	117.23
2028	134.31	107.97	141.94	137.12	135.56	139.09	123.10	130.00	116.22	128.50	140.70	133.65	126.69	133.16	127.55	120.81
2029	139.41	110.65	153.46	141.86	140.22	143.31	130.36	136.13	119.81	134.67	147.43	136.19	131.48	140.01	132.84	126.18
2030	143.41	113.01	144.60	145.97	144.27	147.69	137.59	138.47	123.43	137.32	151.63	140.66	135.71	142.66	137.35	128.97
2031	147.07	115.37	150.58	150.48	148.79	152.36	145.88	140.49	120.33	141.82	156.25	145.40	140.07	147.17	142.12	131.50
2032	151.52	118.19	149.28	155.19	153.39	157.16	141.66	144.84	123.98	146.64	161.22	150.43	141.31	152.14	145.44	134.84
2033	154.78	121.19	156.37	160.57	158.70	162.14	150.13	151.61	121.90	154.03	168.01	155.59	141.76	159.46	151.47	141.80
2034	159.01	122.76	155.95	162.12	160.38	165.56	149.51	144.21	124.87	150.90	166.30	159.25	144.98	156.60	152.18	137.09
2035	165.20	123.75	161.74	166.54	164.74	171.16	155.78	148.52	128.86	153.76	170.93	164.96	149.61	158.76	158.21	141.68
2036	168.73	124.31	155.87	168.62	166.90	174.47	155.88	144.93	126.00	153.53	173.41	168.11	152.76	157.65	160.93	142.49
2037	173.64	125.47	159.33	172.30	170.52	179.40	158.83	149.13	123.16	157.19	178.48	172.90	157.29	160.11	166.63	147.42
2038	177.53	126.38	161.62	175.51	173.56	183.64	157.16	151.76	127.61	159.30	182.76	176.97	159.60	161.97	171.14	150.06
2039	181.22	127.89	164.21	177.43	175.69	187.57	159.52	153.49	124.43	160.10	184.29	181.03	161.96	162.78	174.63	152.10
2040	184.36	129.06	166.76	178.63	176.94	190.97	158.12	142.71	121.80	160.09	185.35	184.63	161.29	162.75	177.22	148.36
Real.lev.2009$	74.79	73.40	76.99	77.59	76.75	79.50	71.71	71.17	73.76	70.11	78.08	76.83	70.30	72.54	72.14	66.52

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **PORTLAND GENERAL ELECTRIC COMPANY'S LC 48 ADDENDUM TO PGE'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 48.

Dated at Portland, Oregon, this 9th day of April 2010.

RDahlgren

Randy Dahlgren
Director, Regulatory Policy & Affairs
On behalf of Portland General Electric Company

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Docket No: LC 48 **Docket Name:** PORTLAND GENERAL ELECTRIC COMPANY Print Sumi

Subject Company: PORTLAND GENERAL ELECTRIC

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2009 Integrated Resource Plan Filed by Randy Dahlgren.

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ACTIONS **SERVICE LIST (Parties)** SCHEDULE

W=Waive Paper service **C=Confidential** **HC=Highly Confidential** Sort by Last Name Sort by Company Name

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