PacifiCorp
A MIDAMERICAN ENERGY HOLDINGS COMPANY

# DRAFT
# 2008 Integrated Resource Plan
# Main Document

April 8, 2009

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

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# EXECUTIVE SUMMARY

[Intentionally left blank] – The executive summary will be provided for the final filed document.

# 2. INTRODUCTION

PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. This IRP, representing the $10^{th}$ plan submitted, fulfills the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. It was developed through a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties.

This IRP also builds on PacifiCorp's prior resource planning efforts and reflects continued advancements in portfolio modeling and performance assessment. These advancements include (1) extensive expansion of resource options considered, (2) a wider range of portfolios developed with alternative input assumptions using the company's capacity expansion optimization tool, (3) more detailed presentation of renewable portfolio standard compliance requirements, and (4) adoption of a portfolio preference scoring methodology that incorporates probability-weighting of $CO_2$ cost futures and importance weighting of various portfolio performance measures. The portfolio preference scoring methodology explicitly incorporates $CO_2$ risk into the portfolio selection decision, and structures the key performance measures into a composite ranking system that shows, in a transparent fashion, how PacifiCorp chose the optimal resource plan among several alternatives.

Finally, this IRP reflects evolution of PacifiCorp's corporate resource planning approach. In early 2008, PacifiCorp embarked on a strategy to more closely align IRP development activities and the annual 10-year business planning process. The purpose of the alignment was to:

- provide corporate benefits in the form of consistent planning assumptions,
- ensure that business planning is informed by the IRP portfolio analysis, and, likewise, that the IRP accounts for near-term resource affordability concerns that are the province of capital budgeting, and;
- improve the overall transparency of PacifiCorp's resource planning processes to public stakeholders.

The planning alignment strategy also came on the heels of the 2007 adoption of the IRP portfolio modeling and analysis framework for Requests for Proposals (RFP) bid evaluation.[1] This latter initiative was part of PacifiCorp's effort to unify planning and procurement under the same analytical framework.

This chapter, outlines the components of the 2008 IRP, summarizes the role of the IRP, describes the IRP/business plan alignment strategy and progress to date, and provides an overview of the public process.

[1] For its 2012 Base Load RFP, PacifiCorp used the IRP Monte Carlo production cost simulation model to evaluate costs and risks of portfolios with bid resources optimized with different input assumptions ($CO_2$ cost, fuel prices, and planning reserve margins).

## 2007 INTEGRATED RESOURCE PLAN COMPONENTS

The basic components of PacifiCorp's 2008 IRP, and where they are addressed in this report, are outlined below.

- The set of IRP principles and objectives that the company adopted for this IRP effort, as well as a discussion on customer/investor risk allocation (this chapter).
- An assessment of the planning environment, including PacifiCorp's 2009 business plan—developed in 2008 and approved by MidAmerican Energy Holdings Company (MEHC) board of directors in December 2008, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3).
- A description of PacifiCorp's transmission planning effort and its linkages to the integrated resource planning effort (Chapter 4).
- A resource needs assessment covering the company's load forecast, status of existing resources, and determination of the load and energy positions for the 10-year resource acquisition period (Chapter 5).
- A profile of the resource options considered for addressing future capacity deficits (Chapter 6).
- A description of the IRP modeling, risk analysis, and portfolio performance ranking processes (Chapter 7).
- Presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp's preferred portfolio (Chapter 8)
- An IRP action plan linking the company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource risks (Chapter 9)
- PacifiCorp's transmission expansion action plan, focusing on the Energy Gateway Transmission project

The IRP appendices, included as a separate volume, comprise detailed IRP modeling results (Appendices A and B), fulfillment of IRP regulatory compliance requirements, (Appendix C), the public input process (Appendix D), additional load forecast information (Appendix E), and the results of PacifiCorp's wind integration cost study (Appendix F) – NOT INCLUDED IN THIS DRAFT

## THE ROLE OF PACIFICORP'S INTEGRATED RESOURCE PLANNING

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[2] The main role of the IRP is to serve as a roadmap for determining and implementing the company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, risk, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting Request for Proposals (RFP) bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

## ALIGNMENT OF PACIFICORP'S IRP AND BUSINESS PLANNING PROCESSES

### Alignment Strategy Overview

The alignment strategy consists of the following three elements:

- **Scheduling synchronization** – PacifiCorp modified its IRP preparation schedule to accommodate business plan preparation beginning in March 2008 and ending in late November 2008, culminating with plan approval in mid-December 2008 by the MidAmerican Energy Holdings Company (MEHC) board of directors.

- **Input assumption synchronization** – The IRP models are updated on a real-time basis as changes to business plan assumptions occur. These changes include, but are not limited to, revised load forecasts, forward price curves, resource costs, and environmental compliance policy assumptions. Public stakeholders are updated on major changes to input assumptions.

- **IRP modeling support for business plan development** – For each business planning scenario[3], PacifiCorp conducts IRP modeling to produce a resource portfolio for capital budget-

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[2] The Oregon and Utah Commissions cite "long run public interest" as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Utah Commission cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decisionmaking process.

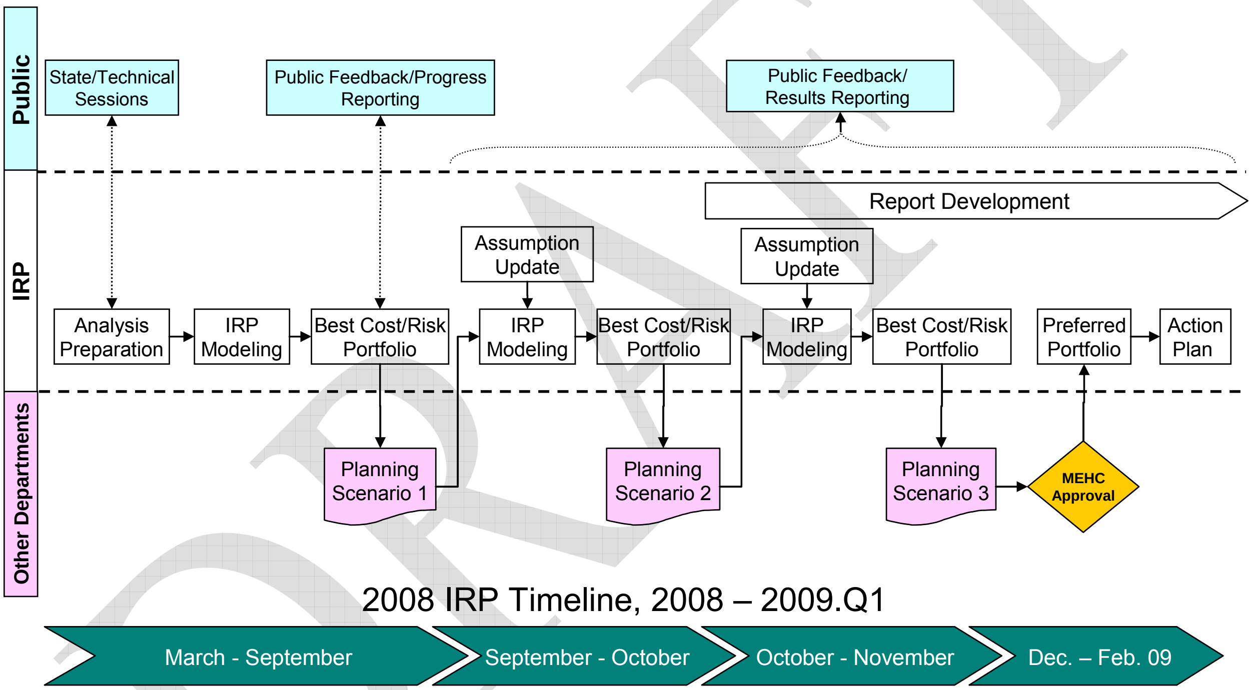
[3] A business planning scenario represents a unique set of assumptions for producing a planning outcome and associated financial results for a 10-year period. The business planning schedule accounts for preparation of three scenarios. Typically, the goal of each successive scenario is to (1) improve customer service and operational and financial results by optimizing operational expenditures and capital investments in accordance with the company's business strategy, and (2) incorporate updated assumptions into the business planning process. Each planning scenario requires a complete processing cycle, including input collection and aggregation, tax estimation, cash-flow optimization through debt issuance and equity investment, quality assurance, and management review.

The key product for each planning scenario is a documentation package that describes the planning assumptions and contains a set of pro-forma financial statements conveying the financial impacts of the planning assumptions. PacifiCorp submits each planning scenario to MidAmerican Energy Holdings Company for review and approval on pre-established dates. At the end of the year, after the business plan receives MEHC board approval, high-level business planning information is provided in filings as required by state and federal regulations. Certain information ing and rate impact analysis by the corporate finance department. In an iterative process, resource constraints are applied to the portfolio optimization modeling to ensure that subsequent portfolios are deemed affordable and financeable by senior management.

- **Public process** – Through public meetings or other communication methods, the company's IRP public participants are updated on significant business planning events. The relationship between the business plan and IRP preferred portfolios are documented in the IRP action plan.

Figure 2.1 is a process flow diagram that shows the relationship between IRP activities, business plan preparation, and the public process originally envisioned for the 2008 IRP development cycle.

**Figure 2.1 – IRP/Business Plan Process Flow**




## Planning Process Alignment Challenges

A key challenge for the alignment was to reconcile the different planning perspectives associated with the two-year IRP development cycle and the annual corporate business planning cycle. As mentioned above, the IRP is a strategic planning roadmap focused on the long-term costs and risks of resource portfolios, accounting for uncertainty. In contrast, PacifiCorp's business plan focuses on maintaining a strong financial position while ensuring customer's generation needs are met economically given the expected operating environment. Central to this business planning goal is an emphasis on acquiring and managing the company's assets to smooth the cost

is also released on a confidential basis to various rating agencies and in certain regulatory dockets or other venues where necessary.

impacts for customers. Successful alignment of the two planning processes thus entails balancing these perspectives as resource decisions are made.

Another key challenge for the planning process alignment was to accommodate the preparation timing differences and analytical requirements for the two planning processes. The 10-year business plan is an annual process that entails frequent input assumption updates and preparation of multiple versions of the plan for internal prudence reviews. On the other hand, the IRP is a biennial planning process requiring extensive upfront model preparation, a public input process, and completion of specific analytical tasks cited in the state's IRP standards and guidelines and IRP acknowledgment orders. Meshing the planning processes entails significantly more departmental coordination, along with an acceleration of the IRP modeling workflow to start portfolio development two to three months earlier than is typically done for the IRP.

A final key challenge was to provide modeling support for both the IRP and business plan while at the same time implementing major modeling enhancements. These enhancements included (1) unbundling Class 2 demand-side management programs (energy efficiency) from the load forecasts and instituting a Class 2 DSM supply curve modeling approach, (2) expansion of resource options to include wind with different resource qualities, additional renewable technologies, energy storage, nuclear, distributed generation, fuel cells, and additional front office transaction product types, (3) improvements in modeling renewable portfolio standard (RPS) requirements, (4) computer and network infrastructure upgrades, and (5) a major upgrade of the Planning and Risk production cost model.

Given these challenges, the expectation was that the alignment would be conducted over a two-year span.

**Alignment Strategy Progress**

PacifiCorp successfully implemented all the planned IRP modeling system improvements, and maintained input consistency with business plan assumptions throughout the planning cycle. Importantly, the business plan benefited from implementation of the DSM class 2 supply curves, providing for the first time energy efficiency program targets based on integrated resource portfolio modeling with these resource options included. PacifiCorp also successfully provided an optimized resource portfolio for each business planning scenario.

However, two alignment strategy objectives were not met. For the business plan, PacifiCorp originally intended to conduct alternative portfolio development with different input assumptions (basically a subset of the input scenarios defined for the IRP), and run Monte Carlo production cost simulations to compare portfolio stochastic costs and risks. Additionally, public reporting goals on the progress of business plan preparation could not be accommodated in the schedule. There were two reasons for not meeting these objectives. First, business plan portfolio optimization modeling required frequent updates in reaction to volatile energy markets, the financial market crisis, a deteriorating load growth outlook, and continued resource cost increases. This caused a delay of the start of IRP modeling, while the turnaround time for business plan modeling precluded establishment of a meaningful public comment and response process. Second, the modeling enhancements and system upgrades—particularly for the Planning and Risk model—took longer than expected.

As a consequence of the IRP modeling delay, the business plan was approved by the MEHC board of directors in December 2008—prior to the completion of IRP modeling and selection of the IRP preferred portfolio. In accordance with the alignment strategy, the major resource changes relative to the business plan were analyzed for financial and ratepayer impact by the PacifiCorp Energy Finance Department. Major differences between the business plan resources and the IRP preferred portfolio are described in Chapters 8 and 9.

## PUBLIC PROCESS

The IRP standards and guidelines for certain states require PacifiCorp have a public process allowing stakeholder involvement in all phases of plan development. The company held 17 public meetings/conference calls during 2008 and early 2009 designed to facilitate information sharing, collaboration, and expectations setting for the IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Table 2.1 lists the public meetings/conferences and major agenda items covered.

**Table 2.1 – 2008 IRP Public Meetings**

| Meeting Type | Date | Main Agenda Items |
|---|---|---|
| General Meeting | 2/29/2008 | 2008 IRP modeling plan, business planning process, 2007 IRP Update |
| State Stakeholder Input | 4/9/2008 | Utah stakeholder comments |
| State Stakeholder Input | 4/10/2008 | Wyoming stakeholder comments |
| State Stakeholder Input | 4/21/2008 | Oregon and California stakeholder comments |
| State Stakeholder Input | 4/22/2008 | Washington stakeholder comments |
| State Stakeholder Input | 4/23/2008 | Idaho stakeholder comments |
| State Stakeholder Input | 5/14/2008 | Utah stakeholder comments |
| General Meeting | 5/22/2008 | Input scenario ("case") definitions, resource characterization |
| Workshop | 5/23/2008 | $CO_2$ costs and modeling, EPRI $CO_2$ study results |
| Workshop | 6/26/2008 | Load forecasting methodology, preliminary load forecast |
| General Meeting | 11/12/2008 | Load forecast update, IRP/Business plan alignment, IRP status (conf. call) |
| General Meeting | 12/18/2008 | Load forecast update, portfolio development results, load & resource balance |
| General Meeting | 1/7/2009 | Repeat of 12/18/2008 agenda for Washington and Idaho stakeholders |
| General Meeting | 2/2/2009 | Stochastic modeling results, portfolio performance, preferred portfolio |
| General Meeting | 3/11/2009 | IRP status and state commission filing update (conference call) |
| State Stakeholder | 3/19/2009 | Utah state commission filing schedule for IRP (conference call) |
| General Meeting | TBD | IRP action plan review (conference call) |

New for this IRP was a series of state stakeholder dialogue sessions conducted from April through May 2008. The purpose of these sessions, targeting a state-specific audience, were to (1) capture key resource planning issues of most concern to each state and discuss how these can be tackled from a system planning perspective, (2) ensure that stakeholders understand PacifiCorp's planning principles and the logic behind its planning process, and (3) set expectations for what can be accomplished in the current IRP/business planning cycle. This change in public process was intended to enhance interaction with stakeholders early on in the planning cycle, and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during general public meetings.

Appendix D, in the separate appendix volume, provides more details concerning the public meeting process and individual meetings.

In addition to the public meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and consultation throughout the IRP process. The company maintains a website (http://www.pacificorp.com/Navigation/Navigation23807.html), an e-mail "mailbox" (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support stakeholder communications and address inquiries by public participants.

# 3. THE PLANNING ENVIRONMENT

## INTRODUCTION

This chapter profiles the major external influences that impact PacifiCorp's long-term resource planning as well as recent procurement activities driven by the company's past IRPs. External influences are comprised of events and trends affecting the economy and power industry marketplace, along with government policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

A key resource planning consideration has been the faltering U.S. economy and tightening of credit markets. Changing economic circumstances have required the company to continuously re-evaluate and adjust load growth and market price expectations throughout this planning cycle, a process mentioned in the previous chapter in the context of 2009 business plan preparation. For capital expenditure planning, the company's challenge has been to minimize customer rate impacts in light of a substantial capital spending requirement needed to address customer load growth, support government environmental and energy policies, and maintain transmission grid reliability. To address this challenge, PacifiCorp is scrutinizing capital projects for cost reductions or deferrals that make economic sense in today's market environment. Along these lines, the company recently decided to seek more cost-effective alternatives to the planned Lake Side 2 combined-cycle gas plant project in Utah. The implications of this resource decision for the IRP are addressed in this chapter.

Concerning the power industry marketplace, the major issues addressed include capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC) and the prospects for long-term natural gas commodity price escalation and continued high volatility. As discussed elsewhere in the IRP, future natural gas prices and the role of gas-fired generation and market purchases are some of the critical factors impacting the determination of the preferred portfolio that best balances low-cost and low-risk planning objectives.

On the government policy and regulatory front, the largest issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter focuses on climate change regulatory initiatives, particularly at the state level. A high-level summary of the company's greenhouse gas emissions mitigation strategy, as well as an overview of the Electric Power Research Institute's study on carbon dioxide price impacts on western power markets, follows. This chapter also reviews the significant policy developments for currently-regulated pollutants

Other topics covered in this chapter include the Energy Independence and Security Act of 2007, the status of renewable portfolio standards, hydroelectric licensing, and resource procurement activities.

## IMPACT OF THE 2012 COMBINED-CYCLE GAS PLANT PROJECT TERMINATION

In February 2009, PacifiCorp decided to terminate the construction contract for the Lake Side 2 combined-cycle plant, which was planned to be in commercial operation by the summer of 2012. The decision to seek other resource alternatives was driven by the worsening recessionary environment, continued declines in forward electricity and gas prices, the outlook for future plant construction costs, and additional transmission import capability into Utah of which the company has recently become aware. The construction termination decision occurred after selection of the 2008 IRP preferred portfolio, but before finalization of the IRP document and preparation of the IRP action plan. Consequently, PacifiCorp decided to conduct additional portfolio analysis to determine the impacts of excluding Lake Side 2 as a planned resource in 2012, and then update the preferred portfolio and develop the action plan accordingly. This analysis consisted of the following five steps:

- Revise the load and resource balance to reflect the absence of the Lake Side 2 CCCT plant in 2012 (shown in Chapter 5).
- Update the IRP models with new transmission and market purchase availability information that can facilitate cost-effective alternatives to a single large 2012 resource addition (described in Chapter 6).
- Use the company's capacity expansion optimization model to develop a set of alternative portfolios without the Lake Side 2 plant, applying the same input scenarios ("cases") that yielded the top-performing portfolios in PacifiCorp's original portfolio analysis. (This portfolio development is summarized in Chapter 8.)
- Conduct stochastic Monte Carlo production cost simulation of the alternative portfolios, and determine the new preferred portfolio with the support of the portfolio preference scoring methodology adopted for this IRP. (The portfolio performance evaluation is described in Chapter 8.)
- Include the findings of the portfolio analysis in the IRP action plan and supporting acquisition path analysis.

## WHOLESALE ELECTRICITY MARKETS

PacifiCorp's system does not operate in an isolated vacuum. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by assuring that resources with the lowest operating cost are serving demand in a region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp participates in the wholesale market in this fashion, making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on time scales ranging from hourly to years in advance. Without the wholesale market, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supplies that would go unutilized in all but the most unusual circumstances and would substantially diminish its capability to efficiently match delivery patterns to the profile of customer demand. The market is not without its risks, as the experience of the 2000-2001 market crisis and the more recent period of rapid price escalation during the summer of 2008 have underscored.

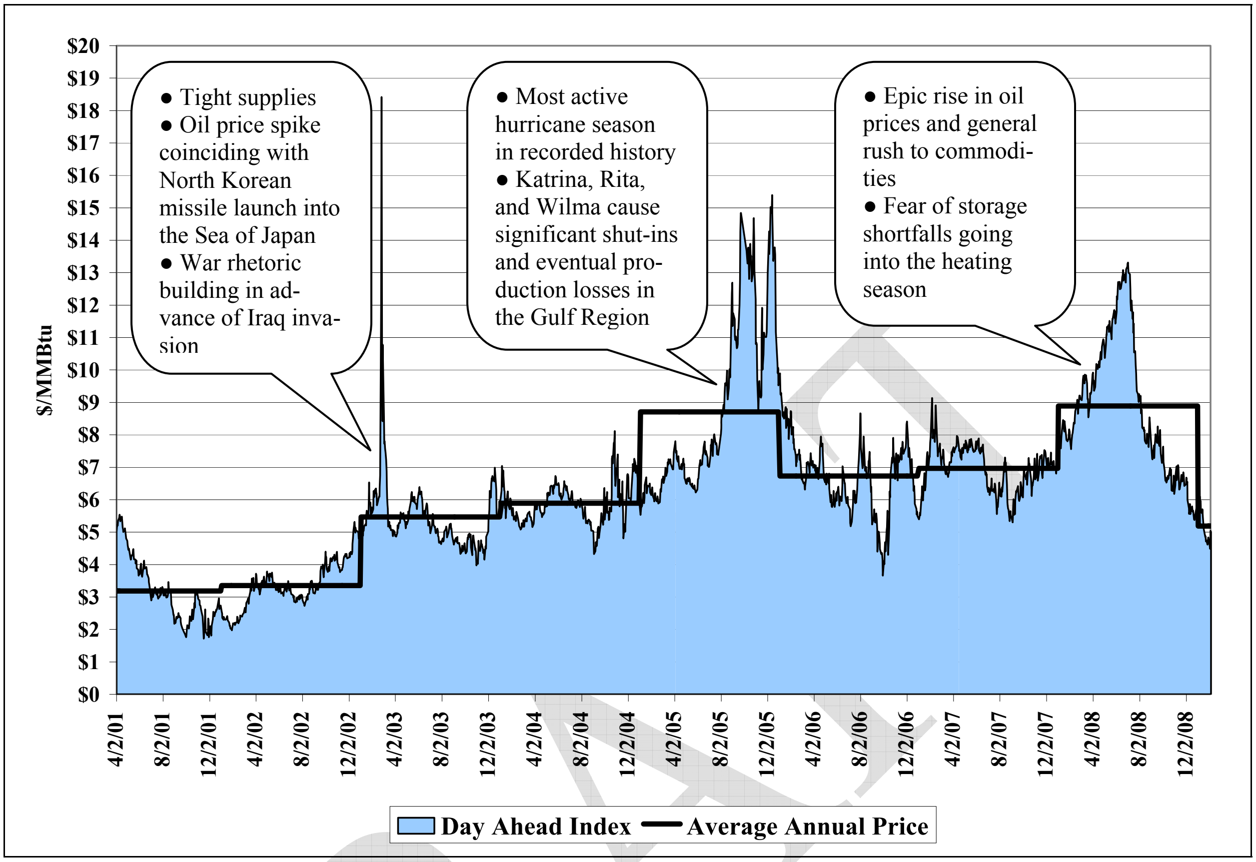
As with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. For example, the Western Electricity Coordinating Council (WECC) publishes an annual assessment of power supply and any number of data services are available that track the status of new resource additions. The most recent WECC power supply assessment indicates that the Basin and Rockies sub-regions will be resource deficit, after accounting for reserves, by 2011.

There are other uncertainties that are more difficult to analyze and that possess heavy influence on the direction of future prices. One such uncertainty is the evolution of natural gas prices. Given the increased role of natural gas-fired generation, gas prices have become a critical determinant in establishing western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on this IRP is the prospect of future green house gas policy. A broad landscape of federal, regional, and state proposals aiming to curb green house gas emissions continues to widen the range of plausible future energy costs, and consequently, future electricity prices. Each of these uncertainties is explored in the cases developed for this IRP and are discussed in more detail below.

**Natural Gas Uncertainty**

Over the last eight years, North American natural gas markets have demonstrated exceptional price escalation and volatility. Figure 3.1 shows historical day-ahead prices at the Henry Hub benchmark from April 2, 2002 through February 3, 2009. Over this period, day-ahead gas prices settled at a low of $1.72 per MMBtu on November 16, 2001 and at a high of $18.41 per MMBtu on February 25, 2003. During the fall and early winter of 2005, prices breached $15 per MMBtu after a wave of hurricanes devastated the gulf region in what turned out to be the most active hurricane season in recorded history. More recently, prices topped $13 per MMBtu in the summer of 2008 when oil prices began their epic climb above $140 per barrel. During this period, the natural gas market was also concerned that declining imports and slow growth in domestic production would create a storage shortfall going into the heating season. However, as the year progressed, it became increasingly evident that gains in unconventional supply was growing at an unprecedented pace, quelling fears of an unbalanced market. At the same time, the market began accounting for sharp declines in demand as the financial crisis evolved into a full-scale global recession. Consequently, prices retreated just as quickly as they rose.

**Figure 3.1 – Henry Hub Day-ahead Natural Gas Price History**




Source: IntercontinentalExchange (ICE), Over the Counter Day-ahead Index

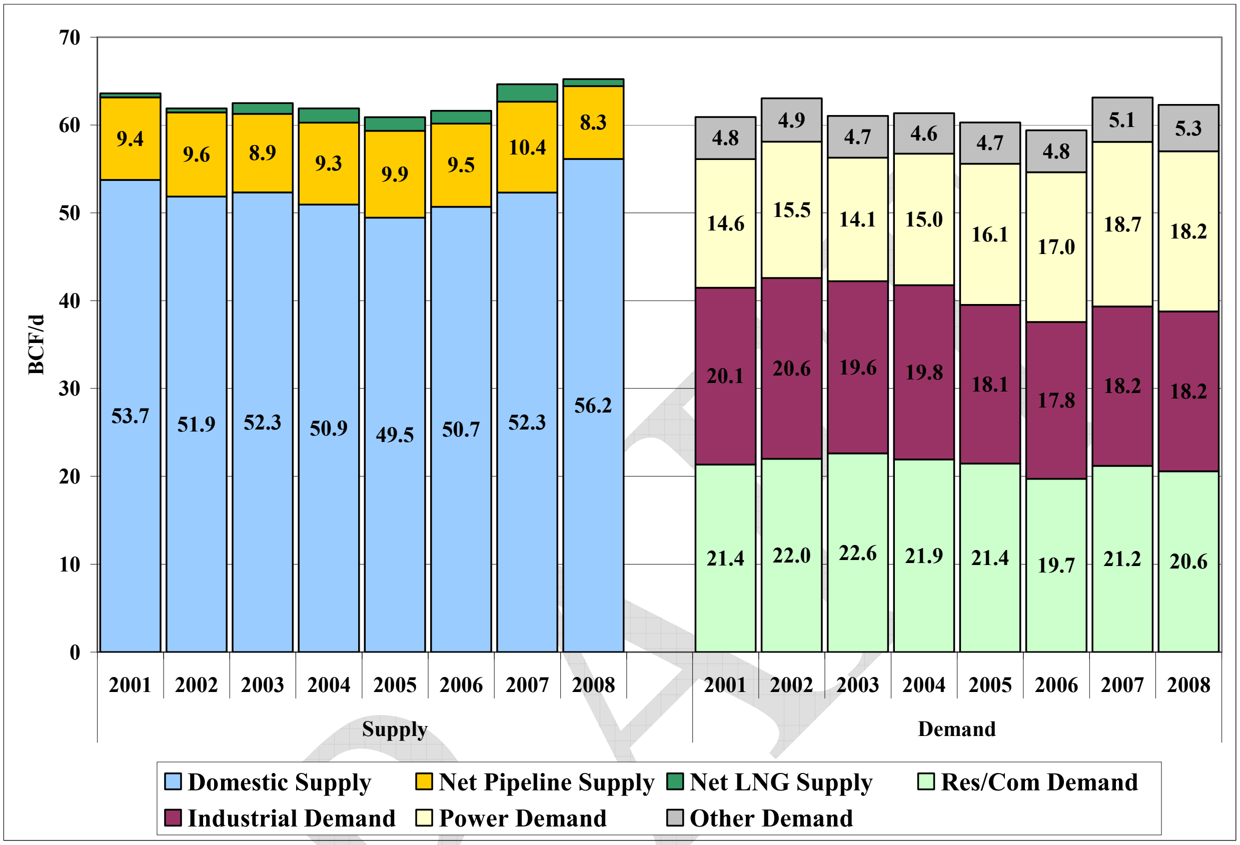
Beyond the geopolitical, extreme weather, and economic events that spawned some rather spectacular highs in the recent past, natural gas prices have exhibited an underlying upward trend from approximately $3 per MMBtu in 2002 to nearly $7 per MMBtu by 2007. Over much of this period, declining volumes from conventional, mature producing regions largely offset growth from unconventional resources. Figure 3.2 shows a breakdown of U.S. supply alongside natural gas demand by end-use sector.

Total supply, led by declines in domestic production, dropped steadily from 2001 through 2005. While total supply posted modest gains in 2006 and 2007, domestic production remained below the levels recorded in 2001. On the demand side, substantial expansion of gas-fired generating resources had more than offset declines in industrial demand for natural gas. This shift reduced the amount of industrial demand that is most price-elastic and increased inelastic generation demand. With higher finding and development costs of unconventional resources, the price level necessary to stimulate such marginal supply had grown. Until the recent economic downturn, substantial oil price escalation also supported higher natural gas prices, lifting the price of marginally competitive gas substitutes and the value of natural gas liquids.

Combined, the above factors contributed to a pronounced supply/demand imbalance in North American natural gas markets, raising prices sufficiently high to discourage marginal demand and, at times, attracting imports from an equally tight global market. This imbalance also made

North American markets more susceptible to upset from weather and other event shocks such as those discussed earlier.

**Figure 3.2 – U.S. Natural Gas Balance History**




Source: U.S. Department of Energy, Energy Information Administration

The supply/demand balance began to shift in 2007 and 2008 thanks to an unprecedented and unexpected burst of growth from unconventional domestic supplies across the lower 48 states. With rapid advancements in horizontal drilling and hydraulic fracturing technologies, producers began drilling in geologic formations such as shale. Some of the most prominent contributors to the rapid growth in unconventional natural gas production have been the Barnett Shale located beneath the city of Forth Worth, Texas and the Woodford Shale located in Oklahoma. Strong growth also continued in the Rocky Mountain region.

Looking forward, many forecasters have been expecting that a gradual restoration of improved supply/demand balance would be achieved largely with growth in liquefied natural gas (LNG) imports. Indeed, there has been tremendous growth in global liquefaction facilities located in major producing regions, and additional projects are expected to come online in 2009 and 2010. Concurrently, U.S. regasification capacity has grown to overbuild proportions. As of the end of 2008 U.S. regasification capacity was 4.7 times larger than the 1.98 BCF/d of LNG imports logged in 2007, and additional capacity is scheduled to go online in 2009 and 2010. Even with substantial gains in global LNG supplies and in domestic regasification capacity, the North

American market has not been able to consistently lure shipments from Asian and European markets, where gas prices are more directly linked to the price of oil.

With the recent expansion of unconventional production and the evolution of global LNG markets, many forecasters and market participants are beginning to reassess how mid- to long-term markets will balance. For example, the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) from 2007 forecasted that LNG imports would top 8 BCF/d by 2015. In the early look of AEO 2009 released in December 2008, the EIA expects 2015 LNG imports to total 3.4 BCF/d – just 41 percent of the LNG imports projected two years earlier. Beyond the near-term, where demand is being depressed by the current economic downturn, it is increasingly believed that unconventional supplies from North America are poised to meet incremental demand upon economic recovery. Under such a scenario, North American gas prices would remain decoupled from the global LNG market, and consequently decoupled from Asian and European natural gas markets, which are more heavily influenced by the price of oil.

Several factors contribute to a wide range of price uncertainty in the mid- to long-term. On the downside, technological advancements underlying the recent expansion of unconventional supplies opens the door to tremendous growth potential in both production and proven reserves from shale formations across North America. A number of shale formations outside of the Barnett and Woodford have already started to show upside potential. A sign of the times, the proposed Kitimat regasification terminal in British Columbia, Canada announced that the project was being redesigned as a liquefaction terminal apparently due to interest in the Horn River and Motney shale formations within the province. On the upside, the next generation of unconventional supplies may prove to be more difficult to extract, raising costs, and consequently, raising prices. Moreover, a concerted U.S. policy effort to shift the transportation sector away from oil toward natural gas has potential to significantly increase demand, and thus natural gas prices.

Western regional natural gas markets are likely to remain well-connected to overall North American natural gas prices. Although Rocky Mountain region production, among the fastest growing in North America, has caused prices at the Opal and Cheyenne hubs to transact at a discount to the Henry Hub benchmark in recent years, major pipeline expansions to the mid-west and east coupled with further pipeline expansion plans to the west are expected to maintain market price correlations going forward. In the Northwest, where natural gas markets are influenced by production and imports from Canada, prices at Sumas have traded at a premium relative to other hubs in the region. This has been driven in large part by declines in Canadian natural gas production and reduced imports into the U.S. In the near-term, Canadian imports from British Columbia are expected to remain below historical levels lending support for basis differentials in the region; however, in the mid- to long-term, production potential from regional shale formations will have the opportunity to soften the Sumas basis.

## Greenhouse Gas Policy Uncertainty

There is a wide range of policy proposals to limit greenhouse gas emissions within the U.S. economy. At the federal level, Senators Bingaman and Specter sponsored the Low Carbon Economy Act of 2007 (the Bingaman Bill), and more recently, Senators Lieberman and Warner introduced the Climate Security Act of 2008 (the Lieberman Warner Bill). While it remains unclear what types of federal proposals will be debated going forward, there have been clear signals that the Obama administration has more of an appetite than the previous administration to address the climate change issue. At the state and regional level, the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade program to restrict carbon dioxide emissions in Northeastern and Mid-Atlantic states, took affect in 2008. A similar approach is being explored in the Midwest under the Midwest Greenhouse Gas Accord. In the West, the Western Climate Initiative continues its work toward establishing rules for its own cap-and-trade program. Additional details on greenhouse gas policy developments are discussed later in this chapter.

As the policy debate continues, a cloud of uncertainty continues to hang over the electric sector, with substantial implications for investment decisions and wholesale electricity markets. There are a host of uncertainties stemming from the policy debate:

- If emission limits are put in place, will they cover the entire U.S. economy or will they target specific sectors?
- Will emission reductions be achieved through a cap-and-trade approach, through a carbon tax, or some combination of the two?
- What role, if any, will domestic and international offsets play in achieving emission reductions in the U.S.?
- Will emission reductions be achieved through a national program that preempts state and regional initiatives, will there be a more Balkanized approach, or will there be a national program layered on top of state and regional initiatives?

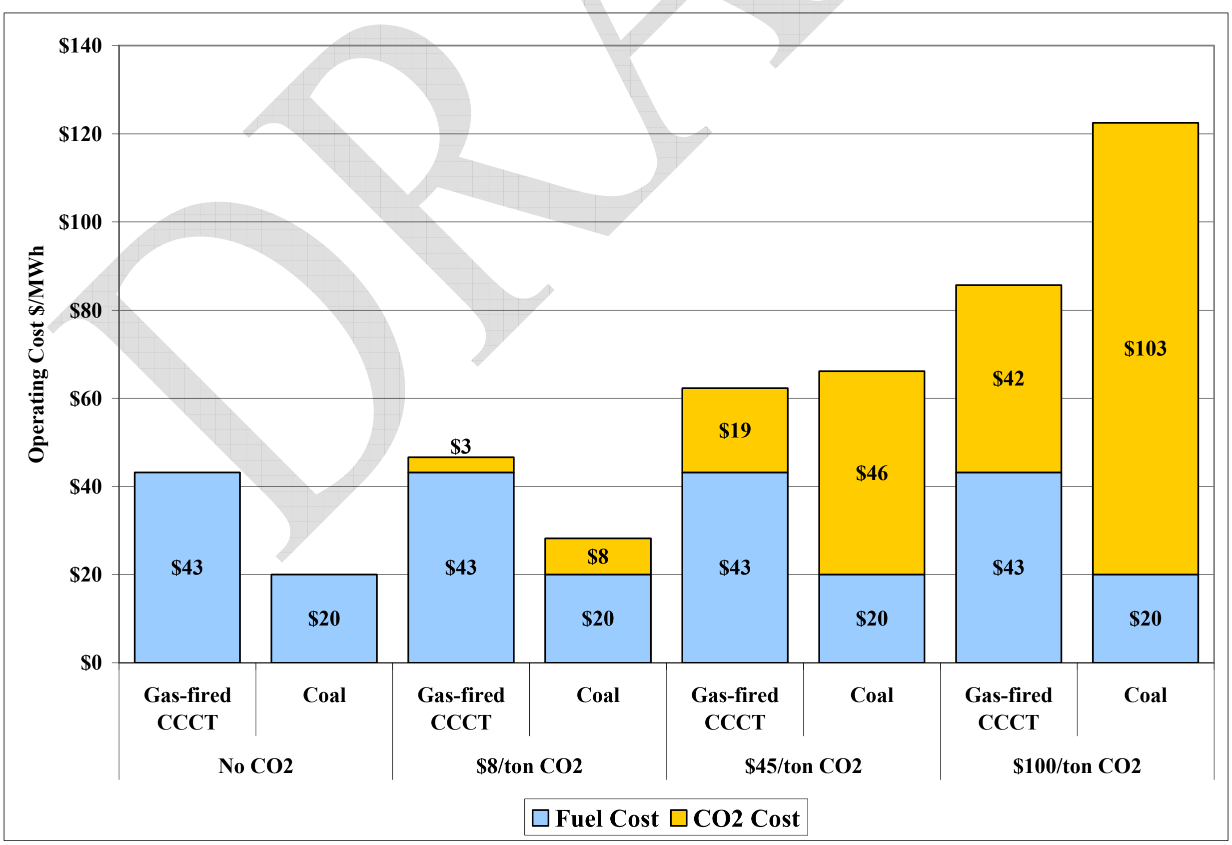
Regardless of how the policy debate unfolds, one thing remains clear. If limits are placed on greenhouse gas emissions, it is highly probable that the electric sector will be required to reduce emissions, and these emission reductions will come with a cost. Whether the costs are directly assessed in the form of a tax or are indicative of opportunity costs monetized in a market developed under a cap-and-trade program, all else equal, the cost to produce electricity will increase, and wholesale prices will respond. The projected cost of greenhouse gas emission reductions are intrinsically tied to policy details and vary considerably. Even for a given policy, there are a wide range of future cost estimates driven by long-term assumptions such as electricity demand, technological advancements, and varying interpretations of policy implementation rules. For example, in the December 17, 2008 auction for RGGI carbon dioxide emission allowances, prices cleared at $3.38/ton. In contrast, the Energy Information Administration's (EIA) analysis of the Lieberman Warner Bill projected nominal allowance prices by 2030 ranging from nearly $35/ton to approximately $275/ton.

When a cost is placed on greenhouse gas emissions, it effectively becomes an additional variable cost facing an electric generator, and in much the same way that fuel costs affect plant dispatch decisions, emission costs influence how a plant operates. Because electric generators burn different types of fuel, have varying levels of efficiency, and are bound by different operational limitations, the impact of incremental green house gas costs varies across different types of technologies. To understand how green house gas emission costs will discriminately affect electricity markets, one can consider a simplified representation of the power system – a system that includes two types of resources: (1) a coal-fired plant, and (2) a gas-fired combined cycle plant.

Coal-fired assets, with limited operational flexibility and access to relatively low cost fuel, tend run around the clock. This type of base load capacity is often used to satisfy demand even when it is quite low. On the other hand, while natural gas-fired combined cycle assets typically have an efficiency advantage relative to a coal plant, they are often faced with higher fuel costs and have more operational flexibility to alter their production in response to changing conditions. Consequently, this type of resource is often ramped up as demand increases and ramped down when demand falls. In this way, coal resources are more likely to establish off-peak electricity prices than on-peak electricity prices. Conversely, natural-gas fired capacity is more likely to set electricity prices during peak demand periods. When green house gas emission costs are introduced, this basic trend can be altered.

Figure 3.3 shows illustrative dispatch costs for a coal plant and a natural-gas fired combined cycle plant at different carbon dioxide pricing points – no cost, $8/ton, $45/ton, and $100/ton. The coal plant is assumed to have a heat rate of 10,000 Btu/kWh and is faced with fuel prices of $2 per MMBtu. The gas-fired plant is assumed to have a heat rate of 7,200 Btu/kWh and is faced with a fuel price of $6 per MMBtu. Without any incremental carbon cost, Figure 3.3 shows a decided cost advantage for the coal asset. While the operating cost advantage for a coal plant is maintained when carbon costs are at $8/ton, the cost advantage begins to narrow. At $45/ton, both technologies are on nearly equal footing, with a slight advantage now in favor of the gas-fired combined cycle asset. Finally, at $100/ton, the cost advantage is reversed and is now decidedly in favor of the gas-fired plant.

**Figure 3.3 – Green House Gas Cost Implications for Electric Generators**



From the simplified example in Figure 3.3, one can appreciate how green house gas costs might affect wholesale electricity markets. With no carbon costs, the marginal unit is the gas-fired combined cycle, which, in this example, would support electricity prices somewhere north of $43 per MWh. When carbon costs climb to $100/ton, the marginal coal unit from this example would support wholesale electricity prices north of $120 per MWh. Of course, in reality, the power system is more complex than this simplified representation. There are additional resources—hydro power, nuclear, gas-fired peaking plants, and renewables—competing in the market. Moreover, there are other interactions that are likely to take place as greenhouse gas costs escalate and operational changes are implemented accordingly. For example, as carbon costs rise, it is possible that natural gas demand would increase, exerting upward pressure on gas prices. Similarly, even though natural fired capacity has a cost advantage relative to coal at higher carbon costs, coal does not have the operational flexibility to ramp output up and down with swings in demand. Regardless, given the range of potential policy outcomes, it is evident that the implications for greenhouse gas costs in the wholesale electricity market are highly variable and highly uncertain.

There are additional implications for the wholesale electricity market that extend beyond the direct cost impacts discussed above. For example, if carbon costs are exceptionally high and/or particularly volatile, the number of parties willing and or able to transact may begin to dwindle, and it is possible that depth and liquidity in the forward markets may suffer. Similarly, if a more Balkanized policy landscape materializes, there is a risk that transaction costs among market participants would increase. In yet another scenario, it is conceivable that poorly coordinated implementation rules among multiple programs might cause some market participants to retreat from specific trading hubs that are caught in a jurisdictional web of rules and ambiguity.

## CURRENTLY REGULATED EMISSIONS

Currently, PacifiCorp's generation units must comply with the federal Clean Air Act (CAA) which is implemented by the States subject to Environmental Protection Agency (EPA) approval and oversight. The Clean Air Act directs the EPA to establish air quality standards to protect public health and the environment. PacifiCorp's plants must comply with air permit requirements designed to ensure attainment of air quality standards as well as the new source review (NSR) provisions of the CAA. NSR requires existing sources to obtain a permit for physical and operational changes accompanied by a significant increase in emissions.

### Ozone

Final action on the revisions to the National Ambient Air Quality Standards for ozone was completed on March 12, 2008. The EPA announced that the National Ambient Air Quality Standards for primary and secondary ground-level ozone would be significantly strengthened. The primary ozone standard, which is designed to protect public health and the secondary standard, which is designed to protect public welfare (including crops, vegetation, wildlife, buildings, national monuments, and visibility) from the negative effects of ozone, were both reduced to 0.075 parts per million.

The new standards took effect on May 27, 2008. States have until March 12, 2009, to make recommendations to the EPA as to whether an area should be designated attainment (meeting the standard), nonattainment (not meeting the standard) or unclassifiable (not enough information to make a decision). The EPA must promulgate its attainment/nonattainment designations by March 12, 2010, unless a one-year extension is granted because of insufficient information. By March 12, 2011, or one year after the EPA promulgates its designations, states will be required to submit their state implementation plans detailing how they will meet the new standards. A number of rules have been issued by the EPA that will potentially help states make progress toward meeting the revised ozone standards, including the Clean Air Interstate Rule to reduce ozone forming emissions from power plants in the eastern United States, and the Clean Diesel Program to reduce emissions from highway, non-road and stationary diesel engines nationwide.

Immediately following the promulgation of the strengthened ozone standards, multiple lawsuits were filed against the EPA. New York and thirteen other states sued the Environmental Protection Agency on May 27, 2008, demanding stricter air quality standards for ozone. New York was joined in the lawsuit by California, Connecticut, Delaware, Illinois, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New Mexico, Oregon, the Pennsylvania Department of Environmental Protection, and Rhode Island. New York City and the District of Columbia also joined in the lawsuit. A coalition of environmental and public health advocates also filed a lawsuit against the Environmental Protection Agency on May 27, 2008, in a bid to strengthen the ozone standard. Meanwhile, Mississippi and a coalition of industry trade groups filed separate petitions for review May 23, 2008, and May 27, 2008, respectively, in the District of Columbia Circuit Court of Appeals, arguing the new standards are too strict.

After EPA tightened the 8-hour standard to 0.075 parts per million, several Utah counties located along the Wasatch Front were put in jeopardy of being designated non-attainment. Utah is now using certified monitored ozone data from 2005–2007 to determine specifically which areas need to be designated non-attainment of the 0.075 parts per million standard. The state must submit a recommendation to the EPA by March 2009. The EPA will then either accept or modify the state's recommendation, based on certified data from 2006-2008, and issue a final designation by March 2010. In Utah, ozone is principally a summer time problem when temperatures are high and daylight hours are long, but it may have implications to wintertime particulate problems as well. It is a mix of chemicals emitted mainly from vehicle tailpipes, diesel engines and industrial smokestacks. The Utah Department of Environmental Quality has indicated that its anticipated control strategy would focus on transportation, including tightening regulations for gasoline stations, and possibly consumer products, and certain industrial emissions.

Currently, with the exception of the Gadsby power plant, all of PacifiCorp Energy's operating fossil-fueled facilities are located in areas that are in attainment with the ozone National Ambient Air Quality Standards. The Gadsby plant is a gas fired facility located in downtown Salt Lake City, Salt Lake County, Utah. Salt Lake County is currently a non-attainment area for ozone. The Utah Department of Environmental Quality has stated that at this time, no coal- or natural gas-fueled power plants will be the subject of new control strategies.

## Particulate Matter

On October 17, 2006, the EPA issued new National Ambient Air Quality Standards for particle pollution. The final standards addressed two categories of particle pollution: fine particles ($PM_{2.5}$), which are 2.5 micrometers in diameter and smaller; and inhalable coarse particles

($PM_{10}$), which are smaller than 10 micrometers. The Environmental Protection Agency strengthened the 24-hour fine particle standard from the 1997 level of 65 micrograms per cubic meter to 35 micrograms per cubic meter, and retained the current annual fine particle standard at 15 micrograms per cubic meter. The Agency also retained the existing national 24-hour $PM_{10}$ standard of 150 micrograms per cubic meter and revoked the annual $PM_{10}$ standard.

The new federal standards has put Utah's Wasatch Front – including all of Salt Lake and Davis Counties and portions of Weber, Box Elder and Toole counties – into a "non-attainment" status – as well as the low-lying portions of Utah and Cache Counties. Utah has until 2012 to draft a plan to EPA on how it will achieve compliance with the fine particulate NAAQS. According to the Utah Department of Environmental Quality, much of the particulate pollution is attributable to emissions from automobiles. Utah's monitoring suggests a seasonal problem characterized by episodic periods of very high concentrations of fine particulate that consists mostly of secondary particulate. The formation of these secondary particles is driven by winter-time temperature inversions which trap air in urbanized valleys. The mix of emissions associated with the urbanized areas reacts very quickly under these conditions to produce spikes in the concentration of fine particulate. Under these conditions, the observed concentrations are fairly uniform throughout the entire urbanized area. This underscores the association of urban areas with a mix of emissions that inherently reacts under these conditions to form PM2.5, and helps to define PM2.5 somewhat as an "urban" pollutant. All of this serves to highlight the distinction between urban and rural areas. Much of this phenomenon is also due to the fact that population is generally located within the lowland valley areas in which air is easily trapped by a temperature inversion. In other words, it is not enough to simply have an urban area with an urban mix of emissions; there must also be a barrier to dispersion under these conditions, which allows PM2.5 concentrations to build up over a period of several days and reach concentrations that exceed the NAAQS. This characterization of Utah's difficulties with fine particulate has shaped the State's approach to making the area designations.

Currently, with the exception of the Gadsby power plant, all of PacifiCorp's operating fossil-fueled facilities are located in areas that are in attainment with the fine particulate National Ambient Air Quality Standard. The Gadsby plant is a gas-fired facility located in downtown Salt Lake City, Salt Lake County, Utah. Salt Lake County has been proposed as a non-attainment area for fine particulate matter. The Utah Department of Environmental Quality has stated that at this time, no coal- or natural gas-fueled power plants will be the subject of new fine particulate matter control strategies.

**Regional Haze**

Within existing law, EPA's Regional Haze Rule and the related efforts of the Western Regional Air Partnership will require nitrogen oxide, sulfur dioxide, and particulate matter emissions reductions to improve visibility in scenic areas. Arizona, New Mexico, Oregon, Utah and Wyoming originally submitted state implementation plans addressing regional haze based upon 40 CFR 51.309, focusing on the reduction of sulfur dioxide emissions from large industrial sources located throughout the West. Regional Sulfur Dioxide Emissions and Milestone Reports, one of the requirements of the 309 state implementation plan, are submitted each year. The reports determine whether sulfur dioxide emitted by large industrial sources exceeds the sulfur dioxide emission milestones set in the states' Regional Haze state implementation plans. The sulfur dioxide milestones take into account emissions reductions either achieved or expected to be achieved from the installation of Best Available Retrofit Technology on eligible units.

The State of Wyoming submitted revisions to the 2003 309 Regional Haze state implementation plan to EPA Region 8 on November 24, 2008 and will now focus on impairment caused by sources of nitrogen oxides and particulate matter. Work on this phase of regional haze planning is underway with a draft SIP expected in the spring of 2009. Utah similarly adopted revisions to its regional haze state implementation plan on September 3, 2008, which became effective and enforceable in Utah on November 10, 2008. The package of materials was submitted to the EPA on September 18, 2008 and will become federally enforceable after EPA approves them.

Additionally, administrative rulemakings by EPA, including the Clean Air Interstate Rule will require significant reductions in emissions from electrical generating units that directly impact the national market for sulfur dioxide allowances. Compliance costs associated with anticipated future emissions reductions will largely depend on the levels of required reductions, the allowed compliance mechanisms, and the compliance time frame.

## Mercury

In March 2005, the EPA released the final Clean Air Mercury Rule ("CAMR"), a two-phase program that would have utilized a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the 1999 nationwide level of 48 tons to 15 tons. The CAMR required initial reductions of mercury emission in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70 percent by 2018. The individual states in which PacifiCorp operates facilities regulated under the CAMR submitted state implementation plans reflecting their regulations relating to state mercury control programs. On February 8, 2008, a three-judge panel of the United States Court of Appeals for the District of Columbia Circuit held that the EPA improperly removed electricity generating units from Section 112 of the Clean Air Act and, thus, that the CAMR was improperly promulgated under Section 111 of the Clean Air Act. The court vacated the CAMR's new source performance standards and remanded the matter to the EPA for reconsideration. On March 24, 2008, the EPA filed for rehearing of the decision of the three-judge panel by the full court; rehearing was denied in May 2008. On September 17, 2008, the Utility Air Regulatory Group petitioned the United States Supreme Court for a writ of certiorari to review the United States Court of Appeals for the District of Columbia Circuit's February 8, 2008 decision overturning the rule. The EPA filed a petition to the United States Supreme Court on October 17, 2008 seeking to overturn the lower court's ruling.

While the Supreme Court considers whether to grant the petition for a writ of certiorari, all new coal fueled electric generating units and modifications of existing units will be required to obtain permits under Section 112 (g) of the Clean Air Act.[4] Under this provision, if no applicable emission limits have been established for a category of listed hazardous air pollutant sources, no person may construct a new major source or modify an existing major source in the category unless the EPA Administrator or the delegated state agency determines on a case by case basis that the unit will meet standards equivalent to the maximum achievable emission controls. Thus, new

[4] Refer to the memorandum from Robert Meyers, Deputy Assistant Administrator, Environmental Protection Agency, Office of Air and Radiation, dated January 7, 2009.

major sources or modifications to an existing major source would be required to perform a case by case analysis of the maximum achievable control technology and meet the emissions limitation that could be achieved in practice by the best performing sources in that category. If the Supreme Court decides to hear the appeal, any required maximum achievable control technology analysis requirement will likely be stayed for the duration of the rehearing. Until the court or the EPA take further action, it is not known the extent to which future mercury rules may impact PacifiCorp's current plans to reduce mercury emissions at their coal-fired facilities.

PacifiCorp is committed to responding to environmental concerns and investing in higher levels of protection for its coal-fired plants. PacifiCorp and MEHC anticipate spending $1.2 billion over a ten-year period to install necessary equipment under future emissions control scenarios to the extent that it's cost-effective.

## CLIMATE CHANGE

Climate change has emerged as an issue that requires attention from the energy sector, including utilities. Because of its contribution to United States and global carbon dioxide emissions, the U.S. electricity industry is expected to play a critical role in reducing greenhouse gas emissions. In addition, the electricity industry is composed of large stationary sources of emissions that are thought to be often easier and more cost-effective to control than from numerous smaller sources. PacifiCorp and parent company MidAmerican Energy Holdings Company recognize these issues and have taken voluntary actions to reduce their respective $CO_2$ emission rates. PacifiCorp's efforts to achieve this goal include adding zero-emitting renewable resources to its generation portfolio such as wind, geothermal, landfill gas, solar, combined heat and power (CHP), and hydro capacity upgrades, as well as investing in on-system and customer-based energy efficiency and conservation programs. PacifiCorp also continues to examine risk associated with future $CO_2$ emissions costs. The section below summarizes issues surrounding climate change policies.

### Impacts and Sources

As far as sources of emissions are concerned, according to the U.S. Energy Information Administration, $CO_2$ emissions from the combustion of fossil fuels are proportional to fuel consumption. Among fossil fuel types, coal has the highest carbon content, natural gas the lowest, and petroleum in-between. In the Administration's *Annual Energy Outlook 2009 Early Release* reference case, energy-related $CO_2$ emissions reflect the quantities of fossil fuels consumed and, because of their varying carbon content, the mix of coal, petroleum, and natural gas. Given the high carbon content of coal and its use currently to generate more than one-half of U.S. electricity, prospects for $CO_2$ emissions depend in part on growth in electricity demand. Electricity sales growth in the *AEO2009* reference case slows as a result of a variety of regulatory and socioeconomic factors, including appliance and building efficiency standards, higher energy prices, housing patterns, and economic activity. With slower electricity growth and increased use of renewables for electricity generation influenced by RPS laws in many States, electricity-related $CO_2$ emissions grow by just 0.5 percent per year from 2007 to 2030. $CO_2$ emissions from transportation activity also slow in comparison with the recent past, as Federal CAFE standards increase the efficiency of the vehicle fleet, and higher fuel prices moderate the growth in travel.

Taken together, all these factors tend to slow the growth of the absolute level of primary energy consumption and promote a lower carbon fuel mix. As a result, energy-related emissions of $CO_2$ grow by 7 percent from 2007 to 2030—lower than the 11-percent increase in total energy use. Over the same period, the economy becomes less carbon-intensive as $CO_2$ emissions grow by about one-tenth of the increase in GDP, and emissions per capita decline by 14 percent.

According to the U.S. Energy Information Administration, the factors that influence growth in $CO_2$ emissions are the same as those that drive increases in energy demand. Among the most significant are population growth and shifts to warmer regions that increase the need for cooling; increased penetration of computers, electronics, appliances, and office equipment; increases in commercial floor space; growth in industrial output; increases in highway, rail, and air travel; and continued reliance on coal and natural gas for electric power generation. The increases in demand for energy services are partially offset by efficiency improvements and shifts toward less energy-intensive industries. New $CO_2$ mitigation programs, macroeconomic conditions, more rapid improvements in technology, or more rapid adoption of voluntary programs could result in lower $CO_2$ emissions levels.

PacifiCorp carefully tracks $CO_2$ emissions from operations and reports them in its annual emissions filing with the California Climate Action Registry.

## International and Federal Policies

Numerous policy activities have taken place and continue to develop. At the global level, most of the world's leading greenhouse gas (GHG) emitters, including the European Union (EU), Japan, China, and Canada, have ratified the Kyoto Protocol. The Protocol sets an absolute cap on GHG emissions from industrialized nations from 2008 to 2012 at seven percent below 1990 levels. The Protocol calls for both on-system and off-system emissions reductions. While the U.S. has thus far rejected the Kyoto Protocol, numerous proposals to reduce greenhouse gas emissions have been offered at the federal level. The proposals differ in their stringency and choice of policy tools.

In June 2008, the Lieberman-Warner Bill—the Climate Security Act (CSA)—failed in the Senate. The CSA set a goal for reducing greenhouse gas emissions of more than 60 percent by 2050.[5] Furthermore, the CSA sought to institute a domestic offset program that would allow facilities to meet up to 15 percent of their compliance with allowances generated by offset projects, or by purchasing or borrowing credits. The CSA also included a "Bonus Allowance Account" whereby companies would be awarded for sequestering their carbon emissions.[6] Perceived effects on the national economy derailed the CSA's passage. The EPA estimated the CSA would decrease the nation's gross domestic product between $238 billion and $983 billion by 2030,

[5] Erin Kelly, "Senate Poised to Take Up Sweeping Global Warming Bill," USA Today, http://www.usatoday.com/news/washington/environment/2008-05-17-global-warming_N.htm, May 17, 2008.
[6] *Id.*

while increasing electricity prices 44 percent by 2030.[7] Further, due to rising electricity costs the average household's consumption would decrease an average of $1,375 by 2030.[8]

In addition to the CSA, On October 7, 2008, the former Chairman of the Committee on Energy and Commerce, John D. Dingell, released draft climate change legislation calling for the lowering of emissions to 80 percent of 2005 levels by 2050. The draft legislation proposes to balance its costs through high quality offsets, special reserve emission allowances, and carbon capture and sequestration.[9]

Recent Democratic victories in the House, Senate and the Presidency appear likely to boost efforts to strengthen U.S. global warming policy. Congress and federal policy makers are considering climate change legislation and a variety of national climate change policies and President Obama has expressed support for an economy-wide greenhouse gas cap and trade program that would reduce emissions 80 percent below 1990 levels by 2050. As a result of these policies, PacifiCorp's electric generating facilities are likely to be subject to regulation of greenhouse gas emissions within the next several years.

### U.S. Environmental Protection Agency's Advance Notice of Public Rulemaking

On July 11, 2008, the Environmental Protection Agency released an Advance Notice of Proposed Rulemaking inviting public comment on the benefits and ramifications of regulating greenhouse gases under the Clean Air Act. This Advance Notice of Proposed Rulemaking is one of the steps the Environmental Protection Agency has taken in response to the United States Supreme Court's decision in *Massachusetts v. Environmental Protection Agency*.[10] A decision to regulate greenhouse gas emissions under one section of the Clean Air Act could or would lead to regulation of greenhouse gas emissions under other sections of the Act, including sections establishing permitting requirements for major stationary sources of air pollutants.

The Advance Notice of Proposed Rulemaking reflects the complexity and magnitude of the question of whether and how greenhouse gases could be effectively controlled under the Clean Air Act. Many of the key issues for discussion and comment in the Advance Notice of Proposed Rulemaking included:

- Descriptions of key provisions and programs in the Clean Air Act, and advantages and disadvantages of regulating greenhouse gas emissions under those provisions.

[7] U.S. EPA, EPA Analysis of the Lieberman-Warner Climate Security Act of 2008, available at: http://www.epa.gov/climatechange/downloads/s2191_EPA_Analysis.pdf.

[8] "U.S. Environmental Protection Agency Estimates Cost of Lieberman-Warner Bill to Limit Greenhouse Gas Emissions," National Rural Electric Cooperative Association, available at: http://www.nreca.org/main/NRECA/PublicPolicy/issuespotlight/20080319ClimateChange.htm, March 19, 2008.

[9] John D. Dingell, Climate Change Discussion Draft Legislation, U.S House of Representatives, Committee on Energy and Commerce, October 7, 2008; For a complete list of the cap-and-trade legislation introduced in Congress in 2008, see http://www.pewclimate.org/docUploads/Chart-and-Graph-120108.pdf.

[10] In April 2007, the Supreme Court concluded in that case that greenhouse gas emissions meet the Clean Air Act definition of "air pollutant," and that section 202(a)(1) of the Clean Air Act therefore authorizes regulation of greenhouse gas emissions subject to an Agency determination that greenhouse gas emissions from new motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare (Endangerment Finding).

- How a decision to regulate greenhouse gas emissions under one section of the Clean Air Act could or would lead to regulation of greenhouse gas emissions under other sections of the Act, including sections establishing permitting requirements for major stationary sources of air pollutants.
- Issues relevant for Congress to consider for possible future climate legislation and the potential for overlap between future legislation and regulation under the existing Clean Air Act.
- Scientific information relevant to, and the issues raised by, an endangerment analysis.
- Information regarding potential regulatory approaches and technologies for reducing greenhouse gas emissions.

The Environmental Protection Agency accepted public comment on the Advance Notice of Proposed Rulemaking until November 28, 2008. PacifiCorp's parent, MidAmerican Energy Holdings Company submitted comments on the Advance Notice of Proposed Rulemaking. In these comments, MidAmerican stressed the company's position that Clean Air Act regulations are an inferior strategy for reducing greenhouse gas emissions compared to a comprehensive legislative program that Congress is expected to enact. Promulgating greenhouse gas regulations under the Clean Air Act would be, at best, unnecessary because Congress is expected to enact a program that is economy-wide, market-based, incents technology, and encourages other countries to take action. MidAmerican further highlighted that any mandatory domestic program to reduce greenhouse gas emissions should be implemented consistent with the following principles:

- Technology development and deployment is essential to achieving a 60 to 80 percent reduction in greenhouse gas emissions. A significant national commitment to funding and advancing low-carbon technologies is critical.
- Immediate opportunities for emissions reduction and avoidance should be pursued through investments in energy efficiency, renewable energy and increasing the efficiency of existing generation.
- Any program to regulate greenhouse gas emissions should seek to avoid short-term responses that do not provide a long-term path to a low carbon future.
- Programs implemented to reduce greenhouse gas emissions should achieve their intended purpose—reducing or avoiding emissions—and not simply serve as a source of revenue or offsetting taxes.

## Regional State Initiatives

Activities undertaken by regional state climate change initiatives continued to be significant in 2008 and will continue into 2009. The most notable developments are as follows:

### Midwestern Regional Greenhouse Gas Accord

On November 3, 2008, the ten Midwestern Regional Greenhouse Gas Accord Partners released Draft Recommendations, suggesting a target of between 15-25 percent below 2005 levels by 2020 and a target of between 60-80 percent below 2005 levels by 2050. They also recommended that the program cover a comprehensive slate of activities including electricity generation and imports, industrial combustion sources, credible and measurable industrial process sources, transportation fuels, and fuels serving residential, commercial, and industrial buildings. The Advisory Group hopes to include 85-95 percent of emissions for each sector, and suggests linking the Midwestern Greenhouse Gas Accord cap-and-trade program to the Regional Greenhouse Gas Initiative, Western Climate Initiative, and other mandatory greenhouse gas emissions reduction programs.

**Regional Greenhouse Gas Initiative**
In 2008, the ten Regional Greenhouse Gas Initiative Partners held successful pre-compliance auctions in September and December. The first auction sold 12,565,387 carbon dioxide allowances at a clearing price of $3.07 per allowance, raising more than $38.5 million. The second auction sold 31,505,898 allowances at a clearing price of $3.38 per allowance, raising more than $106 million. Under the Regional Greenhouse Gas Initiative, this combined $140 million will be used on a wide variety of approved efforts to limit and sequester carbon, as well as adapt to the impacts of climate change.

**Western Climate Initiative**
In September 2008, the Western Climate Initiative Partners released their proposal for a regional cap-and-trade program beginning in 2012. The seven states and four provinces would cover 20 percent of the United States, and 70 percent of the Canadian, economies respectively. Covered emitters include electricity generators and industrial and commercial stationary sources that emit more than 25,000 metric tons of carbon dioxide equivalent per year. Beginning in 2015, the market would expand to also cover petroleum-based fuel combustion from residential, commercial, and industrial operations, for an overall goal of reducing emissions to 15 percent below 2005 levels by 2020.

**<u>Individual State Initiatives</u>**

**State Economy-wide Greenhouse Gas Emission Reduction Goals**
An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing economy-wide goals for the reduction of greenhouse gas emissions in their respective states. Washington's goals seek to, (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25 percent below 1990 levels; and (iii) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050. Oregon's goals seek to, (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75 percent below 1990 levels. In 2008, Colorado announced Executive Order D-004-08, setting a goal of reducing greenhouse gas emissions to 20 percent below 2005 levels by 2020, and 80 percent below 2005 levels by 2050. Each state's legislation also calls for state government developed policy recommendations in the future to assist in the monitoring and achievement of these goals.

**State Greenhouse Gas Emission Performance Standards**
In addition, California and Washington have adopted legislation that impose greenhouse gas emission performance standards to all electricity generated within the state or delivered from

outside the state to serve retail load. The greenhouse gas emissions performance standard is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility, effectively prohibiting the use of new pulverized coal generation to serve retail load. The state of Idaho had adopted a de-facto prohibition on new pulverized coal generation located within the state when it decided not to participate in the federal Clean Air Mercury Rule's cap-and-trade program, and as a result received a zero state budget for mercury emissions.

**Other Recent State Accomplishments**

In October 2008, the California Public Utilities Commission and the California Energy Commission completed a collaborative proceeding to develop and provide recommendations to the California Air Resources Board on measures and strategies for reducing greenhouse gas emissions in the electricity and natural gas sectors. The October 16, 2008 final decision[11] is the second policy decision to be issued pursuant to this effort. In an earlier decision, Decision 08-03-018 issued in March 2008, the Commissions provided their initial greenhouse gas policy recommendations to the Air Resources Board. In December, the Air Resources Board adopted the "Assembly Bill 32 Scoping Plan to Reduce Greenhouse Gas Emissions in California." The strategy relies on 31 new rules, including a cap-and-trade program, set to begin in 2012, impacting power plants, refineries, and large factories. Assembly Bill 32 (2006) requires California to cut greenhouse emissions to 1990 levels by 2020. The Air Resources Board is also implementing mandatory greenhouse gas reporting with a regulation that was approved by the Board in December 2007, and became effective on December 2, 2008.[12]

In October 2008, the Oregon Environmental Quality Commission approved new mandatory greenhouse gas reporting rules. The reporting rules are aimed at developing a statewide strategy for reducing emissions to 10 percent below 1990 levels by 2020, and to 75 percent below 1990 levels by 2050. Additionally, the Legislature passed Oregon House Bill 3619 expanding the business energy tax credit program with additional incentives for manufacturers of renewable energy equipment located in Oregon.

In 2008, the Utah Legislature passed Senate Bill 202 establishing a renewable energy target of 20 percent by 2025, with zero-carbon emitting electricity facilities exempt from the target. The bill also establishes a process for establishing a carbon capture and storage regulatory framework. The Utah Carbon Capture and Geologic Sequestration Workgroup was subsequently formed.

In June 2008, the Washington Department of Ecology adopted its final rules implementing a greenhouse gas emissions performance standard of 1,100 pounds of greenhouse gas per megawatt for all new electrical generation built within Washington, or used to serve the Washington retail load. The Department also adopted guidelines for carbon capture and sequestration projects. House Bill 2815 directs the Department of Ecology to develop, in coordination with the Western Climate Initiative, a design for a cap and trade system to meet the state's greenhouse gas emissions reductions limits of 50 percent below 1990 levels by 2050. In December 2008, the

[11] Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies, available at: http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/92288.pdf .

[12] Mandatory Greenhouse Gas Emissions Reporting, available at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

Department delivered to the legislature specific recommendations for approval, and requested authority to implement the preferred design of the greenhouse gas reduction system in order to have the system in effect by January 1, 2012.[13] Second, House Bill 2815 requires operations emitting at least 10,000 metric tons, or on-road motor vehicle fleets that emit 2,500 tons of greenhouse gases, to report their emissions to the Washington Department of Ecology beginning in 2010 for 2009 emissions. House Bill 2687 addresses the Department of Ecology's authority and direction for participation in the Western Climate Initiative, and directs the state to ensure that a design for a cap-and-trade system confers equitable economic benefits and opportunities to electric utilities. Further, the language directs the state to advocate for a regional system that addresses competitive disadvantages that could be experienced because of implementing strict greenhouse gas reduction programs. Senate Bill 6580 requires the Department of Community, Trade, and Economic Development to develop and provide advisory climate change responses to counties and cities, establish a local government global warming mitigation and adaptation program to address climate change through land use and transportation planning, and present a report to the legislature regarding policies to address and assess the impacts of climate change.

Wyoming House Bill 89, Pore Space Ownership, and House Bill 90, Carbon Capture and Sequestration, were signed into law on March 4, 2008. House Bill 89 is intended to affirm the "American or Majority Rule" that the ownership of "pore space" in underground strata below the surface lands and waters of the state of Wyoming is vested in the several owners of the surface, but can be severed from the surface rights and sold separately. "Pore space" is defined to mean subsurface space that can be used as storage space for $CO_2$ or other substances. Wyoming House Bill 90 establishes a permit program for carbon storage and sequestration underground injection wells. The law establishes a permit program for injection of $CO_2$ and associated constituents for sequestration to be issued by Wyoming Department of Environmental Quality. The law specifically states that injection of $CO_2$ for enhanced recovery of oil or gas approved by Wyoming Oil and Gas Conservation Commission is not subject to the new permit program. The Wyoming Carbon Sequestration Working Group was subsequently formed.[14]

**Corporate Greenhouse Gas Mitigation Strategy**

PacifiCorp is committed to engage proactively with policymaking focused on GHG emissions issues through a strategy that includes the following elements.

- **Policy –** PacifiCorp has supported legislation that enables GHG reductions while addressing core customer requirements. PacifiCorp will continue to work with regulators, legislators, and other stakeholders to identify viable tools for GHG emissions reductions.
- **Planning –** PacifiCorp has incorporated a reasonable range of values for the cost of $CO_2$ in the 2009 IRP in concert with numerous alternative future scenarios to reflect the risk of future regulations that can affect relative resource costs. Additional voluntary actions to mitigate greenhouse gas emissions could increase customer rates and represent key public policy decisions that the company will not undertake without prior consultation with regulators and lawmakers at state and federal levels.

[13] Growing Washington's Economy in a Carbon-Constrained World: A Comprehensive Plan to Address the Challenges and Opportunities of Climate Change, available at: http://www.ecy.wa.gov/pubs/0801025.pdf.
[14] http://deq.state.wy.us/carbonsequestration.htm

- **Procurement –** PacifiCorp recognizes the potential for future $CO_2$ costs in requests for proposal (RFPs), consistent with its treatment in the IRP. Commercially available carbon-capturing and storage technologies at a utility scale do not exist today. Carbon-capturing technologies are under development for both pulverized coal plant designs and for coal gasification plant designs, but require research to increase their scale for electric utility use.
- **Accounting –** PacifiCorp has adopted transparent accounting of GHG emissions by joining the California Climate Action Registry. The Registry applies rigorous accounting standards, based in part on those created by the World Business Council on Sustainable Development and the World Resources Institute, to the electric sector.

The current strategy is focused on meaningful results, including installed renewables capacity and effective demand-side management programs that directly benefit customers. While these efforts provide multiple benefits of which lower GHG emissions are a part, they are clearly attractive within an effective climate strategy and will continue to play a key role in future procurement efforts.

## EPRI ANALYSIS OF $CO_2$ PRICES AND THEIR POTENTIAL IMPACT ON THE WESTERN U.S. POWER MARKET

In 2008, the Electric Power Research Institute (EPRI) organized and conducted a broad-brush study to identify and analyze the likely effects of climate change policy for western U.S. (WECC region) generators and customers. A diverse collection of nine western generation companies, including PacifiCorp, funded and participated extensively in this effort.

The WECC region has certain unique power system characteristics, which make it an interesting laboratory to study the effects of climate policy. These include a large existing base of hydro generation supporting the regional market, as well as a growing collection of state-level Renewable Portfolio Standard targets. These existing and anticipated generation resources together form an important baseline serving this region if their potential can be realized. On the other hand there are significant uncertainties surrounding this realization, including the sustainability of hydro generation into the future, and the feasibility of infrastructure investments (i.e. transmission capacity, backup generation) needed to realize such an extensive renewables build out.

The study results attempt to reflect and recognize uncertainties in future power markets, through an examination of several alternative future scenarios. A Reference Case, reflecting a largely stable and optimistic future, was described for baseline purposes. In addition, a case called “Wild Card”, reflecting a more pessimistic view of future events, was presented as an alternative. The study was designed to examine macro-level effects of alternative $CO_2$ price levels on power system dispatch, new generation investment decisions, emissions levels and power prices. The analysis included: representation of a full electric system supply-demand balance; capacity expansion and retirement methodology driven by the relative economics of both existing and new resources, and; a demand response representation, allowing future load growth to respond to future price changes.

Key conditioning assumptions of the Reference Case include: future load growth in this market was assumed equal to the recent historical period 1995-2005, at 1.73 percent per year; natural gas prices (real 2006 dollars) were set to a recent (May 6, 2008) NYMEX forward curve projection through the year 2020, then held constant at 2020 levels; capital costs for new generating plant were driven by EPRI internal estimates from 2007, and further inflated 25 percent in recognition of continual and inexorable escalation (at least until very recently) in all global construction markets, and; western state RPS targets were assumed to be met in future years, per individual state law.

The behavior of the power system and electric customers was investigated over a future period 2006 through 2030, for a series of $CO_2$ price points (starting at $0/ton and escalating up to $100/ton) imposed beginning in 2012. The analysis assumed that the $CO_2$ price would remain constant (in real 2006 $) from 2012 through 2030. This flat scenario $CO_2$ price structure was designed to show how the electric sector would equilibrate to specific prices levels over time.

The results of this analysis show, in the first instance, that a higher $CO_2$ price will drive up the power price and drive down emissions. The power price in the initial year (2012) increases almost linearly with the $CO_2$ price, because the power system has very limited response capability in the very short term. There is some capability to switch resource usage from coal to natural gas, but it is actually quite limited in WECC, so the only real option is to pass price increases on to consumers. Similarly, the short-term ability to reduce emissions is virtually nil except at very high $CO_2$ prices where the level of demand itself is reduced through price effects.

This inflexibility is much less true as time marches on. In later years the response is both more pronounced for emissions and more limited for power prices, as the generating stock begins to turn over and new investments are made in non-emitting generation. Note in particular that emissions reductions by 2030 accelerate significantly once the $50-$60 $CO_2$ price range is reached, when nuclear generation starts to penetrate the market. It is only when wholesale power prices reach roughly the $100 range that the nuclear technology can expect to cover its investment and carrying costs. The response of power price to $CO_2$ price is also more moderated in later years, as low-busbar cost, non-emitting technologies enter the mix and temper power prices.

The generation mix details of these phenomena are equally illuminating. In the absence of a $CO_2$ policy the existing mix of generation is not appreciably affected. As time marches into the future, demand growth is largely met with new renewable generation and new natural gas-fired generation. A small amount of customer response to rising prices tempers demand growth just a bit. Emissions keep growing.

A $50/ton $CO_2$ price brings about noticeable future changes. In the first instance, it is interesting to note that this represents the “stabilization” price, or the price that essentially flattens emissions growth into the future. As power prices are also driven up in this case, customer response is also greater and demand growth is tempered even further. Higher power prices also begin to affect the generation mix, pushing out existing coal over time and eliciting more gas generation as replacement energy. Notably, at a $50 $CO_2$ price there is still little change in the overall generation mix over time, as the power price is not yet quite high enough to usher in significant capacity in non-emitting technologies.

At $CO_2$ prices of $85 and higher, the generation mix begins to change noticeably due to the new technology opportunities presented by higher power prices. Note first that in this case emissions shrink significantly over time, in reaction to both increased customer price response and to changes in generation technology. Existing coal generation shrinks virtually to nothing by 2030, and is replaced in part with non-emitting nuclear generation – assumed to be available in the 2020 timeframe – as well as renewables. On the other hand, power prices actually moderate over time at the $85 $CO_2$ level, due in large part to the switch out of coal generation (and its $85/ton surcharge) and into very low busbar-cost alternatives such as nuclear and renewables.

An alternative, more pessimistic case was investigated as well. The "Wild Card" case represents an alternative future – one in which both events and policy responses to them work against future greenhouse gas control. Key differences in assumptions for the "Wild Card" case include: an assumed higher load growth rate; assumed higher natural gas prices; higher capital costs (25 percent premium); an assumed lower customer demand response, and; assumed nuclear power unavailability for the duration of the study.

The "Wild Card" future requires a higher $CO_2$ price than the Reference Case to stabilize emissions over time (closer to the $70-$80 range). Due to higher capital costs overall, as well as the nuclear penetration constraint, capital stock turnover is much more sluggish in the pre-2030 time frame, and emissions are still growing at the $50 $CO_2$ price level. Existing generation – coal and gas – is necessarily used more heavily, and emissions stubbornly resist reduction.

Even at a $100 $CO_2$ price, emissions reductions in the "Wild Card" case are still minimal. In fact it takes a $CO_2$ price in the range of $125-$150 to effect significant reduction, under a "Wild Card" future.

Power prices are impacted as well. The "Wild Card" future leads to a persistent $20 premium in wholesale power prices, regardless of the size of the $CO_2$ price assumed.

The foregoing analysis of western power markets was an attempt to postulate several alternative futures, and examine the implications of each on suppliers and consumers. The analysis is aggregate – high-level and suggestive – and certainly glosses over many details and intricacies in an attempt to focus squarely on the larger picture. Many "devils in the details" have been undoubtedly simplified, including the following.

All details of power system operations are treated abstractly, at best. This abstraction is clearest in the representation of renewable generation and its growth potential. Realistically, there will need to be significant infrastructure (i.e. transmission capacity, backup combustion turbine generation or energy storage to mitigate intermittency) built in the west, additional to renewable generation capacity, to support its usage. This additional infrastructure has been represented in the analysis as a simple capital adder to the renewables cost estimate. Whether this additional investment will be financially - or politically - feasible is certainly an open question. It may be that the renewables contribution has been overestimated. On the other hand, the base renewables projections (the vast bulk of the renewables capacity in any scenario) used in this analysis are merely what has been mandated by numerous western states as their avowed targets, and these targets are already today well within reach in many states.

Natural gas prices are also an important driver of the analysis, and they have been notoriously volatile for the last 30 years. Among knowledgeable professionals there are resource depletion arguments that indicate prices will go up, and liquefied natural gas emergence arguments that indicate prices will go down. Still and all, the NYMEX forward curve remains the best consensus estimate of what will happen to gas prices in the future; this has formed the basis of the estimates in this analysis.

Customer response to price changes is universally recognized as a real phenomenon, and just as universally acknowledged as impossible to accurately measure. In this analysis the long-term elasticity parameter finally chosen (-0.50) is based on EPRI studies from early in the decade, but it could well be overstated.

The above caveats notwithstanding, there are several important conclusions that can be drawn from the analysis. These include the following.

It is certainly possible to wring emissions growth out of the power sector in western states, given high enough $CO_2$ price signals and sufficient time. In the Reference Case future, a price of about $50 will flatten emissions growth, and a price of about $80 will substantially reduce it. In the "Wild Card" future, it will require about an $80 price to flatten growth and a price in excess of $125 to make substantial reductions.

$CO_2$ prices in these ranges are unprecedented, and will lead to unprecedented retail power prices as well, in the range of 40-80 percent higher (depending on $CO_2$ price level)—in the immediate aftermath of price imposition—than they are in WECC today. Such levels will cause anxiety for the electricity sector and its customers as well. However, over time (18 years is the horizon of this analysis, actually, higher prices will create investment incentives for the addition of non-emitting generation, and more such capacity will enter the market if it functions reasonably well. This will tend to temper power price differentials over time. In the analysis retail prices in 2030 are projected to end up more like 15-30 percent higher than the $0 case, a far cry from the differentials in 2012.

Customer response to price increases will tend to hold power price levels down in its turn as well. Without this effect prices might be expected to rise even higher. This is a mixed blessing at best, as it will represent a real loss in consumer welfare, albeit not measured explicitly in the analysis.

Natural gas price and availability are critical linchpins in the Western power system in early years, as short-term reductions in emissions will depend on the ability of natural gas generation to fill the gaps left by coal cutbacks. This criticality will fade over time, as new non-emitting technologies increasingly will enter the market and fill the void.

For the western power industry, the EPRI analysis helps inform possible decisions by highlighting two important $CO_2$ price signals necessary to effectuate changes within the electricity sector.

The first is the $CO_2$ price that is just high enough to encourage a utility interested in building new electricity generation to choose a lower-emitting—albeit more expensive—technology over a cheaper, but higher-emitting technology. A second $CO_2$ price is one that is sustained at a high enough level as to make existing fossil-fueled power plants uneconomic to continue operating. Under either situation, higher costs will inevitably be passed on to consumers in the form of higher electricity rates, but if accompanied by sufficient time to adapt to the new regulatory regime, costs can be mitigated.

## ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

In late December 2007, Congress passed the Energy Independence and Security Act (P.L. 110-140, which has three major provisions covering corporate average fuel economy standards, the renewable fuels standard, and appliance/lighting efficiency standards.

For corporate average fuel economy, the law sets a target of 35 miles per gallon for the combined fleet of cars and light trucks by model year 2020. Also, a fuel economy program is established for medium- and heavy-duty trucks, and a separate fuel economy standard is created for work trucks. These were the first new corporate average fuel economy standards in 32 years, and the increases represent a roughly 40 percent increase over today's requirements.

For the renewable fuels standard, the law sets a modified standard that starts at 9.0 billion gallons of renewable fuel in 2008 and rises to 36 billion gallons by 2022. Of the latter total, 21 billion gallons is required to be obtained from cellulosic ethanol and other advanced biofuels. This represents a six-fold increase over the mandate that is in place.

In the area of energy efficiency (specifically appliance and lighting efficiency standards), the law set energy efficiency standards for broad categories of incandescent lamps (light bulbs), incandescent reflector lamps, and fluorescent lamps. A required target is set for lighting efficiency, and energy efficiency labeling is required for consumer electronic products. The law will effectively phase out most common types of incandescent light bulbs over the next four to six years by increasing the energy efficiency standards of light bulbs by 30 percent. The new standard is technology-neutral, allowing consumers a choice among several efficient lighting technologies, including improved halogen-incandescent bulbs, compact fluorescent lamps and eventually light-emitting diodes and other advanced lighting technologies. The impact of the lighting efficiency standards has been accounted for in PacifiCorp's load forecasting and IRP portfolio modeling (See Chapter 5, Resource Needs Assessment). Efficiency standards are set by law for external power supplies, residential clothes washers, dishwashers, dehumidifiers, refrigerators, refrigerator/freezers, freezers, electric motors, residential boilers, commercial walk-in coolers, and commercial walk-in freezers. Further, the U.S. Department of Energy is directed to set standards by rulemaking for furnace fans and battery chargers.

The Act also requires a 30 percent reduction in energy consumption by 2015 in federal buildings. (The General Services Administration owns and leases over 340 million square feet of space in more than 8,900 buildings, located in every state.)

The Act also encourages the development of carbon capture technology by (1) expanding and improving the Department of Energy's existing carbon sequestration research, (2) requiring a national assessment of capacity to sequester carbon, (3) requiring the Secretary of Energy to conduct seven large-scale geologic sequestration tests, with at least one as an international partnership, an d(4) increasing the funding authorization for all projects included in the new carbon capture and storage research, development and demonstration program, with an emphasis on large-scale geologic carbon dioxide injection demonstration projects.

Another title of the Act is the Advanced Geothermal Energy Research and Development Act of 2007. It calls for research, development, demonstration, and commercial application in five major areas: (1) geopressured resource production, which is co-produced in oil and gas fields; (2) cost-sharing drilling; (3) enhanced geothermal systems; (4) creation of a national exploration and development geothermal technology transfer and information center; and (5) international geothermal collaboration.

## RENEWABLE PORTFOLIO STANDARDS

A renewable portfolio standard (RPS) is a policy that obligates each retail seller of electricity to include in its resource portfolio (the resources procured by the retail seller to supply its retail customers) a certain amount of electricity from renewable energy resources, such as wind and solar energy. The retailer can satisfy this obligation by either (1) owning a renewable energy facility and producing its own power, or (2) purchasing renewable electricity from someone else's facility.

Some RPS statutes or rules allow retailers to trade their obligation as a way of easing compliance with the RPS. Under this trading approach, the retailer, rather than maintaining renewable energy in its own energy portfolio, instead purchases tradable credits that demonstrate that someone else has generated the required amount of renewable energy.

RPS policies are currently implemented at the state level (although interest in a federal RPS is expanding), and vary considerably in their requirements with respect to time frame, resource eligibility, treatment of existing plants, arrangements for enforcement and penalties, and whether they allow trading of renewable energy credits. By 2008, twenty-five states adopted mandatory renewable portfolio standards, five states adopted voluntary renewable portfolio standard, and fourteen states had adopted no form of renewable portfolio standard.

Within PacifiCorp's service territory, California, Oregon, and Washington have mandatory renewable portfolio standards, with Utah having adopted a voluntary renewable portfolio standard. Each state is summarized in Table 3.1 and additional discussion below.

**Table 3.1 – Summary of state renewable goals (as applicable to PacifiCorp)**

| State | Goal |
|---|---|
| **California** | Obtain 20 percent of electricity from renewable resources by 2010. |
| **Oregon** | Obtain 25 percent of electricity from renewable resources by 2025 in the |

| State | Goal |
|---|---|
| | following increments:<br>• 5 percent: 2011 – 2014<br>• 15 percent: 2015 – 2019<br>• 20 percent : 2020 – 2024<br>• 25 percent: 2025 and beyond |
| **Utah** | By 2025, obtain 20 percent of annual adjusted retail sales from cost effective renewable resources, as determined by the Public Service Commission or renewable energy certificates. |
| **Washington** | Obtain 15 percent of electricity from renewable resources by 2020 in the following increments:<br>• 3 percent by January 1, 2012 through December 31, 2015<br>• 9 percent by January 1, 2016 through December 31, 2019<br>• 15 percent by January 1, 2020 and each year thereafter |

**California**

California law requires electric utilities to increase their procurement of renewable resources by at least one percent of their annual retail electricity sales per year so that 20 percent of their annual electricity sales are procured from renewable resources by no later than December 31, 2010. In May 2008, PacifiCorp and other small multi-jurisdictional utilities received further guidance from the California Public Utilities Commission on the treatment of small multi-jurisdictional utilities in the California Renewable Portfolio Standard program within decision, D.08-05-029. In August 2008, concurrent with its annual renewable portfolio standard compliance filing, PacifiCorp, joined by Sierra Pacific Power Company, filed a Joint Motion for Review of the decision. As discussed in D.08-05-029, since the inception of the Renewable Portfolio Standard program, PacifiCorp and other small multi-jurisdictional utilities operated in a state of regulatory uncertainty regarding the nature of their Renewable Portfolio Standard program compliance obligations. PacifiCorp's filing represented its interpretation of D.08-05-029, including banking of renewable portfolio standard procurement made while it awaited further guidance from the California Public Utilities Commission on the treatment of small multi-jurisdictional utilities during the 2004-2006 period. PacifiCorp believes its interpretation is consistent with D.08-05-029 and best serves the interests of its customers by recognizing past, good faith efforts to comply with California's Renewable Portfolio Standard program beginning January 1, 2004. PacifiCorp is currently awaiting the California Public Utilities Commission's response to the Joint Motion for Review.

**Oregon**

In June 2007, the Oregon Renewable Energy Act was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least five percent in 2011 through 2014, 15 percent in 2015 through 2019, 20 percent in 2020 through 2024, and 25 percent in 2025 and subsequent years. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council area, and unbundled renewable energy credits can be used. The Oregon Public Utilities Commission and the Oregon Department of Energy have undertaken additional rule-making proceedings to further implement the initiative.

**Utah**

In March 2008, Utah's governor signed Utah Senate Bill 202, "Energy Resource and Carbon Emission Reduction Initiative;" legislation supported by PacifiCorp. Among other things, this provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used.

**Washington**

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are three percent of retail sales by January 1, 2012 through 2015, nine percent of retail sales by January 1, 2016 through 2019 and 15 percent of retail sales by January 1, 2020. Qualifying renewable energy sources must be located within the Pacific Northwest. The Washington Utilities and Transportation Commission adopted final rules to implement the initiative.

**Federal Renewable Portfolio Standard**

Congress is expected to take up federal energy policy legislation, including the possibility of a federal RPS, as early as spring 2009. President Obama has pledged to "spark the creation of a clean energy economy" as part of his plan aimed at reinvigorating the U.S. economy, in part by doubling production of "alternative energy" in the next three years—aided by subsidies for "low emissions coal plants," biofuels and renewable energies—and by pursuing a federal renewable portfolio standard mandating that 25 percent of U.S. electricity come from renewable sources by 2025. Passage of a federal renewable portfolio standard would break a major standoff in Congress as both the House and Senate have passed various forms of a renewable portfolio standard in recent years but failed to concur on the details.

Proponents of a national renewable portfolio standard argue it would ease the move toward a mandatory cap on greenhouse gas emissions by requiring utilities to invest in low-carbon energy sources. Enactment of a federal renewable portfolio standard would be a significant shift in the way electric utilities are regulated, dramatically increasing the authority of the federal government to dictate the makeup of a utility's energy portfolio—a power currently exercised by state governments.

**Renewable Energy Certificates**

Absent either a RPS compliance obligation or an opportunity to bank unbundled renewable energy certificate (RECs) for future year RPS compliance, PacifiCorp has historically relied on an assumption that a renewable project may generate $5 per megawatt-hour for five years from the sale of unbundled RECs. Unbundled REC sales have helped mitigate the near-term cost differential between new renewable resources and traditional generating resources.

However, once greenhouse gas emissions are regulated, surplus unbundled REC sales would cease. PacifiCorp assumes if an unbundled REC is sold, then the underlying power (aka "null" power) would likely have a carbon emissions rate imputed upon it by regulatory authorities, thus obligating PacifiCorp to purchase either allowances or carbon offsets sufficient to cover the imputed carbon emissions. By selling an unbundled REC, PacifiCorp may generate revenue, but risks incurring a new carbon liability. Once greenhouse gases are regulated—and until the unbundled REC and carbon markets are reconciled—PacifiCorp plans to cease selling unbundled RECs.

## HYDROELECTRIC RELICENSING

The issues involved in relicensing hydroelectric facilities are multifaceted. They involve numerous federal and state environmental laws and regulations, and participation of numerous stakeholders including agencies, Indian tribes, non-governmental organizations, and local communities and governments.

The value to relicensing hydroelectric facilities is continued availability of hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility as they can be called upon to meet peak customer demands almost instantaneously and provide back-up for intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation. With the exception of two hydroelectric projects, all of PacifiCorp's applicable generating facilities now operate under contemporary Orders from the Federal Energy Regulatory Commission (FERC). The Klamath River hydroelectric project continues to work with parties to reach a settlement agreement on future project conditions, and the Condit project is seeking a Surrender Order to decommission the project.

FERC hydroelectric relicensing is administered within a very complex regulatory framework and is an extremely political and often controversial public process. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate for those impacts. Stakeholder consultation is conducted throughout the process. If resolution of issues cannot be reached in this process, litigation often ensues which can be costly and time-consuming. There is only one alternative to relicensing, that being decommissioning. Both choices, however, can involve significant costs.

The FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other certain criteria. The FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural activities, recreation, land-use, and aesthetics against the project's energy production benefits. However, because some of the responsible state and federal agencies have the ability to place mandatory conditions in the license, the FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority within the relicensing to require installation of fish passage facilities (fish ladders and screens) at projects. This is often the largest single capital investment that will be made in a project and can render some projects uneconomic. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other leading to potentially contrary, or additive, licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in settlement negotiations with stakeholders, the results of which are submitted to the FERC for incorporation into a new license. The FERC welcomes settlement agreements into the relicensing process, and with associated recent license orders, has generally accepted agreement terms.

**Potential Impact**

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and generally takes nearly ten or more years to complete, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2008, PacifiCorp had incurred $56.6 million in costs for ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As relicensing and/or decommissioning efforts continue for the Klamath River and Condit hydroelectric projects, additional process costs are being incurred that will need to be recovered from customers. Also, new requirements contained in FERC licenses or decommissioning Orders could amount to over $1.2 billion over the next 30 to 50 years. Such costs include capital and operations and maintenance investments made in fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures as well as project operational changes such as increased in-stream flow requirements to protect fish resulting in lost generation. Over 95 percent of these relicensing costs relate to PacifiCorp's three largest hydroelectric projects: Lewis River, Klamath River and North Umpqua.

**Treatment in the IRP**

The known or expected operational impacts mandated in the new licenses are incorporated in the projection of existing hydroelectric resources discussed in Chapter 4.

**PacifiCorp's Approach to Hydroelectric Relicensing**

PacifiCorp continues to manage this process by pursuing a negotiated settlement as part of the Klamath River relicensing process. PacifiCorp believes this proactive approach, which involves meeting agency and others' interests through creative solutions is the best way to achieve environmental improvement while managing costs. PacifiCorp also has reached agreements with licensing stakeholders to decommission projects where that has been the most cost-effective outcome for customers.

## RECENT RESOURCE PROCUREMENT ACTIVITIES

### 2012 Request for Proposals for Base Load Resources

PacifiCorp issued this RFP on April 5, 2007, to procure up to 1,700 MW of base-load resources for 2012-2014. In December 2008, PacifiCorp submitted an application for "Approval of Significant Energy Resource Decision and for Certificate of Public Convenience and Necessity" to the Public Service Commission of Utah for the Lake Side 2 combine-cycle plant. As discussed above, in February 2008, the company terminated the construction contract for this plant.

### 2008 All-Source Request for Proposals

The 2008 All-Source RFP, which was issued on October 2, 2008, sought up to 2,000 MW of system-wide base-load capacity, intermediate load capacity, third-quarter market purchases, load curtailment, PURPA Qualifying Facilities, and dispatchable/schedulable renewables, with on-line dates between 2012 through 2016.[15] Both the Public Utility Commission of Oregon and the Public Service Commission of Utah approved the RFP.

In late February 2009, PacifiCorp suspended this RFP due to uncertainty caused by the ongoing financial crisis, the economic recession and its impact on loads, and belief that ratepayers and the company might get a better deal than the proposals submitted in the RFP as the year goes on and markets continue to adjust to the economic environment. Additionally, PacifiCorp also believes suppliers will be much more likely to secure financing once the banking sector has stabilized.

PacifiCorp will monitor the market over the next six to eight months with the intention to lift the suspension, issue an Amendment to the RFP and request updated proposals from the existing bidders and new proposals. PacifiCorp also intends to refresh its benchmark proposals at that time.

### Renewable Request for Proposal (RFP 2008R)

PacifiCorp issued RFP 2008R on January 31, 2008 for renewable resources of less than 100 MW for resources greater than five years in length, or greater than 100 MW for resources less than or equal to five years in length. The 2008R RFP solicited renewable resources that have a commercial operation date prior to December 31, 2009. On September 5, 2008, PacifiCorp executed a 20-year power purchase agreement with Duke Energy Corporation for the entire output of the 99-megawatt Campbell Hill project, located in Wyoming.

### Renewable Request for Proposal (RFP 2008R-1)

PacifiCorp issued RFP 2008R-1 on October 6, 2008. This RFP solicited 500 MW of renewable generation projects—with no single resource greater than 300 megawatts—with on-line dates prior to December, 2011. An amendment to this RFP was filed in Utah on January 12, 2009 and in Oregon on January 8, 2009. Bidders for existing proposals that have been received will have an opportunity to update their pricing. The amendment also allows new bidders to participate. The amendment was filed and approved by the Oregon Public Utility Commission January 20, 2009. PacifiCorp anticipates making procurement decisions by July 2009.

[15] PacifiCorp's website for competitive solicitations: http://www.pacificorp.com/Article/Article62880.html.

## Demand-side Resources

The company released a comprehensive demand-side management RFP (2008 DSM RFP) in November 2008. This RFP constitutes one of the items in PacifiCorp's IRP action plan, documented in the 2007 IRP Update report (June 2008, page 25). The 2008 DSM RFP requested bids on eighteen defined products: four Class 1 products and fourteen Class 2 products. The RFP also allowed for proposals on three non-defined products, one for Class 1 load management products, one for Class 2 energy efficiency products, and one for Class 3 price-responsive products. The non-defined product requests allowed bidders to propose products not initially identified in the RFP that they believe may be of benefit to the company. Contracting for new products accepted under the 2008 DSM RFP will be concluded by mid-summer with regulatory approvals and implementation scheduled to begin the fourth quarter of 2009.

Other procurement work anticipated in 2009 includes the issuance of RFPs for program evaluations of legacy products, engineering resources in support of commercial, industrial and agricultural program delivery, and the procurement of ongoing irrigation load management services in Utah and Idaho.

# 4. TRANSMISSION PLANNING

## PURPOSE OF TRANSMISSION

The basic purpose of PacifiCorp's bulk transmission network is to reliably transport electric energy from generation resources (generation or market purchases) to various load centers. There are several related benefits associated with a robust transmission network:

1. Reliable delivery of power to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to supply aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably unscheduled outages.
3. Economic exchange of electric power among all systems and industry participants.
4. Development of economically feasible renewable generation in areas where it is best suited.
5. Protection against extreme market conditions where limited transmission constrains energy supply.
6. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff.
7. Increased capability and capacity to access Western energy supply markets.

PacifiCorp's transmission network is a critical component of the IRP process and is highly integrated with other transmission providers in the western United States. It has a long history of reliable service in meeting the bulk transmission needs of the region. Its purpose will become more critical in the future as energy resources become more dynamic and customer expectations become more demanding.

## INTEGRATED RESOURCE PLANNING PERSPECTIVE

Transmission constraints and the ability to address capacity or congestion issues in a timely manner represent important planning considerations for ensuring that peak load and energy obligations are met on a reliable basis. The cycle time to add significant transmission infrastructure is often longer than adding generation resources or securing third party resources. Transmission additions must be integrated into regional plans and then permits must be obtained to site and construct the physical assets. Inadequate transmission capacity limits the utilities ability to access what would otherwise be cost effective generating resources.

Transmission assets tend to be long lived which go beyond a twenty-year planning horizon typically considered for resource planning. The result is a set of transmission assets modeled for least cost planning that addresses PacifiCorp's control area needs as well as enables a first-cut evaluation of the impacts of a large multi-state transmission project.

As discussed in the following sections, PacifiCorp is engaged in a significant transmission expansion effort called Energy Gateway that requires cooperative transmission planning with regional and sub-regional planning groups across the Western Interconnection. Transmission infrastructure will continue to play an important role in future IRP plans as segments are added due to Energy Gateway along with other system reinforcement projects.

## INTERCONNECTION-WIDE REGIONAL PLANNING

Various regional planning processes have developed over the last several years in the Western Interconnection[16]. It is expected that, in the future, these processes will be the primary forums where major transmission projects are identified, evaluated, developed and coordinated. In the Western Interconnection, regional planning has evolved into a three tiered approach where an interconnection-wide entity, the Western Electricity Coordinating Council (WECC) conducts regional planning at a very high level, several sub-regional planning groups focus with greater depth on their specific areas and transmission providers perform local planning studies within their sub-region. This coordinated planning helps to insure that customers in the region are served reliably and at the least cost.

In 2006, WECC took on a larger and more defined responsibility for interconnection-wide transmission expansion planning under the Federal Energy Regulatory Commission's Order 890. WECC's role in meeting the region's need for regional economic transmission planning and analyses is to provide impartial and reliable data, public process leadership, and analytical tools and services. The activities of WECC in this area are guided and overseen by a board-level committee and the Transmission Expansion Planning Policy Committee (TEPPC).

TEPPC's three main functions include: (1) overseeing database management, (2) providing policy and management of the planning process, and (3) guiding the analyses and modeling for Western Interconnection economic transmission expansion planning. These functions compliment but do not replace the responsibilities of WECC members and stakeholders to develop and implement specific expansion projects.

TEPPC organizes and steers WECC regional economic transmission planning activities. Specific responsibilities include:

- Steering decisions on key assumptions and the process by which economic transmission expansion planning data are collected, coordinated and validated;
- Approving transmission study plans, including study scope, objectives, priorities, overall methods/approach, deliverables, and schedules;
- Steering decisions on analytical methods and on selecting and implementing production cost and other models found necessary;
- Ensuring the economic transmission expansion planning process is impartial, transparent, properly executed and well communicated;
- Ensuring that regional experts and stakeholders participate, including state/provincial energy offices, regulators, resource and transmission developers, load serving entities, environmental and consumer advocate stakeholders through a stakeholder advisory group;
- Advising the WECC Board on policy issues affecting economic transmission expansion planning; and

[16] The Western Interconnection stretches from Western Canada South to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains.

- Approving recommendations to improve the economic transmission expansion planning process.

TEPPC analyses and studies focus on plans with west-wide implications and include high level assessments of congestion and congestion costs. The analyses and studies also evaluate the economics of resource and transmission expansion alternatives on a regional, screening study basis. Resource and transmission alternatives may be targeted at relieving congestion, minimizing and stabilizing regional production costs, diversifying fuels, achieving renewable resource and clean energy goals, or other purposes. Alternatives often draw from state energy plans, integrated resource plans, large regional expansion proposals, sub-regional plans and studies, and other sources if relevant in a regional context.

Members and stakeholders of TEPPC includes transmission providers, policy makers, governmental representatives, and others with expertise in planning, building new economic transmission, evaluating the economics of transmission or resource plans; or managing public planning processes.

Similar to the TEPPC activities and process at WECC, a similar process exists under the oversight of the Planning Coordination Committee which provides for the reliability aspects of transmission system planning.

**Sub-regional Planning Groups**

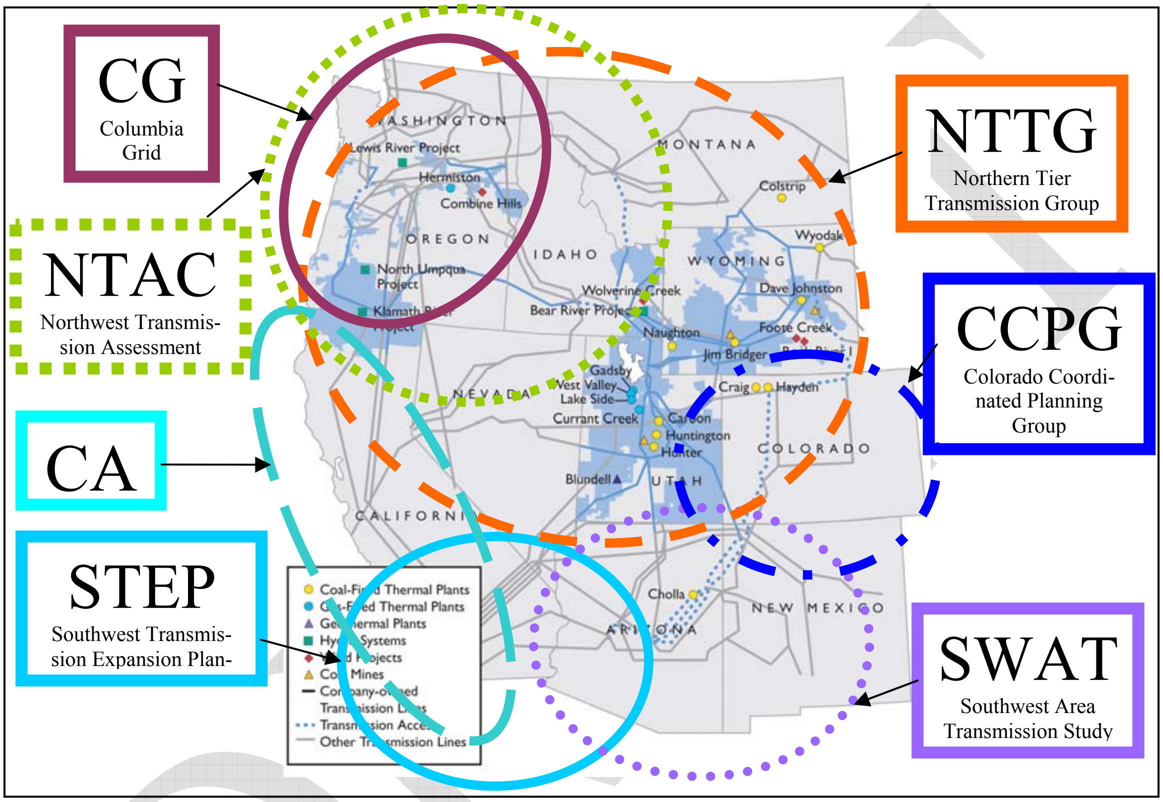
Recognizing that planning the entire western interconnection in one forum is impractical due to the overwhelming scope of work, a number of smaller sub-regional groups have been formed to address specific challenges in various areas of the interconnection. Generally all of these forums provide similar regional planning functions, including the development and coordination of major transmission plans within their respective areas; however it is these sub-regional forums where the majority of transmission projects are expected to be developed. These forums coordinate with each other directly through liaisons and through TEPPC. A current list of sub-regional groups is provided below:

- **NTTG** – Northern Tier Transmission Group
- **CCPG** – Colorado Coordinated Planning Group
- **CG** – Columbia Grid
- **NTAC** - Northwest Transmission Assessment Committee
- **STEP** - Southwest Transmission Expansion Planning
- **SWAT** – Southwest Area Transmission Study
- **CA** – California Independent System Operator
- **WestConnect** – A southwest sub-regional planning group that includes participants from CCPG, SWAT and other utilities

PacifiCorp is one of the founding members of Northern Tier Transmission Group (NTTG). Originally formed in early 2007, NTTG has an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. The NTTG footprint includes approximately 2.7 million customers and more than 27,000 miles of transmission lines within Oregon, Washington, California, Idaho, Montana, Wyoming and Utah. In addition to PacifiCorp, other members include Deseret Power Electric Cooperative, NorthWestern Energy, Idaho Power, Portland General Electric, and the Utah Associated Municipal Power Systems.

The geographical areas covered by these sub-regional planning groups are approximately shown in Figure 4.1 below:

**Figure 4.1 – Sub-regional Transmission Planning Groups in the WECC**




## Energy Gateway

Since the last major transmission infrastructure construction in the 1970s and early 1980s, load growth and increased use of the western transmission system has steadily eroded the surplus capacity of the network. In the early 1990s when limited transmission capacity in high growth regions became more severe, low natural gas prices generally made adding gas fired generation close to load centers less expensive than transmission infrastructure additions. As natural gas prices started moving up in the year 2000, transmission construction became more attractive, but long transmission lead times to resource centers and rate recovery uncertainty suppressed new transmission investment.

Repeated sub-regional studies, including the Rocky Mountain Area Transmission Study dated September 2004, the Western Governor's Association Transmission Task Force Report dated May 2006 and the Northern Tier Transmission Group Fast Track Project Process in 2007 plus subsequent PacifiCorp planning studies concluded the critical need to alleviate transmission congestion and move transmission constrained energy resources to regional load centers.

The recommended bulk electric transmission additions for PacifiCorp took on a consistent footprint which is now known as Energy Gateway by establishing a triangle over Idaho, Utah and Wyoming with paths extending into Oregon and Washington.

Prior to 2007, PacifiCorp transmission activity was primarily focused on maintaining existing transmission reliability, executing queue studies, addressing compliance issues, and participating in shaping regional policy issues. Investments in main grid assets for load service, regional expansion or economic expansion to meet specific customer requests for service were addressed as transmission customers requested service.

**New Transmission Requirements**

Historically, transmission planning took place at the utility level and was focused on connecting specific utility generation resources to designated load centers. Under 888/889 Federal Energy Regulatory Commission rules, customer requests for transmission service were sporadic and uncoordinated with high levels of uncertainty in many markets which inhibited transmission investments.

Due to PacifiCorp's transmission system being a major component of the Western Interconnection, the company has the responsibility to provide network customers adequate transmission capability that optimizes generation resources and provides reliable service both today and into the future. Based on current projections, loads and the dynamic blend of energy resources are expected to become more complex over the next twenty years which will challenge the existing capabilities of the transmission network.

In addition to ensuring sufficient capacity is available to meet the needs of its network customers, the Federal Energy Regulatory Commission in Order 890 encourages transmission providers such as PacifiCorp to plan and implement regional solutions for transmission reliability and expansion.

Based on the aggregate needs of PacifiCorp and others utilities in various sub-regional planning groups, a blueprint for transmission expansion was developed. The expansion plan is a culmination of prior studies and multiple utilities' integrated resource plans (PacifiCorp, Idaho Power, NorthWestern, and Portland General Electric) as well as identified potential plans of independent resource developers. It identifies a transmission expansion plan that will support multiple load centers, resource locations and resource types. In total the expansion plan, now referred to as Energy Gateway calls for the construction of numerous transmission segments – totaling approximately 2,000 miles.

The Energy Gateway blueprint uses a "hub and spoke" concept to most efficiently integrate transmission lines and collection points with resources and loads centers aimed at serving PacifiCorp customers while keeping in sight Regional and Sub Regional needs.

In addition to regulatory requirements for regional planning, future siting and permitting of new transmission lines will require significant participation and input from many stakeholders in the west. As part of new transmission line permitting PacifiCorp will have to demonstrate that several key requirements have been met; 1) the company has satisfied an ongoing requirement for transmission to serve customers, 2) the company is planning and building for the future and is obtaining corridors and mitigating environmental impacts prudently, and 3) that any projects being proposed economically meet the reliability and infrastructure needs of the region over all. This regional process and the Western Electricity Coordinating Council's planning process are considered critical to gaining wide support and acceptance for PacifiCorp's transmission expansion plan.

**Reliability**

PacifiCorp's transmission network is increasingly measured against new Federal Energy Regulatory Commission (FERC) / National Electric Reliability Corporation (NERC) mandatory reliability standards which require infrastructure to be in place in case of unplanned outage events. Mandatory compliance with the NERC planning standards is required of the NERC Regional Councils (Regions) and their members as well as all other electric industry participants if the reliability of the interconnected bulk electric systems is to be maintained in the competitive electricity environment.[17] The majority of these new mandatory standards are the responsibility of the transmission owner.

NERC Planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy means the electric system needs to be able to supply aggregate electrical demand for customers at all times. Security means the electric system must withstand sudden disturbances or unanticipated loss of system elements.[18] Increasing transmission capacity often requires redundant facilities in order to meet NERC reliability criteria.

The ability to recover from system disturbances impacting main grid transmission often require accommodating multiple contingency scenarios which Energy Gateway helps facilitate along with other system reinforcement projects. There have been a number of main grid transmission outages in the latter part of 2007 resulting in curtailment of schedules, curtailments of interruptible loads and generation curtailments. These outages occurred on main grid paths and the ability to recover was severely limited because mitigation measures were electrically restricted due to lack of transmission capacity.

**Resource Locations**

As an extension of the 'hub and spoke' strategy, PacifiCorp must consider logical resource locations for the long-term based on environmental constraints, economical generation resources, and federal and state energy policies. PacifiCorp's primary energy resources in descending order are located in Utah, Wyoming, desert southwest and the west. Energy Gateway leverages the dynamic and future mix of energy resources and market access points at key locations and supports the company's preferred resource portfolio.

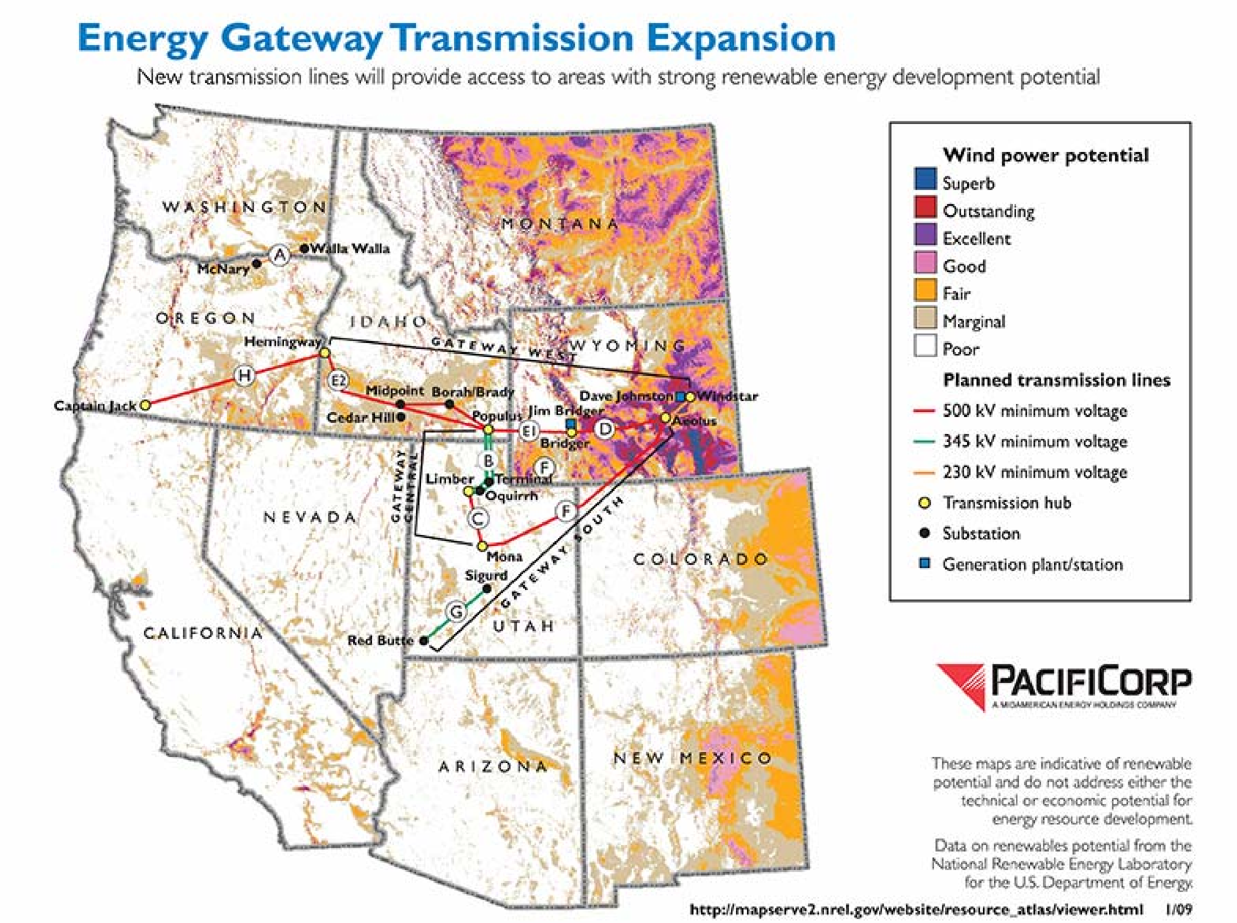
Energy Gateway anticipates the availability and/or development of new resources including renewable energy resources in each of these key areas. The combination of resources cited in the 2008 IRP action plan and Energy Gateway support building to these resource locations.

[17] Western Electricity Coordinating Council Reliability Criteria
[18] Western Electricity Coordinating Council Reliability Criteria

As a complement to the 'hub and spoke' concept, the Western Governors Association has been developing a process for identifying western renewable energy zones (WREZ). These renewable energy zones would be used to facilitate needed infrastructure to integrate and deliver large volumes of renewable energy to the west. Energy Gateway is well positioned access key renewable energy zones, primarily in Wyoming. The geographical areas for wind power potential are approximately shown in Figure 4.2 below.

**Figure 4.2 – Western States Wind Power Potential Up to 25,000 Megawatts**

**(Class 5 Wind Locations or Higher)**




As another indicator of the importance of Energy Gateway to customers and the region, the Department of Energy sponsored a study through Idaho National Laboratories to assess the economic impact of not building transmission on the Pacific Northwest. The report was published in July 2008 and references:

> *"The model indicates that the PNWER (Pacific Northwest Economic Region) has a potential economic loss of $15B to $25B annually and 300,000 to 450,000 jobs over 30 years if just the one infrastructure transmission line project with the*

*greatest economic impact is not built (i.e., BC to NorCal), and upwards of $55B to $85B annually and 1,750,000 jobs over 30 years if the five transmission line projects of greatest economic impact are not built (i.e., Alberta to PacNW Project, BC to NorCal,* ***Gateway West****, Southern Xing & I-5 Corridor Projects, and Mountain States Intertie). These transmission line projects … transport bulk power and are considered critical for access to preferred electrical generation by areas with high economic development and growth. Note, however, that even if these five projects come to fruition, the added power will not adequately serve the projected PNWER population increase, assuming consumption habits remain the same".*[19]

*"Preliminary engineering review and analysis of planned transmission projects within the PNWER region resulted in the following initial ranking of the projects based on estimates of potential economic value of each project, the likelihood of project execution, the resource area(s) being accessed, the size of the project, and the value of the project to the transmission system as a whole. This analysis was subjective in nature and conducted for comparison purposes only before the full economic analysis and ranking was performed. This ranking was partially based on project listings in the IRPs, knowledge of potential generation resource areas and load centers, areas of transmission need, etc. As stated above, this report ranks evaluated projects according to the INL's assessment of their overall economic impact to PNWER according to the specific factors used in the evaluation. Other analyses may place different emphasis on different factors, resulting in a different overall ranking of projects. Despite these potential differences, all of the projects are considered valuable and necessary to adequately address growing electric power needs. The INL's preliminary ranking is shown in Table 1:*[20]

***Table 1. Preliminary Ranking of Transmission Projects***

| *#* | *Preliminary Rank Project Name* | *#* | *Preliminary Rank Project Name* |
|---|---|---|---|
| *1* | *BC to NorCal* | *9* | *Inland Project (WY to Las Vegas)* |
| *2* | *Alberta to PacNW Project* | *10* | *Inland Project (MT to Las Vegas* |
| *3* | *Gateway West –* ***PacifiCorp*** | *11* | *McNary – John Day* |
| *4* | *Southern Crossing* | *12* | *Southwest Intertie Project (SWIP) North* |
| *5* | *Gateway South –* ***PacifiCorp*** | *13* | *Alstom to San Francisco Bay project (Alaska to Alstom project not included)* |
| *6* | *Gateway Central –* ***PacifiCorp*** | *14* | *Montana Alberta Tie* |
| *7* | *Mountain States Intertie* | *15* | *Port Angeles-Juan de Fuca"* |
| *8* | *Interstate 5 Corridor Lines* | | |

## ENERGY GATEWAY PRIORITIES

The greater part of the Energy Gateway project originates in Wyoming and Utah and migrates west to Oregon and Washington and south to southern Utah and Nevada. The Energy Gateway

[19] Idaho National Laboratory: The Cost of Not Building Transmission, page vi
[20] Idaho National Laboratory: The Cost of Not Building Transmission, page 5

project takes into account the existing 2006 transaction commitments which include transmission facilities from southern Idaho to northern Utah (Path C), Mona to Oquirrh and Walla Walla to McNary.

PacifiCorp is actively pursuing the Energy Gateway transmission project under the following overarching key objectives:

- **Network customer driven** – Energy Gateway is primarily driven by PacifiCorp's retail and network customers' needs. Including Energy Gateway as a base allows PacifiCorp to move forward with the knowledge that over the coming years, transmission lines will be utilized to their fullest potential.
- **Support multiple resource scenarios** – The transmission expansion project must be able to accommodate a variety of future resource scenarios including meeting renewable portfolio standards, supporting natural gas fueled combustion turbines and market purchases, and recognizing that clean coal-based generation may re-emerge as a viable resource.
- **Consistent with past and current regional plans** – The proposed projects are consistent with a number of regional planning efforts. The need to expand transmission capacity has been known for years and should not be a surprise to the regional planning process and justification of need. The regional planning process should reduce the number of parties that may be publicly opposed to these projects due to the scrutiny placed on justification.
- **Get it built** – A significant barrier to achieving "steel in the ground" has historically been frustrated by lengthy multi-party negotiations related to planning and governance structure. Minimizing the impacts of these barriers through action-oriented objectives will be key to project success.
- **Secure the support of state and federal utility commissions for rate recovery** – Throughout the process, the project will seek input of state and federal regulators to ensure concerns are communicated early and addressed. The project should be undertaken in a manner that is acceptable to commissions and customers.
- **Protect the investment to the benefit of customers** – An appropriate balance must be struck to ensure that network customers do not subsidize third party use and ensure that PacifiCorp's long-term network allocation requirements are retained.

**Phasing of Energy Gateway**

PacifiCorp has been clear in its position regarding the initial announcement of Energy Gateway that significant infrastructure of new transmission capacity is needed to adequately serve PacifiCorp's existing and future loads over the long-term. The company's position has not changed in this regard and requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South) of new transmission capacity to adequately serve its customers load and growth needs for the long-term.

PacifiCorp also recognized in its originally announced Energy Gateway Program the need and benefits of potentially "upsizing or scaling up" the Energy Gateway Program to increase transmission capacity by two-fold (6,000 MW). This upsizing would potentially provide a number of local and regional benefits such as: maximizing the use of new proposed corridors, potential to reduce environmental impacts, provide economies of scale needed for large infrastructure, lower cost per megawatt of transport capacity made available, and improved opportunity for third parties to obtain new long-term firm transmission capacity.

PacifiCorp still believes there are viable expectations and reasons for upsizing Energy Gateway and has vigorously pursued other participants the past year and a half. To this point, significant barriers still exist preventing PacifiCorp and other third parties from making a business decision to upsize the Energy Gateway Program without taking significant financial and delivery risk. PacifiCorp believes that both short-term and long-term benefits exist as a result of upsizing the Energy Gateway Program and that existing barriers may be overcome at some future date. However; the company must prudently move ahead now with steps necessary to serve its customers while keeping in sight these potential benefits perceived by upsizing.

PacifiCorp is proceeding with efforts regarding planning and rating requirements for the Energy Gateway Program which facilitates a planned ultimate transmission capacity of 3,000 MW for Gateway West and 3,000 MW for Gateway South (6,000 MW total). In order to achieve the ratings while meeting customer requirements, PacifiCorp plans to achieve the ratings in stages or phases based on need and construction timing

The core transmission expansion plan will construct lines and stations required to deliver 1,500 MW on Gateway West and 1,500 MW on Gateway South (3,000 MW total) of transmission capacity required to meet PacifiCorp's long-term regulatory requirement to serve loads. Additional stages may continue at some future date as determined by, economic, business and regulatory drivers that may be better defined in the upcoming years. Further expansion to the Desert Southwest will also be considered.

Each segment will be justified individually within the overall program. A combination of benefits including net power cost savings derived from the IRP, reliability, capital offsets for renewable resource development in low yield geographic regions and system loss reductions will be used to assess the viability of each segment.

The primary justification due to net power cost savings is derived from modeling alternative resource options under an assortment of forecast assumptions with and without Energy Gateway. The difference between the Energy Gateway build options and no transmission expansion yields a net power savings. Additional considerations listed above are considered on a segment-by-segment basis.

Each Energy Gateway segment will be reviewed again before significant commitments are made to ensure its justification. Therefore, depending on conditions or alternatives certain segments could be deferred or not constructed if not warranted. It is also reasonable to expect certain core segments will be justified in multiple scenarios. Segments will be reevaluated during each IRP cycle and annual business plan similar to generation/market resource plans to ensure they are required.

# 5. RESOURCE NEEDS ASSESSMENT

## INTRODUCTION

This chapter presents PacifiCorp's assessment of resource need, focusing on the first 10 years of the IRP's 20-year study period, 2009 through 2018. The company's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are addressed first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are comprised of a year-by-year comparison of projected loads against the resource base without new additions. This comparison indicated when PacifiCorp is expected to be either deficit or surplus on both a capacity and energy basis for each year of the planning horizon.

## LOAD FORECAST

### Methodology Overview

PacifiCorp estimates total load by starting with customer class sales forecasts in each state and then adds line losses to the customer class forecasts to determine the total load required at the generators to meet customer demands. Forecasts are based on statistical and econometric modeling techniques. These models are driven by county and state level forecasts of employment and income that are provided by public agencies or purchased from commercial econometric forecasting services.[21] Appendix E provides additional details on the state-level forecasts.

### Evolution and changes in Integrated Resource Planning Load Forecasts

Through the course of the 2008 integrated resource planning cycle, PacifiCorp relied on the November 2008 load forecast for the development of the load and resource balance and portfolio evaluations. Portfolio analysis started as early as June 2008 with preliminary load forecast and continued through December 2008. Under stable economic conditions, the company would normally prepare one load forecast per year. However, the unstable and volatile economic conditions required the company to update its load forecasts frequently to attempt to capture price and usage changes between June 2008 and November 2008. Because of the magnitude of the forecast changes and the company's plan to align IRP filing with the Business Plan, the company decided that it was prudent to incorporate latest load forecast updates in the IRP. Consequently, PacifiCorp's IRP analysis from November 2008 onward reflects the November 2008 load forecast.

In order to improve company's sales and load forecasting methods, capabilities, and accuracy, several improvements in the load forecasting approach were identified jointly by the company and the company's consultant, ITRON, and the load forecast methodology was changed to incorporate these improvements. Forecast change is driven primarily by six major changes in forecast assumptions. First, load research data was used to model the impact of weather on monthly retail sales and peaks by state by class. The company collects hourly load data from a sample of customers for each class in each state. These data are primarily used for rate design

[21] PacifiCorp relies on county and state level economic and demographic forecasts provided by Global Insight, in addition to state office of planning and budgeting sources.

but they also provide an opportunity to better understand usage patterns particularly as they relate to changes in temperature. The greater frequency and more data points associated with this hourly data make it better suited to capture load changes driven by changes in temperature than the monthly data used in the company's prior forecasts.

Second, the time period used to define normal weather was updated from the NOAA's 30 year period of 1971-2000 to 20 year time period of 1988-2007. The company identified a trend of increasing summer and winter temperatures in the company's service territory that was not being captured in the thirty year data. ITRON surveys have identified that many other utilities are also using more recent data for determining normal temperatures. Based on this review and on the recommendation of ITRON, the company adopted a 20-year rolling average as the basis for determining normal temperatures. This better captures the trend of increasing temperatures observed in both summer and winter.

Third, the historical data period used to develop the monthly retail sales forecasts was updated to cover 1997-2007.

Fourth, monthly peaks were forecasted for each state using a peak model and estimated with historical data from 1990-2007. As an improvement to the forecasting process, the company developed a model that relates peak loads to the weather that generated the peaks. This model allows the company to better predict monthly and seasonal peaks. The peak model is discussed in greater detail in the following section.

Fifth, system line losses were updated to reflect actual losses for the 5-years ending December 31, 2007. The company previously used the results of the most recent system line loss study which was based on calendar year 2001 data. The company had observed that actual losses were higher than those from the previous line loss study. Upon investigation and discussions with the consultant who prepared the previous line loss study, it was determined that the previous study only reflected losses associated with retail load. Because there are also system losses associated with wholesale sales, the prior loss value was understated. The use of actual losses is a reasonable basis for capturing total system losses and has been incorporated in this forecast.

Finally, analyses were performed and adjustments were made for the impact of current economic conditions. Because the model is estimated over a period of relative prosperity, it is necessary to make an explicit adjustment for the economic downturn, and hence the forecast was revised. In October 2008, forecast in near term was adjusted downward to reflect the recent recession impacts mirroring load changes experienced in previous recession (2001-2002). In the November update, the forecast was further adjusted downward in the Industrial sector for Utah (2010 onwards) and Wyoming (2009 onwards) to reflect the additional recession impacts.

**Modeling overview**

The following section describes the modeling techniques used to develop the load forecast.

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential, commercial, irrigation, public street lighting, and sales to public authority sales forecasts by jurisdiction is developed as a use per customer times the forecasted number of customers.

The residential use-per-customer is forecasted by statistical end-use forecasting techniques. This approach incorporates end use information (saturation forecasts and efficiency forecasts) but is estimated using monthly billing data. Saturation trends are based on analysis of the company's saturation survey data and efficiency trends are based on EIA forecasts that incorporate market forces as well as changes in appliance and equipment efficiency standards. Major drivers of the statistical end use based residential model are weather-related variables, end-use information such as equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price.

The commercial, irrigation, public street lighting, and sales to public authority use-per-customer forecast is developed using an econometric model. For the commercial class, sales per customer are forecasted using regression analysis techniques with non-manufacturing employment being used as the major economic driver in addition to weather related variables. For other classes, sales per customer are forecasted through regression analysis techniques using time trend variables.

The customer forecasts are generally based on a combination of regression analysis and exponential smoothing techniques using historical data from 1997 to 2007. For the residential class, the customer forecasts are developed using a regression model with Global Insight's forecast of the state's number of households as the major driver. For the commercial class, forecasts rely on a regression model with the forecasted residential customer numbers being used as the major driver. For other classes (irrigation, street lighting, and public authority), customer forecasts are developed based on exponential smoothing models.

The industrial sales forecast is developed for each jurisdiction using a model which is dependent on input for the Customer Account Managers (CAMs). The industrial customers are separated into three categories: i) existing customers that are tracked by the CAMs, ii) new large customers or expansions by existing large customers, iii) industrial customers that are not tracked by the CAMs. Customers are tracked by the CAMs if (1) they have a peak load of 5 megawatts or more or if (2) they have a peak load of 1 megawatt or more and have a history of large variations in their monthly usage. The forecast for the first two categories is developed through the data gathered by the CAM assigned to each customer.

The forecast for the first two categories is developed through the data gathered by the CAM assigned to each customer. The account managers have ongoing direct contact with large customers and are in the best position to know about the customer's plans for changes in business processes, which might impact their energy consumption.

The portion of the industrial forecast related to new large customers and expansion by existing large customers is developed based on direct input of the customers, forecasted load factors, and the probability of the project occurrence. Projected loads associated with new customers or expansions of existing large customers are categorized into three groups. Tier 1 customers are those with a signed master electric service agreement ("MESA") or engineering material and procurement agreement ("EMPA"). When a customer signs a MESA or EMPA, this contractually commits the company to provide services under the terms of agreement. Tier 2 includes customers with a signed engineering services agreement (ESA). This means that customer paid the company to perform a study that determines what improvements the company will need to make to serve the requested load. Tier 3, consists of customers who made inquiries but have not signed a formal agreement. Projected loads from customers in each of these tiers are assigned probabilities depending on project specific information received from the customer.

Smaller industrial customers are more homogeneous and are modeled using regression analysis with trend and economic variables. Manufacturing employment was employed as the major economic driver. The total industrial sales forecast is developed by aggregating the forecast for the three industrial customer categories. The segments are forecasted differently within the industrial class because of the diverse makeup of the customers within the class.

After monthly energy by customer class is developed, hourly loads is developed in two steps. First, monthly and seasonal peak forecasts for each state are developed. The monthly peak model uses historic peak producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables. These weather variables include the average temperature on the peak day and average daily temperatures for two days prior to peak day. Second, hourly load forecasts for each state are obtained from the hourly load models using state specific hourly load data and daily weather variables. Hourly load forecasts are developed using a model which incorporates the 20-year average temperatures, the actual weather pattern for a year, and day type variables such as weekends and holidays. The model uses HDD (heating degree days) and CDD (cooling degree days) values for each of the twenty years and averages the results using a Rank and Average method instead of averaging by date as in the previous thirty year process. This helps to incorporate both mild and extreme days in weather pattern more effectively representing the daily volatility in weather experienced during a typical year. Also, the method preserves the extreme temperatures and maps them to a year to produce a more accurate estimate of daily temperatures. The hourly load forecasts are adjusted for line losses and calibrated to monthly and seasonal peaks. After the hourly load forecasts for each state are developed, hourly loads are aggregated to the total company system level. System coincident peaks are then identified as well as the contribution of each jurisdiction to those monthly system peaks.

The following sections describe the November 2008 energy and coincident peak load forecasts.

## Energy Forecast

Table 5.1 shows average annual energy load growth rates for the PacifiCorp system and individual states. Growth rates are shown for the forecast period 2009 through 2018.

**Table 5.1 – Forecasted Average Annual Energy Growth Rates for Load**

| | Total | OR | WA | CA | UT | WY | ID | SE-ID |
|---|---|---|---|---|---|---|---|---|
| **2009-2018** | 2.1% | 1.2% | 0.7% | 1.6% | 2.5% | 3.4% | 1.5% | 1.5% |

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.1% percent annually from fiscal year 2009 to 2018. Table 5.2 shows the forecasted load for each specific year for each state served by PacifiCorp and the average annual growth (AAG) rate over the entire time period.

**Table 5.2 – Annual Load Growth forecasted (in Megawatt-hours) 2009 through 2018**

| Year | Total | OR | WA | CA | UT | WY | ID | SE-ID |
|---|---|---|---|---|---|---|---|---|
| 2009 | **61,558,392** | 15,475,197 | 4,481,972 | 1,006,036 | 24,211,643 | 10,077,831 | 3,746,722 | 2,558,992 |
| 2010 | **62,572,227** | 15,488,359 | 4,490,263 | 1,036,284 | 24,766,082 | 10,422,330 | 3,784,242 | 2,584,666 |
| 2011 | **63,979,543** | 15,733,361 | 4,528,860 | 1,072,927 | 25,331,349 | 10,873,984 | 3,825,481 | 2,613,580 |
| 2012 | **65,860,922** | 16,096,835 | 4,564,434 | 1,108,124 | 26,227,765 | 11,341,534 | 3,875,330 | 2,646,900 |
| 2013 | **67,602,494** | 16,395,770 | 4,586,107 | 1,119,431 | 26,990,389 | 11,738,006 | 4,024,940 | 2,747,851 |
| 2014 | **69,299,539** | 16,648,638 | 4,620,452 | 1,128,072 | 27,811,230 | 12,117,111 | 4,142,098 | 2,831,937 |
| 2015 | **70,735,798** | 16,790,823 | 4,652,542 | 1,136,689 | 28,631,507 | 12,498,120 | 4,172,873 | 2,853,245 |
| 2016 | **72,193,764** | 16,979,579 | 4,692,854 | 1,148,202 | 29,355,209 | 12,926,718 | 4,211,552 | 2,879,649 |
| 2017 | **73,110,441** | 17,080,573 | 4,709,745 | 1,153,152 | 29,791,003 | 13,240,453 | 4,237,529 | 2,897,985 |
| 2018 | **74,348,970** | 17,281,372 | 4,752,289 | 1,165,356 | 30,363,899 | 13,581,557 | 4,278,351 | 2,926,146 |
| **Average Annual Growth Rate** | | | | | | | | |
| 2009-18 | **2.1%** | **1.2%** | **0.7%** | **1.6%** | **2.5%** | **3.4%** | **1.5%** | **1.5%** |
| 2018-28 | **1.2%** | **1.1%** | **0.9%** | **1.1%** | **1.6%** | **0.6%** | **0.9%** | **0.9%** |
| 2009-28 | **1.6%** | **1.2%** | **0.8%** | **1.3%** | **2.0%** | **1.9%** | **1.2%** | **1.2%** |

## System-Wide Coincident Peak Load Forecast

The system coincident peak load is the maximum load required on the system in any hourly period. Forecasts of the system peak for each month are prepared based on the load forecast produced using the methodologies described above. From these hourly forecasted values, the coincident system peaks and the non-coincident peaks (within each state) during each month are extracted.

In the 1990's the annual system peak has usually occurred in the winter. After 2000, the annual system peak has generally occurred in the summer. The system peak has switched to the summer as a result of several factors. First, the increasing demand for summer space conditioning in the residential and commercial classes and a decreasing demand for electric related space conditioning in the winter has contributed to shift from a winter peak to a summer peak. This trend in space conditioning is expected to continue. Second, Utah with a summer peak that is relatively higher than the winter peak has been growing faster than the system. This growth also has contributed to a shift from a winter peak to a summer peaking system.

Total system load factor is expected to be relatively stable over the 2009 to 2018 time period. There are several factors working in opposite directions, leading to this result. First, the relatively high growth in high load factor industrial sales, particularly in Wyoming, tends to push up the system load factor. Second, as discussed above, the shift in space conditioning tends to push down the system load factor. And, third, efficiency standards such as the 2012 federal lighting standards also tend to push down the system load factor.

**Table 5.3 – Forecasted Coincidental Peak Load Growth Rates**

| Average Annual Growth Rate | Total | OR | WA | CA | UT | WY | ID | SE-ID |
|---|---|---|---|---|---|---|---|---|
| **2009-2018** | **2.4%** | **1.6%** | **1.8%** | **1.9%** | **2.6%** | **3.1%** | **2.5%** | **3.0%** |

PacifiCorp's eastern system peak is expected to continue growing faster than the western system peak, with average annual growth rates of 2.7 percent and 1.6 percent, respectively, over the forecast horizon.

Table 5.4 below shows that for the same time period the total peak is expected to grow by 2.4 percent.

**Table 5.4 – Forecasted Coincidental Peak Load in Megawatts**

| Year | Total | OR | WA | CA | UT | WY | ID | SE-ID |
|---|---|---|---|---|---|---|---|---|
| **2009** | **10,143** | 2,463 | 761 | 167 | 4,509 | 1,253 | 628 | 362 |
| **2010** | **10,360** | 2,476 | 768 | 174 | 4,626 | 1,290 | 654 | 372 |
| **2011** | **10,631** | 2,526 | 780 | 181 | 4,708 | 1,354 | 682 | 401 |
| **2012** | **10,978** | 2,579 | 816 | 187 | 4,854 | 1,394 | 716 | 431 |
| **2013** | **11,261** | 2,638 | 800 | 190 | 5,008 | 1,440 | 748 | 437 |
| **2014** | **11,451** | 2,695 | 815 | 189 | 5,174 | 1,485 | 691 | 402 |
| **2015** | **11,730** | 2,728 | 826 | 191 | 5,322 | 1,530 | 718 | 414 |
| **2016** | **12,032** | 2,763 | 836 | 194 | 5,458 | 1,577 | 759 | 446 |
| **2017** | **12,251** | 2,795 | 846 | 199 | 5,568 | 1,616 | 773 | 454 |
| **2018** | **12,522** | 2,836 | 889 | 197 | 5,686 | 1,656 | 786 | 473 |
| **Average Annual Growth Rate** | | | | | | | | |
| **AAG 2009-2018** | **2.4%** | **1.6%** | **1.8%** | **1.9%** | **2.6%** | **3.1%** | **2.5%** | **3.0%** |
| **AAG 2018-2028** | **1.4%** | **1.4%** | **1.1%** | **1.2%** | **1.8%** | **0.7%** | **0.9%** | **0.6%** |
| **AAG 2009-2028** | **1.9%** | **1.5%** | **1.4%** | **1.5%** | **2.2%** | **1.9%** | **1.7%** | **1.8%** |

One noticeable aspect of the states contribution to the system coincidental peak forecast is that they do not smoothly increase from year to year, and in Idaho, the contribution to system coincident peak decreases in 2014.

Idaho's contribution to the coincident peak is forecasted to decrease in 2014 even though the total system peak increases from year to year. This behavior occurs because state level coincident peaks do not occur at the same time as the system level coincident peak, and because of differences among the states with regard to load growth and customer mix. While each state's peak load is forecast to grow each year when taken on its own, its contribution to the system coincident peak will vary since the hour of system peak does not coincide with the hour of peak load in each state. As the growth patterns of the class and states change over time, the peak will move within the season, month or day, and each state's contribution will move accordingly, sometimes resulting in a reduced contribution to the system coincident peak from year to year in a particular state. This is seen in a few areas in the forecast as well as experienced in history. For example, the Idaho state load is driven in the summer months by the activity in the irrigation class. The planting and irrigating practices usually cause this state to experience the maximum load in late June or early July. This load then quickly decreases week by week. Consequently, there can be as much as 300 megawatts of load difference between the maximum load and the loads during the last weeks of July.

## Jurisdictional Peak Load Forecast

The economies, industry mix, appliance and equipment adoption rates, and weather patterns are different for each jurisdiction that PacifiCorp serves. Because of these differences the jurisdictional hourly loads have different patterns than the system coincident hourly load. In addition, the growth for the jurisdictional peak demands can be different from the growth in the jurisdictional contribution to the system peak demand. Table 5.5 reports the jurisdictional peak demand growth over the forecast horizon.

**Table 5.5 – Jurisdictional Peak Load forecast (Megawatts) 2009 through 2018**

| Year | OR | WA | CA | UT | WY | ID | SE-ID |
|---|---|---|---|---|---|---|---|
| **2009** | 2,781 | 850 | 187 | 4,678 | 1,343 | 776 | 434 |
| **2010** | 2,795 | 856 | 197 | 4,796 | 1,371 | 785 | 448 |
| **2011** | 2,825 | 863 | 204 | 4,875 | 1,419 | 795 | 453 |
| **2012** | 2,854 | 876 | 210 | 5,033 | 1,473 | 806 | 485 |
| **2013** | 2,914 | 884 | 212 | 5,202 | 1,532 | 835 | 491 |
| **2014** | 2,958 | 897 | 214 | 5,360 | 1,581 | 858 | 497 |
| **2015** | 2,989 | 909 | 216 | 5,522 | 1,631 | 867 | 493 |
| **2016** | 3,010 | 919 | 218 | 5,662 | 1,680 | 874 | 511 |
| **2017** | 3,033 | 931 | 221 | 5,775 | 1,729 | 881 | 518 |
| **2018** | 3,059 | 942 | 223 | 5,902 | 1,776 | 890 | 536 |
| **Average Annual Growth Rate** | | | | | | | |
| **2009-2018** | **1.1%** | **1.1%** | **2.0%** | **2.6%** | **3.2%** | **1.5%** | **2.4%** |
| **2018-2028** | **1.3%** | **1.4%** | **1.2%** | **1.8%** | **0.7%** | **0.9%** | **0.9%** |
| **2009-2028** | **1.2%** | **1.3%** | **1.6%** | **2.2%** | **1.8%** | **1.2%** | **1.6%** |

# EXISTING RESOURCES

In 2009 PacifiCorp owns, or has interest in, resources with a system peak capacity of 13,143 megawatts. Table 5.6 provides anticipated system peak capacity ratings by resource category as of July 2007.

**Table 5.6 – Capacity Ratings of Existing Resources**

| Resource Type | MW * | Percent |
|---|---|---|
| Pulverized Coal | 6,128 | 46.6% |
| Gas-CCCT | 2,025 | 15.4% |
| Gas-SCCT | 380 | 2.9% |
| Hydroelectric | 1,450 | 11.0% |

| | | |
|---|---|---|
| Class 1 DSM ** | 345 | 2.6% |
| Renewable | 247 | 1.9% |
| Purchase *** | 2,061 | 15.7% |
| Qualifying Facilities | 271 | 2.1% |
| Interruptible | 237 | 1.8% |
| **Total** | **13,145** | **100%** |

* Represents the capacity available at the time of system peak.
** Class 1 Demand-side management is PacifiCorp's dispatchable load control.
*** Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.

### Thermal Plants

In September 2008, the Chehalis combine cycle combustion turbine plant began operations adding 509 MW of summer peak capacity to the PacifiCorp thermal fleet. Table 5.7 lists existing PacifiCorp's coal fired thermal plants and table 5.8 lists existing natural gas fired plants.

### Table 5.7 – Coal Fired Plants

| Plant | PacifiCorp Percentage Share | State | Average Net Maximum Capacity |
|---|---|---|---|
| Carbon 1 | 100% | Utah | 67.0 |
| Carbon 2 | 100% | Utah | 105.0 |
| Cholla 4 | 100% | Arizona | 395.0 |
| Colstrip 3 | 10% | Montana | 74.0 |
| Colstrip 4 | 10% | Montana | 74.0 |
| Craig 1 | 19% | Colorado | 82.5 |
| Craig 2 | 19% | Colorado | 82.5 |
| Dave Johnston 1 | 100% | Wyoming | 106.0 |
| Dave Johnston 2 | 100% | Wyoming | 106.0 |
| Dave Johnston 3 | 100% | Wyoming | 220.0 |
| Dave Johnston 4 | 100% | Wyoming | 330.0 |
| Hayden 1 | 24% | Colorado | 45.1 |
| Hayden 2 | 13% | Colorado | 33.0 |
| Hunter 1 | 94% | Utah | 403.1 |
| Hunter 2 | 60% | Utah | 259.3 |
| Hunter 3 | 100% | Utah | 460.0 |
| Huntington 1 | 100% | Utah | 445.0 |
| Huntington 2 | 100% | Utah | 450.0 |
| Jim Bridger 1 | 67% | Wyoming | 353.3 |
| Jim Bridger 2 | 67% | Wyoming | 353.3 |
| Jim Bridger 3 | 67% | Wyoming | 353.3 |
| Jim Bridger 4 | 67% | Wyoming | 353.3 |
| Naughton 1 | 100% | Wyoming | 160.0 |
| Naughton 2 | 100% | Wyoming | 210.0 |
| Naughton 3 | 100% | Wyoming | 330.0 |

| Plant | PacifiCorp Percentage Share | State | Average Net Maximum Capacity |
|---|---|---|---|
| Wyodak | 80% | Wyoming | 268.0 |

**Table 5.8 – Natural Gas Plants**

| Coal-fueled | PacifiCorp Percentage Share | State | Average Net Maximum Capacity |
|---|---|---|---|
| Currant Creek | 100% | Utah | 541 |
| Gadsby 1 | 100% | Utah | 60 |
| Gadsby 2 | 100% | Utah | 75 |
| Gadsby 3 | 100% | Utah | 100 |
| Gadsby 4 | 100% | Utah | 40 |
| Gadsby 5 | 100% | Utah | 40 |
| Gadsby 6 | 100% | Utah | 40 |
| Hermiston 1 * | 50% | Oregon | 124 |
| Hermiston 2 * | 50% | Oregon | 124 |
| Lake Side | 100% | Utah | 544 |
| Chehalis | 100% | Washington | 520 |

* Remainder of Hermiston plant under purchase contract by the company for a total of 248 MW.

## Renewables

PacifiCorp's renewable resources, presented by resource type, are described below.

### Wind

PacifiCorp acquires wind power from owned plants and various purchase agreements. Since the 2007 IRP, PacifiCorp has acquired several large wind resources including Seven Mile I and II, and Marengo II, Glenrock I and III, and Rolling Hills. These projects came on line in 2008. The company also entered into 20-year power purchase agreements for the total output of several projects including Mountain Wind I and II and Spanish Fork in 2008, Duke Energy's (Three Buttes Windpower LLC) Campbell Hill project and Oregon Wind Farm I in 2009, and Oregon Wind Farm II in 2010.

Table 5.9 shows existing and firm planned wind facilities owned by PacifiCorp, while Table 5.10 shows existing wind power purchase agreements. For the year ended December 31, 2008, PacifiCorp's total installed wind capacity totaled 802 MW, along with 315 MW of purchased power capacity.

**Table 5.9 – PacifiCorp-owned Wind Resources**

| Utility-Owned Wind Projects | Nameplate (MW) | In-Service Year | State |
|---|---|---|---|
| Foote Creek I [1/] | 33.0 | 2005 | WY |
| Leaning Juniper | 100.5 | 2006 | WA |
| Goodnoe Hills East Wind | 94.0 | 2007 | WA |
| Marengo | 140.4 | 2007 | WA |

| Utility-Owned Wind Projects | Nameplate (MW) | In-Service Year | State |
|---|---|---|---|
| Glenrock Wind I | 99.0 | 2008 | WY |
| Glenrock Wind III | 39.0 | 2008 | WY |
| Marengo II | 70.2 | 2008 | WA |
| Rolling Hills Wind | 99.0 | 2008 | WY |
| Seven Mile Hill Wind | 99.0 | 2008 | WY |
| Seven Mile Hill Wind II | 19.5 | 2008 | WY |
| High Plains (Under Construction) | 99.0 | 2009 | WY |
| TOTAL | 893.0 | | |

[1/] Net total capacity for Foote Creek I is 41 MW.

**Table 5.10 – Wind Power Purchase Agreements**

| Power Purchase Agreements | Nameplate (MW) | In-Service Year | State |
|---|---|---|---|
| Foote Creek III | 25.2 | 2005 | WY |
| Foote Creek IV | 16.8 | 2005 | WY |
| Wolverine Creek | 64.5 | 2005 | ID |
| Rock River I | 50.0 | 2006 | WY |
| Mountain Wind Power I | 60.0 | 2008 | WY |
| Mountain Wind Power II | 79.5 | 2008 | WY |
| Spanish Fork | 18.9 | 2008 | UT |
| Three Buttes Wind Power (Duke) | 99.0 | 2009 | WY |
| Oregon Wind Farm I | 45.0 | 2009 | OR |
| Oregon Wind Farm II | 20.0 | 2010 | OR |
| TOTAL | 478.9 | | |

PacifiCorp also has wind integration, storage and return agreements with Bonneville Power Administration, Eugene Water and Electric Board, Public Service Company of Colorado, and Seattle City Light.

### Geothermal

PacifiCorp owns and operates the Blundell Geothermal Plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 megawatts, was completed at the end of 2007.

### Biomass

Since the 2007 IRP, PacifiCorp has acquired power through power purchase agreements, as well as from several small biomass facilities under Qualifying Facility Agreements. Examples are found in Table 5.11.

**Table 5.11 – Existing Biomass resources**

| Biomass Projects | Nameplate (MW) |
|---|---|
| Biomass One, LLC | 25.0 |
| Davis County Waste Management | 1.6 |
| Douglas Country Forest Products | 6.25 |
| DR Johnson Lumber Company | 8.3 |
| Evergreen BioPower | 10.0 |
| Roseburg Forest Products | 20.0 |
| Rough & Ready Lumber | 1.28 |
| Simplot Phosphates, LLC | 9.5 |

### Biogas

Since the 2007 IRP, PacifiCorp has acquired power through power purchase agreements, as well as from several small biomass facilities under Qualifying Facility Agreements. Examples are found in Table 5.12.

**Table 5.12 – Existing Biogas resources**

| Biogas Project | Nameplate (MW) |
|---|---|
| Sunderland Dairy | 0.15 |
| Wadeland South, LLC | 0.125 |
| Weber County, State of Utah | 0.95 |
| Hill Air Force Base | 2.5 |
| Ballard Hog Farms Inc | 0.05 |
| George Deruyter & Sons Dairy | 1.2 |
| Finley BioEnergy | 4.8 |
| Oregon Environmental Industries | 3.2 |

### Solar

PacifiCorp has invested in Solar II, the world's largest solar energy plant, located in the Mojave Desert. The company has installed panels of photovoltaic (PV) cells in its service area, including The High Desert Museum in Bend Oregon, PacifiCorp office in Moab, Utah, an elementary school in Green River, Wyoming, and has worked with Jackson County Fairgrounds and the Salt Palace in Salt Lake City, Utah on photovoltaic solar panels. Other locations in the service territory with solar include a 60 unit apartment in Salt Lake City, Utah and the North Wasco School district at Mosier, Oregon. Currently, there are 410 net meters throughout the company, mostly residential, and most have solar technology followed by wind and hydroelectric.

## Hydroelectric Generation

PacifiCorp owns or purchases 1,450 megawatts of hydroelectric generation. These resources account for approximately 11 percent of PacifiCorp's total generating capability, in addition to providing operational benefits such as flexible generation, spinning reserves and voltage control. Hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate from its hydroelectric plants is dependent upon a number of factors, including the water content of snow pack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. When these conditions result in above average runoff, PacifiCorp is able to generate a higher than average amount of electricity using its hydroelectric plants. However, when these factors are unfavorable, PacifiCorp must rely to a greater degree on its more expensive thermal plants and the purchase of electricity to meet the demands of its customers.

PacifiCorp has added approximately 5 megawatts of additional capacity to its hydroelectric portfolio since the release of the 2007 IRP. This additional capacity is found in Table 5.13.

**Table 5.13 – Hydroelectric additions**

| Hydroelectric Project | Nameplate (MW) |
|---|---|
| Bell Mountain Power | 0.45 |
| City of Albany, Dept of Public Works | 0.5 |
| Cottonwood Hydro | 0.85 |
| Curtiss Livestock | 0.075 |
| Loyd Fery | 0.04 |
| Mountain Energy | 0.05 |
| Roush Hydro, Inc | 0.08 |
| Yakima Tieton | 2.95 |

Table 5.14 provides an operational profile for each of PacifiCorp's hydroelectric generation facilities. The dates listed refer to a calendar year.

**Table 5.14 – Hydroelectric Generation Facilities – Nameplate Capacity as of January 2009**

| Plant | PacifiCorp Share (MW) | Location | License Expiration Date | Retirement Date |
|---|---|---|---|---|
| **West** | | | | |
| Big Fork | 4.15 | Montana | 2053 | 2053 |
| Clearwater 1 | 15.00 | Oregon | 2038 | 2038 |
| Clearwater 2 | 26.00 | Oregon | 2038 | 2038 |
| Copco 1 | 20.00 | California | 2006 | 2046 |
| Copco 2 | 27.00 | California | 2006 | 2046 |
| East Side | 3.20 | Oregon | 2006 | 2016 |
| Fish Creek | 11.00 | Oregon | 2038 | 2038 |
| Iron Gate | 18.00 | California | 2006 | 2046 |
| JC Boyle | 97.98 | Oregon | 2006 | 2046 |
| Lemolo 1 | 31.99 | Oregon | 2038 | 2038 |
| Lemolo 2 | 33.00 | Oregon | 2038 | 2038 |
| Merwin | 136.00 | Washington | 2059 | 2059 |
| Rogue | 46.76 | Oregon | Various | Various |

| Plant | PacifiCorp Share (MW) | Location | License Expiration Date | Retirement Date |
|---|---|---|---|---|
| Slide Creek | 18.00 | Oregon | 2038 | 2038 |
| Soda Springs | 11.00 | Oregon | 2038 | 2038 |
| Swift 1 | 240.00 | Washington | 2059 | 2059 |
| Toketee | 42.50 | Oregon | 2038 | 2038 |
| West Side | 0.60 | Oregon | 2006 | 2016 |
| Yale | 134.00 | Washington | 2059 | 2059 |
| Small West Hydro* | 18.11 | CA/OR/WA | Various | Various |
| **East** | | | | |
| Bear River | 108.73 | ID/UT | Various | Various |
| Small East Hydro** | 33.85 | ID/UT/WY | Various | Various |

* Includes Bend, Condit, Fall Creek, and Wallowa Falls
** Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock.
Note: Operational Capacity may differ from Nameplate Capacity due to operating conditions.

### Hydroelectric Relicensing Impacts on Generation

Table 5.15 lists the estimated impacts to average annual hydro generation from FERC license renewals. PacifiCorp assumed that all hydroelectric facilities currently involved in the relicensing process will receive new operating licenses, but that additional operating restrictions imposed in new licenses will reduce generation available from these facilities.

**Table 5.15 – Estimated Impact of FERC License Renewals on Hydroelectric Generation**

| Year | Lost Generation (MWh) |
|---|---|
| 2009 | 160,356 |
| 2010 | 160,356 |
| 2011 | 160,356 |
| 2012 | 195,560 |
| 2013 | 195,560 |
| 2014 | 195,560 |
| 2015 | 338,917 |
| 2016 | 415,328 |
| 2017 | 415,328 |
| 2018 | 413,435 |
| 2019 | 415,566 |
| 2020 | 415,566 |
| 2021 | 415,566 |
| 2022 | 415,566 |
| 2023 | 415,566 |
| 2024 | 415,566 |
| 2025 | 415,566 |
| 2026 | 415,566 |
| 2027 | 415,566 |
| 2028 | 415,566 |

Note: Excludes the decommissioning of Condit, Cove, Powerdale, and American Fork.

## EXISTING DSM RESOURCES

### Demand-side Management

Demand-side management resources/products vary in their dispatchability, reliability of results, term of load reduction benefit and persistence over time. Each has its value and place in effectively managing utility investments, resource costs and system operations. Those that have greater persistence and firmness (can count on them to be delivered) can be relied upon as base resources for planning purposes; those that do not are well-suited as system reliability tools only. Reliability tools are used to avoid outages or high resource costs as a result of weather conditions, plant outages, market prices, and unanticipated system failures. Demand-side management resources/products can be divided into four general classes based on their relative characteristics, the classes are:

- **Class 1 DSM: Resources from fully dispatchable or scheduled firm capacity product offerings/programs** – Class 1 programs are those for which capacity savings occur as a result of active company control or advanced scheduling. Once customers agree to participate in Class 1 DSM program, the timing and persistence of the load reduction is involuntary on their part within the agreed limits and parameters of the program. In most cases, loads are shifted rather than avoided. Examples include residential and commercial central air conditioner load control programs ("Cool Keeper") that are dispatchable in nature and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program).

- **Class 2 DSM: Resources from non-dispatchable, firm energy and capacity product offerings/programs** – Class 2 programs are those for which sustainable energy and capacity savings are achieved through facilitation of technological advancements in equipment, appliances, lighting and structures. Class 2 programs generally provide financial and/or service incentives to customers to replace equipment and appliances in existing customer owned facilities (or to upgrade in new construction) to more efficient lighting, motors, air conditioners, insulation levels, windows, etc. Savings will endure over the life of the improvement (firm). Program examples include air conditioning efficiency programs ("Cool Cash"), comprehensive commercial and industrial new and retrofit energy efficiency programs ("Energy FinAnswer") and refrigerator recycling programs ("See ya later refrigerator").

- **Class 3 DSM: Resources from price responsive energy and capacity product offerings/programs** – Class 3 DSM programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. Savings are measured at a customer-by-customer level (via metering and/or metering against baselines), and customers are compensated or charged in accordance with a program's pricing parameters. As a result of their voluntary nature, savings are less predictable, making them less suitable to incorporate into resource planning exercises, at least until such time that their size and customer behavior profile provide sufficient information for a reliable diversity result for modeling and planning purposes. Savings typically only endure for the duration of the incentive offering and loads tend to be shifted rather than avoided. Program examples include large customer energy bid programs ("Energy Exchange"), time-of-use pricing plans, critical peak pricing plans, and inverted tariff designs.

- **Class 4 DSM: Resources from energy efficiency education and non-incentive based voluntary curtailment programs/communications/pleas** – Class 4 programs resources may be in the form of energy and/or capacity reductions. The reductions are typically achieved from voluntary actions taken by customers, behavior changes, to save energy and/or reduce costs, benefit the environment or in response to public or utility company pleas to conserve or shift their usage to off peak hours. Program savings are difficult to measure and in many cases tend to vary over time. While not specifically relied upon in resource planning, Class 4 savings appear in historical load data therefore into resource planning through the plan load forecasts. The value of Class 4 DSM is long-term in nature. Class 4 programs help foster an understanding and appreciation as to why utilities seek customer participation in Class 1, 2 and 3 programs, as well provide a foundational understanding of how to use energy wisely. Program examples include Utah's PowerForward program, company brochures with energy savings tips, customer news letters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs such as "Do the bright thing" and "Let's turn the answers on". Studies have shown potential savings up to 15% from behavior changes[22], especially when coupled with complimentary DSM programs to assist customers with a portion of the actions taken.[23] Although these behavior savings are often difficult and costly to track and measure, enough studies have measured their effects to expect at least a very modest degree of savings (equal to or greater than those expected to be acquired through DSM programs; e.g. 1+%) to be realized and reflected in customer usage and future load forecasts.

PacifiCorp has been operating successful DSM programs since the late 1980s. While the company's DSM focus has remained strong over this time, since the 2001 western energy crisis, the company's DSM pursuits have been expanded in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1 through 4) and resource planning considerations. Company investments continue to increase year on year with 2008 investments exceeding $76 million (all states). Work continues on the expansion of program portfolios in the states of Utah, Washington, Idaho and California. In late 2008 the company received approval to begin offering DSM programs to Wyoming customers beginning in January 2009. In Oregon the company is working closely with the Energy Trust of Oregon on helping to identify additional resource opportunities, improve delivery and communication coordination, and ensure adequate funding and company support in pursuit of DSM resource targets.

The following represents a brief summary of the existing resources by class.

[22] Lynn Fryer Stein, "California Information Display Pilot Technology Assessment" (December 2004), prepared by Primen Inc., for Southern California Edison.

[23] John Green and Lisa A. Skumatz, "Evaluating the Impacts of Education/Outreach Programs: Lessons on Impacts, Methods and Optimal Education, "paper presented at the American Council for an Energy Efficient Economy summer Study on Energy Efficiency in Buildings (2000).

**Class 1 Demand-side Management**
Currently there are four Class 1 programs running across PacifiCorp's six state service area; Utah's "Cool Keeper" residential and small commercial air conditioner load control program; Idaho's and Utah's scheduled firm irrigation load management programs; Idaho's and Utah's dispatchable irrigation load management programs; and special contract curtailment agreements with large business customers. In 2008 the programs provided approximately 560 megawatts of Class 1 DSM program resources during the highest summer peak load hours.

**Class 2 Demand-side Management**
The company currently manages thirteen distinct Class 2 products, many of the products are offered in multiple states. In all, the combination of Class 2 programs across the company's six state service area total thirty-four. The cumulative historical energy and capacity savings (1992-2008) associated with Class 2 DSM program activity has accounted for nearly 3.4 million megawatt hours and over 600 megawatts of load reductions.

**Class 3 Demand-side Management**
The company has numerous Class 3 programs currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), residential seasonal inverted rates (Utah), residential year-around inverted rates (California, Oregon, and Washington) and Energy Exchange programs (Oregon, Utah, Idaho, Wyoming and Washington). Savings associated with these programs are captured within the company's load forecast, with the exception of the more immediate call-to-action programs like Energy Exchange and Utah's PowerForward programs. The impacts of these programs are thus captured in the integrated resource planning framework. Energy Exchange and Utah's PowerForward are examples of Class 3 programs relied upon as reliability resources as opposed to base resources. System-wide participation in metered time-of-day and time-of-use programs as of December 31, 2008 was about 21,700 customers, up from about 21,200 in 2006. Approximately 1.28 million residential customers—89% of the company's residential customer base—are currently subject to inverted rate plans either seasonally or year-around.

PacifiCorp continues to evaluate Class 3 programs for applicability to long-term resource planning. As discussed in Chapter 6, five additional programs were provided as resource options in preliminary IRP modeling scenarios.

**Class 4 Demand-side Management**
Educating customers regarding energy efficiency and load management opportunities is an important component of the company's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts, bill messages, newsletters, school education programs, and personal contact. Specific firm load reductions due to Class 4 DSM activity will show up in Class 2 DSM program results and non-program/documented reductions in the load forecast over time.

Table 5.16 summarizes the existing DSM programs, and describes how they are accounted for as planned resources.

### Table 5.16 – Existing DSM Summary, 2009-2018

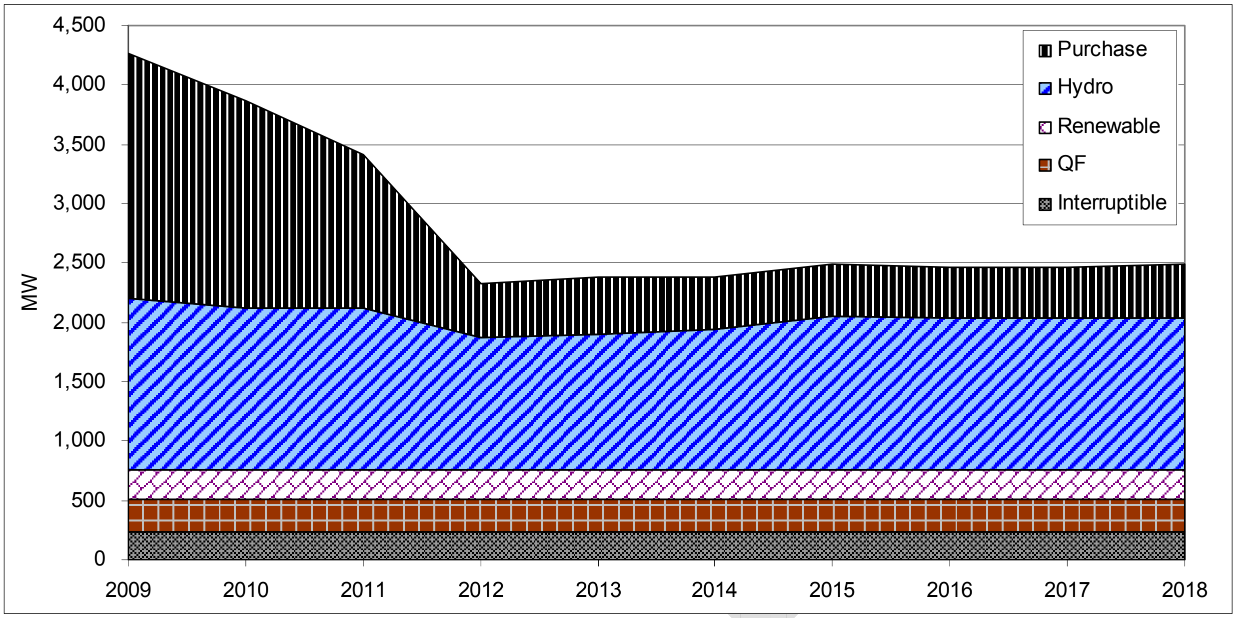
| Program Class | Description | Energy Savings or Capacity at Generator | Included as Base Resources for 2009-2018 Period |
|---|---|---|---|
| 1 | Residential/small commercial air conditioner load control | 100 MW summer peak | Yes |
| | Irrigation load management | 220 MW summer peak | Yes |
| | Interruptible contracts | 237 MW | Yes |
| 2 | Company and Energy Trust of Oregon programs | 483 MWa and 908 MW (2008 IRP selections) | Yes |
| 3 | Energy Exchange | 0-37 MW (assumes no other Class 3 competing products running) | No, leveraged as economic and reliability resource dependent on market prices/system loads |
| | Time-based pricing | MWa/MW unavailable 22.,000 customers | No, historical behavior captured in load forecast |
| | Inverted rate pricing | MWa/MW unavailable 1.28 million residential | No, historical behavior captured in load forecast |
| 4 | PowerForward | 0-80 MW summer peak | No, leveraged as economic and reliability resource dependent on market prices/system loads |
| | Energy Education | MWa/MW unavailable | No, captured in load forecast over time and other Class 1 and Class 2 program results |

## Contracts

PacifiCorp obtains the remainder of its energy requirements, including any changes from expectations, through long-term firm contracts, short-term firm contracts, and spot market purchases.

Figure 5.1 presents the contract capacity in place for 2008 through 2018 as of January 2009. As shown, major capacity reductions in purchases and hydro contracts occur. (For planning purposes, PacifiCorp assumes that current qualifying facility and interruptible load contracts are extended to the end of the IRP study period.) Note that renewable wind contracts are shown at their capacity contribution levels.

**Figure 5.1 – Contract Capacity in the 2008 Load and Resource Balance**

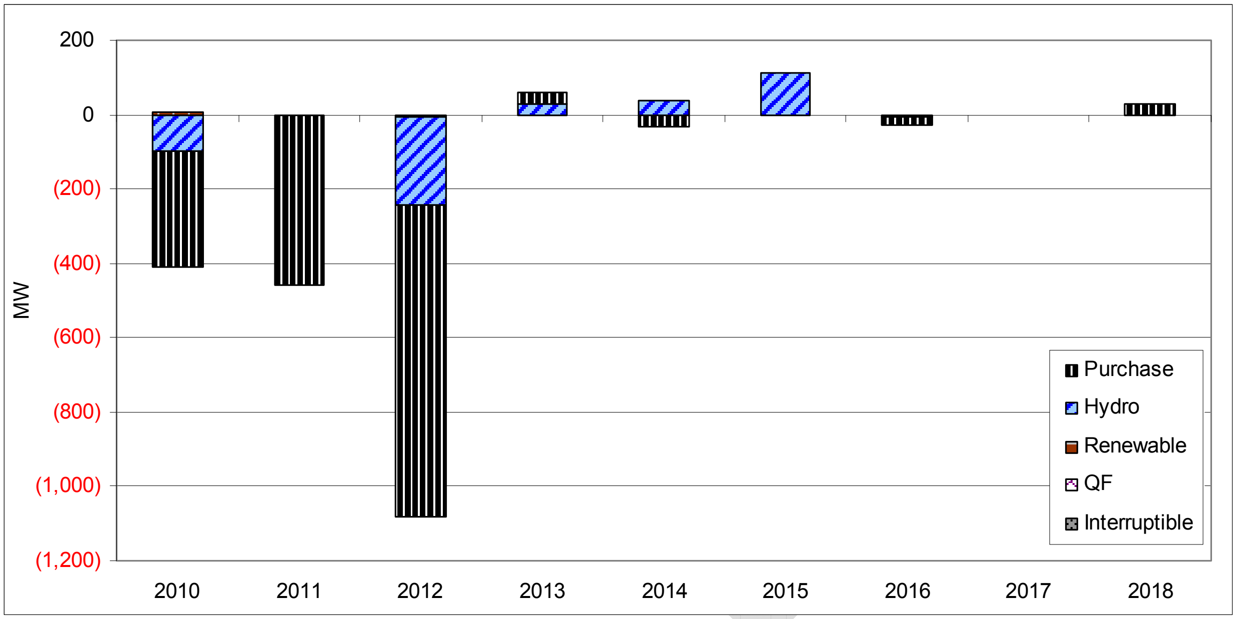



Listed below are the major contract expirations expiring between the summer 2011 and summer 2012:

- BPA Peaking 575 MW
- Morgan Stanley 100 MW
- Morgan Stanley 100 MW
- Colockum Capacity Exchange 108 MW
- Rocky Reach 65 MW
- Grant Displacement 63 MW

Figure 5.2 shows the year-to-year changes in contract capacity. Early year fluctuations are due to changes in short-term balancing contracts of one year or less, and expiration of the contracts cited above.

**Figure 5.2 – Changes in Contract Capacity in the Load and Resource Balance**




## LOAD AND RESOURCE BALANCE

### Capacity and Energy Balance Overview

The purpose of the load and resource balance is to compare the annual obligations for the first ten years of the study period with the annual capability of PacifiCorp's existing resources, absent new resource additions. This is done with respect to two views of the system, the capacity balance and energy balance.

The capacity balance compares generating capability to expected peak load at time of system peak load hours. It is a key part of the load and resource balance because it provides guidance as to the timing and severity of future resource deficits. It was developed by first determining the system coincident peak load hour for each of the first ten years (2009-2018) of the planning horizon. The peak load and the firm sales were added together for each of the annual system peak hours to compute the annual peak-hour obligation. Then the annual firm-capacity availability of the existing resources was determined for each of these annual system peak hours. The annual resource deficit (surplus) was then computed by multiplying the obligation by the planning reserve margin, and then subtracting the result from the existing resources.

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy over the first ten years of the planning horizon (2009-2018). The average obligation (load plus sales) was computed and subtracted from the average existing resource availability for each month and time-of-day period. This was done for each side of the PacifiCorp system as well as at the system level. The energy balance complements the capacity balance in that it also indicates when resource deficits occur, but it also provides insight into what type of resource will best fill the need. The usefulness of the energy balance is limited as it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed with the portfolio studies described in Chapter 8.

Capacity and energy balance information is reported for two scenarios: with the Lake Side 2 combined-cycle plant included as a firm planned resource in 2012, and Lake Side 2 excluded as a resource, resulting in a larger capacity deficit beginning in that year.

## Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculation. The main component categories consist of the following: existing resources, obligation, reserves, position, and reserve margin. This section provides a description of these various components.

### Existing Resources

The firm capacities of the existing resources are shown in table 4.6 by resource category and summed to show the total available existing resource capacity for the east, west and for the PacifiCorp system. A description of each of the resource categories follows:

- **Thermal**. This includes all thermal plants that are wholly-owned or partially-owned by PacifiCorp. The capacity balance counts them at maximum dependable capability at time of system peak. The energy balance also counts them at maximum dependable capability, but derates them for forced outages and maintenance. This includes the existing fleet of 11 coal-fired plants, six natural gas-fired plants, and two co-generation units. These thermal resources account for roughly two-thirds of the firm capacity available in the PacifiCorp system.

- **Hydro**. This includes all hydroelectric generation resources operated in the PacifiCorp system as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance assumes the average capacity of the 6 highest load hours occurring during the 3 days of highest demand in January and July. The energy associated with critical level stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. Over 90 percent of the hydroelectric capacity is situated on the west side of the PacifiCorp system.

- **Demand-Side Management (DSM).** In 2009, there are projected to be about 345 megawatts of Class 1 demand-side management programs included as existing resources. These are further projected to increase to 525 MW by 2018. Both the capacity balance and the energy balance count DSM programs by program capacity. DSM resources directly curtail load and thus planning reserves are not held for them.

- **Renewable.** This category contains one geothermal project, 21 existing wind projects and two planned wind projects. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. Project-specific capacity credits for the wind resources were statistically determined. Wind energy is counted according to hourly generation data used to model the projects.

- **Purchase.** This includes all of the major contracts for purchases of firm capacity and energy in the PacifiCorp system. The capacity balance counts these by the maximum contract availability at time of system peak. The energy balance counts the optimum model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

- **Qualifying Facilities (QF).** All Qualifying Facilities that provide capacity and energy are included in this category. Like other power purchases, the capacity balance counts them at maximum system peak availability and the energy balance counts them by optimum model dispatch. It is assumed that all Qualifying Facility agreements will stay in place for the entire duration of the 20-year planning period. It should be noted that three of the Qualifying Facility resources (Kennecott, Tesoro, and US Magnesium) are considered non-firm and thus do not contribute to capacity planning.

- **Interruptible.** There are three east-side load curtailment contracts in this category. These agreements with Monsanto, MagCorp and Nucor provide 237 MW of load interruption capability at time of system peak. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus planning reserves are not held for them.

**Obligation**
The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load and firm contracted sales of energy and capacity. The following are descriptions of each of these components:

- **Load**. The largest component of the obligation is the retail load. The capacity balance counts the peak load (MW) at the hour of system coincident peak load. The energy balance counts the load as an average of monthly time-of-day energy (MWa).

  Due to new federal lighting standards being implemented under the Energy Policy Act of 2005, the load forecast required adjustment because lighting efficiency measures were embedded in the Class 2 DSM supply curves provided to PacifiCorp. Increasing the load forecast to account for this available energy efficiency "supply" ensures that an appropriate quantity of Class 2 DSM is selected by the capacity expansion model. Table 5.17 shows the impact of the hourly energy adjustments to annual system peak loads. (Note that this upward load adjustment applies only for capacity expansion modeling purposes. The company's official load forecast is reported net of this DSM adjustment.)

**Table 5.17 –Federal Lighting Standard Impact on System Peak loads**

| Year | Federal Lighting Adjustment (MW) |
|---|---|
| 2009 | 6.3 |
| 2010 | 10.3 |
| 2011 | 8.5 |
| 2012 | 12.2 |
| 2013 | 20.3 |

| Year | Federal Lighting Adjustment (MW) |
|---|---|
| 2014 | 50.8 |
| 2015 | 69.2 |
| 2016 | 94.1 |
| 2017 | 132.7 |
| 2018 | 151.6 |
| 2019 | 144.5 |
| 2020 | 173.1 |
| 2021 | 174.6 |
| 2022 | 200.9 |
| 2023 | 217.7 |
| 2024 | 226.2 |
| 2025 | 232.0 |
| 2026 | 234.1 |
| 2027 | 239.4 |
| 2028 | 245.0 |

- **Sales**. This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system peak and the energy balance counts them by optimum model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

**Reserves**
The reserves are the total megawatts of planning and non-owned reserves that must be held for this load and resource balance. A description of the two types of reserves follows:

- **Planning reserves**. This is the total reserves that must be held to provide the planning reserve margin. It is the net firm obligation multiplied by the planning reserve margin as in the following equation:

  ***Planning reserves*** *= (Obligation – Purchase – DSM – Interruptible) x PRM*

- **Non-owned reserves**. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. This amounts to an annual reserve obligation of about 7 megawatts and 70 megawatts on the west and east-sides, respectively.

**Position**
The position is the resource surplus (deficit) resulting from subtracting the existing resources from the obligation. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

**Reserve Margin**
The reserve margin is the ratio of existing resources to the obligation. A positive reserve margin indicates that existing resources exceeds obligation. Conversely, a negative reserve margin indi-

cates that existing resources do not meet obligation. If existing resources equals the obligation, then the reserve margin is 0%. It should be pointed out that the reserve margin can be negative when the corresponding position is non-negative. This is because the reserve margin is measured relative to the obligation, while the position is measured relative to the obligation plus reserves.

## Capacity Balance Determination

### Methodology

The capacity balance is developed by first determining the system coincident peak load hour for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system peak hours and summed as follows:

***Existing Resources*** *= Thermal + Hydro + DSM + Renewable + Purchase + QF + Interruptible*

The peak load and firm sales are then added together for each of the annual system peak hours to compute the annual peak-hour obligation:

***Obligation*** *= Load + Sales*

The amount of reserves to be added to the obligation is then calculated. This is accomplished by first removing the firm purchase and load curtailment components of the existing resources from the obligation. This resulting net obligation is then multiplied by the planning reserve margin. The non-owned reserves are then added to this result to yield the megawatts of required reserves. The formula for this calculation is the following:

***Reserves*** *= (Obligation – Purchase – DSM – Interruptible) x PRM + Non-owned reserves*

Finally, the annual capacity position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources as shown in the following formula:

***Capacity Position*** *= Existing Resources – Obligation – Reserves*

### Load and Resource Balance Assumptions

The assumptions underlying the current load and resource balance are generally the same as those from the 2007 IRP update with a few exceptions. The following is a summary of these assumption changes:

- **Wind Commitment.** In the 2007 IRP, 400 megawatts of the overall 1,400-megawatt commitment are included in the load and resource balance. The remaining 1,000 megawatts were treated as part of the overall wind resource potential evaluated in portfolio modeling. In the 2008 IRP, there are 263 MW of firm planned wind projects included in the load and resource balance.

- **Coal plant turbine upgrades.** The current load and resource balance assumes 162 MW of coal plant turbine upgrades, which is down from the 202 MW assumed in the 2007 IRP Update Report.

**Capacity Balance Results**

Table 5.18 shows, with Lake Side 2 included, the annual capacity balances and component line items using a target planning reserve margin of 12 percent to calculate the planning reserve amount. Balances for the system as well as PacifiCorp's east and west control areas are shown. (It should be emphasized that while west and east balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.) For comparison purposes, Table 5.19 shows the system-level capacity balance assuming a 15 percent planning reserve margin.

## Table 5.18 – Capacity Loads and Resources including Lake Side 2 (12% Target Reserve Margin)

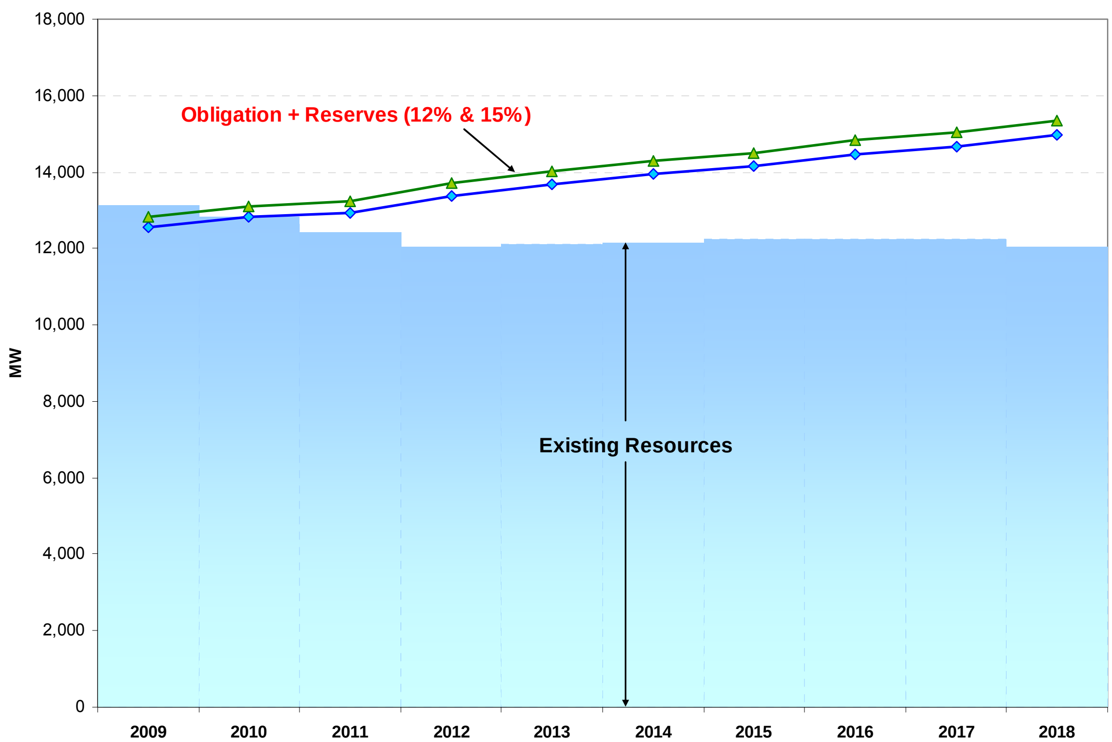
| Calendar Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| **East** | | | | | | | | | | |
| Thermal | 5,983 | 5,998 | 6,025 | 6,662 | 6,662 | 6,674 | 6,675 | 6,683 | 6,684 | 6,459 |
| Hydro | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 |
| DSM | 345 | 395 | 435 | 465 | 475 | 485 | 495 | 505 | 515 | 525 |
| Renewable | 157 | 157 | 157 | 157 | 157 | 157 | 154 | 154 | 154 | 154 |
| Purchase | 751 | 546 | 541 | 341 | 341 | 341 | 341 | 320 | 320 | 320 |
| QF | 151 | 151 | 151 | 151 | 151 | 151 | 151 | 151 | 151 | 151 |
| Interruptible | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 |
| Transfers | 876 | 952 | 602 | 235 | 263 | 465 | 230 | 230 | 393 | 589 |
| **East Existing Resources** | **8,636** | **8,572** | **8,284** | **8,384** | **8,422** | **8,645** | **8,418** | **8,415** | **8,589** | **8,571** |
| Load | 6,757 | 6,949 | 7,150 | 7,404 | 7,643 | 7,779 | 8,029 | 8,303 | 8,491 | 8,696 |
| Sale | 781 | 768 | 758 | 747 | 745 | 745 | 745 | 745 | 659 | 659 |
| **East Obligation** | **7,538** | **7,717** | **7,908** | **8,151** | **8,388** | **8,524** | **8,774** | **9,048** | **9,150** | **9,355** |
| Planning reserves | 745 | 785 | 803 | 853 | 880 | 895 | 924 | 958 | 969 | 993 |
| Non-owned reserves | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| **East Reserves** | **815** | **855** | **874** | **923** | **951** | **966** | **995** | **1,029** | **1,040** | **1,063** |
| **East Obligation + Reserves** | **8,352** | **8,572** | **8,781** | **9,074** | **9,339** | **9,490** | **9,769** | **10,077** | **10,190** | **10,418** |
| **East Position** | **284** | **1** | **(498)** | **(690)** | **(917)** | **(845)** | **(1,350)** | **(1,662)** | **(1,601)** | **(1,848)** |
| **East Reserve Margin** | **16%** | **12%** | **6%** | **4%** | **1%** | **2%** | **(3%)** | **(6%)** | **(5%)** | **(8%)** |
| **West** | | | | | | | | | | |
| Thermal | 2,550 | 2,559 | 2,568 | 2,579 | 2,591 | 2,591 | 2,591 | 2,591 | 2,577 | 2,577 |
| Hydro | 1,315 | 1,218 | 1,216 | 980 | 1,009 | 1,046 | 1,157 | 1,150 | 1,149 | 1,146 |
| DSM | - | - | - | - | - | - | - | - | - | - |
| Renewable | 90 | 96 | 96 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Purchase | 1,310 | 1,203 | 753 | 115 | 144 | 111 | 111 | 111 | 111 | 139 |
| QF | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 |
| Transfers | (878) | (953) | (603) | (235) | (264) | (465) | (229) | (229) | (392) | (588) |
| **West Existing Resources** | **4,507** | **4,242** | **4,150** | **3,649** | **3,691** | **3,492** | **3,840** | **3,833** | **3,654** | **3,483** |
| Load | 3,393 | 3,422 | 3,490 | 3,587 | 3,638 | 3,722 | 3,769 | 3,824 | 3,893 | 3,978 |
| Sale | 499 | 490 | 290 | 258 | 258 | 258 | 158 | 108 | 108 | 108 |
| **West Obligation** | **3,892** | **3,912** | **3,780** | **3,845** | **3,896** | **3,980** | **3,927** | **3,932** | **4,001** | **4,086** |
| Planning reserves | 310 | 325 | 363 | 448 | 450 | 464 | 458 | 459 | 467 | 474 |
| Non-owned reserves | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| **West Reserves** | **316** | **332** | **370** | **454** | **457** | **471** | **464** | **465** | **473** | **480** |
| **West Obligation + Reserves** | **4,208** | **4,243** | **4,149** | **4,299** | **4,353** | **4,451** | **4,391** | **4,397** | **4,474** | **4,566** |
| **West Position** | **299** | **(1)** | **0** | **(650)** | **(662)** | **(958)** | **(551)** | **(564)** | **(820)** | **(1,082)** |
| **West Reserve Margin** | **20%** | **12%** | **12%** | **(5%)** | **(5%)** | **(12%)** | **(2%)** | **(2%)** | **(9%)** | **(14%)** |
| **System** | | | | | | | | | | |
| **Total Resources** | **13,143** | **12,815** | **12,433** | **12,033** | **12,112** | **12,137** | **12,258** | **12,248** | **12,243** | **12,054** |
| **Obligation** | **11,430** | **11,628** | **11,687** | **11,996** | **12,284** | **12,504** | **12,701** | **12,980** | **13,151** | **13,441** |
| **Reserves** | **1,131** | **1,187** | **1,243** | **1,377** | **1,407** | **1,437** | **1,459** | **1,494** | **1,513** | **1,543** |
| **Obligation + Reserves** | **12,561** | **12,815** | **12,931** | **13,373** | **13,692** | **13,940** | **14,160** | **14,474** | **14,664** | **14,984** |
| **System Position** | **583** | **(0)** | **(498)** | **(1,340)** | **(1,579)** | **(1,803)** | **(1,902)** | **(2,226)** | **(2,421)** | **(2,930)** |
| **Reserve Margin** | **17%** | **12%** | **8%** | **1%** | **(1%)** | **(2%)** | **(3%)** | **(5%)** | **(6%)** | **(10%)** |

**Table 5.19 – System Capacity Loads and Resources including Lake Side 2 (15% Target Reserve Margin)**

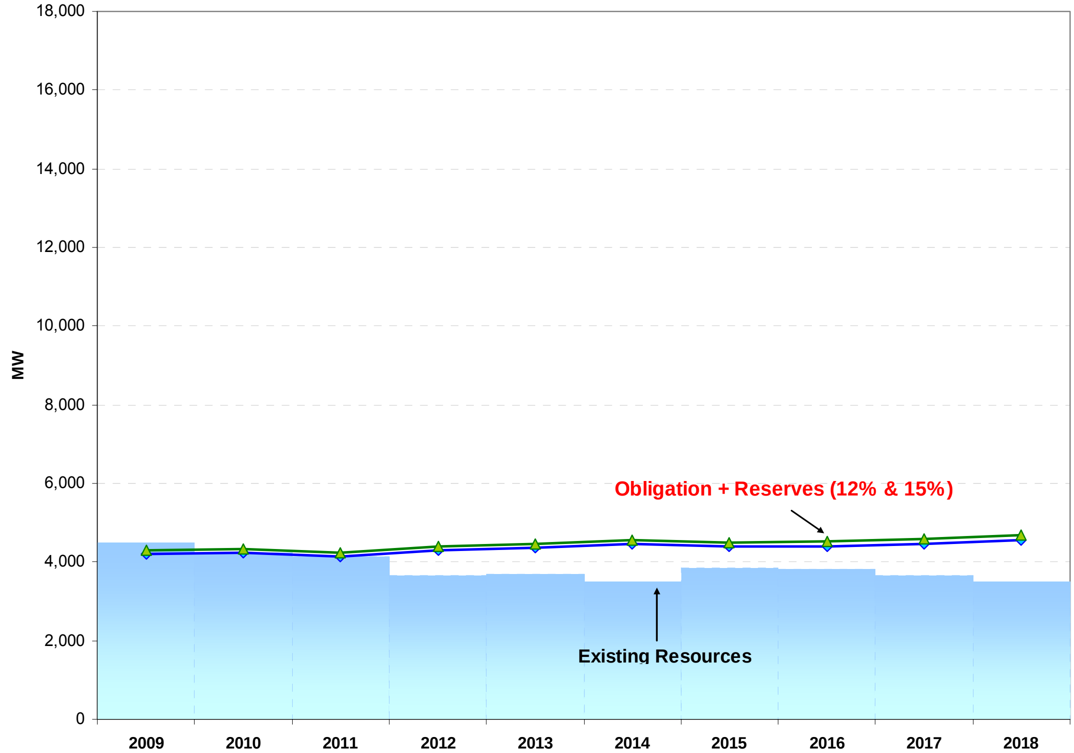
| Calendar Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| **System** | | | | | | | | | | |
| **Total Resources** | 13,143 | 12,815 | 12,433 | 12,033 | 12,112 | 12,137 | 12,258 | 12,248 | 12,243 | 12,054 |
| **Obligation** | 11,430 | 11,628 | 11,687 | 11,996 | 12,284 | 12,504 | 12,701 | 12,980 | 13,151 | 13,441 |
| **Reserves** | 1,395 | 1,464 | 1,535 | 1,703 | 1,740 | 1,776 | 1,805 | 1,848 | 1,872 | 1,910 |
| **Obligation + Reserves (15%)** | 12,824 | 13,092 | 13,222 | 13,698 | 14,024 | 14,280 | 14,505 | 14,828 | 15,023 | 15,351 |
| **System Position** | 319 | (277) | (789) | (1,665) | (1,912) | (2,143) | (2,247) | (2,580) | (2,780) | (3,297) |
| **Reserve Margin** | 18% | 13% | 8% | 1% | (1%) | (2%) | (3%) | (5%) | (6%) | (10%) |

Figures 5.3 through 5.5 display the annual capacity positions (resource surplus or deficits) for the system, west control area, and east control area, respectively. The decrease in resources in 2008 is caused by the expected expiration of the West Valley lease agreement. The slight increase in 2009 is due to executed front office transactions and an increase in the curtailment portion of the Monsanto contract. The large decrease in 2012 is primarily due to the expiration of the BPA peaking contract in August 2011. Additionally, Figure 5.4 highlights a decrease in obligation in the west starting in 2014 attributable to the expiration of the Sacramento Municipal Utility District and City of Redding power sales contracts.

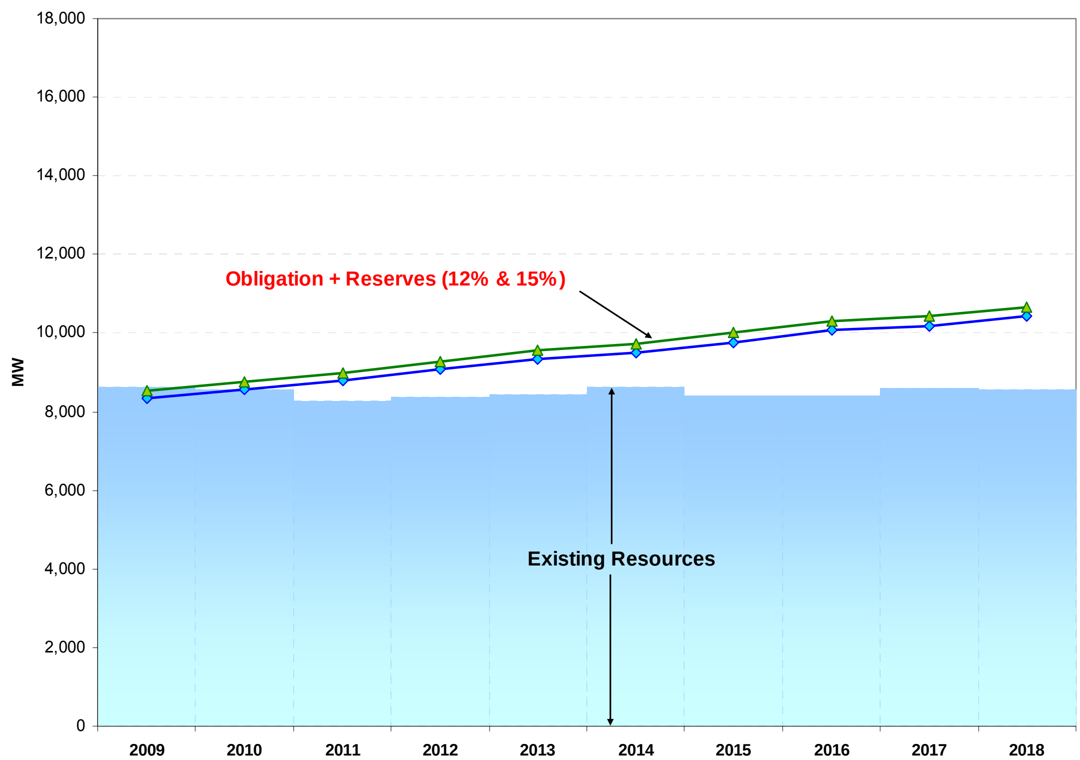
**Figure 5.3 – System Capacity Position Trend including Lake Side 2**



## Figure 5.4 – West Capacity Position Trend including Lake Side 2




## Figure 5.5 – East Capacity Position Trend including Lake Side 2



**Capacity Balance Impact of Removing the 2012 RFP Combined-Cycle Gas Resource**

Tables 5.20 and 5.21 show the capacity balance without the addition of the Lake Side 2 combined-cycle resource in 2012 (596 MW capacity contribution) at 12-percent and 15-percent target planning reserve margins, respectively. Figures 5.6 and 5.7 graphically show the capacity position trend for the system and east control area, respectively.

### Table 5.20 – System Capacity Loads and Resources without Lake Side 2 (12% Target Reserve Margin)

| Calendar Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| **East** | | | | | | | | | | |
| Thermal | 5,983 | 5,998 | 6,025 | 6,066 | 6,066 | 6,078 | 6,079 | 6,087 | 6,088 | 5,863 |
| Hydro | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 |
| DSM | 345 | 395 | 435 | 465 | 475 | 485 | 495 | 505 | 515 | 525 |
| Renewable | 157 | 157 | 157 | 157 | 157 | 157 | 154 | 154 | 154 | 154 |
| Purchase | 751 | 546 | 541 | 341 | 341 | 341 | 341 | 320 | 320 | 320 |
| QF | 151 | 151 | 151 | 151 | 151 | 151 | 151 | 151 | 151 | 151 |
| Interruptible | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 |
| Transfers | 1,150 | 952 | 602 | 422 | 440 | 230 | 490 | 504 | 265 | 414 |
| **East Existing Resources** | 8,910 | 8,572 | 8,284 | 7,975 | 8,003 | 7,814 | 8,082 | 8,093 | 7,865 | 7,800 |
| | | | | | | | | | | |
| Load | 6,757 | 6,949 | 7,150 | 7,404 | 7,643 | 7,779 | 8,029 | 8,303 | 8,491 | 8,696 |
| Sale | 781 | 768 | 758 | 747 | 745 | 745 | 745 | 745 | 659 | 659 |
| **East Obligation** | 7,538 | 7,717 | 7,908 | 8,151 | 8,388 | 8,524 | 8,774 | 9,048 | 9,150 | 9,355 |
| | | | | | | | | | | |
| Planning reserves | 745 | 785 | 803 | 853 | 880 | 895 | 924 | 958 | 969 | 993 |
| Non-owned reserves | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| **East Reserves** | 815 | 855 | 874 | 923 | 951 | 966 | 995 | 1,029 | 1,040 | 1,063 |
| | | | | | | | | | | |
| **East Obligation + Reserves** | 8,352 | 8,572 | 8,781 | 9,074 | 9,339 | 9,490 | 9,769 | 10,077 | 10,190 | 10,418 |
| **East Position** | 558 | 1 | (498) | (1,099) | (1,336) | (1,676) | (1,686) | (1,984) | (2,325) | (2,619) |
| **East Reserve Margin** | 19% | 12% | 6% | (1%) | (4%) | (8%) | (7%) | (10%) | (13%) | (16%) |
| | | | | | | | | | | |
| **West** | | | | | | | | | | |
| Thermal | 2,550 | 2,559 | 2,568 | 2,579 | 2,591 | 2,591 | 2,591 | 2,591 | 2,577 | 2,577 |
| Hydro | 1,315 | 1,218 | 1,216 | 980 | 1,009 | 1,046 | 1,157 | 1,150 | 1,149 | 1,146 |
| DSM | - | - | - | - | - | - | - | - | - | - |
| Renewable | 90 | 96 | 96 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Purchase | 1,310 | 1,203 | 753 | 115 | 144 | 111 | 111 | 111 | 111 | 139 |
| QF | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 |
| Transfers | (1,152) | (953) | (603) | (422) | (442) | (228) | (489) | (504) | (263) | (415) |
| **West Existing Resources** | 4,233 | 4,242 | 4,150 | 3,462 | 3,513 | 3,729 | 3,580 | 3,558 | 3,783 | 3,656 |
| | | | | | | | | | | |
| Load | 3,393 | 3,422 | 3,490 | 3,587 | 3,638 | 3,722 | 3,769 | 3,824 | 3,893 | 3,978 |
| Sale | 499 | 490 | 290 | 258 | 258 | 258 | 158 | 108 | 108 | 108 |
| **West Obligation** | 3,892 | 3,912 | 3,780 | 3,845 | 3,896 | 3,980 | 3,927 | 3,932 | 4,001 | 4,086 |
| | | | | | | | | | | |
| Planning reserves | 310 | 325 | 363 | 448 | 450 | 464 | 458 | 459 | 467 | 474 |
| Non-owned reserves | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| **West Reserves** | 316 | 332 | 370 | 454 | 457 | 471 | 464 | 465 | 473 | 480 |
| | | | | | | | | | | |
| **West Obligation + Reserves** | 4,208 | 4,243 | 4,149 | 4,299 | 4,353 | 4,451 | 4,391 | 4,397 | 4,474 | 4,566 |
| **West Position** | 25 | (1) | 0 | (837) | (840) | (721) | (811) | (839) | (691) | (909) |
| **West Reserve Margin** | 13% | 12% | 12% | (10%) | (10%) | (6%) | (9%) | (9%) | (5%) | (10%) |
| | | | | | | | | | | |
| **System** | | | | | | | | | | |
| **Total Resources** | 13,143 | 12,815 | 12,433 | 11,437 | 11,515 | 11,543 | 11,662 | 11,651 | 11,648 | 11,456 |
| **Obligation** | 11,430 | 11,628 | 11,687 | 11,996 | 12,284 | 12,504 | 12,701 | 12,980 | 13,151 | 13,441 |
| **Reserves** | 1,131 | 1,187 | 1,243 | 1,377 | 1,407 | 1,437 | 1,459 | 1,494 | 1,513 | 1,543 |
| **Obligation + Reserves** | 12,561 | 12,815 | 12,931 | 13,373 | 13,692 | 13,940 | 14,160 | 14,474 | 14,664 | 14,984 |
| **System Position** | 583 | (0) | (498) | (1,936) | (2,176) | (2,397) | (2,498) | (2,823) | (3,016) | (3,528) |
| **Reserve Margin** | 17% | 12% | 8% | (4%) | (6%) | (7%) | (8%) | (10%) | (11%) | (14%) |

## Table 5.21 – System Capacity Loads and Resources without Lake Side 2 (15% Target Reserve Margin)

| Calendar Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| **System** | | | | | | | | | | |
| **Total Resources** | 13,143 | 12,815 | 12,433 | 11,437 | 11,515 | 11,543 | 11,662 | 11,651 | 11,648 | 11,456 |
| **Obligation** | 11,430 | 11,628 | 11,687 | 11,996 | 12,284 | 12,504 | 12,701 | 12,980 | 13,151 | 13,441 |
| **Reserves** | 1,395 | 1,464 | 1,535 | 1,703 | 1,740 | 1,776 | 1,805 | 1,848 | 1,872 | 1,910 |
| **Obligation + Reserves** | 12,824 | 13,092 | 13,222 | 13,698 | 14,024 | 14,280 | 14,505 | 14,828 | 15,023 | 15,351 |
| **System Position** | 319 | (277) | (789) | (2,261) | (2,509) | (2,737) | (2,843) | (3,177) | (3,375) | (3,895) |
| **Reserve Margin** | 18% | 13% | 8% | (4%) | (5%) | (7%) | (7%) | (9%) | (11%) | (14%) |

## Figure 5.6 – System Capacity Position Trend without Lake Side 2

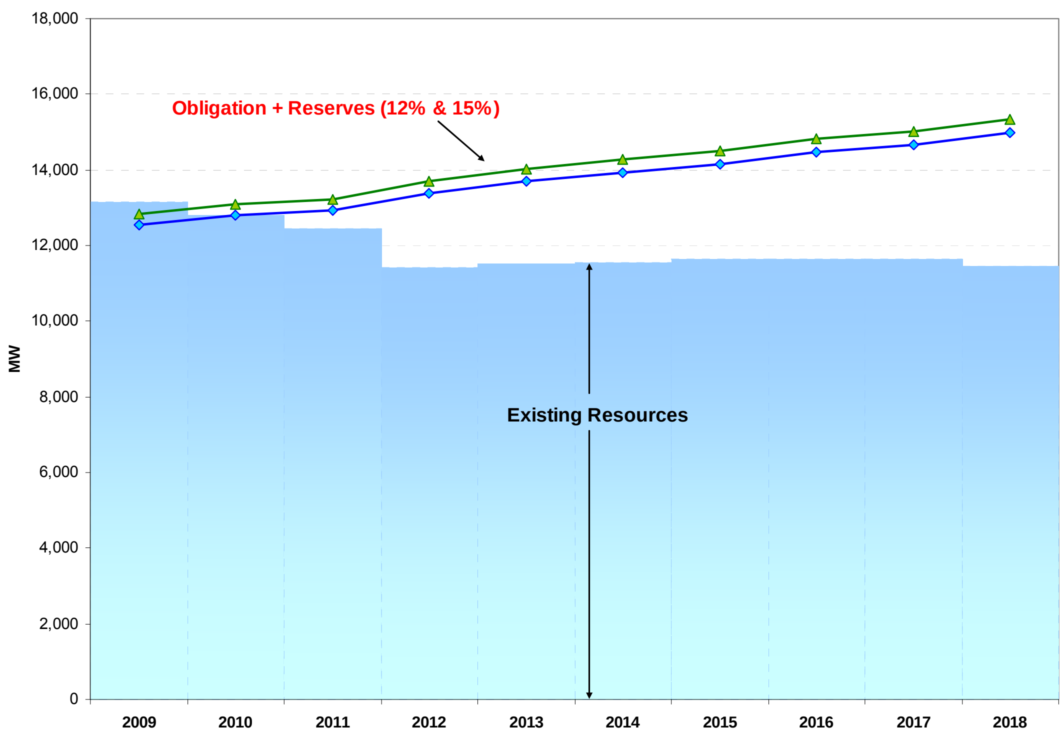
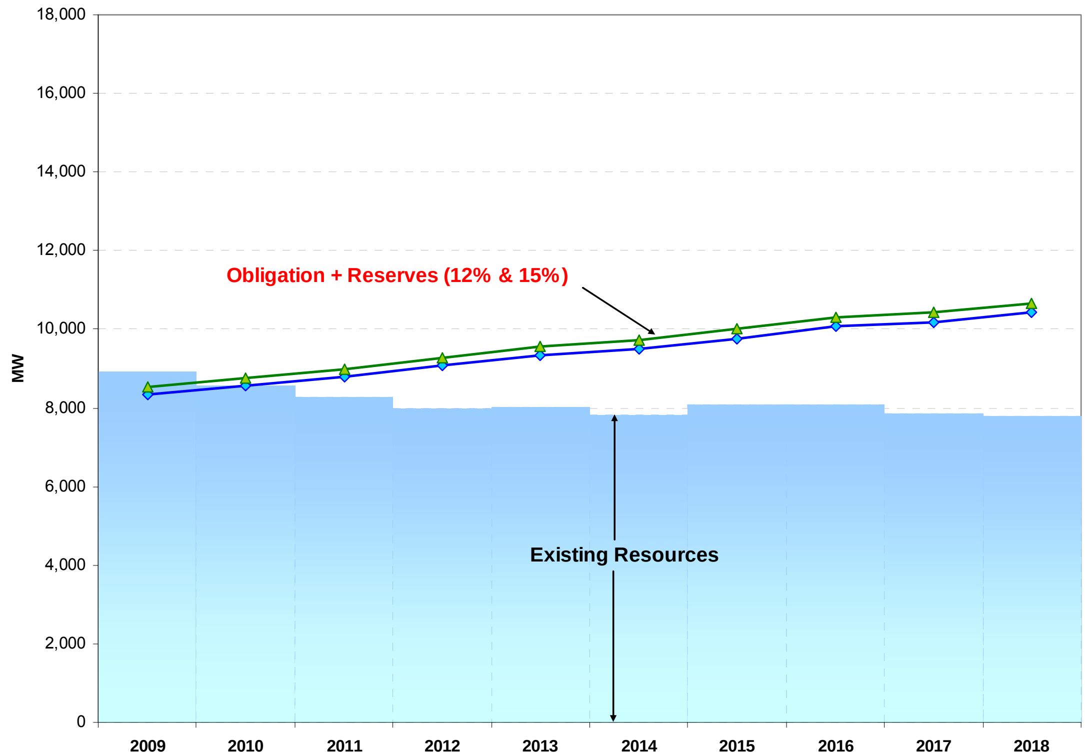


**Figure 5.7 – East Capacity Position Trend without Lake Side 2**




## Energy Balance Determination

### Methodology

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy. The on-peak hours are weekdays and Saturdays from hour-ending 7:00 am to 10:00 pm; off-peak hours are all other hours. The existing resource availability is computed for each month and daily time block without regard to economic considerations. Peaking resources such as the Gadsby units are counted only for the on-peak hours. This is calculated using the formulas that follow. Please refer to the section on load and resource balance components for details on how energy for each component is counted.

***Existing Resources*** = *Thermal* + *Hydro* + *DSM* + *Renewable* + *Purchase* + *QF* + *Interruptible*

The average obligation is computed using the following formula:

***Obligation*** = *Load* + *Sales*

The energy position by month and daily time block is then computed as follows:

***Energy Position*** = *Existing Resources – Obligation – Reserve Requirements (12% PRM)*

## Energy Balance Results

Figures 5.8 through 5.10 show—with Lake Side 2 included—the energy balances for the system, west control area, and east control area, respectively. They indicate the energy balance on a monthly average basis across all hours, and also indicate the average annual energy position. The cross-over point, where the system starts to become energy deficient on a summer hour basis, is 2015, absent any economic considerations.

**Figure 5.8 – System Average Monthly and Annual Energy Balances**

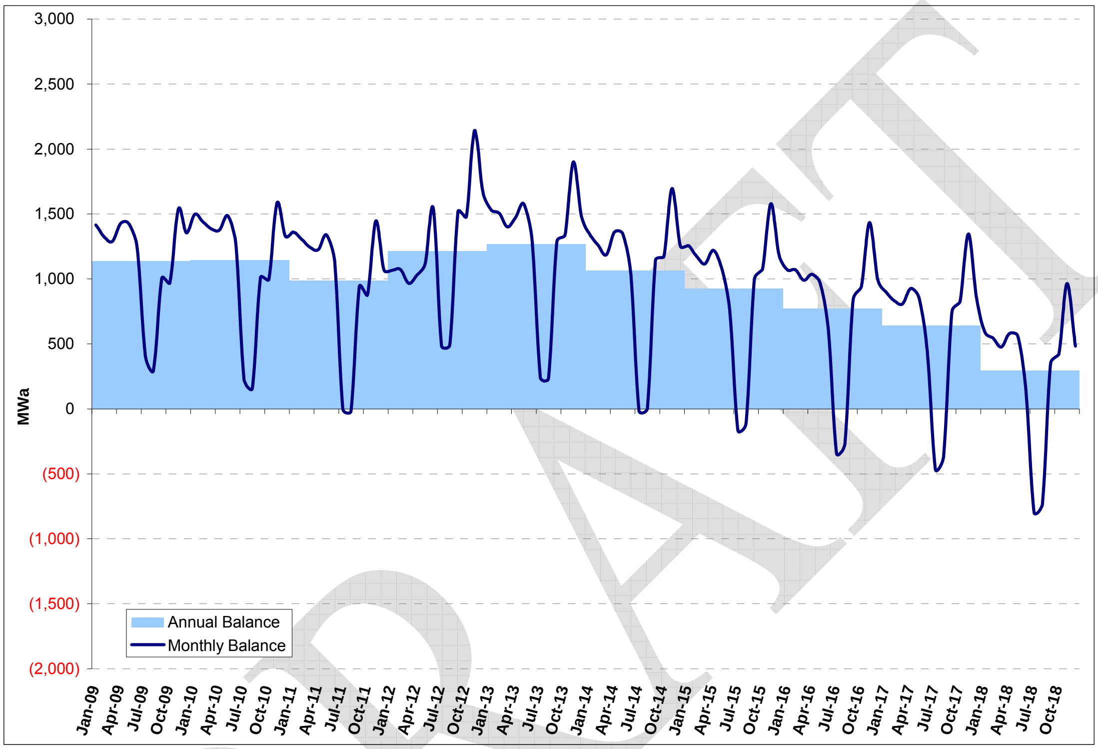


**Figure 5.9 – West Average Monthly and Annual Energy Balances**

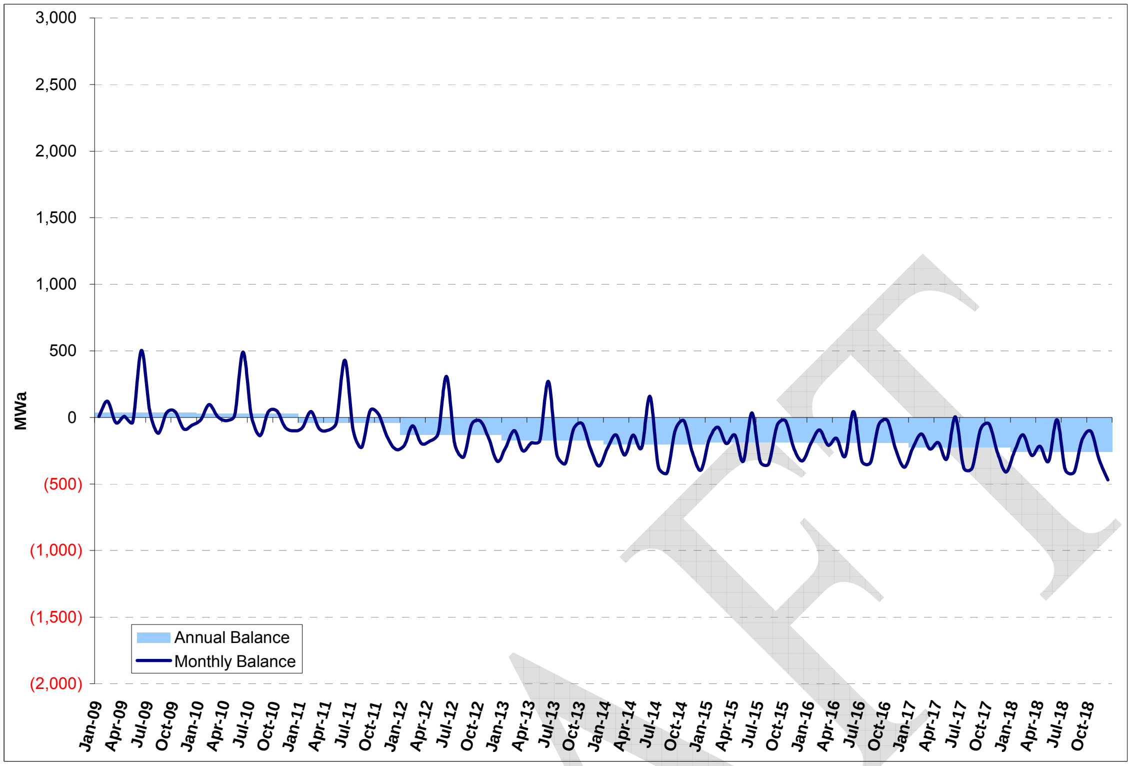
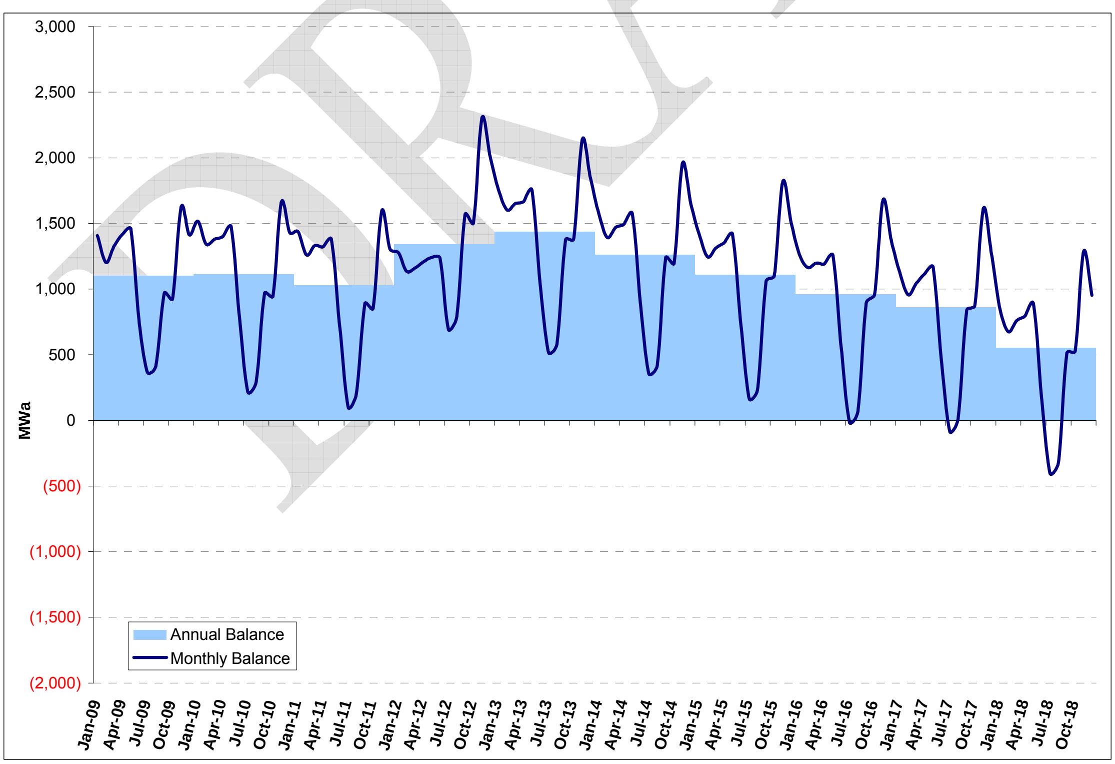



**Figure 5.10 – East Average Monthly and Annual Energy Balances**



**Energy Balance Impact of Removing the 2012 RFP Combined-Cycle Gas Resource**
Figures 5.11 and 5.12 show the system and east control area energy balances without Lake Side 2, respectively. System energy deficits during the summer hours begin in 2012 without the benefit of this resource.

**Figure 5.11 – System Average Monthly and Annual Energy Balances**

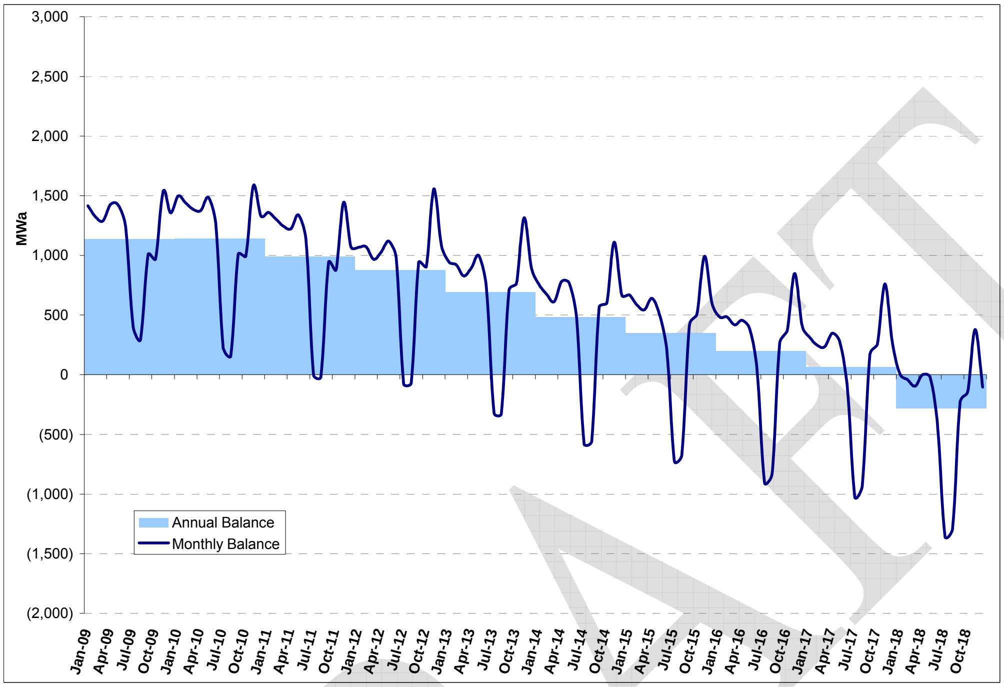
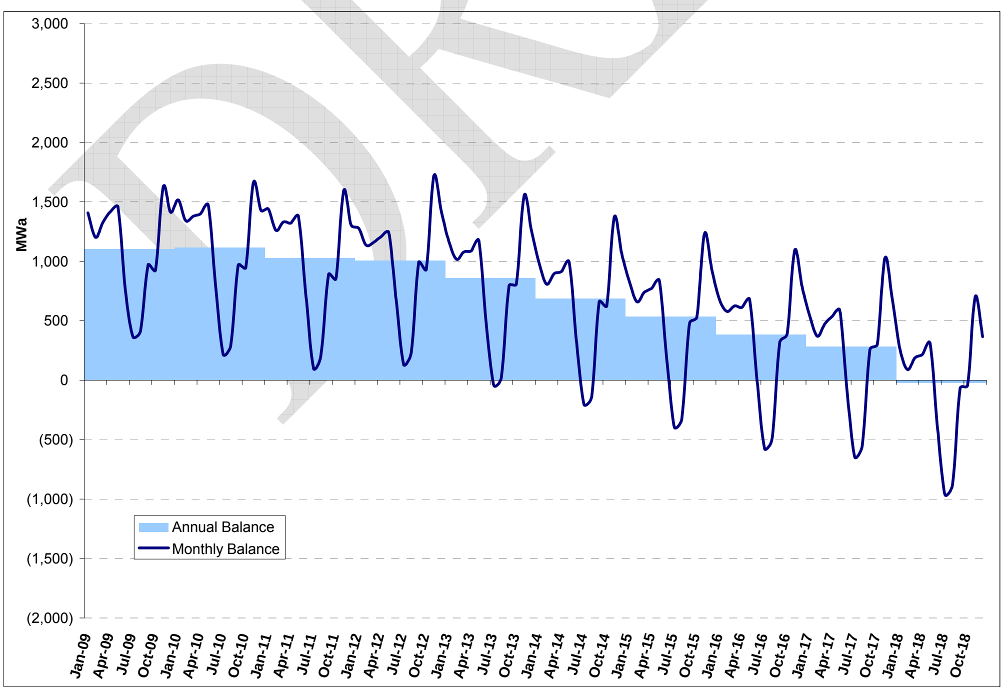



**Figure 5.12 – East Average Monthly and Annual Energy Balances**



## Load and Resource Balance Conclusions

The company projects a summer peak resource deficit for the PacifiCorp system beginning in 2010 to 2011, depending on the planning reserve margin assumed. The PacifiCorp deficits prior to 2012 will be met by additional renewables, demand-side programs, market purchases, and coal plant turbine upgrades. The company will consider other options during this time frame if they are cost-effective and provide other system benefits. Then, beginning 2012, base load, intermediate load, or both types of resource additions will be necessary to cover the widening capacity deficit. The capacity balance at a 12 percent planning reserve margin indicates the start of a deficit beginning in 2011—the system is short by 498 MW. This capacity deficit increases to 1,340 MW in 2012 and then to almost 3,000 MW in 2018. With the Lake Side 2 gas plant excluded, the 2012 capacity deficit increases to 1,936 MW and to 3,895 MW by 2018. On an annual basis, and disregarding economic considerations, the company becomes deficit with respect to summer energy by 2016 with Lake Side 2 included, but becomes deficit as soon as 2012 without this resource.

# 6. RESOURCE OPTIONS

## INTRODUCTION

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of supply-side generation (utility-scaled and distributed resources), demand-side management programs, transmission expansion projects, and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

## SUPPLY-SIDE RESOURCES

### Resource Selection Criteria

The list of supply-side resource options has been modified in relation to previous IRP resource lists to reflect the realities evidenced through permitting, public meeting comments, and studies undertaken to better understand the details of available generation resources. For instance, coal options have been decreased with a greater emphasis on carbon capture and sequestration. Natural gas options have been expanded to include a dry-cooled combined cycle option and separate gas options were developed for Wyoming. Alternative energy resources have been given a greater emphasis. Specifically additional solar generation options and geothermal options have been included in the analysis compared to the previous IRP. Additional solar resources include utility-size (10 MWs or greater) concentrated photovoltaic as well as solar thermal with six hours of thermal storage. Energy storage systems continue to be of interest, and advanced large batteries (1 MW) have been reviewed as well as traditional pumped hydro and compressed air energy storage.

### Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2007 IRP. This resource list was reviewed and modified to reflect public input and permitting realities. Once the basic list of resources was determined, the cost and performance attributes for each resource were estimated. A number of information sources were used to identify parameters needed to model these resources. Supporting utility-scale resources were a number of engineering studies conducted by PacifiCorp to understand the cost of coal and gas resources in recent years. Additionally, experience with the construction of the 2x1 combined cycle plants at Currant Creek and Lake Side as well as other recent simple-cycle projects at Gadsby and West Valley provided PacifiCorp with a detailed understanding of the cost of new power generating facilities. Preparation of benchmark submittals for PacifiCorp's recent generation RFPs were also used to update actual project experience, while government studies were relied upon for characterizing future carbon capture costs.

Extensive new studies on the cost of the coal-fired options were not prepared in keeping with the reduced emphasis on these resources for new near-term generation.

The results of these estimating efforts were compared with other cost databases, such as the one supporting the IPM® market model developed by ICF International, which the company now uses for national emissions policy impact analysis among other uses. The IPM® cost estimates were used when cost agreement was close.

The WorleyParsons Group was contracted to conduct a high-level renewable generation study specifically for solar, biomass and geothermal resources. The geothermal cost was adjusted to be consistent with estimated project costs for a third unit expansion at Blundell.

Wind costs are based on actual project experience in both the northwest and Wyoming, as well as current projections. Wind costs have been subject to increasing prices due to a lack of supply. Nuclear costs are reflective of recent cost estimates associated with preliminary development activities as well as published estimates of new projects. Hydrokinetic, or wave power, has been added based on proposed projects in the Northwest. Other generation options, such as energy storage and fuel cells, were adopted from PacifiCorp's previous IRP. In some cases costs from the previous IRP were updated using cost increases for other studied resources.

New to PacifiCorp's IRP process is the addition of a variety of small-scale generation resources, consisting of distributed standby generators (DSG), combined heat and power (CHP), and onsite solar supply-side resource options. Together these small resources are referred to as distributed generation. Quantec LLC (now called the Cadmus Group, Inc.) originally provided the distributed generation costs and attributes as part of the DSM potential study conducted for PacifiCorp in 2007.[24] The DSM potential report identified the economic potential for distributed generation resources by state.

## Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for many of the proposed generation options is high. Various factors contribute to this uncertainty. Recent experience with lump-sum contracting indicates a greater risk premium is being used by bidders for the traditional turn-key contracts preferred by PacifiCorp for major projects. Shortage of skilled labor and volatile commodity prices are a large part of the increase in project costs for lump-sum contracting. This trend is expected to continue although an economic slowdown could increase the competitiveness of future proposals as supply and demand reach a better balance. Projects in high demand, such as wind turbines, have seen cost increases as much as 40 percent since the 2007 IRP was developed due to tight turbine supplies. The wind capital costs in the supply-side table were escalated at 5 percent for the years 2009 to 2011 to reflect a continuation of near-term real cost escalation, then return to the nominal inflation rate of about 2 percent thereafter.

Technologies, such as IGCC and some proposed renewable concepts like solar, have a greater uncertainty because only a few demonstration units have been built and operated. There is a potential for future relative cost decreases for these technologies. As these technologies mature and

[24] Quantec LLC, Assessment of Long-Term, System Wide Potential for Demand-Side and Other Supplemental Resources, July 2007.

more plants are built and operated the costs of such new technologies may decrease relative to more mature options such as pulverized coal and conventional natural gas-fired plants.

The supply-side resource options tables below do not consider the potential for such savings since the benefits are not expected to be realized until the next generation of new plants are built and operated for a period of time. Any such benefits are not expected to be available until after 2020, and future IRPs will be able to incorporate the benefit of such future cost reductions. A range of estimated capital costs is displayed in the supply-side resource tables. The capital cost range was created by adjusting the base-line estimates by 5 percent on the low end and 20 percent on the high end.

Introduction of many new distributed generation technologies designed to fill the needs of niche markets has helped spur reductions in capital and operating costs. In the DSM potential report, Quantec LLC provided installed cost reduction percentages reflecting these cost trends. Table 6.1 shows the percentage cost reductions by technology type. PacifiCorp applied these cost reductions to the resources included in the IRP models.

**Table 6.1 – Distributed Generation Installed Cost Reduction**

| Technology | Installed Cost Reduction (%/year) |
|---|---|
| Reciprocating Engine | 1% |
| Microturbine | 3% |
| Fuel Cell | 5% |
| Gas Turbine | 1% |
| Anaerobic Digesters | 3% |
| Industrial Biomass | 0.5% |

## Resource Options and Attributes

Tables 6.2 and 6.3 present cost and performance attributes for supply-side resource options designated for PacifiCorp's east and west control areas, respectively. Tables 6.4 through 6.7 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2008 dollars. The resource costs are presented for both the \$8 and \$45 $CO_2$ tax levels in recognition of the uncertainty in characterizing emission costs.

As mentioned above, the attributes were mainly derived from PacifiCorp's recent cost studies and project experience with certain technologies adjusted to be more in line with the IPM database for ICF International. These options are included in PacifiCorp's IRP models but some duplicate gas technologies, such as the CCCT F 1x1 that were not selected in prior IRP's, were turned off to improve the System Optimizer model performance. Cost and performance values reflect analysis concluded by September 2008. Additional explanatory notes for the tables are as follows:

- Capital costs are intended to be all-inclusive, and account for Allowance for Funds Used During Construction (AFUDC), land, EPC (Engineering, Procurement, and Construction) cost premiums, owner's costs, etc. Capital costs in Tables 6.2 and 6.3 reflect mid-2008 current dollars, and do not include escalation from the current year to the year of commercial operation.

- Wind sites are modeled with differing peak load carrying capability levels and capacity factors. These levels are reported for each wind site in the Wind Capacity Planning Contribution section of Appendix F.
- Certain resource names are listed as acronyms. These include:
  *PC* – pulverized coal
  *IGCC* – integrated gasification combined cycle
  *SCCT* – simple cycle combustion turbine
  *CCCT* – combined cycle combustion turbine
  *CHP* – combined heat and power (cogeneration)
  *CCS* – carbon capture and sequestration
  *REG* – recovered energy generation
- The costs presented do not include any investment tax credits with the exception of utility solar projects that qualify for the 30% federal tax credit under the Emergency Economic Stabilization Act of 2008 signed into law in October 2008. The utility solar projects do not qualify for the federal production tax credit.
- Gas backup for solar with a heat rate of 11,750 Btu/kWh is less efficient than for a standalone CCCT.
- For the nuclear option, costs do not include fuel disposal but do include the cost of transmission.
- The capital cost columns in Tables 6.2 and 6.3 reports the low and high capital cost estimates. The average capital cost is reported in Tables 6.4 through 6.7.
- The capacity shown for retrofitting CCS on existing pulverized coal plants is a net change from current capacity (proportional to 500 MW). The heat rate is the total net plant heat rate based on a nominal 10,000 Btu/kWh without CCS.
- The wind resources entered in the table are representative resources included in the IRP models for planning purposes. Cost and performance attributes of specific resources would be performed as part of the acquisition process. Also, the listed capacity factors are not intended to characterize wind quality for a particular region.
- Heat rates are not adjusted for degradation over time. PacifiCorp assumes that efficiency improvements will offset degradation impacts.

# Table 6.2 – East Side Supply-Side Resource Options

| | Location / Timing | | Plant Details | | | Outage Information | | Costs | | | | Emissions | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installation | Earliest In-Service Date | Average Capacity | Design Plant Life | Annual Heat Rate | Maint. Outage | Equivalent Forced Outage | Low Estimate Capital Cost | High Estimate Capital Cost | Var. O&M | Fixed O&M | SO2 | NOx | Hg | CO2 |
| Description | Location | Mid-Year | (MW) | in Years | BTU/kWh | Rate | Rate (EFOR) | ($/kW) | ($/kW) | ($/MWh) | ($/kw-yr) | lbs/MMBTU | lbs/MMBTU | lbs/Tbtu | lbs/MMBTU |
| **East Side Options (4500')** | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | |
| Utah PC without Carbon Capture & Sequestration | Utah | 2020 | 600 | 40 | 9,106 | 5% | 4% | 2,788 | 3,521 | $ 0.96 | $ 38.80 | 0.100 | 0.070 | 0.40 | 205.35 |
| Utah PC with Carbon Capture & Sequestration | Utah | 2025 | 526 | 40 | 13,087 | 5% | 5% | 5,040 | 6,367 | $ 6.71 | $ 66.07 | 0.050 | 0.020 | 0.20 | 20.54 |
| Utah IGCC with Carbon Capture & Sequestration | Utah | 2025 | 466 | 40 | 10,823 | 7% | 8% | 4,880 | 6,164 | $ 11.28 | $ 53.24 | 0.050 | 0.011 | 0.04 | 20.54 |
| Wyoming PC without Carbon Capture & Sequestration | Wyoming | 2020 | 790 | 40 | 9,214 | 5% | 4% | 3,156 | 3,987 | $ 1.27 | $ 36.00 | 0.100 | 0.070 | 0.60 | 205.35 |
| Wyoming PC with Carbon Capture & Sequestration | Wyoming | 2025 | 692 | 40 | 13,242 | 5% | 5% | 5,707 | 7,209 | $ 7.26 | $ 61.37 | 0.050 | 0.020 | 0.30 | 20.54 |
| Wyoming IGCC with Carbon Capture & Sequestration | Wyoming | 2025 | 456 | 40 | 11,047 | 7% | 8% | 5,525 | 6,979 | $ 13.52 | $ 58.00 | 0.050 | 0.011 | 0.06 | 20.54 |
| Existing PC with Carbon Capture & Sequestration (500 MW) | Utah/Wyo | 2025 | (139) | 20 | 14,372 | 5% | 5% | 1,253 | 1,583 | $ 6.71 | $ 66.07 | 0.050 | 0.011 | 0.30 | 20.54 |
| **Natural Gas** | | | | | | | | | | | | | | | |
| Utility Cogeneration | Utah | 2011 | 10 | 25 | 4,974 | 10% | 8% | 4,822 | 6,091 | $ 23.29 | $ 1.86 | - | - | 0.26 | 118.00 |
| Fuel Cell - Large | Utah | 2013 | 5 | 25 | 7,262 | 2% | 3% | 1,704 | 2,153 | $ 0.03 | $ 8.40 | 0.001 | - | 0.26 | 118.00 |
| SCCT Aero | Utah | 2012 | 118 | 30 | 9,773 | 4% | 3% | 1,070 | 1,351 | $ 5.63 | $ 9.95 | 0.001 | 0.011 | 0.26 | 118.00 |
| Intercooled Aero SCCT | Utah | 2012 | 174 | 30 | 9,402 | 4% | 3% | 999 | 1,262 | $ 2.71 | $ 4.04 | 0.001 | 0.011 | 0.26 | 118.00 |
| Intercooled Aero SCCT | Utah | 2012 | 261 | 30 | 9,402 | 4% | 3% | 999 | 1,262 | $ 2.71 | $ 4.04 | 0.001 | 0.011 | 0.26 | 118.00 |
| Intercooled Aero SCCT | Wyoming | 2012 | 241 | 30 | 9,402 | 4% | 3% | 1,083 | 1,368 | $ 2.94 | $ 4.39 | 0.001 | 0.011 | 0.26 | 118.00 |
| Internal Combustion Engines | Utah | 2009 | 153 | 30 | 8,500 | 5% | 1% | 1,258 | 1,589 | $ 5.20 | $ 12.80 | 0.001 | 0.017 | 0.26 | 118.00 |
| SCCT Frame (2 Frame "F") | Utah | 2012 | 302 | 35 | 11,659 | 4% | 3% | 710 | 897 | $ 4.47 | $ 3.74 | 0.001 | 0.050 | 0.26 | 118.00 |
| SCCT Frame (2 Frame "F") | Wyoming | 2009 | 275 | 35 | 11,659 | 4% | 3% | 770 | 972 | $ 4.85 | $ 4.05 | 0.001 | 0.050 | 0.26 | 118.00 |
| CCCT (Wet "F" 1x1) | Utah | 2013 | 222 | 40 | 7,302 | 4% | 3% | 1,298 | 1,640 | $ 2.94 | $ 12.79 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Wet "F" 1x1) | Utah | 2013 | 50 | 40 | 8,869 | 4% | 3% | 530 | 669 | $ 0.39 | $ 1.60 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT (Wet "F" 2x1) | Utah | 2013 | 506 | 40 | 7,098 | 4% | 3% | 1,182 | 1,493 | $ 2.94 | $ 7.77 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Wet "F" 2x1) | Utah | 2013 | 64 | 40 | 8,557 | 4% | 3% | 596 | 753 | $ 0.39 | $ 1.60 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT (Dry "F" 2x1) | Utah | 2017 | 438 | 40 | 7,368 | 4% | 3% | 1,212 | 1,530 | $ 3.35 | $ 9.69 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Dry "F" 2x1) | Utah | 2017 | 98 | 40 | 8,950 | 4% | 3% | 611 | 772 | $ 0.11 | $ 1.60 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT (Wet "G" 1x1) | Utah | 2013 | 333 | 40 | 6,884 | 4% | 3% | 1,227 | 1,550 | $ 4.56 | $ 6.75 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Wet "G" 1x1) | Utah | 2013 | 72 | 40 | 9,021 | 4% | 3% | 520 | 656 | $ 0.36 | $ 1.63 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Advanced (Wet) | Utah | 2018 | 400 | 40 | 6,760 | 4% | 3% | 1,355 | 1,712 | $ 4.56 | $ 6.75 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Advanced Duct Firing (Wet) | Utah | 2018 | 75 | 40 | 9,021 | 4% | 3% | 665 | 840 | $ 0.36 | $ 1.63 | 0.001 | 0.011 | 0.26 | 118.00 |
| **Other - Renewables** | | | | | | | | | | | | | | | |
| East (Wyoming) Wind (35% CF) | Wyoming | 2010 | 100 | 25 | n/a | n/a | n/a | 2,215 | 2,954 | - | $ 31.43 | - | - | - | - |
| East Side Geothermal (Blundell) | Utah | 2013 | 35 | 40 | n/a | 5% | 5% | 5,782 | 7,304 | $ 5.94 | $ 110.85 | - | - | - | - |
| East Side Geothermal (Green Field) | Utah | 2013 | 35 | 40 | n/a | 5% | 5% | 5,782 | 7,304 | $ 5.94 | $ 110.85 | - | - | - | - |
| Battery Storage | Utah | 2014 | 5 | 30 | 12,000 | 2% | 5% | 1,980 | 2,501 | $ 10.00 | $ 1.00 | 0.100 | 0.400 | 3.00 | 205.35 |
| Pumped Storage | Nevada | 2018 | 350 | 50 | 13,000 | 5% | 5% | 1,684 | 2,127 | $ 4.30 | $ 4.30 | 0.100 | 0.400 | 3.00 | 205.35 |
| Compressed Air Energy Storage (CAES) | Wyoming | 2015 | 350 | 30 | 11,980 | 4% | 3% | 1,483 | 1,873 | $ 5.50 | $ 3.80 | 0.001 | 0.011 | 0.26 | 118.00 |
| Recovered Energy Generation (CHP) | Utah/ Wyoming | 2011 | 12 | 30 | - | 8% | 8% | 5,500 | 5,500 | - | $ 91.92 | - | - | - | - |
| Nuclear | Utah | 2025 | 1,600 | 40 | 10,710 | 7% | 8% | 5,188 | 6,553 | $ 1.63 | $ 146.70 | - | - | - | - |
| Solar Concentrating (PV) - 30% CF | Utah | 2015 | 10 | 20 | n/a | n/a | n/a | 6,194 | 7,824 | - | $ 180.00 | - | - | - | - |
| Solar Concentrating (natural gas backup) - 25% solar | Utah | 2015 | 250 | 20 | n/a | n/a | n/a | 3,943 | 4,980 | - | $ 195.60 | - | - | - | - |
| Solar Concentrating (thermal storage) - 30% solar | Utah | 2012 | 250 | 30 | n/a | n/a | n/a | 4,418 | 5,580 | - | $ 139.50 | - | - | - | - |

# Table 6.3 – West Side Supply-Side Resource Options

| | Location / Timing | | Plant Details | | | Outage Information | | Costs | | | | Emissions | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Description | Installation Location | Earliest In-Service Date Mid-Year | Average Capacity (MW) | Design Plant Life in Years | Annual Heat Rate BTU/kWh | Maint. Outage Rate | Equivalent Forced Outage Rate (EFOR) | Low Estimate Capital Cost ($/kW) | High Estimate Capital Cost ($/kW) | Var. O&M ($/MWh) | Fixed O&M ($/kw-yr) | SO2 lbs/MMBTU | NOx lbs/MMBTU | Hg lbs/Tbtu | CO2 lbs/MMBTU |
| **West Side Options (1500')** | | | | | | | | | | | | | | | |
| **Natural Gas** | | | | | | | | | | | | | | | |
| Fuel Cell - Large | Northwest | 2013 | 5 | 25 | 7,262 | 2% | 3% | 1,704 | 2,153 | $ 0.03 | $ 8.40 | 0.001 | - | 0.26 | 118.00 |
| SCCT Aero | Northwest | 2012 | 129.56 | 30 | 9,773 | 4% | 3% | 972 | 1,228 | $ 5.12 | $ 9.04 | 0.001 | 0.011 | 0.26 | 118.00 |
| Intercooled Aero SCCT | Northwest | 2012 | 287 | 30 | 9,402 | 4% | 3% | 908 | 1,147 | $ 2.46 | $ 3.68 | 0.001 | 0.011 | 0.26 | 118.00 |
| Internal Combustion Engines | Northwest | 2012 | 168 | 30 | 8,500 | 5% | 1% | 1,143 | 1,444 | $ 5.20 | $ 12.80 | 0.001 | 0.017 | 0.26 | 118.00 |
| SCCT Frame (2 Frame "F") | Northwest | 2009 | 338 | 35 | 11,659 | 4% | 3% | 645 | 815 | $ 4.07 | $ 3.40 | 0.001 | 0.050 | 0.26 | 118.00 |
| CCCT (Wet "F" 1x1) | Northwest | 2013 | 244 | 40 | 7,302 | 4% | 3% | 1,180 | 1,491 | $ 2.67 | $ 11.62 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Wet "F" 1x1) | Northwest | 2013 | 55 | 40 | 8,869 | 4% | 3% | 482 | 608 | $ 0.36 | $ 1.45 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT (Wet "F" 2x1) | Northwest | 2013 | 557 | 40 | 7,098 | 4% | 3% | 1,074 | 1,357 | $ 2.67 | $ 7.07 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Wet "F" 2x1) | Northwest | 2013 | 70 | 40 | 8,557 | 4% | 3% | 542 | 685 | $ 0.36 | $ 1.45 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT (Wet "G" 1x1) | Northwest | 2013 | 367 | 40 | 6,884 | 4% | 3% | 1,116 | 1,409 | $ 4.14 | $ 6.13 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Wet "G" 1x1) | Northwest | 2013 | 80 | 40 | 9,021 | 4% | 3% | 472 | 597 | $ 0.33 | $ 1.48 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Advanced (Wet) | Northwest | 2018 | 440 | 40 | 6,760 | 4% | 3% | 1,232 | 1,556 | $ 4.14 | $ 6.13 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Advanced Duct Firing (Wet) | Northwest | 2018 | 83 | 40 | 9,021 | 4% | 3% | 605 | 764 | $ 0.33 | $ 1.48 | 0.001 | 0.011 | 0.26 | 118.00 |
| **Other - Renewables** | | | | | | | | | | | | | | | |
| West Wind | Northwest | 2010 | 50 | 25 | n/a | n/a | n/a | 2,350 | 3,134 | - | $ 31.43 | - | - | - | - |
| Biomass | Northwest | 2015 | 50 | 30 | 10,979 | 5% | 4% | 3,179 | 4,016 | $ 0.96 | $ 38.80 | 0.100 | 0.350 | 0.40 | 205.39 |
| West Side Geothermal (Green Field) | Northwest | 2013 | 35 | 40 | n/a | 5% | 5% | 5,782 | 7,304 | $ 5.94 | $ 110.85 | - | - | - | - |
| Compressed Air Energy Storage (CAES) | Northwest | 2015 | 385 | 30 | 11,980 | 4% | 3% | 1,483 | 1,873 | $ 5.00 | $ 3.45 | 0.001 | 0.011 | 0.26 | 118.00 |
| Hydrokinetic (Wave) - 21% CF | Northwest | 2015 | 100 | 20 | n/a | n/a | n/a | 5,700 | 7,200 | - | $ 180.00 | - | - | - | - |
| **West Side Options (Sea Level)** | | | | | | | | | | | | | | | |
| **Natural Gas** | | | | | | | | | | | | | | | |
| Fuel Cell - Large | Northwest | 2013 | 5 | 25 | 7,262 | 2% | 3% | 1,704 | 2,153 | $ 0.03 | $ 8.40 | 0.001 | - | 0.26 | 118.00 |
| SCCT Aero | Northwest | 2012 | 136 | 30 | 9,773 | 2% | 3% | 924 | 1,167 | $ 4.87 | $ 8.59 | 0.001 | 0.011 | 0.26 | 118.00 |
| Intercooled Aero SCCT | Northwest | 2012 | 302 | 30 | 9,402 | 4% | 3% | 863 | 1,090 | $ 2.35 | $ 3.49 | 0.001 | 0.011 | 0.26 | 118.00 |
| Internal Combustion Engines | Northwest | 2012 | 177 | 30 | 8,500 | 4% | 1% | 1,086 | 1,372 | $ 5.20 | $ 12.80 | 0.001 | 0.017 | 0.26 | 118.00 |
| SCCT Frame (2 Frame "F") | Northwest | 2012 | 356 | 35 | 11,659 | 5% | 3% | 613 | 774 | $ 3.87 | $ 3.23 | 0.001 | 0.050 | 0.26 | 118.00 |
| CCCT (Wet "F" 1x1) | Northwest | 2013 | 256.82 | 40 | 7,302 | 4% | 3% | 1,121 | 1,416 | $ 2.55 | $ 11.07 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Wet "F" 1x1) | Northwest | 2013 | 58 | 40 | 8,869 | 4% | 3% | 458 | 578 | $ 0.34 | $ 1.38 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT (Wet "F" 2x1) | Northwest | 2013 | 586 | 40 | 7,098 | 4% | 3% | 1,020 | 1,289 | $ 2.55 | $ 6.73 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Wet "F" 2x1) | Northwest | 2013 | 74 | 40 | 8,557 | 4% | 3% | 515 | 650 | $ 0.34 | $ 1.38 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT (Wet "G" 1x1) | Northwest | 2013 | 386 | 40 | 6,884 | 4% | 3% | 1,060 | 1,339 | $ 3.94 | $ 5.84 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Duct Firing (Wet "G" 1x1) | Northwest | 2010 | 84 | 40 | 9,021 | 4% | 3% | 449 | 567 | $ 0.31 | $ 1.41 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Advanced (Wet) | Northwest | 2018 | 463 | 40 | 6,760 | 4% | 3% | 1,170 | 1,479 | $ 3.94 | $ 5.84 | 0.001 | 0.011 | 0.26 | 118.00 |
| CCCT Advanced Duct Firing (Wet) | Northwest | 2018 | 87 | 40 | 9,021 | 4% | 3% | 574 | 725 | $ 0.31 | $ 1.41 | 0.001 | 0.011 | 0.26 | 119.00 |

# Table 6.4 – Total Resource Cost for East Side Supply-Side Resource Options, \$8 $CO_2$ Tax

| Description | Capital Cost \$/kW: Total Capital Cost | Capital Cost \$/kW: Payment Factor | Capital Cost \$/kW: Annual Payment (\$/kW-Yr) | Fixed Cost: Fixed O&M \$/kW-Yr: O&M | Fixed Cost: Fixed O&M \$/kW-Yr: Other | Fixed Cost: Fixed O&M \$/kW-Yr: Total | Fixed Cost: Total Fixed (\$/kW-Yr) | Convert to Mills: Capacity Factor | Convert to Mills: Total Fixed Mills/kWh | Convert to Mills: Levelized Fuel ¢/mmBtu | Convert to Mills: Levelized Fuel Mills/kWh | Variable Costs mills/kWh: O&M | Variable Costs mills/kWh: Gas Transportation/ Wind Integration | Variable Costs mills/kWh: Tax Credits | Variable Costs mills/kWh: Environmental | Total Resource Cost (Mills/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **East Side Options (4500')** | | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | | |
| Utah PC without Carbon Capture & Sequestration | 2,934 | 8.40% | \$ 246.57 | \$ 38.80 | \$ 6.00 | \$ 44.80 | \$ 291.37 | 91% | 36.39 | 216.23 | 19.69 | \$ 0.96 | - | - | 5.10 | 62.14 |
| Utah PC with Carbon Capture & Sequestration | 5,306 | 8.25% | \$ 437.60 | \$ 66.07 | \$ 6.00 | \$ 72.07 | \$ 509.68 | 90% | 64.65 | 216.23 | 28.30 | \$ 6.71 | - | - | 0.78 | 100.43 |
| Utah IGCC with Carbon Capture & Sequestration | 5,136 | 8.01% | \$ 411.32 | \$ 53.24 | \$ 6.00 | \$ 59.24 | \$ 470.56 | 85% | 63.20 | 216.23 | 23.40 | \$ 11.28 | - | - | 0.64 | 98.52 |
| Wyoming PC without Carbon Capture & Sequestration | 3,322 | 8.40% | \$ 279.19 | \$ 36.00 | \$ 6.00 | \$ 42.00 | \$ 321.19 | 91% | 40.12 | 238.45 | 21.97 | \$ 1.27 | - | - | 5.16 | 68.52 |
| Wyoming PC with Carbon Capture & Sequestration | 6,007 | 8.25% | \$ 495.50 | \$ 61.37 | \$ 6.00 | \$ 67.37 | \$ 562.86 | 90% | 71.39 | 238.45 | 31.58 | \$ 7.26 | - | - | 0.79 | 111.02 |
| Wyoming IGCC with Carbon Capture & Sequestration | 5,816 | 8.01% | \$ 465.74 | \$ 58.00 | \$ 6.00 | \$ 64.00 | \$ 529.74 | 85% | 71.14 | 238.45 | 26.34 | \$ 13.52 | - | - | 0.66 | 111.66 |
| Existing PC with Carbon Capture & Sequestration (500 MW) | 1,319 | 10.71% | \$ 141.23 | \$ 66.07 | \$ 6.00 | \$ 72.07 | \$ 213.30 | 90% | 27.05 | 238.45 | 34.27 | \$ 6.71 | - | - | 0.86 | 68.89 |
| **Natural Gas** | | | | | | | | | | | | | | | | |
| Utility Cogeneration | 5,076 | 10.12% | \$ 513.46 | \$ 1.86 | \$ 0.50 | \$ 2.36 | \$ 515.82 | 82% | 71.81 | 699.22 | 34.78 | \$ 23.29 | 4.17 | - | 1.58 | 135.63 |
| Fuel Cell - Large | 1,794 | 8.72% | \$ 156.34 | \$ 8.40 | \$ 0.50 | \$ 8.90 | \$ 165.24 | 95% | 19.86 | 699.22 | 50.78 | \$ 0.03 | 6.09 | - | 2.30 | 79.06 |
| SCCT Aero | 1,126 | 9.08% | \$ 102.21 | \$ 9.95 | \$ 0.50 | \$ 10.45 | \$ 112.66 | 21% | 61.24 | 699.22 | 68.34 | \$ 5.63 | 8.20 | - | 3.10 | 146.51 |
| Intercooled Aero SCCT (Utah, 174MW) | 1,052 | 9.08% | \$ 95.45 | \$ 4.04 | \$ 0.50 | \$ 4.54 | \$ 99.99 | 21% | 54.36 | 699.22 | 65.74 | \$ 2.71 | 7.89 | - | 2.98 | 133.68 |
| Intercooled Aero SCCT (Utah, 261MW) | 1,052 | 9.08% | \$ 95.45 | \$ 4.04 | \$ 0.50 | \$ 4.54 | \$ 99.99 | 21% | 54.36 | 699.22 | 65.74 | \$ 2.71 | 7.89 | - | 2.98 | 133.68 |
| Intercooled Aero SCCT (Wyoming, 241MW) | 1,140 | 9.08% | \$ 103.50 | \$ 4.39 | \$ 0.50 | \$ 4.89 | \$ 108.38 | 21% | 58.92 | 699.22 | 65.74 | \$ 2.94 | 6.83 | - | 2.98 | 137.41 |
| Internal Combustion Engines | 1,324 | 9.08% | \$ 120.18 | \$ 12.80 | \$ 0.50 | \$ 13.30 | \$ 133.48 | 94% | 16.21 | 699.22 | 59.43 | \$ 5.20 | 7.13 | - | 2.70 | 90.67 |
| SCCT Frame (2 Frame "F") | 747 | 8.62% | \$ 64.39 | \$ 3.74 | \$ 0.50 | \$ 4.24 | \$ 68.62 | 21% | 37.30 | 699.22 | 81.53 | \$ 4.47 | 9.78 | - | 3.70 | 136.78 |
| SCCT Frame (2 Frame "F") | 810 | 8.62% | \$ 69.82 | \$ 4.05 | \$ 0.50 | \$ 4.55 | \$ 74.37 | 21% | 40.43 | 699.22 | 81.53 | \$ 4.85 | 8.47 | - | 3.70 | 138.97 |
| CCCT (Wet "F" 1x1) | 1,366 | 8.59% | \$ 117.32 | \$ 12.79 | \$ 0.50 | \$ 13.29 | \$ 130.61 | 56% | 26.62 | 699.22 | 51.06 | \$ 2.94 | 6.13 | - | 2.32 | 89.07 |
| CCCT Duct Firing (Wet "F" 1x1) | 558 | 8.59% | \$ 47.88 | \$ 1.60 | \$ 0.50 | \$ 2.10 | \$ 49.98 | 16% | 35.66 | 699.22 | 62.01 | \$ 0.39 | 7.44 | - | 2.81 | 108.32 |
| CCCT (Wet "F" 2x1) | 1,244 | 8.59% | \$ 106.79 | \$ 7.77 | \$ 0.50 | \$ 8.27 | \$ 115.06 | 56% | 23.46 | 699.22 | 49.63 | \$ 2.94 | 5.96 | - | 2.25 | 84.24 |
| CCCT Duct Firing (Wet "F" 2x1) | 628 | 8.59% | \$ 53.88 | \$ 1.60 | \$ 0.50 | \$ 2.10 | \$ 55.98 | 16% | 39.94 | 699.22 | 59.84 | \$ 0.39 | 7.18 | - | 2.71 | 110.06 |
| CCCT (Dry "F" 2x1) | 1,275 | 8.59% | \$ 109.50 | \$ 9.69 | \$ 0.50 | \$ 10.19 | \$ 119.70 | 56% | 24.40 | 699.22 | 51.52 | \$ 3.35 | 6.18 | - | 2.34 | 87.79 |
| CCCT Duct Firing (Dry "F" 2x1) | 644 | 8.59% | \$ 55.25 | \$ 1.60 | \$ 0.50 | \$ 2.10 | \$ 57.35 | 16% | 40.91 | 699.22 | 62.58 | \$ 0.11 | 7.51 | - | 2.84 | 113.95 |
| CCCT (Wet "G" 1x1) | 1,292 | 8.59% | \$ 110.93 | \$ 6.75 | \$ 0.50 | \$ 7.25 | \$ 118.18 | 56% | 24.09 | 699.22 | 48.14 | \$ 4.56 | 5.78 | - | 2.18 | 84.74 |
| CCCT Duct Firing (Wet "G" 1x1) | 547 | 8.59% | \$ 46.96 | \$ 1.63 | \$ 0.50 | \$ 2.13 | \$ 49.09 | 16% | 35.03 | 699.22 | 63.08 | \$ 0.36 | 7.57 | - | 2.86 | 108.89 |
| CCCT Advanced (Wet) | 1,427 | 8.59% | \$ 122.49 | \$ 6.75 | \$ 0.50 | \$ 7.25 | \$ 129.74 | 56% | 26.45 | 699.22 | 47.27 | \$ 4.56 | 5.67 | - | 2.14 | 86.08 |
| CCCT Advanced Duct Firing (Wet) | 700 | 8.59% | \$ 60.10 | \$ 1.63 | \$ 0.50 | \$ 2.13 | \$ 62.24 | 16% | 44.40 | 699.22 | 63.08 | \$ 0.36 | 7.57 | - | 2.86 | 118.27 |
| **Other - Renewables** | | | | | | | | | | | | | | | | |
| East (Wyoming) Wind (35% CF) | 2,566 | 8.72% | \$ 223.58 | \$ 31.43 | \$ 0.50 | \$ 31.93 | \$ 255.51 | 35% | 83.34 | - | - | - | 11.75 | (20.70) | - | 74.38 |
| East Side Geothermal (Blundell) | 6,087 | 7.42% | \$ 451.64 | \$ 110.85 | \$ 0.50 | \$ 111.35 | \$ 562.99 | 90% | 71.41 | - | - | \$ 5.94 | | (20.70) | - | 56.64 |
| East Side Geothermal (Green Field) | 7,608 | 7.42% | \$ 564.55 | \$ 221.70 | \$ 0.50 | \$ 222.20 | \$ 786.74 | 90% | 99.79 | - | - | \$ 11.88 | | (20.70) | - | 90.97 |
| Battery Storage | 2,084 | 8.29% | \$ 172.77 | \$ 1.00 | \$ 0.50 | \$ 1.50 | \$ 174.27 | 21% | 94.73 | 699.22 | 83.91 | \$ 10.00 | 10.07 | - | 6.73 | 205.43 |
| Pumped Storage | 1,773 | 8.19% | \$ 145.14 | \$ 4.30 | \$ 1.35 | \$ 5.65 | \$ 150.79 | 20% | 86.06 | 699.22 | 90.90 | \$ 4.30 | 10.91 | - | 7.29 | 199.46 |
| Compressed Air Energy Storage (CAES) | 1,561 | 8.29% | \$ 129.41 | \$ 3.80 | \$ 1.35 | \$ 5.15 | \$ 134.56 | 47% | 32.89 | 699.22 | 83.77 | \$ 5.50 | 8.70 | - | 3.80 | 134.66 |
| Recovered Energy Generation (CHP) | 5,500 | 9.39% | \$ 516.67 | \$ 91.92 | - | \$ 91.92 | \$ 608.59 | 84% | 82.71 | - | - | - | - | - | - | 82.71 |
| Nuclear | 5,461 | 8.30% | \$ 453.26 | \$ 146.70 | \$ 6.00 | \$ 152.70 | \$ 605.95 | 85% | 81.38 | 113.98 | 12.21 | \$ 1.63 | - | - | - | 95.22 |
| Solar Concentrating (PV) - 30% CF | 6,520 | 6.48% | \$ 422.43 | \$ 180.00 | \$ 6.00 | \$ 186.00 | \$ 608.43 | 30% | 231.52 | - | - | - | - | (1.59) | - | 229.93 |
| Solar Concentrating (natural gas backup) - 25% solar | 4,150 | 6.48% | \$ 268.88 | \$ 195.60 | \$ 6.00 | \$ 201.60 | \$ 470.48 | 33% | 162.75 | 699.22 | 18.96 | - | 2.28 | (1.59) | 0.86 | 183.26 |
| Solar Concentrating (thermal storage) - 30% solar | 4,650 | 5.46% | \$ 253.80 | \$ 139.50 | \$ 6.00 | \$ 145.50 | \$ 399.30 | 30% | 151.94 | - | - | - | - | (1.59) | - | 150.35 |

# Table 6.5 – Total Resource Cost for West Side Supply-Side Resource Options, \$8 $CO_2$ Tax

| Description | Capital Cost \$/kW<br>Total Capital Cost | Capital Cost \$/kW<br>Payment Factor | Capital Cost \$/kW<br>Annual Payment (\$/kW-Yr) | Fixed Cost<br>Fixed O&M \$/kW-Yr<br>O&M | Fixed Cost<br>Fixed O&M \$/kW-Yr<br>Other | Fixed Cost<br>Fixed O&M \$/kW-Yr<br>Total | Fixed Cost<br>Total Fixed (\$/kW-Yr) | Convert to Mills<br>Capacity Factor | Convert to Mills<br>Total Fixed Mills/kWh | Convert to Mills<br>Levelized Fuel ¢/mmBtu | Convert to Mills<br>Levelized Fuel Mills/kWh | Variable Costs mills/kWh<br>O&M | Variable Costs mills/kWh<br>Gas Transportation/ Wind Integration | Variable Costs mills/kWh<br>Tax Credits | Variable Costs mills/kWh<br>Environmental | Total Resource Cost (Mills/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **West Side Options (1500')** | | | | | | | | | | | | | | | | |
| **Natural Gas** | | | | | | | | | | | | | | | | |
| Fuel Cell - Large | 1,794 | 8.72% | \$ 156.34 | \$ 8.40 | \$ 0.50 | \$ 8.90 | \$ 165.24 | 95% | 19.86 | 814.00 | 59.11 | \$ 0.03 | 5.33 | - | 2.30 | 86.63 |
| SCCT Aero | 1,024 | 9.08% | \$ 92.92 | \$ 9.04 | \$ 0.50 | \$ 9.54 | \$ 102.46 | 21% | 55.70 | 814.00 | 79.55 | \$ 5.12 | 7.17 | - | 3.10 | 150.64 |
| Intercooled Aero SCCT | 956 | 9.08% | \$ 86.77 | \$ 3.68 | \$ 0.50 | \$ 4.18 | \$ 90.95 | 21% | 49.44 | 814.00 | 76.53 | \$ 2.46 | 6.90 | - | 2.98 | 138.32 |
| Internal Combustion Engines | 1,204 | 9.08% | \$ 109.25 | \$ 12.80 | \$ 0.50 | \$ 13.30 | \$ 122.55 | 94% | 14.88 | 814.00 | 69.19 | \$ 5.20 | 6.24 | - | 2.70 | 98.20 |
| SCCT Frame (2 Frame "F") | 679 | 8.62% | \$ 58.53 | \$ 3.40 | \$ 0.50 | \$ 3.90 | \$ 62.43 | 21% | 33.94 | 814.00 | 94.91 | \$ 4.07 | 8.56 | - | 3.70 | 145.16 |
| CCCT (Wet "F" 1x1) | 1,242 | 8.59% | \$ 106.66 | \$ 11.62 | \$ 0.50 | \$ 12.12 | \$ 118.78 | 56% | 24.21 | 814.00 | 59.44 | \$ 2.67 | 5.36 | - | 2.32 | 94.00 |
| CCCT Duct Firing (Wet "F" 1x1) | 507 | 8.59% | \$ 43.53 | \$ 1.45 | \$ 0.50 | \$ 1.95 | \$ 45.48 | 16% | 32.45 | 814.00 | 72.19 | \$ 0.36 | 6.51 | - | 2.81 | 114.32 |
| CCCT (Wet "F" 2x1) | 1,131 | 8.59% | \$ 97.08 | \$ 7.07 | \$ 0.50 | \$ 7.57 | \$ 104.65 | 56% | 21.33 | 814.00 | 57.78 | \$ 2.67 | 5.21 | - | 2.25 | 89.25 |
| CCCT Duct Firing (Wet "F" 2x1) | 570 | 8.59% | \$ 48.98 | \$ 1.45 | \$ 0.50 | \$ 1.95 | \$ 50.93 | 16% | 36.34 | 814.00 | 69.66 | \$ 0.36 | 6.28 | - | 2.71 | 115.35 |
| CCCT (Wet "G" 1x1) | 1,175 | 8.59% | \$ 100.85 | \$ 6.13 | \$ 0.50 | \$ 6.63 | \$ 107.48 | 56% | 21.91 | 814.00 | 56.04 | \$ 4.14 | 5.05 | - | 2.18 | 89.32 |
| CCCT Duct Firing (Wet "G" 1x1) | 497 | 8.59% | \$ 42.69 | \$ 1.48 | \$ 0.50 | \$ 1.98 | \$ 44.68 | 16% | 31.88 | 814.00 | 73.43 | \$ 0.33 | 6.62 | - | 2.86 | 115.12 |
| CCCT Advanced (Wet) | 1,297 | 8.59% | \$ 111.36 | \$ 6.13 | \$ 0.50 | \$ 6.63 | \$ 117.99 | 56% | 24.05 | 814.00 | 55.02 | \$ 4.14 | 4.96 | - | 2.14 | 90.32 |
| CCCT Advanced Duct Firing (Wet) | 636 | 8.59% | \$ 54.64 | \$ 1.48 | \$ 0.50 | \$ 1.98 | \$ 56.62 | 16% | 40.40 | 814.00 | 73.43 | \$ 0.33 | 6.62 | - | 2.86 | 123.64 |
| **Other - Renewables** | | | | | | | | | | | | | | | | |
| West Wind | 2,612 | 8.72% | \$ 227.59 | \$ 31.43 | \$ 27.74 | \$ 59.17 | \$ 286.76 | 29% | 112.88 | - | - | - | 11.75 | (20.70) | - | 103.93 |
| Biomass | 3,347 | 8.10% | \$ 271.22 | \$ 38.80 | \$ 0.50 | \$ 39.30 | \$ 310.52 | 91% | 38.78 | 590.00 | 64.78 | \$ 0.96 | - | (20.70) | 6.15 | 89.97 |
| West Side Geothermal (Green Field) | 7,609 | 7.42% | \$ 564.62 | \$ 221.70 | \$ 0.50 | \$ 222.20 | \$ 786.82 | 90% | 99.80 | - | - | \$ 11.88 | - | (20.70) | - | 90.98 |
| Compressed Air Energy Storage (CAES) | 1,561 | 8.29% | \$ 129.41 | \$ 3.45 | \$ 1.35 | \$ 4.80 | \$ 134.21 | 47% | 32.81 | 814.00 | 97.52 | \$ 5.00 | 8.79 | - | 3.80 | 147.91 |
| Hydrokinetic (Wave) - 21% CF | 6,000 | 9.69% | \$ 581.58 | \$ 180.00 | \$ 6.00 | \$ 186.00 | \$ 767.58 | 21% | 417.25 | - | - | - | - | - | - | 417.25 |
| **West Side Options (Sea Level)** | | | | | | | | | | | | | | | | |
| **Natural Gas** | | | | | | | | | | | | | | | | |
| Fuel Cell - Large | 1,794 | 8.72% | \$ 156.34 | \$ 8.40 | \$ 0.50 | \$ 8.90 | \$ 165.24 | 95% | 19.86 | 814.00 | 59.11 | \$ 0.03 | 5.33 | - | 2.30 | 86.63 |
| SCCT Aero | 972 | 9.08% | \$ 88.27 | \$ 8.59 | \$ 0.50 | \$ 9.09 | \$ 97.36 | 21% | 52.93 | 814.00 | 79.55 | \$ 4.87 | 7.17 | - | 3.10 | 147.63 |
| Intercooled Aero SCCT | 908 | 9.08% | \$ 82.43 | \$ 3.49 | \$ 0.50 | \$ 3.99 | \$ 86.43 | 21% | 46.98 | 814.00 | 76.53 | \$ 2.35 | 6.90 | - | 2.98 | 135.74 |
| Internal Combustion Engines | 1,143 | 9.08% | \$ 103.79 | \$ 12.80 | \$ 0.50 | \$ 13.30 | \$ 117.09 | 94% | 14.22 | 814.00 | 69.19 | \$ 5.20 | 6.24 | - | 2.70 | 97.54 |
| SCCT Frame (2 Frame "F") | 645 | 8.62% | \$ 55.61 | \$ 3.23 | \$ 0.50 | \$ 3.73 | \$ 59.34 | 21% | 32.26 | 814.00 | 94.91 | \$ 3.87 | 8.56 | - | 3.70 | 143.29 |
| CCCT (Wet "F" 1x1) | 1,180 | 8.59% | \$ 101.32 | \$ 11.07 | \$ 0.50 | \$ 11.57 | \$ 112.89 | 56% | 23.01 | 814.00 | 59.44 | \$ 2.55 | 5.36 | - | 2.32 | 92.67 |
| CCCT Duct Firing (Wet "F" 1x1) | 482 | 8.59% | \$ 41.35 | \$ 1.38 | \$ 0.50 | \$ 1.88 | \$ 43.23 | 16% | 30.85 | 814.00 | 72.19 | \$ 0.34 | 6.51 | - | 2.81 | 112.70 |
| CCCT (Wet "F" 2x1) | 1,074 | 8.59% | \$ 92.23 | \$ 6.73 | \$ 0.50 | \$ 7.23 | \$ 99.46 | 56% | 20.27 | 814.00 | 57.78 | \$ 2.55 | 5.21 | - | 2.25 | 88.06 |
| CCCT Duct Firing (Wet "F" 2x1) | 542 | 8.59% | \$ 46.53 | \$ 1.38 | \$ 0.50 | \$ 1.88 | \$ 48.42 | 16% | 34.54 | 814.00 | 69.66 | \$ 0.34 | 6.28 | - | 2.71 | 113.53 |
| CCCT (Wet "G" 1x1) | 1,116 | 8.59% | \$ 95.81 | \$ 5.84 | \$ 0.50 | \$ 6.34 | \$ 102.15 | 56% | 20.82 | 814.00 | 56.04 | \$ 3.94 | 5.05 | - | 2.18 | 88.04 |
| CCCT Duct Firing (Wet "G" 1x1) | 472 | 8.59% | \$ 40.56 | \$ 1.41 | \$ 0.50 | \$ 1.91 | \$ 42.47 | 16% | 30.30 | 814.00 | 73.43 | \$ 0.31 | 6.62 | - | 2.86 | 113.53 |
| CCCT Advanced (Wet) | 1,232 | 8.59% | \$ 105.79 | \$ 5.84 | \$ 0.50 | \$ 6.34 | \$ 112.13 | 56% | 22.86 | 814.00 | 55.02 | \$ 3.94 | 4.96 | - | 2.14 | 88.93 |
| CCCT Advanced Duct Firing (Wet) | 605 | 8.59% | \$ 51.91 | \$ 1.41 | \$ 0.50 | \$ 1.91 | \$ 53.82 | 16% | 38.40 | 814.00 | 73.43 | \$ 0.31 | 6.62 | - | 2.89 | 121.65 |

# Table 6.6 – Total Resource Cost for East Side Supply-Side Resource Options, \$45 $CO_2$ Tax

| Description | Capital Cost \$/kW: Total Capital Cost | Capital Cost \$/kW: Payment Factor | Capital Cost \$/kW: Annual Payment (\$/kW-Yr) | Fixed Cost: Fixed O&M \$/kW-Yr: O&M | Fixed Cost: Fixed O&M \$/kW-Yr: Other | Fixed Cost: Fixed O&M \$/kW-Yr: Total | Fixed Cost: Total Fixed (\$/kW-Yr) | Convert to Mills: Capacity Factor | Convert to Mills: Total Fixed Mills/kWh | Convert to Mills: Levelized Fuel ¢/mmBtu | Convert to Mills: Levelized Fuel Mills/kWh | Variable Costs mills/kWh: O&M | Variable Costs mills/kWh: Gas Transportation/ Wind Integration | Variable Costs mills/kWh: Tax Credits | Variable Costs mills/kWh: Environmental | Total Resource Cost (Mills/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **East Side Options (4500')** | | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | | |
| Utah PC without Carbon Capture & Sequestration | 2,934 | 8.40% | \$ 246.57 | \$ 38.80 | \$ 6.00 | \$ 44.80 | \$ 291.37 | 91% | 36.39 | 216.23 | 19.69 | \$ 0.96 | - | - | 28.32 | 85.36 |
| Utah PC with Carbon Capture & Sequestration | 5,306 | 8.25% | \$ 437.60 | \$ 66.07 | \$ 6.00 | \$ 72.07 | \$ 509.68 | 90% | 64.65 | 216.23 | 28.30 | \$ 6.71 | - | - | 4.11 | 103.76 |
| Utah IGCC with Carbon Capture & Sequestration | 5,136 | 8.01% | \$ 411.32 | \$ 53.24 | \$ 6.00 | \$ 59.24 | \$ 470.56 | 85% | 63.20 | 216.23 | 23.40 | \$ 11.28 | - | - | 3.40 | 101.28 |
| Wyoming PC without Carbon Capture & Sequestration | 3,322 | 8.40% | \$ 279.19 | \$ 36.00 | \$ 6.00 | \$ 42.00 | \$ 321.19 | 91% | 40.12 | 238.45 | 21.97 | \$ 1.27 | - | - | 28.66 | 92.02 |
| Wyoming PC with Carbon Capture & Sequestration | 6,007 | 8.25% | \$ 495.50 | \$ 61.37 | \$ 6.00 | \$ 67.37 | \$ 562.86 | 90% | 71.39 | 238.45 | 31.58 | \$ 7.26 | - | - | 4.16 | 114.39 |
| Wyoming IGCC with Carbon Capture & Sequestration | 5,816 | 8.01% | \$ 465.74 | \$ 58.00 | \$ 6.00 | \$ 64.00 | \$ 529.74 | 85% | 71.14 | 238.45 | 26.34 | \$ 13.52 | - | - | 3.47 | 114.47 |
| Existing PC with Carbon Capture & Sequestration (500 MW) | 1,319 | 10.71% | \$ 141.23 | \$ 66.07 | \$ 6.00 | \$ 72.07 | \$ 213.30 | 90% | 27.05 | 238.45 | 34.27 | \$ 6.71 | - | - | 4.51 | 72.54 |
| **Natural Gas** | | | | | | | | | | | | | | | | |
| Utility Cogeneration | 5,076 | 10.12% | \$ 513.46 | \$ 1.86 | \$ 0.50 | \$ 2.36 | \$ 515.82 | 82% | 71.81 | 722.19 | 35.92 | \$ 23.29 | 4.17 | - | 8.87 | 144.06 |
| Fuel Cell - Large | 1,794 | 8.72% | \$ 156.34 | \$ 8.40 | \$ 0.50 | \$ 8.90 | \$ 165.24 | 95% | 19.86 | 722.19 | 52.44 | \$ 0.03 | 6.09 | - | 12.95 | 91.37 |
| SCCT Aero | 1,126 | 9.08% | \$ 102.21 | \$ 9.95 | \$ 0.50 | \$ 10.45 | \$ 112.66 | 21% | 61.24 | 722.19 | 70.58 | \$ 5.63 | 8.20 | - | 17.43 | 163.08 |
| Intercooled Aero SCCT (Utah, 174MW) | 1,052 | 9.08% | \$ 95.45 | \$ 4.04 | \$ 0.50 | \$ 4.54 | \$ 99.99 | 21% | 54.36 | 722.19 | 67.90 | \$ 2.71 | 7.89 | - | 16.77 | 149.62 |
| Intercooled Aero SCCT (Utah, 261MW) | 1,052 | 9.08% | \$ 95.45 | \$ 4.04 | \$ 0.50 | \$ 4.54 | \$ 99.99 | 21% | 54.36 | 722.19 | 67.90 | \$ 2.71 | 7.89 | - | 16.77 | 149.62 |
| Intercooled Aero SCCT (Wyoming, 241MW) | 1,140 | 9.08% | \$ 103.50 | \$ 4.39 | \$ 0.50 | \$ 4.89 | \$ 108.38 | 21% | 58.92 | 722.19 | 67.90 | \$ 2.94 | 6.83 | - | 16.77 | 153.36 |
| Internal Combustion Engines | 1,324 | 9.08% | \$ 120.18 | \$ 12.80 | \$ 0.50 | \$ 13.30 | \$ 133.48 | 94% | 16.21 | 722.19 | 61.38 | \$ 5.20 | 7.13 | - | 15.16 | 105.08 |
| SCCT Frame (2 Frame "F") | 747 | 8.62% | \$ 64.39 | \$ 3.74 | \$ 0.50 | \$ 4.24 | \$ 68.62 | 21% | 37.30 | 722.19 | 84.20 | \$ 4.47 | 9.78 | - | 20.79 | 156.55 |
| SCCT Frame (2 Frame "F") | 810 | 8.62% | \$ 69.82 | \$ 4.05 | \$ 0.50 | \$ 4.55 | \$ 74.37 | 21% | 40.43 | 722.19 | 84.20 | \$ 4.85 | 8.47 | - | 20.79 | 158.74 |
| CCCT (Wet "F" 1x1) | 1,366 | 8.59% | \$ 117.32 | \$ 12.79 | \$ 0.50 | \$ 13.29 | \$ 130.61 | 56% | 26.62 | 722.19 | 52.73 | \$ 2.94 | 6.13 | - | 13.02 | 101.45 |
| CCCT Duct Firing (Wet "F" 1x1) | 558 | 8.59% | \$ 47.88 | \$ 1.60 | \$ 0.50 | \$ 2.10 | \$ 49.98 | 16% | 35.66 | 722.19 | 64.05 | \$ 0.39 | 7.44 | - | 15.82 | 123.36 |
| CCCT (Wet "F" 2x1) | 1,244 | 8.59% | \$ 106.79 | \$ 7.77 | \$ 0.50 | \$ 8.27 | \$ 115.06 | 56% | 23.46 | 722.19 | 51.26 | \$ 2.94 | 5.96 | - | 12.66 | 96.27 |
| CCCT Duct Firing (Wet "F" 2x1) | 628 | 8.59% | \$ 53.88 | \$ 1.60 | \$ 0.50 | \$ 2.10 | \$ 55.98 | 16% | 39.94 | 722.19 | 61.80 | \$ 0.39 | 7.18 | - | 15.26 | 124.57 |
| CCCT (Dry "F" 2x1) | 1,275 | 8.59% | \$ 109.50 | \$ 9.69 | \$ 0.50 | \$ 10.19 | \$ 119.70 | 56% | 24.40 | 722.19 | 53.21 | \$ 3.35 | 6.18 | - | 13.14 | 100.28 |
| CCCT Duct Firing (Dry "F" 2x1) | 644 | 8.59% | \$ 55.25 | \$ 1.60 | \$ 0.50 | \$ 2.10 | \$ 57.35 | 16% | 40.91 | 722.19 | 64.63 | \$ 0.11 | 7.51 | - | 15.96 | 129.13 |
| CCCT (Wet "G" 1x1) | 1,292 | 8.59% | \$ 110.93 | \$ 6.75 | \$ 0.50 | \$ 7.25 | \$ 118.18 | 56% | 24.09 | 722.19 | 49.72 | \$ 4.56 | 5.78 | - | 12.28 | 96.42 |
| CCCT Duct Firing (Wet "G" 1x1) | 547 | 8.59% | \$ 46.96 | \$ 1.63 | \$ 0.50 | \$ 2.13 | \$ 49.09 | 16% | 35.03 | 722.19 | 65.15 | \$ 0.36 | 7.57 | - | 16.09 | 124.19 |
| CCCT Advanced (Wet) | 1,427 | 8.59% | \$ 122.49 | \$ 6.75 | \$ 0.50 | \$ 7.25 | \$ 129.74 | 56% | 26.45 | 722.19 | 48.82 | \$ 4.56 | 5.67 | - | 12.06 | 97.55 |
| CCCT Advanced Duct Firing (Wet) | 700 | 8.59% | \$ 60.10 | \$ 1.63 | \$ 0.50 | \$ 2.13 | \$ 62.24 | 16% | 44.40 | 722.19 | 65.15 | \$ 0.36 | 7.57 | - | 16.09 | 133.57 |
| **Other - Renewables** | | | | | | | | | | | | | | | | |
| East (Wyoming) Wind (35% CF) | 2,566 | 8.72% | \$ 223.58 | \$ 31.43 | \$ 0.50 | \$ 31.93 | \$ 255.51 | 35% | 83.34 | - | - | - | 11.75 | (20.70) | - | 74.38 |
| East Side Geothermal (Blundell) | 6,087 | 7.42% | \$ 451.64 | \$ 110.85 | \$ 0.50 | \$ 111.35 | \$ 562.99 | 90% | 71.41 | - | - | \$ 5.94 | | (20.70) | - | 56.64 |
| East Side Geothermal (Green Field) | 7,608 | 7.42% | \$ 564.55 | \$ 221.70 | \$ 0.50 | \$ 222.20 | \$ 786.74 | 90% | 99.79 | - | - | \$ 11.88 | | (20.70) | - | 90.97 |
| Battery Storage | 2,084 | 8.29% | \$ 172.77 | \$ 1.00 | \$ 0.50 | \$ 1.50 | \$ 174.27 | 21% | 94.73 | 722.19 | 86.66 | \$ 10.00 | 10.07 | - | 37.33 | 238.79 |
| Pumped Storage | 1,773 | 8.19% | \$ 145.14 | \$ 4.30 | \$ 1.35 | \$ 5.65 | \$ 150.79 | 20% | 86.06 | 722.19 | 93.88 | \$ 4.30 | 10.91 | - | 40.44 | 235.60 |
| Compressed Air Energy Storage (CAES) | 1,561 | 8.29% | \$ 129.41 | \$ 3.80 | \$ 1.35 | \$ 5.15 | \$ 134.56 | 47% | 32.89 | 722.19 | 86.52 | \$ 5.50 | 8.70 | - | 21.37 | 154.98 |
| Recovered Energy Generation (CHP) | 5,500 | 9.39% | \$ 516.67 | \$ 91.92 | - | \$ 91.92 | \$ 608.59 | 84% | 82.71 | - | - | - | - | - | - | 82.71 |
| Nuclear | 5,461 | 8.30% | \$ 453.26 | \$ 146.70 | \$ 6.00 | \$ 152.70 | \$ 605.95 | 85% | 81.38 | 113.98 | 12.21 | \$ 1.63 | - | - | - | 95.22 |
| Solar Concentrating (PV) - 30% CF | 6,520 | 6.48% | \$ 422.43 | \$ 180.00 | \$ 6.00 | \$ 186.00 | \$ 608.43 | 30% | 231.52 | - | - | - | - | (1.59) | - | 229.93 |
| Solar Concentrating (natural gas backup) - 25% solar | 4,150 | 6.48% | \$ 268.88 | \$ 195.60 | \$ 6.00 | \$ 201.60 | \$ 470.48 | 33% | 162.75 | 722.19 | 19.59 | - | 2.28 | (1.59) | 4.84 | 187.86 |
| Solar Concentrating (thermal storage) - 30% solar | 4,650 | 5.46% | \$ 253.80 | \$ 139.50 | \$ 6.00 | \$ 145.50 | \$ 399.30 | 30% | 151.94 | - | - | - | - | (1.59) | - | 150.35 |

# Table 6.7 – Total Resource Cost for West Side Supply-Side Resource Options, \$45 $CO_2$ Tax

| Description | Capital Cost \$/kW Total Capital Cost | Payment Factor | Annual Payment (\$/kW-Yr) | Fixed Cost: Fixed O&M \$/kW-Yr O&M | Other | Total | Total Fixed (\$/kW-Yr) | Convert to Mills: Capacity Factor | Total Fixed Mills/kWh | Levelized Fuel ¢/mmBtu | Levelized Fuel Mills/kWh | Variable Costs mills/kWh: O&M | Gas Transportation/ Wind Integration | Tax Credits | Environmental | Total Resource Cost (Mills/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **West Side Options (1500')** | | | | | | | | | | | | | | | | |
| **Natural Gas** | | | | | | | | | | | | | | | | |
| Fuel Cell - Large | 1,794 | 8.72% | \$ 156.34 | \$ 8.40 | \$ 0.50 | \$ 8.90 | \$ 165.24 | 95% | 19.86 | 869.90 | 63.17 | \$ 0.03 | 5.33 | - | 12.95 | 101.33 |
| SCCT Aero | 1,024 | 9.08% | \$ 92.92 | \$ 9.04 | \$ 0.50 | \$ 9.54 | \$ 102.46 | 21% | 55.70 | 869.90 | 85.02 | \$ 5.12 | 7.17 | - | 17.43 | 170.43 |
| Intercooled Aero SCCT | 956 | 9.08% | \$ 86.77 | \$ 3.68 | \$ 0.50 | \$ 4.18 | \$ 90.95 | 21% | 49.44 | 869.90 | 81.79 | \$ 2.46 | 6.90 | - | 16.77 | 157.36 |
| Internal Combustion Engines | 1,204 | 9.08% | \$ 109.25 | \$ 12.80 | \$ 0.50 | \$ 13.30 | \$ 122.55 | 94% | 14.88 | 869.90 | 73.94 | \$ 5.20 | 6.24 | - | 15.16 | 115.42 |
| SCCT Frame (2 Frame "F") | 679 | 8.62% | \$ 58.53 | \$ 3.40 | \$ 0.50 | \$ 3.90 | \$ 62.43 | 21% | 33.94 | 869.90 | 101.43 | \$ 4.07 | 8.56 | - | 20.79 | 168.78 |
| CCCT (Wet "F" 1x1) | 1,242 | 8.59% | \$ 106.66 | \$ 11.62 | \$ 0.50 | \$ 12.12 | \$ 118.78 | 56% | 24.21 | 869.90 | 63.52 | \$ 2.67 | 5.36 | - | 13.02 | 108.79 |
| CCCT Duct Firing (Wet "F" 1x1) | 507 | 8.59% | \$ 43.53 | \$ 1.45 | \$ 0.50 | \$ 1.95 | \$ 45.48 | 16% | 32.45 | 869.90 | 77.15 | \$ 0.36 | 6.51 | - | 15.82 | 132.28 |
| CCCT (Wet "F" 2x1) | 1,131 | 8.59% | \$ 97.08 | \$ 7.07 | \$ 0.50 | \$ 7.57 | \$ 104.65 | 56% | 21.33 | 869.90 | 61.75 | \$ 2.67 | 5.21 | - | 12.66 | 103.62 |
| CCCT Duct Firing (Wet "F" 2x1) | 570 | 8.59% | \$ 48.98 | \$ 1.45 | \$ 0.50 | \$ 1.95 | \$ 50.93 | 16% | 36.34 | 869.90 | 74.44 | \$ 0.36 | 6.28 | - | 15.26 | 132.68 |
| CCCT (Wet "G" 1x1) | 1,175 | 8.59% | \$ 100.85 | \$ 6.13 | \$ 0.50 | \$ 6.63 | \$ 107.48 | 56% | 21.91 | 869.90 | 59.89 | \$ 4.14 | 5.05 | - | 12.28 | 103.27 |
| CCCT Duct Firing (Wet "G" 1x1) | 497 | 8.59% | \$ 42.69 | \$ 1.48 | \$ 0.50 | \$ 1.98 | \$ 44.68 | 16% | 31.88 | 869.90 | 78.48 | \$ 0.33 | 6.62 | - | 16.09 | 133.39 |
| CCCT Advanced (Wet) | 1,297 | 8.59% | \$ 111.36 | \$ 6.13 | \$ 0.50 | \$ 6.63 | \$ 117.99 | 56% | 24.05 | 869.90 | 58.80 | \$ 4.14 | 4.96 | - | 12.06 | 104.01 |
| CCCT Advanced Duct Firing (Wet) | 636 | 8.59% | \$ 54.64 | \$ 1.48 | \$ 0.50 | \$ 1.98 | \$ 56.62 | 16% | 40.40 | 869.90 | 78.48 | \$ 0.33 | 6.62 | - | 16.09 | 141.91 |
| **Other - Renewables** | | | | | | | | | | | | | | | | |
| West Wind | 2,612 | 8.72% | \$ 227.59 | \$ 31.43 | \$ 27.74 | \$ 59.17 | \$ 286.76 | 29% | 112.88 | - | - | - | 11.75 | (20.70) | - | 103.93 |
| Biomass | 3,347 | 8.10% | \$ 271.22 | \$ 38.80 | \$ 0.50 | \$ 39.30 | \$ 310.52 | 91% | 38.78 | 590.00 | 64.78 | \$ 0.96 | - | (20.70) | 34.16 | 117.97 |
| West Side Geothermal (Green Field) | 7,609 | 7.42% | \$ 564.62 | \$ 221.70 | \$ 0.50 | \$ 222.20 | \$ 786.82 | 90% | 99.80 | - | - | \$ 11.88 | - | (20.70) | - | 90.98 |
| Compressed Air Energy Storage (CAES) | 1,561 | 8.29% | \$ 129.41 | \$ 3.45 | \$ 1.35 | \$ 4.80 | \$ 134.21 | 47% | 32.81 | 869.90 | 104.21 | \$ 5.00 | 8.79 | - | 21.37 | 172.18 |
| Hydrokinetic (Wave) - 21% CF | 6,000 | 9.69% | \$ 581.58 | \$ 180.00 | \$ 6.00 | \$ 186.00 | \$ 767.58 | 21% | 417.25 | - | - | - | - | - | - | 417.25 |
| **West Side Options (Sea Level)** | | | | | | | | | | | | | | | | |
| **Natural Gas** | | | | | | | | | | | | | | | | |
| Fuel Cell - Large | 1,794 | 8.72% | \$ 156.34 | \$ 8.40 | \$ 0.50 | \$ 8.90 | \$ 165.24 | 95% | 19.86 | 869.90 | 63.17 | \$ 0.03 | 5.33 | - | 12.95 | 101.33 |
| SCCT Aero | 972 | 9.08% | \$ 88.27 | \$ 8.59 | \$ 0.50 | \$ 9.09 | \$ 97.36 | 21% | 52.93 | 869.90 | 85.02 | \$ 4.87 | 7.17 | - | 17.43 | 167.42 |
| Intercooled Aero SCCT | 908 | 9.08% | \$ 82.43 | \$ 3.49 | \$ 0.50 | \$ 3.99 | \$ 86.43 | 21% | 46.98 | 869.90 | 81.79 | \$ 2.35 | 6.90 | - | 16.77 | 154.78 |
| Internal Combustion Engines | 1,143 | 9.08% | \$ 103.79 | \$ 12.80 | \$ 0.50 | \$ 13.30 | \$ 117.09 | 94% | 14.22 | 869.90 | 73.94 | \$ 5.20 | 6.24 | - | 15.16 | 114.75 |
| SCCT Frame (2 Frame "F") | 645 | 8.62% | \$ 55.61 | \$ 3.23 | \$ 0.50 | \$ 3.73 | \$ 59.34 | 21% | 32.26 | 869.90 | 101.43 | \$ 3.87 | 8.56 | - | 20.79 | 166.90 |
| CCCT (Wet "F" 1x1) | 1,180 | 8.59% | \$ 101.32 | \$ 11.07 | \$ 0.50 | \$ 11.57 | \$ 112.89 | 56% | 23.01 | 869.90 | 63.52 | \$ 2.55 | 5.36 | - | 13.02 | 107.46 |
| CCCT Duct Firing (Wet "F" 1x1) | 482 | 8.59% | \$ 41.35 | \$ 1.38 | \$ 0.50 | \$ 1.88 | \$ 43.23 | 16% | 30.85 | 869.90 | 77.15 | \$ 0.34 | 6.51 | - | 15.82 | 130.66 |
| CCCT (Wet "F" 2x1) | 1,074 | 8.59% | \$ 92.23 | \$ 6.73 | \$ 0.50 | \$ 7.23 | \$ 99.46 | 56% | 20.27 | 869.90 | 61.75 | \$ 2.55 | 5.21 | - | 12.66 | 102.44 |
| CCCT Duct Firing (Wet "F" 2x1) | 542 | 8.59% | \$ 46.53 | \$ 1.38 | \$ 0.50 | \$ 1.88 | \$ 48.42 | 16% | 34.54 | 869.90 | 74.44 | \$ 0.34 | 6.28 | - | 15.26 | 130.87 |
| CCCT (Wet "G" 1x1) | 1,116 | 8.59% | \$ 95.81 | \$ 5.84 | \$ 0.50 | \$ 6.34 | \$ 102.15 | 56% | 20.82 | 869.90 | 59.89 | \$ 3.94 | 5.05 | - | 12.28 | 101.98 |
| CCCT Duct Firing (Wet "G" 1x1) | 472 | 8.59% | \$ 40.56 | \$ 1.41 | \$ 0.50 | \$ 1.91 | \$ 42.47 | 16% | 30.30 | 869.90 | 78.48 | \$ 0.31 | 6.62 | - | 16.09 | 131.80 |
| CCCT Advanced (Wet) | 1,232 | 8.59% | \$ 105.79 | \$ 5.84 | \$ 0.50 | \$ 6.34 | \$ 112.13 | 56% | 22.86 | 869.90 | 58.80 | \$ 3.94 | 4.96 | - | 12.06 | 102.62 |
| CCCT Advanced Duct Firing (Wet) | 605 | 8.59% | \$ 51.91 | \$ 1.41 | \$ 0.50 | \$ 1.91 | \$ 53.82 | 16% | 38.40 | 869.90 | 78.48 | \$ 0.31 | 6.62 | - | 16.22 | 140.03 |

**Distributed Generation**

Table 6.8 reports cost and performance attributes for small distributed standby generation, combined heat and power, and on-site solar supply-side resource options. Tables 6.9 and 6.10 present the total resource cost attributes for these resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2008 dollars. The resource costs are presented for both the $8 and $45 $CO_2$ tax levels in recognition of the uncertainty in characterizing emission costs. Certain technologies were adjusted to reflect benefits that were identified outside of the Quantec DSM potential study and cost of emissions. Maintenance and forced outage data were taken from comparable technologies in the supply-side table. Additional explanatory notes for the tables are as follows:

- A 15-percent administrative cost (for fixed operation and maintenance) is included in the overall cost of the resources.
- The avoided transmission and distribution credit of $23/kW-year is included in the resource costs to reflect a rough estimate of savings by avoiding transmission and distribution investments.
- Federal tax benefits are included for microturbines at $200/kW capacity, while fuel cells receive $500 per 0.05 kW of capacity.
- Installation costs for on-site ("micro") solar generation technologies are treated on a total resource cost basis; that is, customer installation costs are included. However, capital costs are adjusted downward to reflect federal and state tax benefits. The percentages applied included an 80 percent reduction to capital cost for Oregon, 31 percent for Utah, and 25 percent for all other states. The Quantec DSM potential study included the following benefits for commercial and residential customers:
  - Utah
    - *Commercial Credits:* The federal credit is 30 percent of the investment; the state credit is 1 percent of investment
    - *Residential Credits:* The federal credit is 30 percent of the investment up to $2,000 for Residential Energy Efficiency; Utah receives up to $2,000
  - Oregon
    - *Commercial Credits:* The federal credit is 30 percent of the investment; the state Business Credit is 50 percent of investment up to $20 million received over 5 years; The Energy Trust of Oregon credit is $1.25 per watt
    - *Residential Credits:* The federal credit is 30 percent of the investment up to $2,000 for Residential Energy Efficiency; the state credit is 5 percent of investment; the Energy Trust of Oregon credit is $2 per watt
  - Other States
    - *Commercial Credits:* The federal credit is 30 percent of the investment
    - *Residential Credits*: The federal credit is 30 percent of the investment up to $2,000 for Residential Energy Efficiency

- The resource cost for Industrial Biomass reflects the company's recent avoided cost, which reflects the minimum price the company would pay. Factoring in the income tax benefits would lower the resource cost below the company's avoided cost.

## Table 6.8 – Distributed Generation Resource Options

(2008 Dollars)

| Description | Installation Location | 1st Year Avail. | Unit Size MW Average Cap. (MW) | Fuel | Design Life in Years | Annual Heat Rate BTU/kWh | Maint. Outage Rate | Equivalent Forced Outage Rate (EFOR) | Capital Cost $/kW | Var. O&M ($/MWh) | Fixed O&M ($/kW-yr) | Emissions SO2 | Emissions NOx | Emissions Hg | Emissions CO2 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | lbs/MMBTU (Hg: lbs/Tbtu) | | | |
| **Small Combined Heat & Power** | | | | | | | | | | | | | | | |
| Reciprocating Engine | Utah | 2008 | 0.6 | Natural Gas | 20 | 5,005 | 2% | 3% | $ 1,969 | - | $ 79.00 | 0.001 | 0.101 | 0.255 | 118.00 |
| Reciprocating Engine | Wyoming | 2008 | 0.6 | Natural Gas | 20 | 5,005 | 2% | 3% | $ 1,969 | - | $ 79.00 | 0.001 | 0.101 | 0.255 | 118.00 |
| Reciprocating Engine | Oregon | 2008 | 0.6 | Natural Gas | 20 | 5,005 | 2% | 3% | $ 1,969 | - | $ 79.00 | 0.001 | 0.101 | 0.255 | 118.00 |
| Gas Turbine | Utah | 2008 | 3.2 | Natural Gas | 20 | 6,600 | 2% | 3% | $ 1,838 | - | $ 58.00 | 0.001 | 0.050 | 0.255 | 118.00 |
| Gas Turbine | Wyoming | 2008 | 3.2 | Natural Gas | 20 | 6,600 | 2% | 3% | $ 1,838 | - | $ 58.00 | 0.001 | 0.050 | 0.255 | 118.00 |
| Gas Turbine | Oregon | 2008 | 3.2 | Natural Gas | 20 | 6,600 | 2% | 3% | $ 1,838 | - | $ 58.00 | 0.001 | 0.050 | 0.255 | 118.00 |
| Microturbine | Utah | 2008 | 0.2 | Natural Gas | 15 | 7,454 | 2% | 3% | $ 2,831 | - | $ 71.00 | 0.001 | 0.101 | 0.255 | 118.00 |
| Microturbine | Wyoming | 2008 | 0.2 | Natural Gas | 15 | 7,454 | 2% | 3% | $ 2,831 | - | $ 71.00 | 0.001 | 0.101 | 0.255 | 118.00 |
| Microturbine | Oregon | 2008 | 0.2 | Natural Gas | 15 | 7,454 | 2% | 3% | $ 2,831 | - | $ 71.00 | 0.001 | 0.101 | 0.255 | 118.00 |
| Fuel Cell | Utah | 2008 | 0.5 | Natural Gas | 10 | 5,706 | 2% | 3% | $ 5,697 | - | $ 17.00 | 0.001 | 0.003 | 0.255 | 118.00 |
| Fuel Cell | Wyoming | 2008 | 0.5 | Natural Gas | 10 | 5,706 | 2% | 3% | $ 5,697 | - | $ 17.00 | 0.001 | 0.003 | 0.255 | 118.00 |
| Fuel Cell | Oregon | 2008 | 0.5 | Natural Gas | 10 | 5,706 | 2% | 3% | $ 5,697 | - | $ 17.00 | 0.001 | 0.003 | 0.255 | 118.00 |
| Commercial Biomass, Anaerobic Digester | Utah | 2008 | 0.4 | Biomass | 15 | - | 10% | 10% | $ 3,219 | - | $ 67.00 | - | - | - | - |
| Commercial Biomass, Anaerobic Digester | Wyoming | 2008 | 0.4 | Biomass | 15 | - | 10% | 10% | $ 3,219 | - | $ 67.00 | - | - | - | - |
| Commercial Biomass, Anaerobic Digester | Oregon | 2008 | 0.4 | Biomass | 15 | - | 10% | 10% | $ 3,219 | - | $ 67.00 | - | - | - | - |
| Industrial Biomass, Waste | Utah | 2008 | 4.8 | Biomass | 15 | - | 5% | 5% | $ 1,800 | - | $ 39.00 | - | - | - | - |
| Industrial Biomass, Waste | Wyoming | 2008 | 4.8 | Biomass | 15 | - | 5% | 5% | $ 1,800 | - | $ 39.00 | - | - | - | - |
| Industrial Biomass, Waste | Oregon | 2008 | 4.8 | Biomass | 15 | - | 5% | 5% | $ 1,800 | - | $ 39.00 | - | - | - | - |
| **Solar** | | | | | | | | | | | | | | | |
| Rooftop Photovoltaic | Utah | 2008 | 0.005 | Solar | 25 | - | | | $ 9,000 | - | $ 100.00 | - | - | - | - |
| Rooftop Photovoltaic | Wyoming | 2008 | 0.005 | Solar | 25 | - | | | $ 9,000 | - | $ 100.00 | - | - | - | - |
| Rooftop Photovoltaic | Oregon | 2008 | 0.005 | Solar | 25 | - | | | $ 9,000 | - | $ 100.00 | - | - | - | - |
| Water Heaters | Utah | 2008 | 0.002 | Solar | 15 | - | | | $ 3,500 | - | - | - | - | - | - |
| Water Heaters | Wyoming | 2008 | 0.002 | Solar | 15 | - | | | $ 3,500 | - | - | - | - | - | - |
| Water Heaters | Oregon | 2008 | 0.002 | Solar | 15 | - | | | $ 3,500 | - | - | - | - | - | - |
| Attic Fans | Utah | 2008 | 0.000010 | Solar | 10 | - | | | $ 54,000 | - | - | - | - | - | - |
| Attic Fans | Wyoming | 2008 | 0.000010 | Solar | 10 | - | | | $ 54,000 | - | - | - | - | - | - |
| Attic Fans | Oregon | 2008 | 0.000010 | Solar | 10 | - | | | $ 54,000 | - | - | - | - | - | - |
| **Dispatchible Generators** | | | | | | | | | | | | | | | |
| Dispatchible Standby Generators Existing | Utah | 2008 | 1.0 | Diesel | 20 | 9,975 | | | $ 250 | - | $ 7.50 | 0.030 | 0.101 | 0.255 | 118.00 |
| Dispatchible Standby Generators Existing | Wyoming | 2008 | 1.0 | Diesel | 20 | 9,975 | | | $ 250 | - | $ 7.50 | 0.030 | 0.101 | 0.255 | 118.00 |
| Dispatchible Standby Generators Existing | Oregon | 2008 | 1.0 | Diesel | 20 | 9,975 | | | $ 250 | - | $ 7.50 | 0.030 | 0.101 | 0.255 | 118.00 |
| Dispatchible Standby Generators New | Utah | 2008 | 1.0 | Diesel | 20 | 9,975 | | | $ 175 | - | $ 5.00 | 0.030 | 0.101 | 0.255 | 118.00 |
| Dispatchible Standby Generators New | Wyoming | 2008 | 1.0 | Diesel | 20 | 9,975 | | | $ 175 | - | $ 5.00 | 0.030 | 0.101 | 0.255 | 118.00 |
| Dispatchible Standby Generators New | Oregon | 2008 | 1.0 | Diesel | 20 | 9,975 | | | $ 175 | - | $ 5.00 | 0.030 | 0.101 | 0.255 | 118.00 |

## Table 6.9 – Distributed Generation Total Resource Costs, \$8 $CO_2$ tax

(2008 Dollars)

| Description | Capital Cost \$/kW: Cap Cost | Capital Cost \$/kW: Tax Benefits | Capital Cost \$/kW: Transmission & Distribution Credit | Capital Cost \$/kW: Administrative | Capital Cost \$/kW: Net Capital Costs | Capital Cost \$/kW: Payment Factor | Capital Cost \$/kW: Annual Pmt \$/kW-Yr | Fixed Cost: Fixed O&M \$/kW-Yr: O&M | Fixed Cost: Fixed O&M \$/kW-Yr: Other | Fixed Cost: Fixed O&M \$/kW-Yr: Total | Fixed Cost: Total Fixed \$/kW-Yr | Convert to Mills: Capacity Factor | Convert to Mills: Ttl Fixed Mills/kWh | Convert to Mills: Levelized Fuel ¢/mmBtu | Convert to Mills: Levelized Fuel Mills/kWh | Variable Costs mills/kWh: O&M | Variable Costs mills/kWh: Avoided Cost | Variable Costs mills/kWh: Environmental | Total Resource Cost (Mills/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Small Combined Heat & Power** | | | | | | | | | | | | | | | | | | | |
| Reciprocating Engine | \$ 1,969 | \$ - | \$ (204) | \$ 295 | \$ 2,060 | 11.27% | \$ 232.08 | \$ 79.00 | - | \$ 79.00 | \$ 311.08 | 90% | 39.46 | 699.22 | 35.00 | - | - | 1.59 | \$ 76.04 |
| Reciprocating Engine | \$ 1,969 | \$ - | \$ (204) | \$ 295 | \$ 2,060 | 11.27% | \$ 232.08 | \$ 79.00 | - | \$ 79.00 | \$ 311.08 | 90% | 39.46 | 699.22 | 35.00 | - | - | 1.59 | \$ 76.04 |
| Reciprocating Engine | \$ 1,969 | \$ - | \$ (204) | \$ 295 | \$ 2,060 | 11.27% | \$ 232.08 | \$ 79.00 | - | \$ 79.00 | \$ 311.08 | 90% | 39.46 | 814.00 | 40.74 | - | - | 1.59 | \$ 81.79 |
| Gas Turbine | \$ 1,838 | \$ - | \$ (204) | \$ 276 | \$ 1,910 | 11.27% | \$ 215.11 | \$ 58.00 | - | \$ 58.00 | \$ 273.11 | 95% | 32.82 | 699.22 | 46.15 | - | - | 2.09 | \$ 81.06 |
| Gas Turbine | \$ 1,838 | \$ - | \$ (204) | \$ 276 | \$ 1,910 | 11.27% | \$ 215.11 | \$ 58.00 | - | \$ 58.00 | \$ 273.11 | 95% | 32.82 | 699.22 | 46.15 | - | - | 2.09 | \$ 81.06 |
| Gas Turbine | \$ 1,838 | \$ - | \$ (204) | \$ 276 | \$ 1,910 | 11.27% | \$ 215.11 | \$ 58.00 | - | \$ 58.00 | \$ 273.11 | 95% | 32.82 | 814.00 | 53.72 | - | - | 2.09 | \$ 88.63 |
| Microturbine | \$ 2,831 | \$ (200) | \$ (202) | \$ 425 | \$ 2,854 | 11.41% | \$ 325.53 | \$ 71.00 | - | \$ 71.00 | \$ 396.53 | 90% | 50.30 | 699.22 | 52.12 | - | - | 2.36 | \$ 104.78 |
| Microturbine | \$ 2,831 | \$ (200) | \$ (202) | \$ 425 | \$ 2,854 | 11.41% | \$ 325.53 | \$ 71.00 | - | \$ 71.00 | \$ 396.53 | 90% | 50.30 | 699.22 | 52.12 | - | - | 2.36 | \$ 104.78 |
| Microturbine | \$ 2,831 | \$ (200) | \$ (202) | \$ 425 | \$ 2,854 | 11.41% | \$ 325.53 | \$ 71.00 | - | \$ 71.00 | \$ 396.53 | 90% | 50.30 | 814.00 | 60.68 | - | - | 2.36 | \$ 113.33 |
| Fuel Cell | \$ 5,697 | \$ (1,000) | \$ (154) | \$ 855 | \$ 5,398 | 14.96% | \$ 807.73 | \$ 17.00 | - | \$ 17.00 | \$ 824.73 | 95% | 99.10 | 699.22 | 39.90 | - | - | 1.81 | \$ 140.81 |
| Fuel Cell | \$ 5,697 | \$ (1,000) | \$ (154) | \$ 855 | \$ 5,398 | 14.96% | \$ 807.73 | \$ 17.00 | - | \$ 17.00 | \$ 824.73 | 95% | 99.10 | 699.22 | 39.90 | - | - | 1.81 | \$ 140.81 |
| Fuel Cell | \$ 5,697 | \$ (1,000) | \$ (154) | \$ 855 | \$ 5,398 | 14.96% | \$ 807.73 | \$ 17.00 | - | \$ 17.00 | \$ 824.73 | 95% | 99.10 | 814.00 | 46.45 | - | - | 1.81 | \$ 147.36 |
| Commercial Biomass, Anaerobic Digester | \$ - | \$ - | \$ - | \$ - | \$ - | 11.41% | - | - | - | - | - | 80% | 0.00 | - | - | - | 46.30 | - | \$ 46.30 |
| Commercial Biomass, Anaerobic Digester | \$ - | \$ - | \$ - | \$ - | \$ - | 11.41% | - | - | - | - | - | 80% | 0.00 | - | - | - | 58.37 | - | \$ 58.37 |
| Commercial Biomass, Anaerobic Digester | \$ - | \$ - | \$ - | \$ - | \$ - | 11.41% | - | - | - | - | - | 80% | 0.00 | - | - | - | 62.33 | - | \$ 62.33 |
| Industrial Biomass, Waste | \$ - | \$ - | \$ - | \$ - | \$ - | 11.41% | - | - | - | - | - | 90% | 0.00 | - | - | - | 46.30 | - | \$ 46.30 |
| Industrial Biomass, Waste | \$ - | \$ - | \$ - | \$ - | \$ - | 11.41% | - | - | - | - | - | 90% | 0.00 | - | - | - | 58.37 | - | \$ 58.37 |
| Industrial Biomass, Waste | \$ - | \$ - | \$ - | \$ - | \$ - | 11.41% | - | - | - | - | - | 90% | 0.00 | - | - | - | 62.33 | - | \$ 62.33 |
| **Solar** | | | | | | | | | | | | | | | | | | | |
| Rooftop Photovoltaic | \$ 9,000 | \$ (2,790) | \$ (264) | \$ 1,350 | \$ 7,296 | 8.72% | \$ 635.85 | \$ 100.00 | - | \$ 100.00 | \$ 735.85 | 14% | 600.01 | - | - | - | - | - | \$ 600.01 |
| Rooftop Photovoltaic | \$ 9,000 | \$ (2,250) | \$ (264) | \$ 1,350 | \$ 7,836 | 8.72% | \$ 682.92 | \$ 100.00 | - | \$ 100.00 | \$ 782.92 | 14% | 638.38 | - | - | - | - | - | \$ 638.38 |
| Rooftop Photovoltaic | \$ 9,000 | \$ (7,200) | \$ (264) | \$ 1,350 | \$ 2,886 | 8.72% | \$ 251.52 | \$ 100.00 | - | \$ 100.00 | \$ 351.52 | 13% | 308.68 | - | - | - | - | - | \$ 308.68 |
| Water Heaters | \$ 3,500 | \$ (980) | \$ (202) | \$ 525 | \$ 2,843 | 11.41% | \$ 324.31 | - | - | - | \$ 324.31 | 14% | 264.44 | - | - | - | - | - | \$ 264.44 |
| Water Heaters | \$ 3,500 | \$ (875) | \$ (202) | \$ 525 | \$ 2,948 | 11.41% | \$ 336.29 | - | - | - | \$ 336.29 | 14% | 274.21 | - | - | - | - | - | \$ 274.21 |
| Water Heaters | \$ 3,500 | \$ (1,330) | \$ (202) | \$ 525 | \$ 2,493 | 11.41% | \$ 284.39 | - | - | - | \$ 284.39 | 13% | 249.73 | - | - | - | - | - | \$ 249.73 |
| Attic Fans | \$ 54,000 | \$ - | \$ (154) | \$ 8,100 | \$ 61,946 | 14.96% | \$9,269.64 | - | - | - | \$9,269.64 | 14% | 7558.42 | - | - | - | - | - | \$ 7,558.42 |
| Attic Fans | \$ 54,000 | \$ - | \$ (154) | \$ 8,100 | \$ 61,946 | 14.96% | \$9,269.64 | - | - | - | \$9,269.64 | 14% | 7558.42 | - | - | - | - | - | \$ 7,558.42 |
| Attic Fans | \$ 54,000 | \$ - | \$ (154) | \$ 8,100 | \$ 61,946 | 14.96% | \$9,269.64 | - | - | - | \$9,269.64 | 13% | 8139.83 | - | - | - | - | - | \$ 8,139.83 |
| **Dispatchible Generators** | | | | | | | | | | | | | | | | | | | |
| Dispatchible Standby Generators Existing | \$ 250 | \$ - | \$ (211) | \$ 38 | \$ 76 | 10.88% | \$ 8.28 | \$ 7.50 | \$ 1.13 | \$ 8.63 | \$ 16.91 | 0.9% | 211.35 | 2574 | 256.72 | - | - | 3.19 | \$ 471.26 |
| Dispatchible Standby Generators Existing | \$ 250 | \$ - | \$ (211) | \$ 38 | \$ 76 | 10.88% | \$ 8.28 | \$ 7.50 | \$ 1.13 | \$ 8.63 | \$ 16.91 | 0.9% | 211.35 | 2574 | 256.72 | - | - | 3.19 | \$ 471.26 |
| Dispatchible Standby Generators Existing | \$ 250 | \$ - | \$ (211) | \$ 38 | \$ 76 | 10.88% | \$ 8.28 | \$ 7.50 | \$ 1.13 | \$ 8.63 | \$ 16.91 | 0.9% | 211.35 | 2574 | 256.72 | - | - | 3.19 | \$ 471.26 |
| Dispatchible Standby Generators New | \$ 175 | \$ - | \$ (211) | \$ 26 | \$ (10) | 10.88% | \$ (1.10) | \$ 5.00 | \$ 0.75 | \$ 5.75 | \$ 4.65 | 0.9% | 58.10 | 2574 | 256.72 | - | - | 3.19 | \$ 318.01 |
| Dispatchible Standby Generators New | \$ 175 | \$ - | \$ (211) | \$ 26 | \$ (10) | 10.88% | \$ (1.10) | \$ 5.00 | \$ 0.75 | \$ 5.75 | \$ 4.65 | 0.9% | 58.10 | 2574 | 256.72 | - | - | 3.19 | \$ 318.01 |
| Dispatchible Standby Generators New | \$ 175 | \$ - | \$ (211) | \$ 26 | \$ (10) | 10.88% | \$ (1.10) | \$ 5.00 | \$ 0.75 | \$ 5.75 | \$ 4.65 | 0.9% | 58.10 | 2574 | 256.72 | - | - | 3.19 | \$ 318.01 |

# Table 6.10 – Distributed Generation Total Resource Cost, $45 $CO_2$ Tax

(2008 Dollars)

| | Capital Cost $/kW | | | | | | | Fixed Cost | | | | Convert to Mills | | | | Variable Costs mills/kWh | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Payment | Annual Pmt | Fixed O&M $/kW-Yr | | | Total Fixed | Capacity | Ttl Fixed | Levelized Fuel | | | | | Resource Cost |
| Description | Cap Cost | Tax Benefits | Transmission & Distribution Credit | Administrative | Net Capital Costs | Factor | $/kW-Yr | O&M | Other | Total | $/kW-Yr | Factor | Mills/kWh | ¢/mmBtu | Mills/kWh | O&M | Avoided Cost | Environmental | (Mills/kWh) |
| **Small Combined Heat & Power** | | | | | | | | | | | | | | | | | | | |
| Reciprocating Engine | $ 1,969 | $ - | $ (204) | $ 295 | $ 2,060 | 11.27% | $ 232.08 | $ 79.00 | - | $ 79.00 | $ 311.08 | 90% | 39.46 | 722.19 | 36.15 | - | - | 8.93 | $ 84.53 |
| Reciprocating Engine | $ 1,969 | $ - | $ (204) | $ 295 | $ 2,060 | 11.27% | $ 232.08 | $ 79.00 | - | $ 79.00 | $ 311.08 | 90% | 39.46 | 722.19 | 36.15 | - | - | 8.93 | $ 84.53 |
| Reciprocating Engine | $ 1,969 | $ - | $ (204) | $ 295 | $ 2,060 | 11.27% | $ 232.08 | $ 79.00 | - | $ 79.00 | $ 311.08 | 90% | 39.46 | 869.90 | 43.54 | - | - | 8.93 | $ 91.92 |
| Gas Turbine | $ 1,838 | $ - | $ (204) | $ 276 | $ 1,910 | 11.27% | $ 215.11 | $ 58.00 | - | $ 58.00 | $ 273.11 | 95% | 32.82 | 722.19 | 47.66 | - | - | 11.77 | $ 92.25 |
| Gas Turbine | $ 1,838 | $ - | $ (204) | $ 276 | $ 1,910 | 11.27% | $ 215.11 | $ 58.00 | - | $ 58.00 | $ 273.11 | 95% | 32.82 | 722.19 | 47.66 | - | - | 11.77 | $ 92.25 |
| Gas Turbine | $ 1,838 | $ - | $ (204) | $ 276 | $ 1,910 | 11.27% | $ 215.11 | $ 58.00 | - | $ 58.00 | $ 273.11 | 95% | 32.82 | 869.90 | 57.41 | - | - | 11.77 | $ 102.00 |
| Microturbine | $ 2,831 | $ (200) | $ (202) | $ 425 | $ 2,854 | 11.41% | $ 325.53 | $ 71.00 | - | $ 71.00 | $ 396.53 | 90% | 50.30 | 722.19 | 53.83 | - | - | 13.29 | $ 117.42 |
| Microturbine | $ 2,831 | $ (200) | $ (202) | $ 425 | $ 2,854 | 11.41% | $ 325.53 | $ 71.00 | - | $ 71.00 | $ 396.53 | 90% | 50.30 | 722.19 | 53.83 | - | - | 13.29 | $ 117.42 |
| Microturbine | $ 2,831 | $ (200) | $ (202) | $ 425 | $ 2,854 | 11.41% | $ 325.53 | $ 71.00 | - | $ 71.00 | $ 396.53 | 90% | 50.30 | 869.90 | 64.84 | - | - | 13.29 | $ 128.43 |
| Fuel Cell | $ 5,697 | $ (1,000) | $ (154) | $ 855 | $ 5,398 | 14.96% | $ 807.73 | $ 17.00 | - | $ 17.00 | $ 824.73 | 95% | 99.10 | 722.19 | 41.21 | - | - | 10.18 | $ 150.49 |
| Fuel Cell | $ 5,697 | $ (1,000) | $ (154) | $ 855 | $ 5,398 | 14.96% | $ 807.73 | $ 17.00 | - | $ 17.00 | $ 824.73 | 95% | 99.10 | 722.19 | 41.21 | - | - | 10.18 | $ 150.49 |
| Fuel Cell | $ 5,697 | $ (1,000) | $ (154) | $ 855 | $ 5,398 | 14.96% | $ 807.73 | $ 17.00 | - | $ 17.00 | $ 824.73 | 95% | 99.10 | 869.90 | 49.64 | - | - | 10.18 | $ 158.92 |
| Commercial Biomass, Anaerobic Digester | $ - | $ - | $ - | $ - | $ - | 11.41% | - | - | - | - | - | 80% | 0.00 | - | - | - | 46.30 | - | $ 46.30 |
| Commercial Biomass, Anaerobic Digester | $ - | $ - | $ - | $ - | $ - | 11.41% | - | - | - | - | - | 80% | 0.00 | - | - | - | 58.37 | - | $ 58.37 |
| Commercial Biomass, Anaerobic Digester | $ - | $ - | $ - | $ - | $ - | 11.41% | - | - | - | - | - | 80% | 0.00 | - | - | - | 62.33 | - | $ 62.33 |
| Industrial Biomass, Waste | $ - | $ - | $ - | $ - | $ - | 11.41% | - | - | - | - | - | 90% | 0.00 | - | - | - | 46.30 | - | $ 46.30 |
| Industrial Biomass, Waste | $ - | $ - | $ - | $ - | $ - | 11.41% | - | - | - | - | - | 90% | 0.00 | - | - | - | 58.37 | - | $ 58.37 |
| Industrial Biomass, Waste | $ - | $ - | $ - | $ - | $ - | 11.41% | - | - | - | - | - | 90% | 0.00 | - | - | - | 62.33 | - | $ 62.33 |
| **Solar** | | | | | | | | | | | | | | | | | | | |
| Rooftop Photovoltaic | $ 9,000 | $ (2,790) | $ (264) | $ 1,350 | $ 7,296 | 8.72% | $ 635.85 | $ 100.00 | - | $ 100.00 | $ 735.85 | 14% | 600.01 | - | - | - | - | - | $ 600.01 |
| Rooftop Photovoltaic | $ 9,000 | $ (2,250) | $ (264) | $ 1,350 | $ 7,836 | 8.72% | $ 682.92 | $ 100.00 | - | $ 100.00 | $ 782.92 | 14% | 638.38 | - | - | - | - | - | $ 638.38 |
| Rooftop Photovoltaic | $ 9,000 | $ (7,200) | $ (264) | $ 1,350 | $ 2,886 | 8.72% | $ 251.52 | $ 100.00 | - | $ 100.00 | $ 351.52 | 13% | 308.68 | - | - | - | - | - | $ 308.68 |
| Water Heaters | $ 3,500 | $ (980) | $ (202) | $ 525 | $ 2,843 | 11.41% | $ 324.31 | - | - | - | $ 324.31 | 14% | 264.44 | - | - | - | - | - | $ 264.44 |
| Water Heaters | $ 3,500 | $ (875) | $ (202) | $ 525 | $ 2,948 | 11.41% | $ 336.29 | - | - | - | $ 336.29 | 14% | 274.21 | - | - | - | - | - | $ 274.21 |
| Water Heaters | $ 3,500 | $ (1,330) | $ (202) | $ 525 | $ 2,493 | 11.41% | $ 284.39 | - | - | - | $ 284.39 | 13% | 249.73 | - | - | - | - | - | $ 249.73 |
| Attic Fans | $ 54,000 | $ - | $ (154) | $ 8,100 | $ 61,946 | 14.96% | $9,269.64 | - | - | - | $ 9,269.64 | 14% | 7558.42 | - | - | - | - | - | $ 7,558.42 |
| Attic Fans | $ 54,000 | $ - | $ (154) | $ 8,100 | $ 61,946 | 14.96% | $9,269.64 | - | - | - | $ 9,269.64 | 14% | 7558.42 | - | - | - | - | - | $ 7,558.42 |
| Attic Fans | $ 54,000 | $ - | $ (154) | $ 8,100 | $ 61,946 | 14.96% | $9,269.64 | - | - | - | $ 9,269.64 | 13% | 8139.83 | - | - | - | - | - | $ 8,139.83 |
| **Dispatchible Generators** | | | | | | | | | | | | | | | | | | | |
| Dispatchible Standby Generators Existing | $ 250 | $ - | $ (211) | $ 38 | $ 76 | 10.88% | $ 8.28 | $ 7.50 | $ 1.13 | $ 8.63 | $ 16.91 | 0.9% | 211.35 | 2574 | 256.72 | - | - | 17.81 | $ 485.88 |
| Dispatchible Standby Generators Existing | $ 250 | $ - | $ (211) | $ 38 | $ 76 | 10.88% | $ 8.28 | $ 7.50 | $ 1.13 | $ 8.63 | $ 16.91 | 0.9% | 211.35 | 2574 | 256.72 | - | - | 17.81 | $ 485.88 |
| Dispatchible Standby Generators Existing | $ 250 | $ - | $ (211) | $ 38 | $ 76 | 10.88% | $ 8.28 | $ 7.50 | $ 1.13 | $ 8.63 | $ 16.91 | 0.9% | 211.35 | 2574 | 256.72 | - | - | 17.81 | $ 485.88 |
| Dispatchible Standby Generators New | $ 175 | $ - | $ (211) | $ 26 | $ (10) | 10.88% | $ (1.10) | $ 5.00 | $ 0.75 | $ 5.75 | $ 4.65 | 0.9% | 58.10 | 2574 | 256.72 | - | - | 17.81 | $ 332.63 |
| Dispatchible Standby Generators New | $ 175 | $ - | $ (211) | $ 26 | $ (10) | 10.88% | $ (1.10) | $ 5.00 | $ 0.75 | $ 5.75 | $ 4.65 | 0.9% | 58.10 | 2574 | 256.72 | - | - | 17.81 | $ 332.63 |
| Dispatchible Standby Generators New | $ 175 | $ - | $ (211) | $ 26 | $ (10) | 10.88% | $ (1.10) | $ 5.00 | $ 0.75 | $ 5.75 | $ 4.65 | 0.9% | 58.10 | 2574 | 256.72 | - | - | 17.81 | $ 332.63 |

## Resource Option Description

### Coal

Potential coal resources are shown in the supply-side resource options tables as supercritical pulverized coal boilers (PC) and integrated gasification combined cycles (IGCC) in Utah and Wyoming. Costs for large coal-fired boilers, since the 2007 IRP, have risen by approximately 50% to 60% due to many factors involving material shortages, labor shortages, and the risk of fixed price contracting. Additionally the uncertainty of future carbon regulations and a difficulty in obtaining construction and environmental permits for coal based generation alternatives has encouraged the company to postpone the selection of coal as a resource before 2020.

Supercritical technology was chosen over subcritical technology for pulverized coal for a number of reasons. Increasing coal costs are making the added efficiency of the supercritical technology cost-effective for long-term operation. Additionally, there is a greater competitive marketplace for large supercritical boilers than for large subcritical boilers. Increasingly, large boiler manufacturers only offer supercritical boilers in the 500-plus megawatt sizes. Due to the increased efficiency of supercritical boilers, overall emission quantities are smaller than for a similarly sized subcritical unit. Compared to subcritical boilers, supercritical boilers can follow loads better, ramp to full load faster, use less water, and require less steel for construction. The smaller steel requirements have also leveled the construction cost estimates for the two coal technologies. The costs for a supercritical pulverized coal facility reflect the cost of adding a new unit at an existing site. PacifiCorp does not expect a significant difference in cost for a multiple unit at a new site versus the cost of a single unit addition at an existing site.

Carbon dioxide capture and sequestration technology represents a potential cost for new and existing coal plants if future regulations require it. Research projects are underway to develop more cost-effective methods of capturing carbon dioxide from the flue gas of conventional boilers. The costs included in the supply side resource tables utilize amine based solvent systems for carbon capture. Sequestration would bury the $CO_2$ underground for long-term storage and monitoring.

PacifiCorp and its parent company MEHC are monitoring $CO_2$ capture technologies for possible retrofit opportunities at its existing coal-fired fleet, as well as applicability for future coal plants that could serve as cost-effective alternatives to IGCC plants if $CO_2$ removal becomes necessary in the future. An option to capture $CO_2$ at an existing coal-fired unit has been included in the supply side resource tables. Currently there are only a couple of large-scale sequestration projects in operation around the world and a number of these are in conjunction with enhanced oil recovery. Carbon capture and sequestration (CCS) is not considered a viable option before 2025 due to risk issues associated with technological maturity and underground sequestration liability.

An alternative to supercritical pulverized-coal technology for coal-based generation would be the use of IGCC technology. A significant advantage for IGCC when compared to conventional pulverized coal with amine-based carbon capture is the reduced cost of capturing carbon dioxide from the process. Gasification plants have been built and demonstrated around the world, primarily as a means of producing chemicals from coal. Only a limited number of IGCC plants have been constructed specifically for power generation. In the United States, these facilities have been demonstration projects and cost significantly more than conventional coal plants in both capital and operating costs. These projects have been constructed with significant funding from the federal government. A number of IGCC technology suppliers have teamed up with large constructor to form consortia who are now offering to build IGCC plants. A few years ago, these consortia were willing to provide IGCC plants on a lump-sum, turn-key basis. However, in today's market, the willingness of these consortia to design and construct IGCC plants on lump-sum turn key basis is in question. The costs presented in the supply-side resource options tables reflect recent studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

PacifiCorp was selected by the Wyoming Infrastructure Authority (WIA) to participate in joint project development activities for an IGCC facility in Wyoming. The ultimate goal was to develop a Section 413 project under the 2005 Energy Policy Act. PacifiCorp commissioned and managed feasibility studies with one or more technology suppliers/consortia for an IGCC facility at its Jim Bridger plant with some level of carbon capture. Based on the results of initial feasibility studies, PacifiCorp declined to submit a proposal to the federal agencies involved in the Section 413 solicitation.

PacifiCorp is a member of the Gasification User's Association. In addition, PacifiCorp communicates regularly with the primary gasification technology suppliers, constructors, and other utilities. The results of all these contacts were used to help develop the coal-based generation projects in the supply side resource tables. Over the last two years PacifiCorp has help a series of public meetings as a part of an IGCC Working Group to help provide a broader level of understanding for this technology.

**Coal Plant Efficiency Improvements**

Fuel efficiency gains for existing coal plants (which are manifest in lower plant heat rates) are realized by (1) emphasizing continuous improvement in operations, and (2) upgrading components if economically justified. Such fuel efficiency improvements can result in a smaller emission footprint for a given level of plant capacity, or the same footprint when plant capacity is increased.

The efficiency of generating units degrades gradually as components wear out over time. During operation, controllable process parameters are adjusted to optimize unit output and efficiency. Typical overhaul work that contributes to improved efficiency includes (1) steam turbine overhauls, (2) cleaning and repairing condensers, feed water heaters, and cooling towers and (3) cleaning boiler heat transfer surfaces.

When economically justified, efficiency improvements are obtained through major component upgrades. Examples include turbine upgrades using new blade and sealing technology, improved seals and heat exchange elements for boiler air heaters, cooling tower fill upgrades, and the addition of cooling tower cells. Such upgrade opportunities are analyzed on a case by case basis, and it is difficult to plan far in advance since decisions are tied to the existence of commercially-proven technology advancements available during a plant's next major overhaul cycle. PacifiCorp is taking advantage of improved upgrade technology through its "dense pack" coal plant turbine upgrade initiative. This initiative, to be completed by 2016, is factored into the 2008 IRP via a 170 MW coal plant capacity gain without a corresponding increase in fuel consumption, heat input, or emissions. Capacity expansion modeling to support the 2008 business plan indicated that this upgrade initiative was cost-effective. This resource is included in the current IRP models as a result.

**Natural Gas**
Natural gas generation options are numerous and a limited number of representative technologies are included in the supply-side resource options table. Simple cycle and combined cycle combustion turbines are included. A dry cooled combined cycle has been included. As with other generation technologies, the cost of natural gas generation has increased substantially from previous IRPs. Costs for gas generation have increased by 40% to 70%, depending on the option, due not only to general utility cost issues mentioned earlier, but also due to the decrease in coal-based projects thereby putting an increased demand on natural gas options that can be more easily permitted.

Combustion turbine options include both simple cycle and combined cycle configurations. The simple cycle options include traditional frame machines as well as aero-derivative combustion turbines. Two aero-derivative machine options were chosen. The General Electric LM6000 machines are flexible, high efficiency machines and can be installed with high temperature SCR systems, which allow them to be located in areas with air emissions concerns. These types of gas turbines are identical to those recently installed at Gadsby and West Valley. LM6000 gas turbines have quick-start capability (less than 10 minutes to full load) and higher heating value heat rates near 10,000 Btu/kWh. Also selected for the supply-side resource options table is General Electric's new LMS-100 gas turbine. This machine was recently installed for the first time in a commercial venture. It is a cross between a simple-cycle aero-derivative gas turbine and a frame machine with significant amount of compressor intercooling to improve efficiency. The machines have higher heating value heat rates of less than 9,500 Btu/kWh and similar starting capabilities as the LM6000 with significant load following capability (up to 50 megawatt per minute).

Frame simple cycle machines are represented by the "F" class technology. These machines are about 150 megawatts at western elevations, and can deliver good simple cycle efficiencies.

Other natural gas-fired generation options include internal combustion engines and fuel cells. Internal combustion engines are represented by a large power plant consisting of 14 machines at 10.9 megawatts. These machines are spark-ignited and have the advantages of a relatively attractive heat rate, a low emissions profile, and a high level of availability and reliability due to the number of machines. At present, fuel cells hold less promise due to high capital cost, partly attributable to the lack of production capability and continued development. Fuel cells are not ready for large scale deployment and are not considered available as a supply-side option until after 2013.

Combined cycle power plants options have been limited to 1x1 and 2x1 applications of "F" style combustion turbines and a "G" 1x1 facility. The "F" style machine options would allow an expansion of the Lake Side facility. Both the 1x1 and 2x1 configurations are included to give some flexibility to the portfolio planning. Similarly, the "G" machine has been added to take advantage of the improved heat rate available from these more advanced gas turbines. The "G" machine is only presented as a 1x1 option to keep the size of the facility reasonable for selection as a portfolio option. These natural gas technologies are considered mature and installation lead times and capital costs are well known. The capital cost pressure currently being observed with constructing large coal-based generation plants is also being experienced with natural gas-fired plants.

### Wind

Representation of wind projects was accomplished by developing a set of proxy wind sites composed of 100-MW blocks that could be selected as distinct resource options in the System Optimizer model. (Note that the 100-megawatt size reflects a suitable average size for modeling purposes, and does not imply that acquisitions are of this size.) Table 6.11 shows the regions in which wind resources are located and the representative capacity factors and quantity limits available to the System Optimizer model for selection. Note that these are aggregate limits for the entire modeling simulation period.

**Table 6.11 – Proxy Wind Sites and Characteristics**

| Transmission Bubble | Location | Capacity Factor (%) | Maximum Capacity (MW) |
|---|---|---|---|
| Southwest Wyoming | Southwest Wyoming | 24 | 1,400 |
| | | 29 | 1,300 |
| | | 35 | 1,300 |
| Northeast Wyoming | Northeast Wyoming | 24 | 1,400 |
| | | 29 | 1,300 |
| | | 35 | 1,300 |

| Transmission Bubble | Location | Capacity Factor (%) | Maximum Capacity (MW) |
|---|---|---|---|
| Wyoming (Aeolus substation) | Southwest Wyoming | 24 | 500 |
| | | 29 | 500 |
| | | 35 | 500 |
| Goshen | Southeast Idaho | 24 | 300 |
| | | 29 | 300 |
| Walla Walla | Southeast Washington | 24 | 200 |
| | | 29 | 300 |
| | | 35 | 300 |
| Yakima | South Central Washington | 24 | 300 |
| | | 29 | 200 |
| West Main | Central Oregon | 24 | 700 |
| | | 29 | 500 |
| | | 35 | 100 |
| Mid-Columbia | Southwest Washington | 24 | 100 |
| | | 29 | 100 |
| | | 35 | 100 |
| Utah | Northern Utah | 24 | 200 |
| | | 29 | 200 |

For other wind resource attributes, the company used multiple sources to derive attributes. Capital costs were derived from recent PacifiCorp projects and offers by developers. The EPRI TAG database was also used for certain cost figures, such as operation and maintenance costs. These costs were adjusted for current market conditions. Wheeling costs, applicable for wind projects cited in the west, and average incremental transmission costs for east-side resources needed beyond local interconnection and 230 kV step-up were included in the resources as appropriate.

**Other Renewable Resources**
Other renewable generation resources included in the supply-side resource options table include geothermal, biomass, landfill gas, waste heat and solar. The financial attributes of these renewable options are based on the TAG database and have been adjusted based on PacifiCorp's recent construction and study experience.

The geothermal resource is a dual flash design with a wet cooling tower. This concept would be similar to an expansion of the Blundell Plant. Speculative risks associated with steam field development, as well as recent escalation in drilling costs, are not captured in the geothermal cost characterization.

The biomass project would involve the combustion of whole trees that would be grown in a plantation setting, presumably in the Pacific Northwest. Three solar resources were defined. A concentrating photovoltaic (PV) system represents a utility scale PV resource. Optimistic performance and cost figures were used equivalent to the best reported PV efficiencies. Solar thermal projects are represented by both a solar concentrating design (trough system with natural gas backup) and a solar concentrating design (thermal tower arrangement with 6 hours of thermal storage). The system parameters for these systems were suggested by the WorleyParsons Group study and reflect current proposed projects in the desert southwest.

**Energy Storage**
The storage of energy is represented in the supply-side resource options table with three systems. The three systems are advanced battery applications, pumped hydro and compressed air energy storage. These technologies convert off-peak capacity to on-peak energy and thereby reduce the quantity of required overall capacity installed for peaking needs. Battery applications are typically smaller systems (less than 10 megawatts) that can have the most benefit in a smaller local area. Utility-scale demonstrations are just beginning to be conducted. Advanced battery applications are not available for selection in the modeling before 2014.

Pumped hydro is dependant on a good site combined with the ability to permit the facility, a process that can take many years to accomplish. PacifiCorp does not have any specific pumped hydro projects under development and does not consider this a viable resource before 2018 because of the necessary study and permitting issues.

Compressed air energy storage (CAES) can be an attractive means of utilizing intermittent energy. In a CAES plant, off-peak energy is used to pressurize an underground cavern. The pressurized air would then feed the power turbine portion of a combustion turbine saving the energy normally used in combustion turbine to compress air. CAES plants operate on a simple cycle basis and therefore displace peaking resources. A CAES plant could be built in conjunction with wind resources to level the production for such an intermittent resource. A CAES plant, whether associated with wind or not, would have to stand on its own for cost-effectiveness. Only two

CAES plants have been built in the world. CAES is not considered practical for PacifiCorp until 2015.

**Combined Heat and Power and Other Distributed Generation Alternatives**
CHP are a small (ten megawatts or less) gas compressor heat recovery system using a binary cycle. These projects would be contracted at the customer site. They are labeled as Recovered Energy Generation (CHP) and utility cogeneration in the supply-side table.

A large CHP (40 to 120 megawatts) combustion turbine with significant steam based heat recovery from the flue gas has not been included in PacifiCorp's supply side table for the eastern service territory due to a lack of large potential industrial applications. These CHP opportunities are site-specific, and the generic options presented in the supply-side resource options table are not intended to represent any particular project or opportunity.

Small distributed generation resources are unique in that they reside at the customer load. The generation can either be used to reduce the customer load, such as net metering, or sold to the utility. Distributed standby generation provides peak load reductions over a contracted number of hours from on-site generators owned by the customer but managed by the utility. Small CHP resources generate electricity and utilize waste heat for space and water heating requirements. Fuel is either natural gas or renewable biogas. On-site solar resources, also referred to as "micro solar", include electric generation and energy-efficiency measures that use solar energy. The DG resources are up to 4.8 MW in size.

Table 6.12 shows the megawatt economic potential for distributed standby generation cited in the DSM potential study and the amount of the resource included in the IRP models. Due to the small potential in PacifiCorp's California, Yakima, Walla Walla, and Idaho service territories, these resources were excluded as model options. For distributed CHP, Tables 6.13 and 6.14 show the economic potential and amounts included in the IRP models, respectively. PacifiCorp used screening thresholds of 5 MW by state and 8 MW by technology to exclude resources from the IRP models. Such screening for small distributed generation resources was necessary to accommodate the large number of other resource options included in the IRP models.[25]

**Table 6.12 – Standby Generation Economic Potential and Modeled Capacity**

| | Distributed Standby Generation (MW) | | | | | |
|---|---|---|---|---|---|---|
| | Cumulative Economic Potential | | | IRP Model Option | | |
| Year | Existing | New | Total | Existing | New | Total |
| 2009 | 6.9 | 9.9 | 16.8 | 5.7 | 9.5 | 15.2 |
| 2010 | 9.3 | 14.9 | 24.2 | 8.0 | 14.2 | 22.2 |
| 2011 | 11.8 | 19.9 | 31.6 | 10.3 | 18.9 | 29.2 |
| 2012 | 16.6 | 24.8 | 41.5 | 14.9 | 23.6 | 38.5 |
| 2013 | 21.5 | 29.8 | 51.3 | 19.4 | 28.4 | 47.8 |
| 2014 | 28.8 | 34.8 | 63.6 | 26.3 | 33.1 | 59.4 |
| 2015 | 36.1 | 39.7 | 75.9 | 33.1 | 37.8 | 71.0 |
| 2016 | 43.5 | 44.7 | 88.2 | 40.0 | 42.5 | 82.6 |

[25] Chapter 9 summarizes a portfolio optimization study for which all distributed generation resources were made available to the System Optimizer model for selection, using the preferred portfolio $CO_2$ tax, gas price, and medium load growth input assumptions.

| Year | Distributed Standby Generation (MW) | | | | | |
|---|---|---|---|---|---|---|
| | Cumulative Economic Potential | | | IRP Model Option | | |
| | Existing | New | Total | Existing | New | Total |
| 2017 | 50.8 | 49.7 | 100.5 | 46.9 | 47.3 | 94.1 |
| 2018 | 50.8 | 54.6 | 105.4 | 46.9 | 52.0 | 98.9 |
| 2019 | 50.8 | 59.6 | 110.4 | 46.9 | 56.7 | 103.6 |
| 2020 | 50.8 | 64.6 | 115.4 | 46.9 | 61.5 | 108.3 |
| 2021 | 50.8 | 69.5 | 120.3 | 46.9 | 66.2 | 113.0 |
| 2022 | 50.8 | 74.5 | 125.3 | 46.9 | 70.9 | 117.8 |
| 2023 | 50.8 | 79.5 | 130.3 | 46.9 | 75.6 | 122.5 |
| 2024 | 50.8 | 84.4 | 135.2 | 46.9 | 80.4 | 127.2 |
| 2025 | 50.8 | 89.4 | 140.2 | 46.9 | 85.1 | 132.0 |
| 2026 | 50.8 | 94.4 | 145.2 | 46.9 | 89.8 | 136.7 |
| 2027 | 50.8 | 99.3 | 150.1 | 46.9 | 94.6 | 141.4 |
| 2028 | 50.8 | 99.3 | 150.1 | 46.9 | 99.5 | 146.4 |

## Table 6.13 – Distributed CHP Economic Potential (MW)

| Year | Economic Potential (MW) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Combined Heat & Power (CHP) | | | | | | On-Site Solar | | | Total |
| | Reciprocating Engine | MicroTurbine | Fuel Cell | Gas Turbine | Industrial Biomass | Anaerobic Digesters | Photovoltaic (PV) | Solar Water Heaters | Solar Attic Fans | |
| 2009 | 0.3 | 0.0 | 0.0 | 0.0 | 0.4 | 0.0 | 0.2 | 0.0 | 0.0 | 1.1 |
| 2010 | 1.4 | 0.2 | 0.1 | 0.1 | 1.9 | 0.1 | 0.8 | 0.1 | 0.0 | 4.7 |
| 2011 | 3.0 | 0.4 | 0.2 | 0.2 | 4.1 | 0.3 | 1.6 | 0.2 | 0.1 | 10.0 |
| 2012 | 6.2 | 0.8 | 0.4 | 0.4 | 8.3 | 0.5 | 2.9 | 0.3 | 0.1 | 20.0 |
| 2013 | 10.5 | 1.3 | 0.7 | 0.7 | 14.2 | 0.9 | 4.3 | 0.4 | 0.2 | 33.2 |
| 2014 | 14.8 | 1.8 | 1.0 | 1.0 | 20.0 | 1.3 | 5.9 | 0.5 | 0.2 | 46.5 |
| 2015 | 19.1 | 2.4 | 1.3 | 1.3 | 25.8 | 1.6 | 7.4 | 0.7 | 0.3 | 59.9 |
| 2016 | 23.5 | 2.9 | 1.6 | 1.6 | 31.6 | 2.0 | 9.1 | 0.8 | 0.3 | 73.4 |
| 2017 | 27.8 | 3.4 | 1.9 | 1.9 | 37.5 | 2.4 | 10.7 | 0.9 | 0.3 | 86.8 |
| 2018 | 32.1 | 4.0 | 2.2 | 2.2 | 43.3 | 2.7 | 12.3 | 1.0 | 0.4 | 100.2 |
| 2019 | 36.4 | 4.5 | 2.5 | 2.5 | 49.1 | 3.1 | 13.6 | 1.1 | 0.4 | 113.3 |
| 2020 | 40.7 | 5.0 | 2.8 | 2.8 | 55.0 | 3.4 | 14.7 | 1.2 | 0.4 | 126.1 |
| 2021 | 45.1 | 5.6 | 3.1 | 3.1 | 60.8 | 3.8 | 15.7 | 1.2 | 0.5 | 138.8 |
| 2022 | 49.4 | 6.1 | 3.4 | 3.4 | 66.6 | 4.2 | 16.4 | 1.3 | 0.5 | 151.2 |
| 2023 | 53.1 | 6.5 | 3.7 | 3.6 | 71.6 | 4.5 | 17.0 | 1.3 | 0.5 | 161.9 |
| 2024 | 56.2 | 6.9 | 3.9 | 3.8 | 75.8 | 4.8 | 17.6 | 1.3 | 0.5 | 170.8 |
| 2025 | 58.0 | 7.2 | 4.0 | 3.9 | 78.3 | 4.9 | 18.0 | 1.3 | 0.5 | 176.2 |
| 2026 | 59.9 | 7.4 | 4.2 | 4.1 | 80.8 | 5.1 | 18.4 | 1.4 | 0.5 | 181.6 |
| 2027 | 61.7 | 7.6 | 4.3 | 4.2 | 83.3 | 5.2 | 18.8 | 1.4 | 0.5 | 187.1 |
| 2028 | 63.6 | 7.8 | 4.4 | 4.3 | 85.9 | 5.4 | 19.2 | 1.4 | 0.5 | 192.6 |

## Table 6.14 – Distributed CHP Resources Included as IRP Model Options

| Year | IRP Model Options (MW) | | | |
|---|---|---|---|---|
| | Combined Heat & Power (CHP) | | On-Site ("Micro") Solar | Total |
| | Reciprocating Engine | Industrial Bio-mass | Photovoltaic (PV) | |
| 2009 | 0.3 | 0.3 | 0.2 | 0.8 |
| 2010 | 1.2 | 1.5 | 0.7 | 3.4 |
| 2011 | 2.7 | 3.2 | 1.4 | 7.2 |
| 2012 | 5.4 | 6.6 | 2.5 | 14.5 |
| 2013 | 9.2 | 11.1 | 3.7 | 24.1 |
| 2014 | 13.0 | 15.7 | 5.0 | 33.8 |
| 2015 | 16.8 | 20.3 | 6.4 | 43.6 |
| 2016 | 20.6 | 24.9 | 7.9 | 53.4 |

| Year | IRP Model Options (MW) | | | |
|---|---|---|---|---|
| | Combined Heat & Power (CHP) | | On-Site ("Micro") Solar | |
| | Reciprocating Engine | Industrial Bio-mass | Photovoltaic (PV) | Total |
| 2017 | 24.4 | 29.5 | 9.2 | 63.2 |
| 2018 | 28.2 | 34.1 | 10.6 | 73.0 |
| 2019 | 32.1 | 38.7 | 11.8 | 82.5 |
| 2020 | 35.9 | 43.3 | 12.7 | 91.8 |
| 2021 | 39.7 | 47.8 | 13.5 | 101.0 |
| 2022 | 43.5 | 52.4 | 14.2 | 110.1 |
| 2023 | 46.7 | 56.4 | 14.7 | 117.8 |
| 2024 | 49.4 | 59.6 | 15.2 | 124.3 |
| 2025 | 51.1 | 61.6 | 15.5 | 128.2 |
| 2026 | 52.7 | 63.6 | 15.9 | 132.2 |
| 2027 | 54.3 | 65.5 | 16.3 | 136.1 |
| 2028 | 56.0 | 67.6 | 16.6 | 140.2 |

### Nuclear
An emissions-free nuclear plant has been included in the supply-side resource options table. This option is based recent internal studies, press reports and information from a paper prepared by the Uranium Information Centre Ltd., "The Economics of Nuclear Power," May 2008. A 1,600 MW plant is characterized utilizing advanced nuclear plant designs. Nuclear power is not considered a viable option in the PacifiCorp service territory before 2025.

## DEMAND-SIDE RESOURCES

### Resource Options and Attributes

### Source of Demand-side Management Resource Data
Demand-side resource opportunity estimates used in the development of the 2008 IRP were derived from data provided from the "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" study completed in June 2007 (DSM potential study). Preliminary results from the DSM potential study were initially incorporated in the 2007 IRP Update. However, these estimates were not modeled under the prescribed supply-curve methodology until the development of the 2008 IRP. The DSM potential study provided a broad estimate of the size, type, location and cost of demand-side resources. The demand-side resource information was converted into supply-curves by type of DSM; e.g. capacity-based Classes 1 and 3 DSM and energy-based Class 2 DSM for modeling against competing supply-side alternatives.

### Demand-side Management Supply Curves
Resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and costs of resources. Supply curves incorporate a linear relationship between quantities and costs (at least up to the maximum quantity available) to help identify at any particular cost how much of a particular resource can be acquired. Resource modeling utilizing supply curves allows utilities to sort out and select the least-cost resources (products and quantities) based on each resource's cost versus quantity in comparison against the supply curves of alternative and competing resource types.

As with supply-side resources, the development of demand-side resource supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to demand-side supply curves include:

- Resource quantities available in year one—either megawatts or megawatt-hours— recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year
- Resource quantities available over time; for example, Class 2 energy-based resource measure lives
- Seasonal availability and hours available (Class 1 and Class 3 capacity resources)
- The shape or hourly contribution of the resource (load shape of the Class 2 energy resource)
- Levelized resource costs (dollars per megawatt per year for Class 1 and 3 capacity resources, or dollars per megawatt-hour for Class 2 energy resources)

Once developed, demand-side resource supply curves are treated like any other discrete supply-side resource in the IRP modeling environment. A complicating factor for modeling is that the DSM supply curves must be configured to meet the input specifications for two models: the System Optimizer capacity expansion optimization model, and the Planning and Risk production cost simulation model.

<u>Class 1 DSM Capacity Supply Curves</u>
Supply curves were created for four discrete Class 1 DSM products: residential air conditioning load control, irrigation load control, dispatchable commercial curtailment, and commercial and industrial thermal energy storage. The potentials and costs for each product were provided at the state level resulting in four products across six states, or twenty-four supply curves before accounting for system load areas (some states cover more than one load area). After accounting for load areas, a total of forty Class 1 DSM supply curves were used in the 2008 IRP modeling process.

The starting point for supply curve development was DSM product information originally used for PacifiCorp's 2007 IRP. This information was further refined based on the following:

- Updated costs
- Customer surveys and acceptance data from the DSM potential study information
- Adjustments to DSM potential study results based on amended assumptions
- Another years experience delivering Class 1 DSM products
- The 2007 IRP modeling results.

In developing information on the four products and creation of supply curves, assumption changes (from those used in the DSM potential study) were made to two of the four products. The net potential for irrigation load control in the east was increased, as was the cost, to recognize the percentage of customers expected to select a dispatchable control option over a scheduled firm control option. In a second case, a new Class 1 product was created in order to incorporate the potential from a Class 3 product, commercial curtailment, for base resource consideration. The product recognizes how the company intends to pursue, through program design, available commercial control opportunities (e.g. leverage controllable commercial loads using customer energy management systems combined with contracts for utility dispatched operation of customer distributed standby generators.)

The potential and cost of the Class 3 commercial curtailment product was used to create the new Class 1 product for three reasons. First, the potential captured in the Class 3 product was assumed to come from customer control of end-use equipment, not from any distributed standby generation capabilities. Second, the potential for distributed standby generation was included in the IRP model as a supply-side resource option. (It is already captured as a model resource). Third, the levelized cost for the Class 3 commercial curtailment product is in the same range as the levelized cost for distributed standby generation; approximately $50-$60 per kilowatt per year.

Other product price differences between west and east control areas were driven by resource differences in each market, such as irrigation pump sizes, types of pumping, and product performance differences (for example, residential air conditioning load control in the west is nearly twice the cost of east-side programs due to climatic differences that lead to less control per installed switch.) Pricing is also impacted by resource opportunity differences. The DSM potential study assumed the same fixed costs regardless of quantify of a particular product available. Therefore, the weighted average cost per control area for products with less opportunity in a particular state have a higher cost per kilowatt-year for that product.

The combination residential air conditioning and electric water heating dispatchable load control product was not provided to the System Optimizer model as a resource option for either control area. In the west, electric water heating control wasn't included as it adds little additional load for the cost, and electric water heating market share continues to decline each year as a result of conversions to gas. In the east, electric water heating control wasn't included because (1) the market potential is very small. (It is predominantly a gas water heating market), (2) an established program already exists that doesn't include a water heater control component, and (3) the potential identified is assumed to be located in areas where gas is not available; such as more rural and mountainous areas where direct load control paging signals are less reliable.

Tables 6.15 and 6.16 show the summary level Class 1 DSM program information, by control area, used in the development of the Class 1 resources supply curves. As previously noted, each of the products were further broken down by quantity available by state and load area in order to provide the model with location-specific details.

**Table 6.15 – Class 1 DSM Program Attributes West Control Area**

| Products | Competing Strategy | Hours Available | Season | Potential (MW) | Cost ($/kW-yr)[1] | Year Available |
|---|---|---|---|---|---|---|
| Residential Air Conditioning | Yes, with combo AC & water heating | Summer 40, not to exceed 6 hours per day | June 1 to Sept. 15 | 11 | $165 | 2009 |
| Irrigation (50% dis- | No | Summer | June 1 to | 20 | $50 | 2009 |

| Products | Competing Strategy | Hours Available | Season | Potential (MW) | Cost ($/kW-yr)[1] | Year Available |
|---|---|---|---|---|---|---|
| patchable and 50% scheduled firm) | | 40, not to exceed 6 hours per day | Sept. 15 | | | |
| Commercial Curtailment (combination dispatchable product, excludes DSG in potential but will include in program to design) | Yes, with C&I Direct Load Control, Thermal Energy Storage, demand buyback, critical peak pricing, real-time pricing, and distributed standby generation | Summer and winter 40, 80 hours total. Not to exceed 6 hours per day | June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29) | 5 | $61 | 2009 |
| Commercial Thermal Energy Storage | | Summer 40 | June 1 to Sept. 15 | 2 | $150 | 2009 |

[1] These costs are before a credit of $23/KW-year is applied for avoided transmission and distribution investment costs.

### Table 6.16 – Class 1 DSM Program Attributes East Control Area

| Products | Competing Strategy | Hours Available | Season | Potential (MW) | Cost ($/kW-yr)[1] | Year Available |
|---|---|---|---|---|---|---|
| Residential Air Conditioning | Yes, with combo AC & WH | Summer 40, not to exceed 6 hours per day | Jun 1 to Sept. 15 | 47 | $93 | 2009 |
| Irrigation (50% dispatchable and 50% scheduled firm) | No | Summer 40, not to exceed 6 hours per day | June 1 to Sept. 15 | 45 | $57 | 2009 |
| Commercial Curtailment (combination dispatchable product, excludes DSG in potential but will include in program to design) | Yes, with C&I Direct Load Control, Thermal Energy Storage, demand buyback, critical peak pricing, real-time pricing, and distributed standby generation | Summer and winter 40, 80 hours total. Not to exceed 6 hours per day | June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29) | 38 | $59 | 2009 |
| Commercial Thermal Energy Storage | | Summer 40 | June 1 to Sept. 15 | 7 | $153 | 2009 |

[1] These costs are before a credit of $23/KW-year is applied for avoided transmission and distribution investment costs.

To configure the supply curves for use in the System Optimizer model, there are a number of data conversions and resource attributes that are required by the System Optimizer model. All programs are defined to operate within a 5x8 hourly window and are priced in $/kW-month. A credit of $23/kW-year for avoided transmission and distribution investment costs is also applied against the cost.[26] The following are the primary model attributes required by the model:

- The Capacity Planning Factor (CPF): This is the percentage of the program size (capacity) that is expected to be available at the time of system peak. For Class 1 and 3 DSM programs, this parameter is set to 1 (100 percent).
- Additional reserves: This parameter indicates whether additional reserves are required for the resource. Firm resources, such as dispatchable load control, do not require additional reserves.
- Daily and annual energy limits: These parameters, expressed in gigawatt-hours, are used to implement hourly limits on the programs. They are obtained by multiplying the hours available by the program size.
- Nameplate capacity (MW) and service life (years)
- Maximum Annual Units: This parameter, specified as a pointer to a vector of values, indicates the maximum number of resource units available in the year for which the resource is designated.
- First year and month available/last year available
- Fractional Units First Year: This parameter tells the model the first year in which a fractional quantity of the resource (as opposed to an integer quantity) can be selected. Year 2008 is entered in order to make these DSM resource options fractionally available in all years.

After the model has selected DSM resources, a program converts the resource attributes and quantities into a data format suitable for direct import into the Planning and Risk model.

<u>Class 3 DSM Capacity Supply Curves</u>
This DSM resource type consists of 50 distinct supply curves, reflecting a combination of products, states, and load areas. The Class 3 DSM programs modeled include the following:

- Residential time-of-use rates (Res RTP)
- Residential critical peak pricing (CPP)
- Commercial and industrial critical peak pricing (C&I CPP)
- Commercial and industrial real-time pricing (C&I RTP)
- Commercial and industrial demand buyback (C&I DBB)

In providing the data for the construction of Class 3 DSM supply curves, the company did not net-out one product's resource potential against a competing product. As Class 3 DSM resource selections are not included as base resources for planning purposes, not taking product interactions into consideration poised no risk of over-reliance (or double counting the potential) of these resources in the final resource plan. For instance, in the development of the supply curves for

[26] The Northwest Power and Conservation Council (NWPCC) and the Energy Trust of Oregon (ETO) use this value for their DSM avoided cost calculations.

residential time-of-use the program's market potential was not adjusted by the market potential or quantity available of a lesser-cost alternative, residential critical peak pricing.

Market potentials and costs for each of the five Class 3 DSM programs modeled were taken from the estimates provided in the DSM potential study and evaluated independently as if it were the only resource available targeting a particular customer segment.

Product price differences between west and east control areas were driven by resource opportunity differences. The DSM potential study assumed the same fixed costs in each state in which it is offered regardless of quantify available. Therefore, states with lower resource availability for a particular product have a higher cost per kilowatt-year for that product.

Tables 6.17 and 6.18 show the summary level Class 3 DSM program information, by control area, used in the development of the Class 3 resources supply curves. As previously noted, each of the products were further broken down by quantify available by state and load bubble in order to provide the model with location specific information.

### Table 6.17 – Class 3 DSM Program Attributes West Control area

| Products | Competing Strategy | Hours Available | Season | Potential (MW) | Cost ($/kW-yr)[1] | Year Available |
|---|---|---|---|---|---|---|
| Residential TOU | Yes, with Res CPP and Res A/C DLC | N/A | Year around | 8 | $173 | 2009 |
| Residential CPP | Yes, with Res TOU and Res A/C DLC | Summer 40 | June 1- Sept. 15 | 22 | $91 | 2009 |
| Commercial and Industrial CPP | Yes, with C&I RTP, DBB and commercial curtailment | Summer and winter 40, 80 hours total | June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29) | 9 | $33 | 2009 |
| Commercial and Industrial RTP | Yes, with C&I CPP, DBB and C&I curtailment | Summer and winter 40, 80 hours total | June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29) | 1 | $8 | 2009 |
| Commercial and Industrial DBB | Yes, with C&I CPP and RTP and C&I curtailment | Summer and winter 25, 50 hours total | June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29) | 10 | $18 | 2009 |

[1] These costs are before a credit of $23/kW-year is applied for avoided transmission and distribution investment costs.

### Table 6.18 – Class 3 DSM Program Attributes East Control area

| Products | Competing Strategy | Hours Available | Season | Potential (MW) | Cost ($/kW-yr)[1] | Year Available |
|---|---|---|---|---|---|---|
| Residential TOU | Yes, with Res CPP and Res A/C DLC | N/A | Year around | 11 | $166 | 2009 |
| Residential CPP | Yes, with Res TOU and Res A/C DLC | Summer 40 | June 1- Sept. 15 | 30 | $88 | 2009 |

| Products | Competing Strategy | Hours Available | Season | Potential (MW) | Cost ($/kW-yr)[1] | Year Available |
|---|---|---|---|---|---|---|
| Commercial and Industrial CPP | Yes, with C&I RTP, DBB and commercial curtailment | Summer and winter 40, 80 hours total | June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29) | 61 | $12 | 2009 |
| Commercial and Industrial RTP | Yes, with C&I CPP, DBB and C&I curtailment | Summer and winter 40, 80 hours total | June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29) | 14 | $6 | 2009 |
| Commercial and Industrial DBB | Yes, with C&I CPP and RTP and C&I curtailment | Summer and winter 25, 50 hours total | June 1 to Sept. 15 and Nov. 1 to Feb. 28 (29) | 27 | $18 | 2009 |

[1] These costs are before a credit of $23/kW-year is applied for avoided transmission and distribution investment costs.

System Optimizer data formats and parameters for Class 3 DSM programs are similar to those defined for the Class 1 DSM programs. The data export program converts the Class 3 DSM programs selected by the model into a data format for import into the Planning and Risk model.

Class 2 DSM, Capacity Supply Curves

The 2008 IRP represents the first time the company has utilized the supply curve methodology in the evaluation and selection of Class 2 DSM energy products. The DSM potential study provided the information to fully assess the contribution of Class 2 DSM resources over IRP planning horizons. Class 2 DSM resource data was provided by state down to the individual measure and facility levels; e.g., specific appliances, motors, air compressors for residential buildings, small offices, etc. In all, the DSM potential study provided Class 2 DSM resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming
- **Measure:**
  - Sixty-two residential measures
  - Seventy-eight commercial measures
  - Thirteen industrial measures
  - Three irrigation measures
- **Facility type:**
  - Six residential facility types
  - Twenty four commercial facility types
  - Twenty eight industrial facility types
  - Two irrigation facility types

The DSM potential study also provided total resource costs, which included both measure cost and a 15 percent adder for administrative costs levelized over measure life at PacifiCorp's cost of capital, consistent with the treatment of supply-side resource costs.

The technical potential for all Class 2 DSM resources across five states over the twenty-year DSM potential study horizon totaled 9.9 million MWh. The technical potential represents the total universe of possible savings before adjustments for what is cost-effective to pursue (economic), likely to be realized (achievable), and impacts of emerging codes and standards such as the 2007 Energy Policy Act, whose impact full wasn't known at the time the DSM potential study was completed.

Despite the granularity of Class 2 DSM resource information available, it was impractical to use this much information in the development of Class 2 DSM resource supply curves. The combination of measures by facility type and state resulted in 12,500 distinct measures that could be modeled using the supply curve methodology.[27] This many supply curves is impossible to handle with PacifiCorp's IRP models. To reduce the resource options for consideration, while not losing the overall resource quantity available, the decision was made to consolidate like measures (by weighted-average load shapes and lives) and costs of sets of measures into bundles to reduce the number of combinations to a more manageable number.

The bundles were developed based on Class 2 DSM potential study technical potentials (all economic screens were removed). The achievable assumption was adjusted from that estimated in the DSM potential study to eighty-five percent of the technical potential to account for the practical limits on acquiring all resources in all years. The assumption is consistent with regional planning assumptions in the Northwest. Five cost bundles, across five states, over twenty years equates to 500 supply curves before allocating across the company load areas shown in Table 6.19.

**Table 6.19 – Load Area Energy Distribution by State**

| State | Goshen | Utah | Walla Walla | West Main | Wyoming | Yakima |
|---|---|---|---|---|---|---|
| CA | | | | 100% | | |
| OR | | | 4% | 96% | | |
| ID | 42% | 58% | | | | |
| UT | | 100% | | | | |
| WA | | | 25% | | | 75% |
| WY | | 18% | | | 82% | |

After the load areas are accounted for (with some states served in more than one load area as noted in table 6.20), the number of supply curves grew to 800, excluding Oregon.

Table 6.20 shows the Class 2 DSM cost bundles used in the 2008 IRP and the associated bundle price. The bundle price can be interpreted as the marginal levelized cost for the group of measures. These prices, adjusted for the $23/kW-year transmission/distribution investment deferral benefit, represent the Class 2 DSM price inputs for the IRP models.

[27] Not all energy efficiency measures analyzed are applicable to all market segments. The two most common reasons for this are (1) differences in existing and new construction and (2) some end-uses do not exist in all building types. For example, a measure may look at the savings associated with increasing an existing home's insulation up to current code levels. However, this level of insulation would already be required in new construction, and thus, would not be analyzed for the new construction segment. Similarly, certain measures, such as those affecting commercial refrigeration would not be applicable to all commercial building types, depending on the building's primary business function; for example, office buildings would not typically have commercial refrigeration.

**Table 6.20 – Class 2 DSM Cost Bundles and Bundle Prices**

| Class 2 DSM Cost Bundle | Resource Cost Range | Bundle Price ($/MWh) |
|---|---|---|
| Cost Bundle 1 | $0.01/kWh to $0.07/kWh | $70 |
| Cost Bundle 2 | $0.07/kWh to $0.09/kWh | $90 |
| Cost Bundle 3 | $0.09/kWh to $0.11/kWh | $110 |
| Cost Bundle 4 | $0.11/kWh to $0.13/kWh | $130 |
| Cost Bundle 5 | $0.13/kWh to $0.15/kWh | $150 |
| Cost Bundle 6 | $0.15/kWh to $0.18/kWh | $180 |

Class 2 DSM resources in Oregon are acquired on behalf of the company through Energy Trust of Oregon programs. To avoid duplicative potential assessment efforts the scope of PacifiCorp's DSM potential study excluded the analysis and evaluation of Class 2 resource potentials in Oregon. As a result, the company relied on resource potential information provided by the Energy Trust of Oregon. The ETO economically screened their Oregon Class 2 DSM supply curves by using values compiled from regional and utility-specific valuation data.

The ETO provided the company one cost bundle, weighted and shaped by the end-use measure potential for each year over a twenty-year horizon. Allocating these resources over two load areas in Oregon for consistency with other modeling efforts generated an additional 40 Class 2 supply curves (one cost bundle multiplied by two load areas multiplied by twenty years).

Table 6.21 shows the peak megawatt capacity represented by the supply curves for each state.

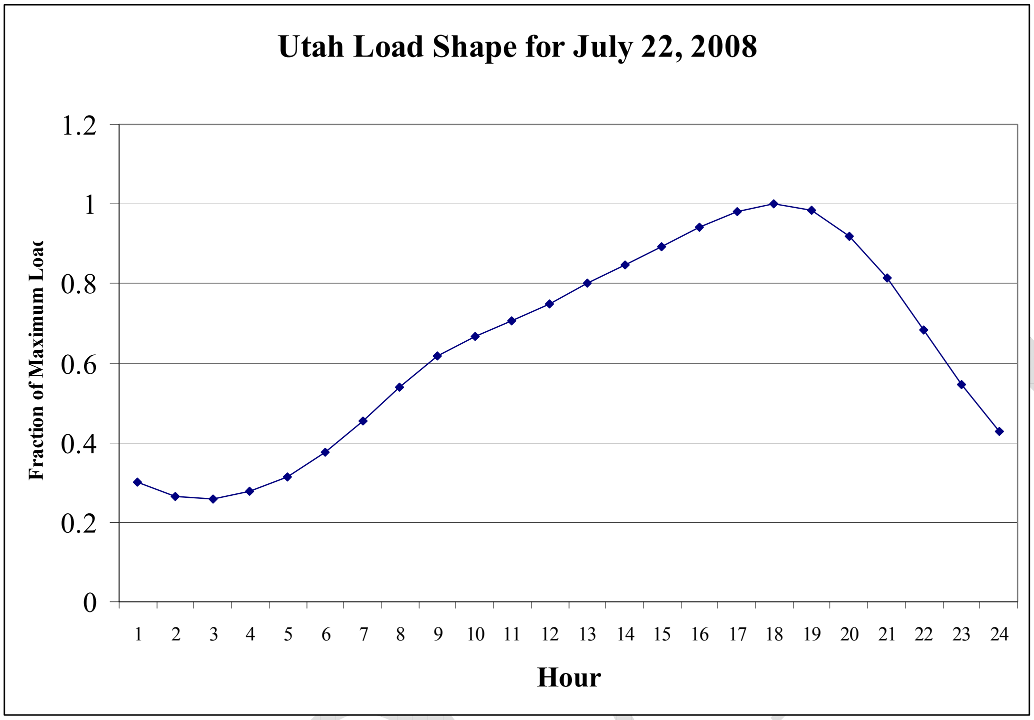
**Table 6.21 – Class 2 DSM Supply Curve Capacities by State**

| State | Capacity (MW) |
|---|---|
| California | 47 |
| Idaho | 143 |
| Oregon | 472 |
| Utah | 1,718 |
| Washington | 255 |
| Wyoming | 290 |
| Total | 2,916 |

In addition to the program attributes described for the Class 1 and 3 DSM resources, the Class 2 DSM supply curves also have load shapes describing the available energy savings on an hourly basis. For System Optimizer, each supply curve is associated with an annual hourly ("8760") load shape configured to the 2008 calendar year. These load shapes are used by the model for each simulation year. In contrast, the Planning and Risk model requires for each supply curve a load shape that covers all 20 years of the simulation.

The load shape is composed of fractional values that represent each hour's demand divided by the maximum demand in any hour for that shape. For example, the hour with maximum demand would have a value of 1.00 (100%), while an hour with half the maximum demand would have a value of 0.50 (50%). Summing the fractional values for all of the hours, and then multiplying this result by peak-hour demand, produces the annual energy savings represented by the supply curve. Figure 6.1 shows the Utah load shape for a representative day: July 22, 2008.

**Figure 6.1 – Utah Load Shape**




## TRANSMISSION RESOURCES

While the Energy Gateway Transmission project was treated as part of the base topology for the IRP models, PacifiCorp included three transmission options that the System Optimizer could select. The first option was an incremental addition to the Energy Gateway West project. This expansion option consisted of a 750 MW capacity increase from Path C in Idaho/northern Utah to the West Main load area, representing Oregon and northern California. This option was available beginning in 2015. The other two options, not associated with the Energy Gateway project, consisted of incremental 200 MW and 400 MW capacities for a Walla Walla to West Main transmission project available beginning in 2014.

## MARKET PURCHASES

### Resource Option Selection Criteria

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). Front office transactions are proxy resources, assumed to be firm, that represent procurement activity made on an annual forward basis to help the company cover short positions. Table 6.22 shows the front office transaction resources included in the IRP models. Note that the Table distinguishes FOT resource assumptions made in February 2009 to support additional portfolio analysis based on termination of the 2012 Lake Side 2 CCCT construction contract. East-side FOT assumption changes were prompted by additional transmission availability from Mona to Utah for which the company recently became aware.

**Table 6.22 – Maximum Available Front Office Transaction Quantity by Market Hub**

| Market Hub or Load Area | Product Type | Maximum Available Capacity (MW) | Availability |
|---|---|---|---|
| Mid-Columbia | 3rd Quarter Heavy Load Hour or Flat Annual | 400 | 2009-2028 |
| California Oregon Border (COB) | 3rd Quarter Heavy Load Hour or Flat Annual | 400 | 2009-2028 |
| West Main | 3rd Quarter Heavy Load Hour | 50 | 2009-2028 |
| Mead | 3rd Quarter Heavy Load Hour | 600 | 2017-2028 |
| Mona | 3rd Quarter Heavy Load Hour | 200 | 2009-2028 |
| Utah | 3rd Quarter Heavy Load Hour | 50 | 2009-2028 |
| Modifications to Support 2012 Gas Resource Deferral Strategy | | | |
| Nevada Utah Border (NUB) | 3rd Quarter Heavy Load Hour | 164 [1/] | 2012 |
| Nevada Utah Border (NUB) | 3rd Quarter Heavy Load Hour | 579 [2/] | 2013 |
| Mid-Columbia | 3rd Quarter Heavy Load Hour or Flat Annual | 400 | 2009-2012 |
| Mid-Columbia | 3rd Quarter Heavy Load Hour or Flat Annual | 775 (400 + 375 with 10% price premium) | 2012-2013 |
| Mid-Columbia | 3rd Quarter Heavy Load Hour or Flat Annual | 400 | 2014-2028 |

[1/] Supported by completion of reactive compensation installation at Camp Williams substation in Utah, and anticipated 300 MW of additional firm transmission from Mead to NUB provided by Nevada Power.

[2/] Supported by completion of the Mona to Oquirrh transmission line by the end of 2012, and anticipated 300 MW of additional firm transmission from Mead to NUB provided by Nevada Power.



To arrive at these maximum quantities, PacifiCorp considered the following:

- Historical operational data and institutional experience with transactions at the market hubs.
- The company's forward market view, including an assessment of expected physical delivery constraints and market liquidity and depth.
- Financial and risk management consequences associated with acquiring purchases at higher levels, such as additional credit and liquidity costs.

The temporary increase in Mid-Columbia FOT market depth, from 400 MW to 775 MW in both 2012 and 2013, is accompanied by an assumed 10 percent price premium.

PacifiCorp examined the recent Mid-Columbia transaction history for forward third-quarter heavy load hour (HLH) products to support this short-term increase.[28] For example, according to the Intercontinental Exchange (ICE), 2008 transaction volumes reached 3,725 MW for third-quarter HLH products delivered in 2009.

## Resource Options and Attributes

Two front office transaction types were included for portfolio analysis: an annual flat product, and a HLH 3rd quarter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. Third-quarter HLH transactions represent purchases received 16 hours per day, 6 days per week from July through September. Because these products are assumed to be firm for this IRP, the capacity contribution of front office transactions is grossed up for purposes of meeting the planning reserve margin. For example, a 100 MW front office transaction is treated as a 112 MW contribution to meeting PacifiCorp's load obligation plus a 12 percent planning reserve margin, with the selling counterparty holding the reserves necessary to make the product firm.

Prices for front office transaction purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges.

For this IRP, the Public Utility Commission of Oregon directed PacifiCorp to evaluate intermediate-term market purchases as resource options and assess associated costs and risks.[29] In formulating market purchase options for the IRP models, the company lacked cost and quantity information with which to discriminate such purchases from the proxy FOT resources already modeled in this IRP. Lacking such information, the company anticipated using bid information from the 2008 All-Source RFP, if applicable, to inform the development of intermediate-term market purchase resources for modeling purposes. The company received no intermediate-term market purchase bids; therefore, such resources were not modeled for this IRP.

## Resource Description

As proxy resources, front office transactions represent a range of purchase transaction types. They are usually standard products, such as HLH, LLH, and/or daily HLH call options (the right to buy or "call" energy at a "strike" price) and typically rely on standard enabling agreements as a contracting vehicle. Front office transaction prices are determined at the time of the transaction, usually via a third party broker and based on the view of each respective party regarding the then-current forward market price for power. An optimal mix of these purchases would include a range in terms for these transactions.

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[28] HLH is the daily time block, hour-ending 7 am – 10 pm, for Monday through Saturday, excluding NERC-observed holidays.

[29] Public Utility Commission of Oregon, In the Matter of PacifiCorp, dba Pacific Power 2007 Integrated Resource Plan, Docket No. LC 42, Order No. 08-232, April 4, 2008, p. 36.

Solicitations for front office transactions can be made years, quarters or months in advance. Annual transactions can be available up to as much as three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

# 7. MODELING AND PORTFOLIO EVALUATION APPROACH

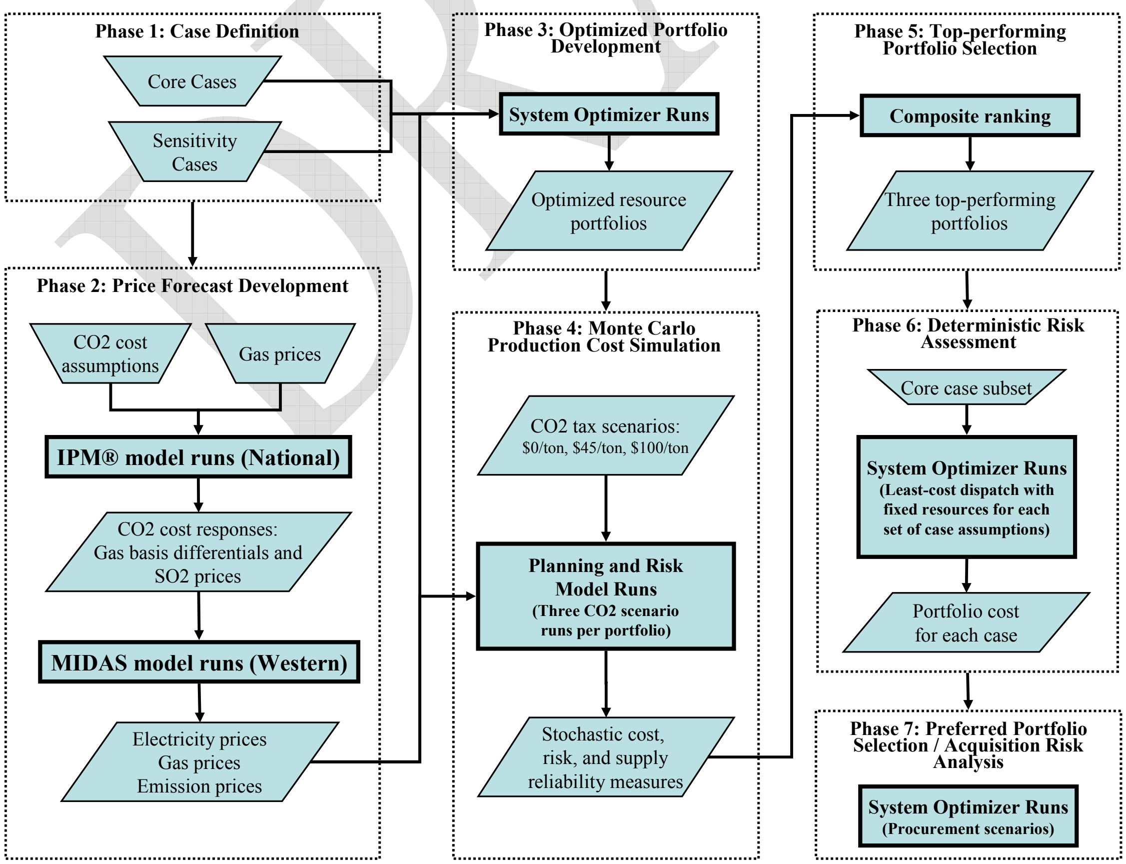
## INTRODUCTION

The IRP modeling effort seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation. This chapter describes the modeling and risk analysis process that supported portfolio performance evaluation. The information drawn from this process, summarized in Chapter 8, was used to help determine PacifiCorp's preferred portfolio and support the analysis of near-term resource acquisition risks.

The 2008 IRP modeling effort consists of seven phases: (1) define input scenario—referred to as *cases*—characterized by alternative carbon dioxide costs, commodity gas prices, wholesale electricity prices, load growth trends, and other cost drivers, (2) case-specific price forecast development, (3) optimized portfolio development for each case using PacifiCorp's System Optimizer capacity expansion model, (4) Monte Carlo production cost simulation of each optimized portfolio to support stochastic risk analysis, (5) selection of top-performing portfolios using a composite ranking scheme that incorporates stochastic portfolio cost and risk assessment measures, (6) deterministic risk analysis using the System Optimizer, and (7) preferred portfolio selection, followed by acquisition risk analysis of preferred portfolio resources. Figure 7.1 presents the seven phases in flow chart form, showing the main process steps, data flows, and models involved for each phase. General modeling assumptions and price inputs are covered first in this chapter, followed by a profile of each modeling phase.



**Figure 7.1 – Modeling and Risk Analysis Process**



## GENERAL ASSUMPTIONS AND PRICE INPUTS

### Study Period and Date Conventions

PacifiCorp executes its IRP models for a 20-year period beginning January 1, 2009 and ending December 31, 2028. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year. The System Optimizer model requires in-service dates designated as the first day of a given month, while the Planning and Risk production cost simulation model allows any date.

### Escalation Rates and Other Financial Parameters

#### Inflation Rates

Integrated resource planning model simulations and price forecasts reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. For the System Optimizer model, a single escalation rate value is used. This value, 1.9 percent, is estimated as the average of the annual corporate inflation rates for the period 2009 to 2030, using PacifiCorp's June 2008 inflation curve. For the Planning and Risk model, the full series of annual values from 2009 through 2028 is used.

#### Discount Factor

The rate used for discounting in financial calculations is PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2008 IRP is 7.4 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[30]

#### Federal and State Renewable Resource Tax Incentives

In October 2008, The U.S. Congress provided a one-year extension of the renewable Production Tax Credit (PTC) through December 31, 2009. The current tax credit of $21/MWh, which applies to the first 10 years of commercial operation, is converted to a levelized net present value and added to the resource capital cost for entry into the System Optimizer model. The renewable PTC, or an equivalent federal financial incentive, is assumed to be available for all years in the study period.

The Emergency Economic Stabilization Act of 2008 (P.L. 110-343) allows utilities to claim the 30-percent investment tax credit for solar facilities placed in service by January 1, 2017. This tax credit is factored into the capital cost for solar resource options in the System Optimizer model.

A number of state incentive programs are also included into the renewable resource capital costs for eligible facilities. These programs include the following

- **Utah** – The current production tax credit for wind, geothermal, and solar facilities located in Utah is $3.5/MWh over 4 years. There is no sunset provision for this tax credit.

- **Oregon** – Oregon's Business Energy Tax Credit (BETC) provides for an investment tax credit of 50 percent of qualifying costs for projects sited in Oregon up to $20 million for a total credit of $10 million. Projects receive up to $2 million per year over 5 years. Qualifying

[30] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

projects include wind, solar, hydro, geothermal, and biomass. Projects are on a first come first served basis up to the Oregon's annual allocated dollars of tax benefits. There is no sunset provision for this credit, but the cap is likely to change from time to time.

- **Idaho** – 3% Investment Tax Credit (ITC) provision on tangible personal property. Credit is available to all construction projects and not unique to renewable projects.

**Asset Lives**

Table 7.1 lists the generation resource asset book lives assumed for levelized fixed charge calculations.

**Table 7.1 – Resource Book Lives**

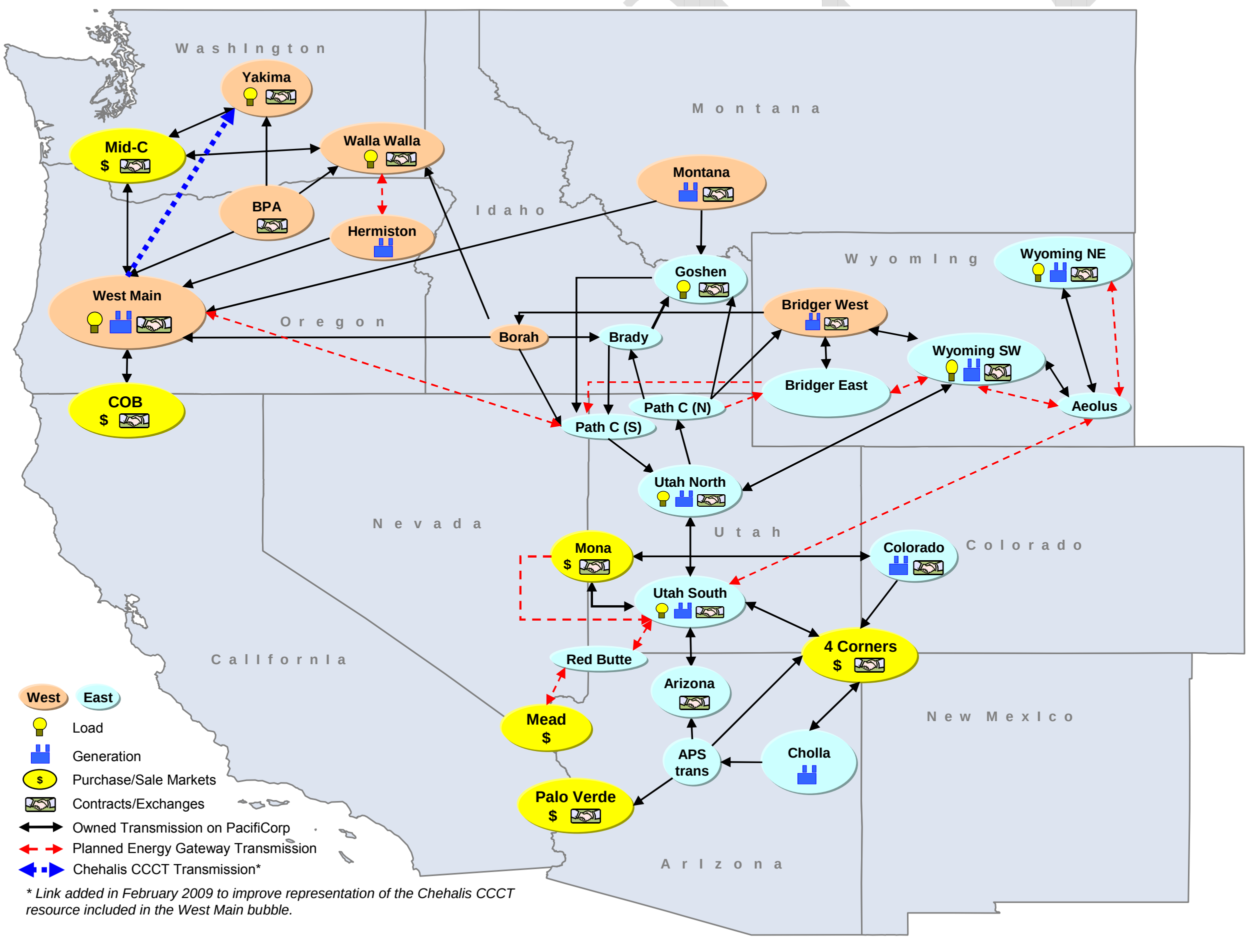
| Resource | Book Life (Years) |
|---|---|
| Supercritical pulverized coal/Integrated Gasification Combined-Cycle | 40 |
| Coal plant retrofit with carbon capture and sequestration | 20 |
| Combined Cycle Combustion Turbine | 40 |
| Pumped Storage | 50 |
| Single Cycle Combustion Turbine (SCCT) Frame | 35 |
| Geothermal | 40 |
| Solar Photovoltaic | 20 |
| Solar Thermal | 30 |
| Compressed Air Energy Storage | 30 |
| Single Cycle Combustion Turbine (SCCT) Frame | 30 |
| Intercooled Aeroderivative SCCT | 30 |
| Internal Combustion Engine | 30 |
| Fuel Cells | 25 |
| Utility-Scale Combined Heat & Power (CHP) | 25 |
| Wind | 25 |
| Battery Storage | 30 |
| Biomass | 30 |
| Hydrokinetic, Wave - Floating Buoy | 20 |
| Nuclear Plant | 40 |
| CHP-Reciprocating Engine | 20 |
| CHP - Gas Turbine | 20 |
| CHP - Microturbine | 15 |
| CHP - Fuel Cell | 10 |
| CHP - Commercial Biomass, Anaerobic Digester | 15 |
| CHP - Industrial Biomass Waste | 15 |
| Solar - Rooftop Photovoltaic | 25 |
| Solar - Water Heaters | 15 |
| Solar - Attic Fans | 10 |
| Dispatchable Standby Generators | 20 |
| Recovered Energy Generation | 30 |
| Microturbine | 15 |

## Transmission System Representation

PacifiCorp uses a transmission topology consisting of 19 bubbles (geographical areas) in its Eastern Control Area and 10 bubbles in its Western Control Area designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Firm transmission paths link the bubbles. The transfer capabilities for these links represent PacifiCorp Merchant function's current firm rights on the transmission lines. This topology is defined for both the System Optimizer and Planning and Risk models, and was also used for IRP modeling support for PacifiCorp's 2009 business plan.

Figure 7.2 shows the IRP transmission system model topology. Segments of the planned Energy Gateway Transmission Project are indicated with red dashed lines.

**Figure 7.2 – Transmission System Model Topology**




The most significant change to the model topology from the one used for the 2007 IRP Update is the expansion of the single Wyoming bubble into three bubbles: Wyoming Southwest, Wyoming Northeast, and Aeolus (substation). This disaggregation supports a more refined view of potential Wyoming resource siting in consideration of transmission constraints—represented as the TOT 4A cut plane—as well as the addition of the planned Aeolus substation that supports Energy Gateway Transmission expansion.

The other major change to the model topology is the addition of the Hermiston bubble in the Western Control Area, which supports the representation of the Walla Walla to McNary segment of the Gateway project.

In February 2009, additional changes were made to the system topology to improve representation of long-term transmission rights for the Chehalis, Washington combined-cycle plant included in the West Main bubble. One of the changes involved the addition of a uni-directional path from the West Main to Yakima bubble. This path addition is shown as a blue dashed line in Figure 7.2. Additionally, the Energy Gateway segment C path (uni-directional, Mona to Oquirrh) was added to facilitate additional market transfer capability from the Mona bubble to Utah South.

## CASE DEFINITION

The first phase of the IRP modeling process was to define the cases (input scenarios) that the System Optimizer model uses to derive optimal resource expansion plans. The cases consist of variations in inputs representing the predominant sources of portfolio cost variability and uncertainty. PacifiCorp generally specified low, medium, and high values to ensure that a reasonably wide range in potential outcomes is captured.

PacifiCorp defined two types of cases: core cases and sensitivity cases. Core cases focus on broad comparability of portfolio performance results for three key variables. These variables include (1) the level of a per-ton carbon dioxide tax, (2) natural gas and wholesale electricity prices based on PacifiCorp's forward price curves and adjusted as necessary to reflect $CO_2$ tax impacts, and (3) retail load growth. The company developed 29 core cases based on a combination of input variable levels.

In contrast, sensitivity cases focus on changes to resource-specific assumptions, alternative $CO_2$/renewable energy regulatory policies, and planning assumptions. The resulting portfolios from the sensitivity cases are typically compared to one of the core case portfolios. PacifiCorp developed 17 sensitivity cases reflecting alternative $CO_2$ compliance strategies, clean base load technology availability, an alternative planning reserve margin level, and inclusion of price-responsive demand-side management programs (Class 3 DSM) as resource options. Also included in the sensitivity case group are two "reference" cases reflecting the 2009 business plan resources for 2009 through 2018, resulting in a total of 19 sensitivity cases.

In developing these cases, PacifiCorp kept to a target range in terms of the total number (40 to 50) in light of the data processing and model run-time requirements involved. To keep the number of cases within this range, PacifiCorp excluded some core cases with improbable combinations of certain input levels, such as a \$100 $CO_2$ tax and high load growth. (With a high $CO_2$ tax, a significant amount of demand reduction is expected to occur in the form of conservation, energy efficiency improvements, and utility load control programs.)

PacifiCorp also relied heavily on feedback from public stakeholders. The company assembled and refined an initial set of cases during April through June 2008, and held three public meetings during May and June to solicit recommendations on their design. The focus of comments was on the number of cases that should be modeled and the appropriateness of the $CO_2$ tax levels selected. Additional case modifications took place from July through November, reflecting additional stakeholder feedback and input assumption updates made to support the 2009 business plan. For example, PacifiCorp augmented the cases defined with the June 2008 forward price curves as the base forecast with additional ones that used the October price curves. This expansion of cases reflected the desire to account in the IRP analysis the rapid and large price decreases experienced during the last half of 2008.

## Case Specifications

Tables 7.2 and 7.3 profile the core and sensitivity/business plan case specifications, respectively. Descriptions of the case variables and explanatory remarks on specific cases follow the tables.

## Table 7.2 – Core Case Definitions

| Case # | CO2 Compliance Strategy and Costs | | Base Gas Cost (Prior to CO2 compliance impact adjustments) | | Load Growth | Renewable Portfolio Standard | Clean Baseload Plant Available | Plant Construction Cost | Planning Reserve Margin | Class 3 DSM for Peak Load Reduction |
|---|---|---|---|---|---|---|---|---|---|---|
| | Compliance Type (CO2 tax, federal cap-and-trade, hard cap) | CO2 Cost per Ton (2008 Dollars)<br><br>Cost compliance begins in 2013, with inflation rate cost escalation | Nominal Prices:<br>Low June 2008<br>Med June 2008<br>High June 2008<br>Low Oct 2008<br>Med Oct 2008<br>High Oct 2008 | Price Curve Date | **Medium** = Expected "1-in-2" Forecast<br>**Low** = Medium AAG minus 1.0 percentage point<br>**High** = Medium AAG plus 1.0 percentage point | **High** = OR System-Allocated (MSP revised protocol)<br>**Base** = Individual state requirements met | **Base** = 2025<br>**Early** = 2020<br>**Late** = 2030 | **Base**<br>**High** = Base + 20% | | **Excluded** as capacity resource<br>**Included** as capacity resource |
| **Core Cases** | | | | | | | | | | |
| 1 | CO2 tax | $0 | Low | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 2 | CO2 tax | $0 | Medium | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 3 | CO2 tax | $0 | High | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 4 | CO2 tax | $45 | Low | Jun-08 | Low | Base, if needed | Base | Base | 12% | Excluded |
| 5 | CO2 tax | $45 | Low | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 6 | CO2 tax | $45 | Low | Jun-08 | High | Base, if needed | Base | Base | 12% | Excluded |
| 7 | CO2 tax | $45 | Medium | Jun-08 | Low | Base, if needed | Base | Base | 12% | Excluded |
| 8 | CO2 tax | $45 | Medium | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 9 | CO2 tax | $45 | Low | Oct-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 10 | CO2 tax | $45 | Medium | Oct-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 11 | CO2 tax | $45 | High | Oct-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 12 | CO2 tax | $45 | Medium | Jun-08 | High | Base, if needed | Base | Base | 12% | Excluded |
| 13 | CO2 tax | $45 | High | Jun-08 | Low | Base, if needed | Base | Base | 12% | Excluded |
| 14 | CO2 tax | $45 | High | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 15 | CO2 tax | $45 | High | Jun-08 | High | Base, if needed | Base | Base | 12% | Excluded |
| 16 | CO2 tax | $70 | Medium | Jun-08 | Low | Base, if needed | Base | Base | 12% | Excluded |
| 17 | CO2 tax | $70 | Medium | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 18 | CO2 tax | $70 | Low | Oct-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 19 | CO2 tax | $70 | Medium | Oct-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 20 | CO2 tax | $70 | High | Oct-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 21 | CO2 tax | $70 | High | Jun-08 | Low | Base, if needed | Base | Base | 12% | Excluded |
| 22 | CO2 tax | $70 | High | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 23 | CO2 tax | $100 | Medium | Jun-08 | Low | Base, if needed | Base | Base | 12% | Excluded |
| 24 | CO2 tax | $100 | Medium | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 25 | CO2 tax | $100 | Low | Oct-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 26 | CO2 tax | $100 | Medium | Oct-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 27 | CO2 tax | $100 | High | Oct-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |
| 28 | CO2 tax | $100 | High | Jun-08 | Low | Base, if needed | Base | Base | 12% | Excluded |
| 29 | CO2 tax | $100 | High | Jun-08 | Medium | Base, if needed | Base | Base | 12% | Excluded |

## Table 7.3 – Sensitivity and Business Plan Reference Case Definitions

| Case # | CO2 Compliance Strategy and Costs | | Base Gas Cost (Prior to CO2 compliance impact adjustments) | | Load Growth | Renewable Portfolio Standard | Clean Baseload Plant Available | Plant Construction Cost | Planning Reserve Margin | Class 3 DSM for Peak Load Reduction |
|---|---|---|---|---|---|---|---|---|---|---|
| | Compliance Type (CO2 tax, federal cap-and-trade, hard cap) | CO2 Cost per Ton (2008 Dollars) Cost compliance begins in 2013, with inflation rate cost escalation | Nominal Prices: Low June 2008 Med June 2008 High June 2008 Low Oct 2008 Med Oct 2008 High Oct 2008 | Price Curve Date | **Medium** = Expected "1-in-2" Forecast **Low** = Medium AAG minus 1.0 percentage point **High** = Medium AAG plus 1.0 percentage point | **High** = OR System-Allocated (MSP revised protocol) **Base** = Individual state requirements met | **Base** = 2025 **Early** = 2020 **Late** = 2030 | **Base** **High** = Base + 20% | | **Excluded** as capacity resource **Included** as capacity resource |
| **Real CO2 Cost Escalation with Changing Load Growth** | | | | | | | | | | |
| 30 | CO2 tax | \$45 (2013) to \$163 (2028) | Medium | Jun-08 | Medium (2009-2020) Low (2021-2028) | Base | Base | Base | 12% | Excluded |
| 31 | CO2 tax | \$45 (2013) to \$163 (2028) | High | Jun-08 | Medium (2009-2020) Low (2021-2028) | Base | Base | Base | 12% | Excluded |
| **National CO2 Cap-and-Trade Policy: Lieberman-Warner "Climate Security Act of 2008" (SB 3036, introduced May 20, 2008)** | | | | | | | | | | |
| 32 | Cap-and-Trade | Market | Medium | Oct-08 | Medium | Base | Base | Base | 12% | Excluded |
| **High-Cost Outcome** | | | | | | | | | | |
| 33 | CO2 tax | \$100 | High | Jun-08 | High | Base | Late | High | 12% | Excluded |
| **Clean Base-Load Generation Availability** | | | | | | | | | | |
| 34 | CO2 tax | \$45 | Medium | Jun-08 | Medium | Base | Early | Base | 12% | Excluded |
| 35 | CO2 tax | \$45 | High | Jun-08 | Medium | Base | Early | Base | 12% | Excluded |
| 36 | CO2 tax | \$70 | Medium | Jun-08 | Medium | Base | Early | Base | 12% | Excluded |
| 37 | CO2 tax | \$70 | High | Jun-08 | Medium | Base | Early | Base | 12% | Excluded |
| **High Plant Construction Costs** | | | | | | | | | | |
| 38 | CO2 tax | \$45 | Medium | Jun-08 | Medium | Base | Base | High | 12% | Excluded |
| 39 | CO2 tax | \$45 | High | Jun-08 | Medium | Base | Base | High | 12% | Excluded |
| **Oregon CO2 Reduction Targets (from HB 3543) Applied as System-wide Hard Caps** | | | | | | | | | | |
| 40 | Hard Cap | N/A | Medium | Jun-08 | Medium | Base | Base | Base | 12% | Excluded |
| **Alternative Planning Reserve Margin Level (15%)** | | | | | | | | | | |
| 41 | CO2 tax | \$45 | Medium | Jun-08 | Medium | Base | Base | Base | 15% | Excluded |
| 42 | CO2 tax | \$70 | Medium | Jun-08 | Medium | Base | Base | Base | 15% | Excluded |
| 43 | CO2 tax | \$100 | Medium | Jun-08 | Medium | Base | Base | Base | 15% | Excluded |
| **Alternative renewable policy assumptions** | | | | | | | | | | |
| 44 | Cap-and-Trade | \$8 allowance price | Medium | Oct-08 | Medium | High | Base | Base | 12% | Excluded |
| 45 | Cap-and-Trade | \$8 allowance price | Medium | Oct-08 | Medium | Base/PTC expires | Base | Base | 12% | Excluded |
| **Business Plan Reference Cases** | | | | | | | | | | |
| 46 | Cap-and-Trade | \$8 allowance price | Medium | Oct-08 | Medium | Fixed RPS-compliant wind schedule | Base | Base | 12% | Excluded |
| 47 | Cap-and-Trade | \$8 allowance price | Medium | Oct-08 | Medium | Optimized RPS-compliant renewables | Base | Base | 12% | Excluded |
| **Class 3 DSM For Peak Load Reduction** | | | | | | | | | | |
| 48 | CO2 tax | \$45 | Medium | Jun-08 | Medium | Base | Base | Base | 12% | Included |

## Carbon Dioxide Compliance Strategy and Costs

Given that no single $CO_2$ reduction compliance approach has emerged as a consistent front-runner for adoption, the long-term planning effort undertaken through this IRP considers a wide range of carbon cost outcomes that are assessed as a direct tax on emissions (each short ton of $CO_2$ emitted). As mentioned above, a $CO_2$ tax is modeled for all the core cases. The $CO_2$ tax has an assumed 2013 implementation date, and increases at PacifiCorp's assumed inflation rate.

The tax is treated as a variable cost in both the System Optimizer and PaR models. In System Optimizer, the tax is accounted for in both resource investment decisions as well as the model dispatch solution. For the PaR model, the tax is accounted for in the model's unit commitment/dispatch solution.

The core cases have been specified with four tax levels: no tax, $45/ton, $70/ton, and $100/ton. The $0 tax serves to create reference portfolios from which the incremental cost of $CO_2$ regulations can be determined. The $45 tax represents a reasonable intermediate value and starting point at which significant changes in resource mix over the long term can be expected to occur. This value—along with the $70 value—are also in line with the Electric Power Research Institute's finding that for its reference $CO_2$ price impact modeling case for western electricity markets, "...it takes a $CO_2$ price of roughly $50/ton to flatten the growth of emissions over time, and closer to $70/ton to effect a significant reduction over time."[31] The $100 tax then reflects a reasonable high-end value associated with an aggressive Federal emission reduction policy.

For sensitivity cases 30 and 31, PacifiCorp developed a $CO_2$ tax trajectory with a real cost escalation, and also assumed that the associated demand response would result in a lower load growth trend beginning in 2021. The $CO_2$ tax values for these cases are shown in Table 7.4.

**Table 7.4 – $CO_2$ Tax Values**

| Year | CO2 Tax Level, 2008 Dollars per Ton | | | |
|---|---|---|---|---|
| | $45 | $70 | $100 | $45, Real Escalation |
| 2013 | 49.44 | $76.91 | $109.87 | 45.00 |
| 2014 | 50.33 | $78.29 | $111.84 | 52.86 |
| 2015 | 51.29 | $79.78 | $113.97 | 60.71 |
| 2016 | 52.31 | $81.37 | $116.25 | 68.57 |
| 2017 | 53.36 | $83.00 | $118.57 | 76.43 |
| 2018 | 54.43 | $84.66 | $120.95 | 84.29 |
| 2019 | 55.51 | $86.36 | $123.36 | 92.14 |
| 2020 | 56.62 | $88.08 | $125.83 | 100.00 |
| 2021 | 57.70 | $89.76 | $128.22 | 107.86 |
| 2022 | 58.80 | $91.46 | $130.66 | 115.71 |
| 2023 | 59.91 | $93.20 | $133.14 | 123.57 |
| 2024 | 61.05 | $94.97 | $135.67 | 131.43 |
| 2025 | 62.15 | $96.68 | $138.11 | 139.29 |
| 2026 | 63.27 | $98.42 | $140.60 | 147.14 |
| 2027 | 64.47 | $100.29 | $143.27 | 155.00 |

[31] Electric Power Research Institute, Slide Presentation, Collaborative EPRI Analysis of $CO_2$ Price Impacts on Western Power Markets, page 18, June 2008.

| Year | CO2 Tax Level, 2008 Dollars per Ton | | | |
|---|---|---|---|---|
| | **$45** | **$70** | **$100** | **$45, Real Escalation** |
| 2028 | 65.70 | $102.19 | $145.99 | 162.86 |

For sensitivity case 32, The $CO_2$ costs are in the form of allowance market prices resulting from implementation of a federal cap-and-trade program such as the Lieberman-Warner Climate Security Act of 2008. (This proposed legislation specified a final $CO_2$ emissions target of 71 percent below 2005 levels in 2050.) Due to the complexity of developing the inputs for this sensitivity case, PacifiCorp did not have time to perform this analysis before this IRP was prepared. PacifiCorp will make the results available to IRP stakeholders once the study has been completed.

Sensitivity case 40 assumes that PacifiCorp is subject to a system-wide hard $CO_2$ cap. A hard cap is a physical emission limit that cannot be exceeded, and is typically expressed as a declining annual value. This sensitivity case is intended to support the following Public Utility Commission of Oregon's 2007 IRP acknowledgment order requirement:

> For the 2007 IRP update and next planning cycle, develop a scenario to meet the $CO_2$ emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.[32]

Oregon's HB 3543 targets are to achieve greenhouse gas emission levels 10 percent below 1990 levels by 2020, and by 2050, achieve reductions of a least 75 percent below 1990 levels. With a 2012 emissions base of 56.1 million tons, these targets translate into 41.4 million tons by 2020 and 33.4 million tons by 2028. Because PacifiCorp plans on a system basis, and its IRP models are not currently capable of representing Oregon-only emission constraints in the context of such system planning, Oregon's hard cap is applied on a system level.

The $CO_2$ compliance strategy and cost assumptions for sensitivity cases 46 and 47 reflect those used for PacifiCorp's 2009 business plan, which is based on a Federal cap-and-trade compliance mechanism. Cap-and-trade assumptions include the following:

- Emissions peaking in 2012 (56.1 million tons) and declining to 2007 emission levels (56.5 million tons by 2025), assuming straight-line annual decreases for modeling purposes
- Straight-line annual emissions decreasing to 1990 levels by 2030
- An initial $CO_2$ allowance price of $8.79/ton starting in 2013 (in 2008 dollars), and increasing at PacifiCorp's annual inflation rates
- No auctioning or banking of allowances



[32] Public Utility Commission of Oregon, Order No. 08-232, Docket LC 42, April 24, 2008, p. 36.

**Table 7.5 – $CO_2$ Prices for the Business Plan Reference Cases**

| Year | CO2 Price 2008 Dollars per Ton |
|---|---|
| 2013 | 8.79 |
| 2014 | 8.95 |
| 2015 | 9.12 |
| 2016 | 9.30 |
| 2017 | 9.49 |
| 2018 | 9.68 |
| 2019 | 9.87 |
| 2020 | 10.07 |
| 2021 | 10.26 |
| 2022 | 10.45 |
| 2023 | 10.65 |
| 2024 | 10.85 |
| 2025 | 11.05 |
| 2026 | 11.25 |
| 2027 | 11.46 |
| 2028 | 11.68 |

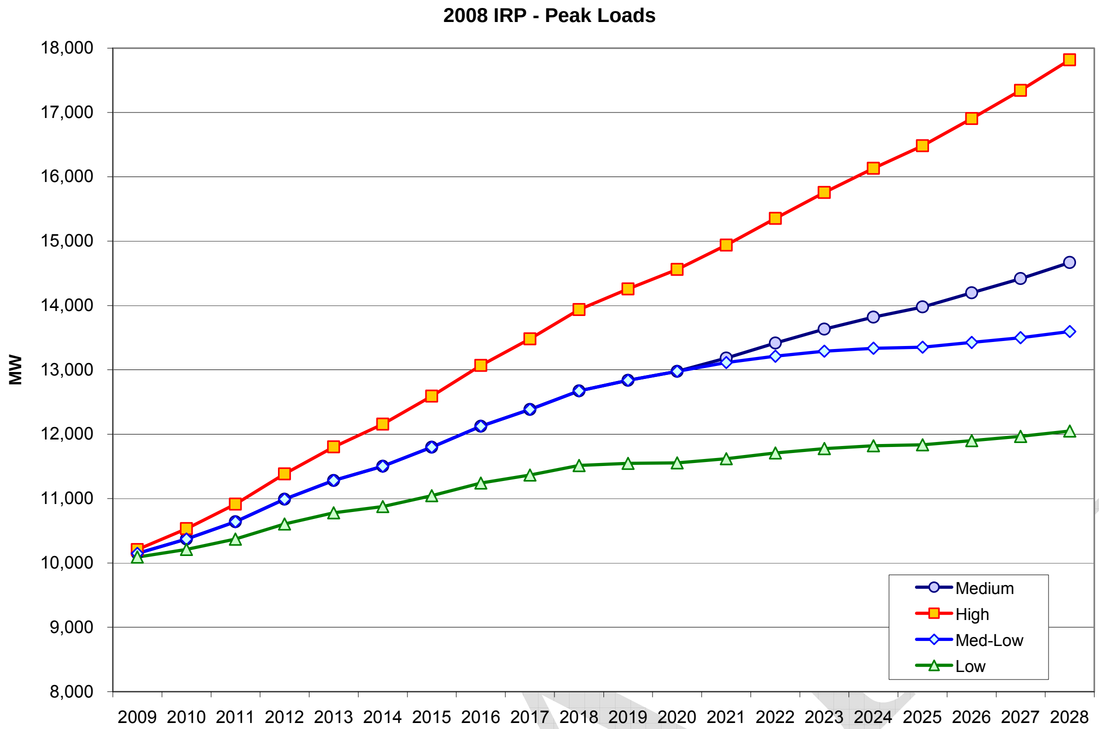
### Natural Gas and Electricity Prices

Due to the strong correlation between natural gas and wholesale electricity prices, these variables were linked together as low, medium, or high values for a case. Two sets of gas/electricity price scenario values were used for defining cases. The June 2008 forward price curves served as the initial base forecast for IRP modeling support for the 2009 business plan and development of IRP scenario price curves reflecting $CO_2$ price responses. Due to the large decline in gas prices following the spring/summer spike, PacifiCorp adopted the October 2008 forward price curves for the final business plan modeling, and incorporated these forecasts as additional cases in the IRP (cases 9, 10, 11, 18, 19, 20, 25, 26, and 27). The price forecasting methodology and resulting scenario price forecasts are presented later in this chapter.

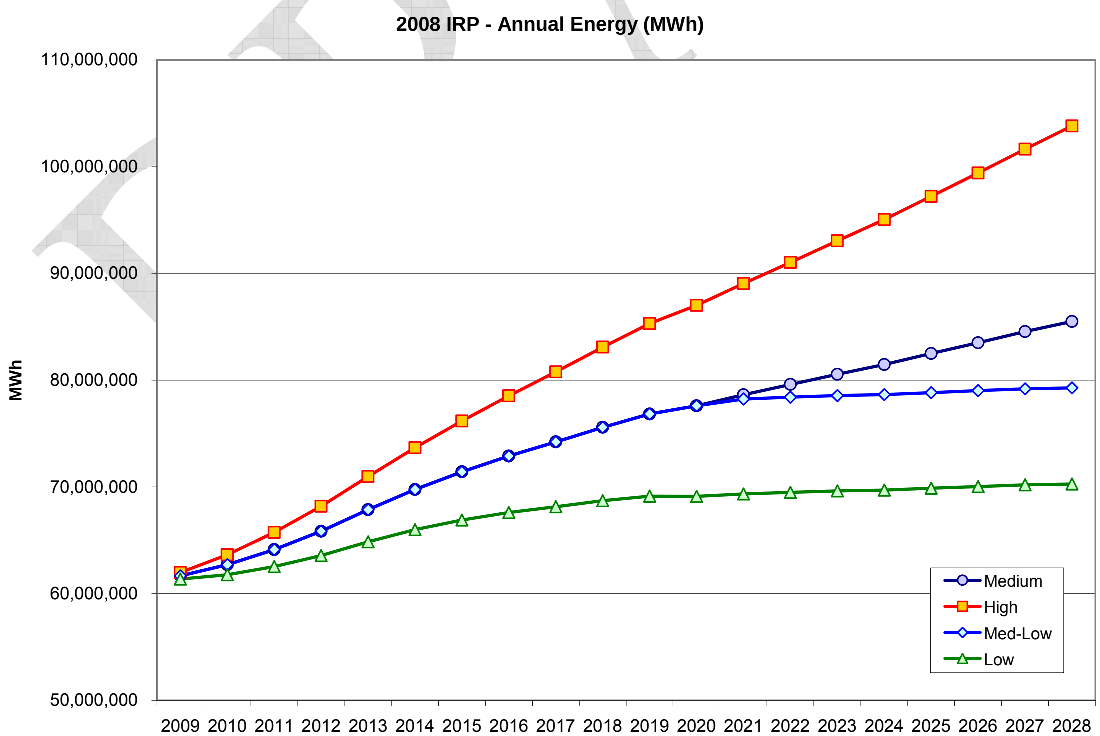
### Retail Load Growth

The low and high load growth forecasts reflect a respective one-percentage-point average annual growth rate decrease and increase relative to the growth rate for the medium (1-in-2) forecast. For cases 30 and 31, PacifiCorp combined the medium forecast for 2009 to 2020, and the low forecast for 2021 to 2028, using a smoothing algorithm to determine the data elements around the breakpoint. Figures 7.3 and 7.4 show the annual peak load and energy forecast values used for the case definitions.

## Figure 7.3 – Peak Load Growth Scenarios




## Figure 7.4 – Energy Load Growth Scenarios



**Renewable Portfolio Standards**
In addition to the base renewable portfolio standards modeled, sensitivity case 44 tests a scenario for which the renewable generation requirement is higher, reflecting imposition of a Federal standard or more aggressive state standards. (Modeling of renewable portfolio standards is discussed in the section on optimized portfolio development.)

For the high RPS generation requirement, PacifiCorp assumed that the current Revised Protocol under the Multi-state Process remains in place, requiring the company to acquire sufficient system resources to meet Oregon's cost allocation share based on their RPS targets. This assumption translates into a 25-percent RPS generation requirement with respect to the forecasted system load by 2026.

**Renewables Production Tax Credit Expiration**
Sensitivity case 45 is intended to study how the loss of the PTC affects the timing and magnitude of renewable resource additions. For this sensitivity, the renewables PTC is assumed to fully expire in 2013.

**Clean Base Load Plant Availability**
Sensitivity cases 34 through 37 evaluate whether clean base load plants—IGCC and new/existing pulverized coal plant retrofits with carbon capture and sequestration—are cost-effective enough to build as early as 2020 given the $45/ton and $70/ton $CO_2$ tax levels and variation in gas prices. The assumed earliest availability for these plants is 2025.

**High Plant Construction Costs**
Sensitivity cases 38 and 39 are intended to determine the resource selection impact of increasing capital costs for all resources by 20 percent above their base values under medium and high gas price conditions. Capital-intensive resources will be disadvantaged under this assumption, so these sensitivities test the extent that such resources are deferred or eliminated from portfolios despite higher gas prices.

**Capacity Planning Reserve Margin**
Cases 41 42, and 43 are intended for development of portfolios built to meet or exceed a 15-percent capacity planning reserve margin. The resulting portfolios are compared with their counterpart portfolios built to a 12-percent planning reserve margin (cases 8, 17, and 24). These comparisons are intended to determine the resource mix impact of higher CO2 tax levels.

**Business Plan Reference Cases**
Cases 46 and 47 represent portfolios that have the major 2009 business plan resources fixed in the model. They were optimized with business plan assumptions, including the $8/ton cap-and-trade program assumptions and October 2008 price forecasts. System Optimizer was allowed to select DSM and distributed generation resources up to 2018, and allowed to select any resource from 2019 onward subject to the annual quantity constraints outlined in Chapter 6. (Business plan resources only cover the period 2009 through 2018.) The difference between the two cases is that the renewable resources were fixed in case 46 for 2009-2018—reflecting the wind acquisi-

tion schedule determined by PacifiCorp's wind development team for the business plan[33]—whereas for case 47, the model was allowed to optimize the amount and timing of renewables subject to the annual quantity constraints.

**Class 3 Demand-side Management Programs for Peak Load Reductions**
For sensitivity case 48, System Optimizer is allowed to select price-responsive DSM programs. These programs, outlined in Chapter 6, include real-time pricing (for commercial and industrial customers), demand buyback, curtailment, and critical peak pricing.



## SCENARIO PRICE FORECAST DEVELOPMENT

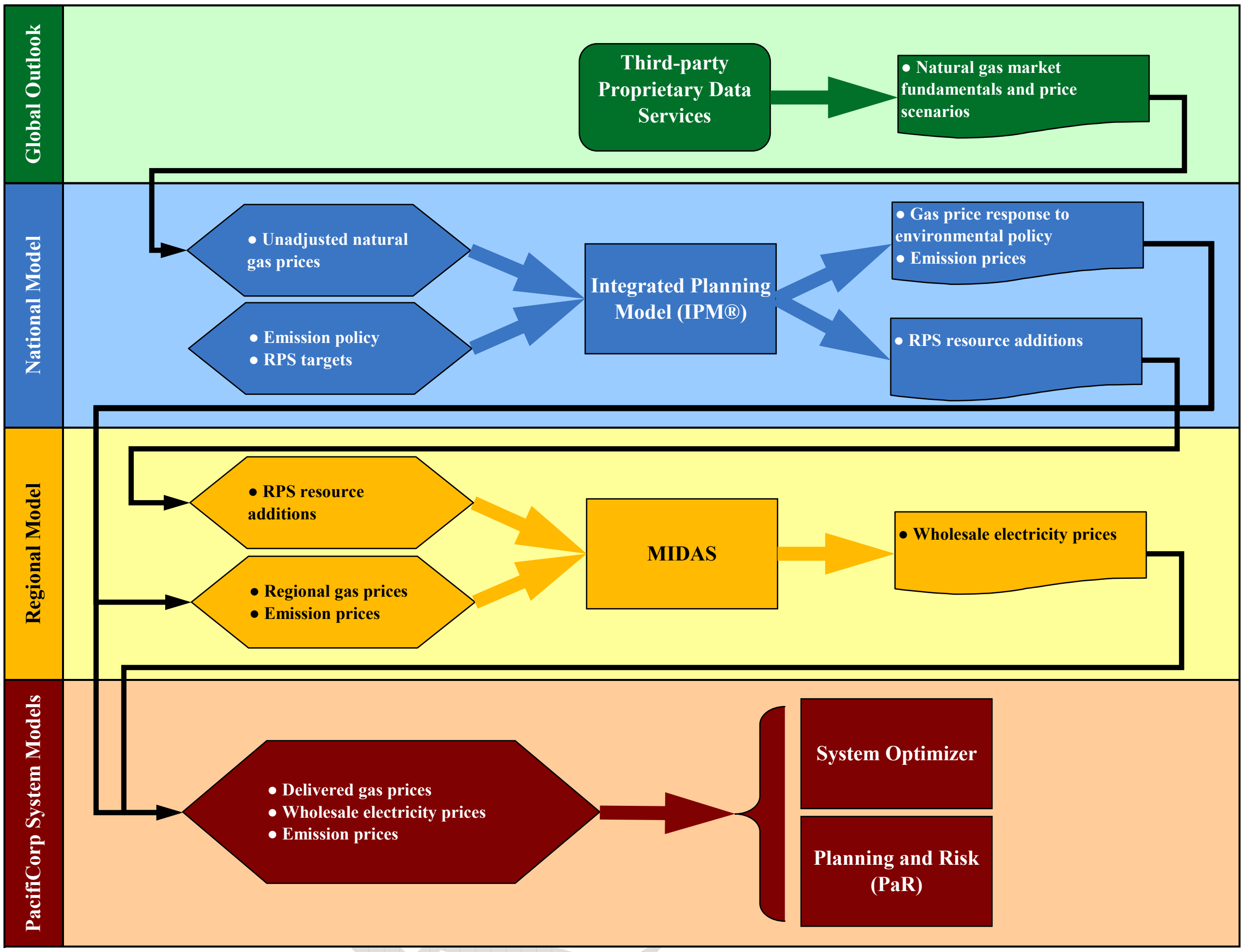
On a central tendency basis, commodity markets tend to respond to the evolution of supply and demand fundamentals over time. Due to a complex web of cross-commodity interactions, price movements in response to supply and demand fundamentals for one commodity can have implications for the supply and demand dynamics and price of other commodities. This interaction routinely occurs in markets common to the electric sector as evidenced by a strong positive correlation between natural gas prices and electricity prices.

Some relationships among commodity prices have a long historical record that have been studied extensively, and consequently, are often forecasted to persist with reasonable confidence. However, robust forecasting techniques are required to capture the effects of secondary or even tertiary conditions that have historically supported such cross-commodity relationships. For example, the strong correlation between natural gas prices and electricity prices is intrinsically tied to the increased use of natural gas-fired capacity to produce electricity. If for some reason in the future natural gas-fired capacity diminishes in favor of an alternative technology, the linkage between gas prices and electricity prices would almost certainly weaken.

PacifiCorp deploys a variety of forecasting tools and methods to capture cross-commodity interactions when projecting prices for those markets most critical to this IRP – natural gas prices, electricity prices, and emission prices. Figure 7.5 depicts a simplified representation of the framework used by PacifiCorp to develop the price forecasts for these different commodities. At the highest level, the commodity price forecast approach begins at a global scale with an assessment of natural gas market fundamentals. This global assessment of the natural gas market yields a price forecast that feeds into a national model where the influence of emission and renewable energy policies is captured. Finally, outcomes from the national model feed into a regional model where the up-stream gas prices and emission prices drive a forecast of wholesale electricity prices. In this fashion, we are able to produce an internally consistent set of price forecasts across a range of potential future outcomes at the pricing points that interface with PacifiCorp's system.

[33] This wind acquisition schedule reflects an assessment of RPS requirements, capital budget impacts, current and prospective commercial opportunities, transmission constraints and expansion considerations (i.e., the Energy Gateway Transmission Project), operational and system integration issues, locational diversity, state procurement rules, and the MEHC renewables acquisition commitment.

**Figure 7.5 – Modeling Framework for Commodity Price Forecasts**




The process begins with an assessment of global gas market fundamentals and an associated forecast of North American natural gas prices. In this step, PacifiCorp relies upon a number of third-party proprietary data and forecasting services to establish a range of gas price scenarios. Each price scenario reflects a specific view of how the North American natural gas market will balance supply and demand. Given the emergence of liquefied natural gas (LNG) in the global marketplace, the linkage of global gas prices to global oil prices, and the potential need for LNG imports to balance supply with domestic demand, any price forecast for the North American market requires a view of global fundamentals.

Once a natural gas price forecast is established, the integrated planning model (IPM®) is used to simulate the entire North American power system. IPM®, a linear program, determines the least cost means of meeting electric energy and capacity requirements over time, and in its quest to lower costs, ensures that all assumed emission policies and renewable portfolio standard (RPS) policies are met. Concurrently, IPM® can be configured with a dynamic natural gas price supply curve that allows natural gas prices to respond to changes in demand triggered by environmental compliance. Additional outputs from IPM® include a forecast of resource additions consistent with all specified RPS targets, electric energy and capacity prices, coal prices, electric sector fuel consumption, and emission prices for policies administered in a cap-and-trade framework.

Once emission prices and the associated gas price response are forecasted with IPM®, results are used in a regional model named Midas, to produce an accompanying wholesales electricity price forecast. Midas is an hourly chronological dispatch model configured to simulate the Western Interconnection and offers a more refined representation of western wholesale electricity markets than is possible with IPM®. Consequently, we are able to produce a more granular price projection that covers all of the markets required for the PacifiCorp system models used in the IRP. The gas, wholesale electricity, and emission price forecasts developed under this framework and used in the cases for this IRP are summarized in the sections that follow.

## Gas and Electricity Price Forecasts

A total of five underlying natural gas price forecasts are used to develop the 28 unique gas price projections for the 48 cases analyzed in this IRP. A range of fundamental assumptions affecting how the North American market will balance supply and demand defines the five underlying price forecasts. Table 7.6 shows representative prices at the Henry Hub benchmark for the five underlying natural gas price forecasts. The five forecasts serve as a point of reference and are adjusted to account for changes in natural gas demand driven by a range of environmental policy and technology assumptions specific to each IRP case.

**Table 7.6 – Underlying Henry Hub Price Forecast Summary (nominal $/MMBtu)**

| Forecast Name | 2010 | 2015 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|
| High - June 2008 | $18.06 | $18.71 | $21.21 | $23.28 | $25.55 |
| High - October 2008 | $11.57 | $14.68 | $19.98 | $21.93 | $24.07 |
| Medium - June 2008 | $11.23 | $9.90 | $12.31 | $13.51 | $14.83 |
| Medium - October 2008 | $7.83 | $8.58 | $11.07 | $12.85 | $14.11 |
| Low - June 2008[34] | $5.83 | $6.29 | $7.09 | $7.78 | $8.54 |

### Price Projections Tied to the High June 2008 Forecast

The underlying June 2008 high gas price forecast is defined by high oil prices and low LNG imports, reduced production from mature natural gas fields, disappointments in new production from frontier gas fields, and policies that hold back new coal and nuclear additions, which supports electric sector natural gas demand despite high prices. Figure 7.6 summarizes prices at the Henry Hub benchmark and Figure 7.7 summarizes the accompanying electricity prices for the forecasts developed around the high June 2008 gas price projection.

[34] This underlying forecast serves as the reference case for development of the "low - October 2008" price forecast scenario.

**Figure 7.6 – Henry Hub Natural Gas Prices from the High June 2008 Underlying Forecast**

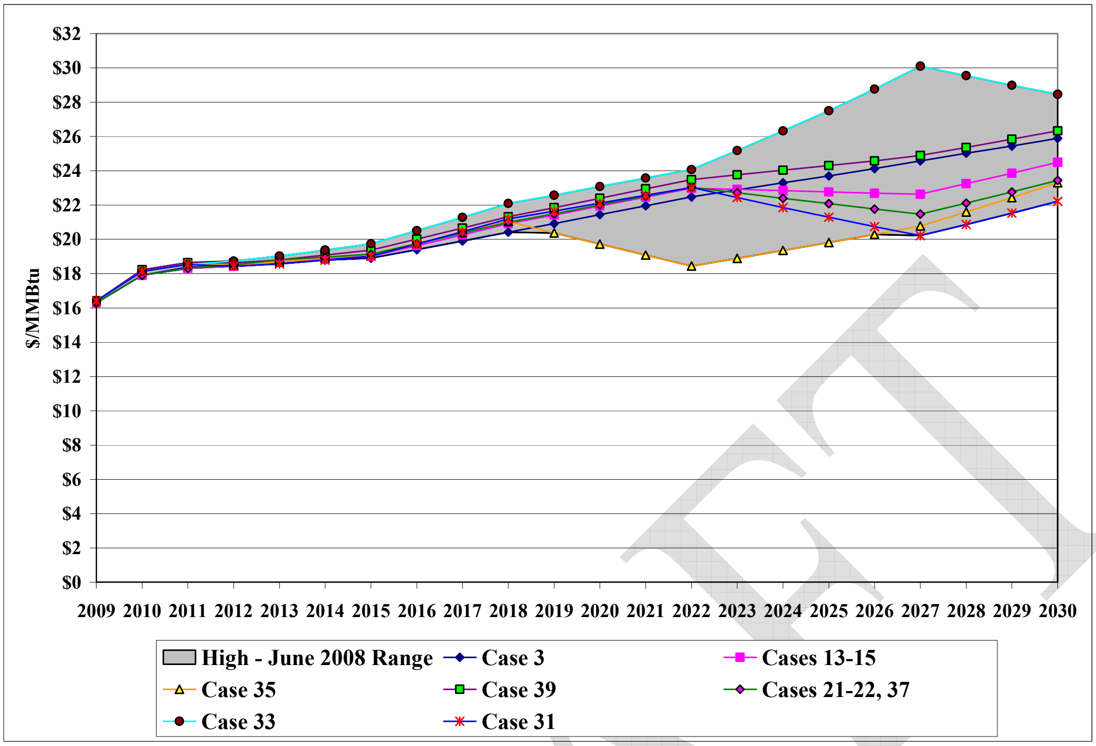
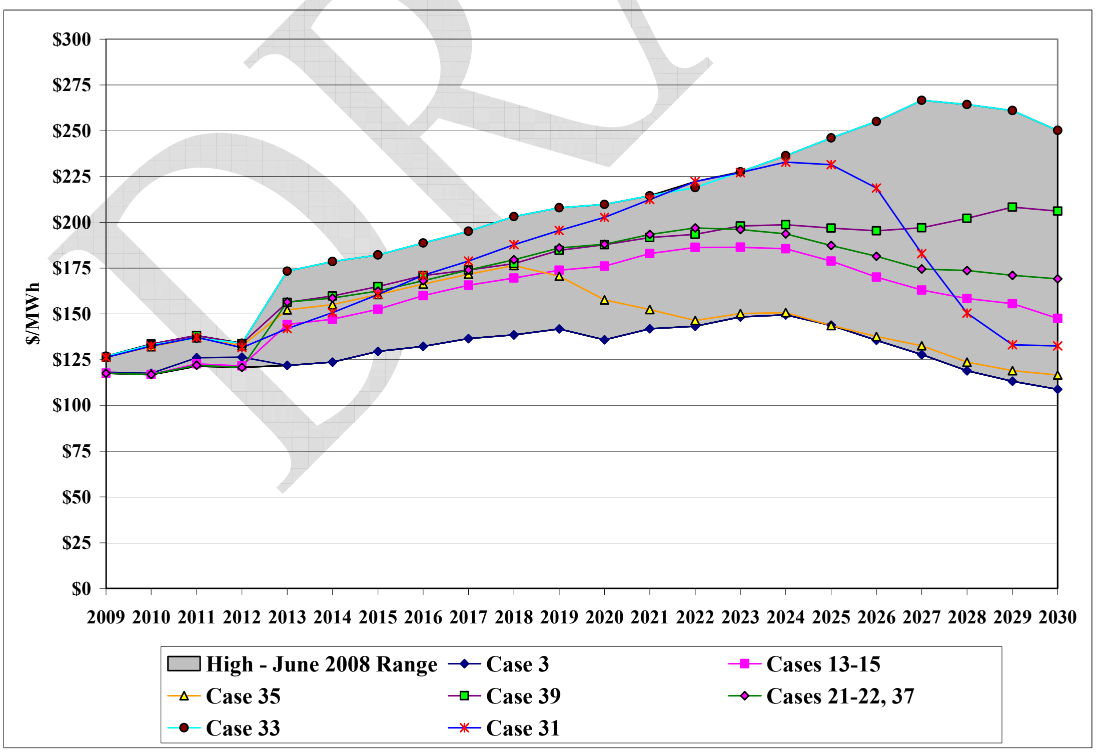



**Figure 7.7 – Western Electricity Prices from the High June 2008 Underlying Gas Price Forecast**




Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

**Price Projections Tied to the High October 2008 Forecast**

A second high gas price forecast was added in October 2008 in response to economic developments, which lowers the near-term price trajectory in response to lagging demand. Longer-term, the October 2008 high gas price forecast is lower than the June 2008 forecast due to a more optimistic outlook for domestic unconventional natural gas production. Figure 7.8 depicts Henry Hub benchmark prices and Figure 7.9 summarizes the accompanying electricity prices for the forecasts developed around the high October 2008 gas price projection.

**Figure 7.8 – Henry Hub Natural Gas Prices from the High October 2008 Underlying Forecast**

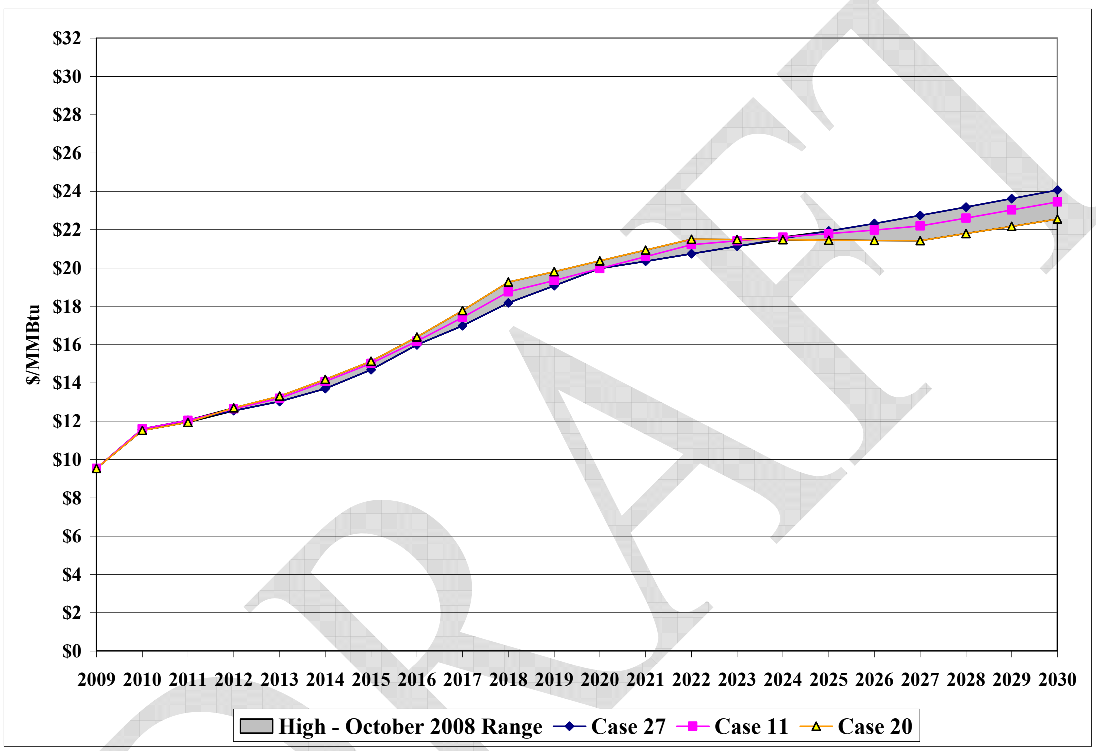
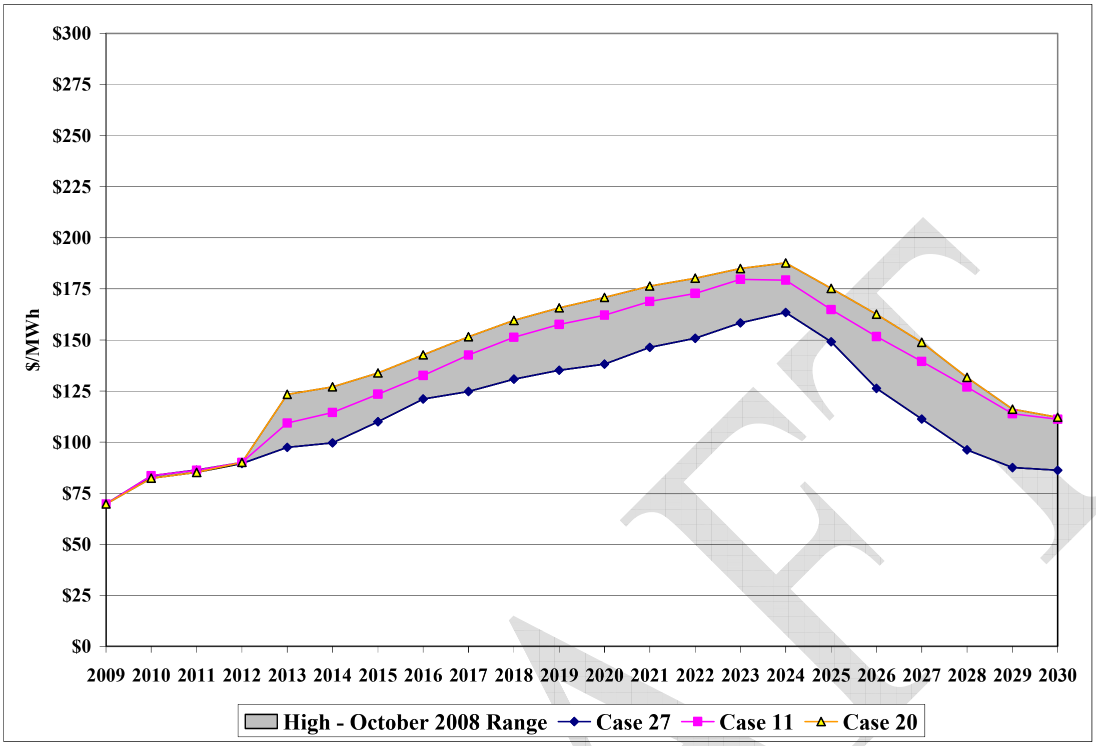


**Figure 7.9 – Western Electricity Prices from the High October 2008 Underlying Gas Price Forecast**




Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

**Price Projections Tied to the Medium June 2008 Forecast**

The underlying June 2008 medium gas price forecast relies upon market forwards for the first six years and a fundamentals-based projection thereafter. For the market portion of the forecast, prices are based upon forwards as of market close on June 30, 2008. The fundamentals-based part of the forecast depicts a future in which declining LNG imports coincide with strong demand from the electric sector driven by resistance to new coal-fired and nuclear capacity. It is assumed that unconventional production will largely be able to keep pace with growing demand, but production costs are projected to be higher than what has been exhibited in the recent expansion of unconventional fields in the Rocky Mountain region and in the Barnett Shale formation. Further, global oil prices are anticipated to remain much higher than historical averages. As with the high price forecasts, a second medium price forecast was added in October 2008 in response to economic developments. Figure 7.10 shows Henry Hub benchmark prices and Figure 7.11 includes the accompanying electricity prices for the forecasts developed around the medium June 2008 gas price projection.

**Figure 7.10 – Henry Hub Natural Gas Prices from the Medium June 2008 Underlying Forecast**

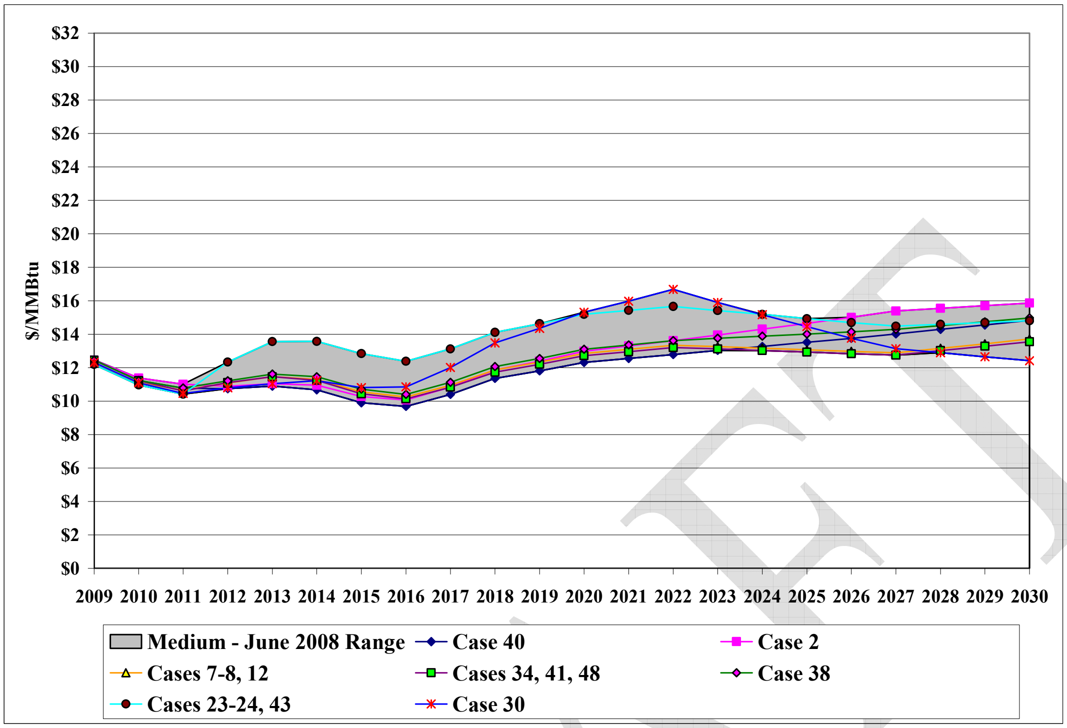
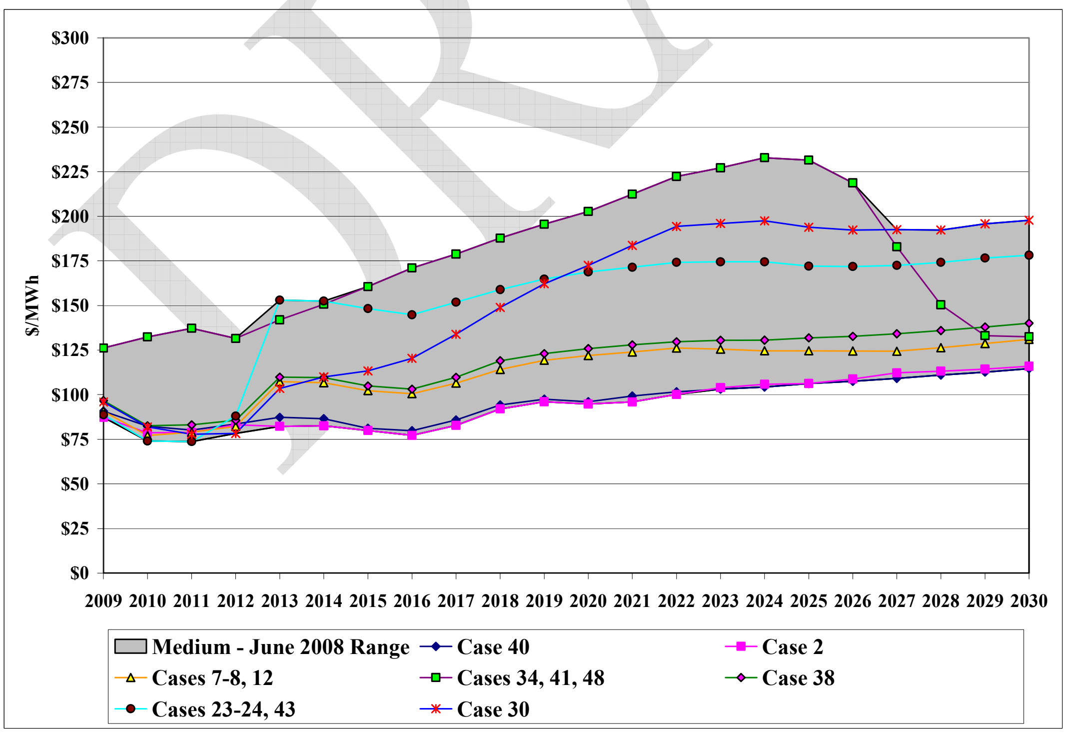



**Figure 7.11 – Western Electricity Prices from the Medium June 2008 Underlying Gas Price Forecast**




Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

**Price Projections Tied to the Medium October 2008 Forecast**

As with the high price forecasts, a second underlying medium gas price forecast was added in October 2008 in response to economic developments. In this second medium price forecast, the market portion of the curve is replaced with forwards as of market close on October 20, 2008. The longer-term forecast is slightly lower than the June 2008 medium forecast, which reflects a lower long-term oil price outlook and a more optimistic view of new supply out of Alaska. Figure 7.12 shows Henry Hub benchmark prices and Figure 7.13 includes the accompanying electricity prices for the forecasts developed around the medium October 2008 gas price projection.

**Figure 7.12 – Henry Hub Natural Gas Prices from the Medium October 2008 Underlying Forecast**

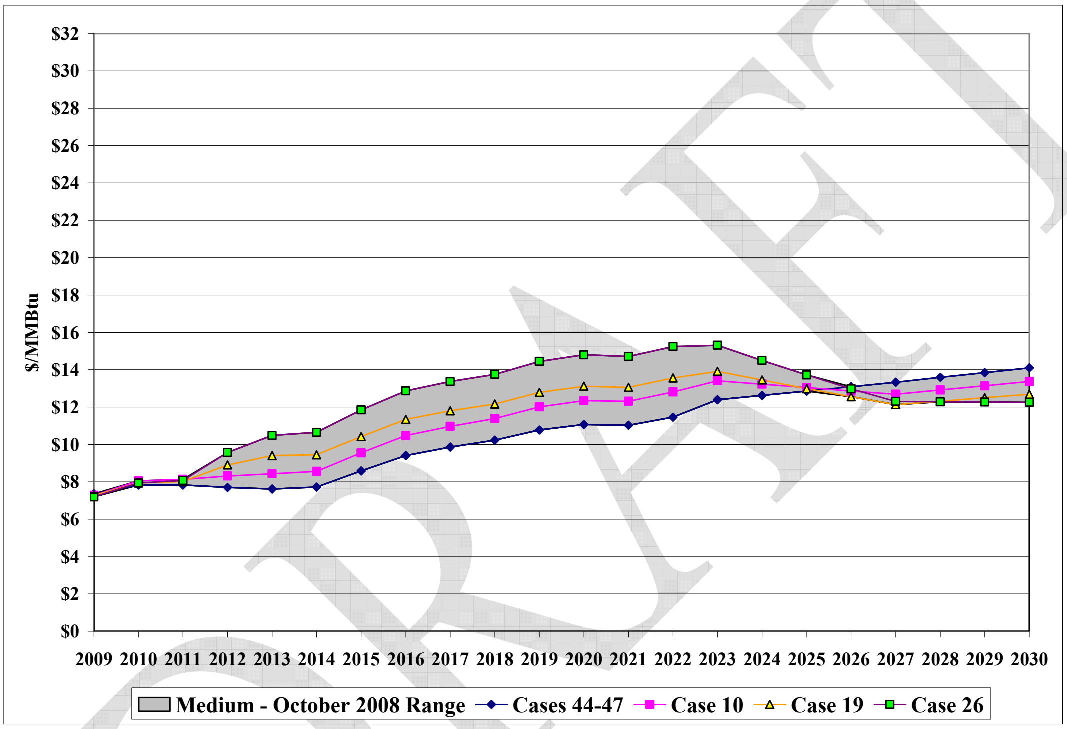
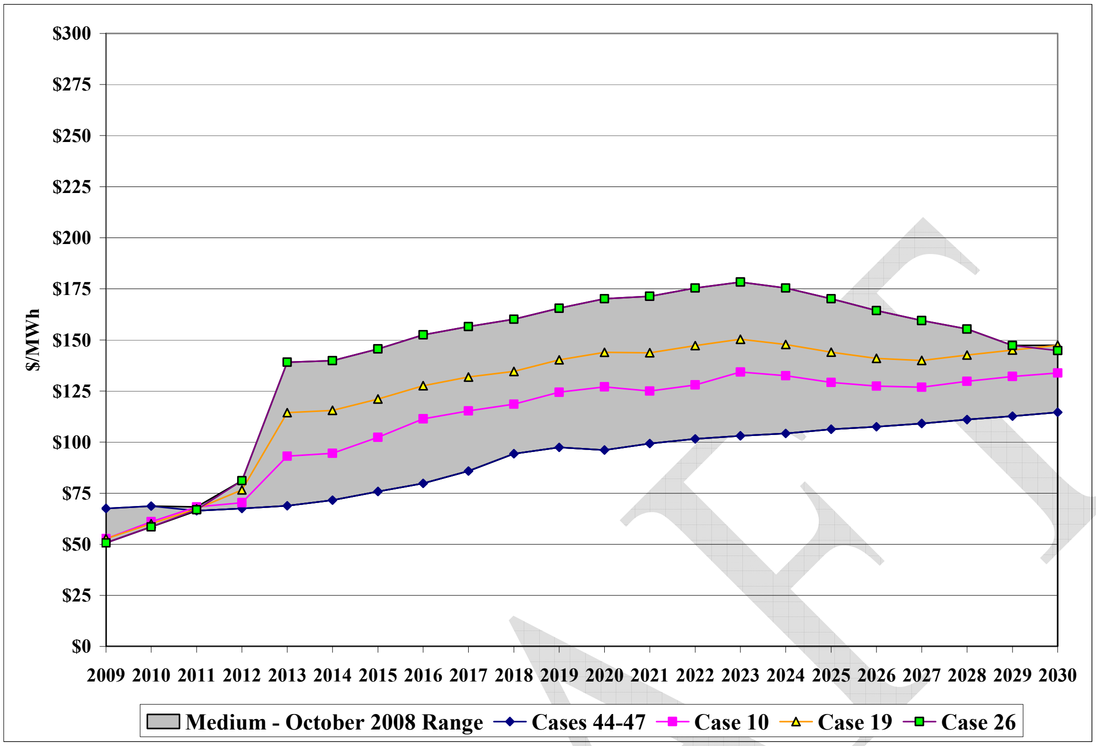


**Figure 7.13 – Western Electricity Prices from the Medium June 2008 Underlying Gas Price Forecast**




Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

## Price Projections Tied to the Low June 2008 Forecast

The underlying June 2008 low gas price forecast is defined by low oil prices and an extended period of growth from unconventional natural gas fields. Through this period of growth in unconventional production, it is assumed that knowledge transfer and technological advancements keep production costs on the decline. Concurrently, global LNG projects continue to come online while Asian markets experience growth in pipeline gas from China and India. Consequently, despite strong domestic growth from unconventional gas fields, LNG imports are diverted to the North American market. On the demand front, recent gas price spikes steer new power plant development away from gas-fired capacity, thereby keeping demand from the electric sector at bay. Given that the low price forecast is already defined by suppressed demand and an optimistic outlook for low cost supply, a second low price forecast was not added in October 2008. Figure 7.14 shows Henry Hub benchmark prices and Figure 7.15 includes the accompanying electricity prices for the forecasts developed around the low June 2008 gas price projection.

**Figure 7.14 – Henry Hub Natural Gas Prices from the Low June 2008 Underlying Forecast**

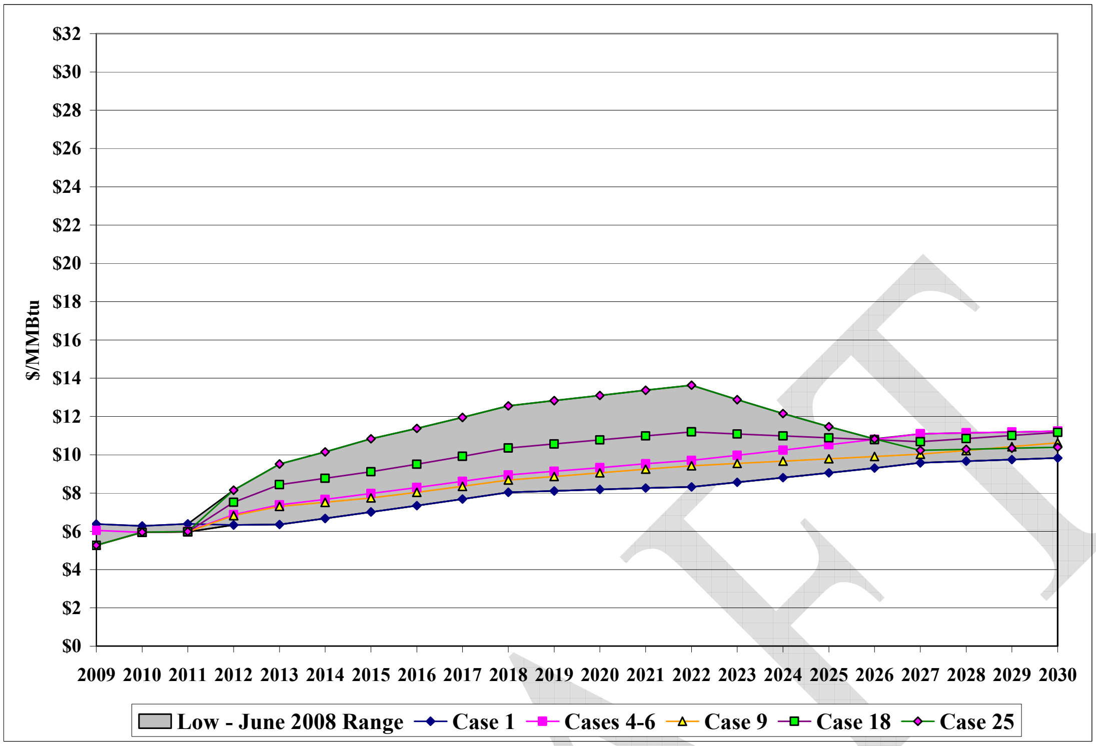
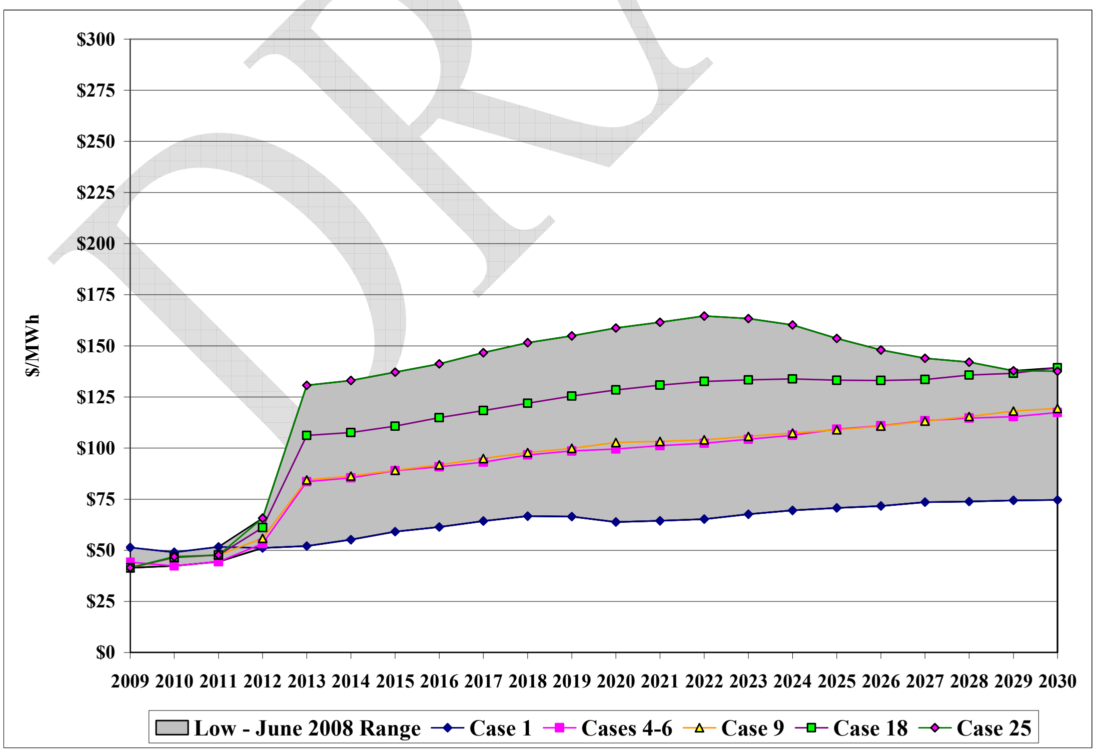



**Figure 7.15 – Western Electricity Prices from the Low June 2008 Underlying Gas Price Forecast**




[1]Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

## Emission Price Forecasts

As events unfolded in 2008, it became increasingly clear that policy uncertainty is not reserved only for greenhouse gas emissions. In February 2008, the D.C. Circuit Court of Appeals vacated the Clean Air Mercury Rule (CAMR) on the grounds that it was illegal for the Environmental Protection Agency (EPA) to de-list mercury as a hazardous pollutant. With this ruling, it became evident that a CAMR-based trading program for mercury allowances would not be implemented, and consequently, mercury allowance price forecasts are not studied in this IRP. Nonetheless, across all cases evaluated, it is assumed that all coal-fired supply side resource options are outfitted with activated carbon injection control technologies. (All fossil fuel plants are assigned a mercury emission rate, and mercury emissions for each portfolio are reported in Chapter 8.)

As with mercury, events in 2008 also introduced increased uncertainty to the sulfur dioxide ($SO_2$) allowance market. In July 2008, the D.C. Circuit Court of Appeals vacated the Clean Air Interstate Rule (CAIR) citing several fatal flaws and remanded it back to EPA with direction to promulgate a new rule. Once CAIR was vacated, the value of existing $SO_2$ allowances, which could be used for future CAIR compliance needs, dropped overnight and prices fell precipitously. The market continued to function, albeit at light trading volumes and at prices detached from long-term fundamentals.

EPA petitioned the court for rehearing in September 2008, and the court asked petitioners from the case to file briefs stating their opinion on EPA's request. In December 2008, the court reversed its previous finding and remanded the rule back to EPA without vacating the rule in its entirety. In its December decision, the court explained that its vactur would sacrifice clear benefits to public health and the environment while EPA fixes the rule. While the latest court ruling reinstates CAIR, it only does so until EPA can promulgate a new rule that addresses the problems identified in the original finding or until legislative action is taken. Consequently, prices for existing $SO_2$ allowance prices remain below the likely cost of future compliance.

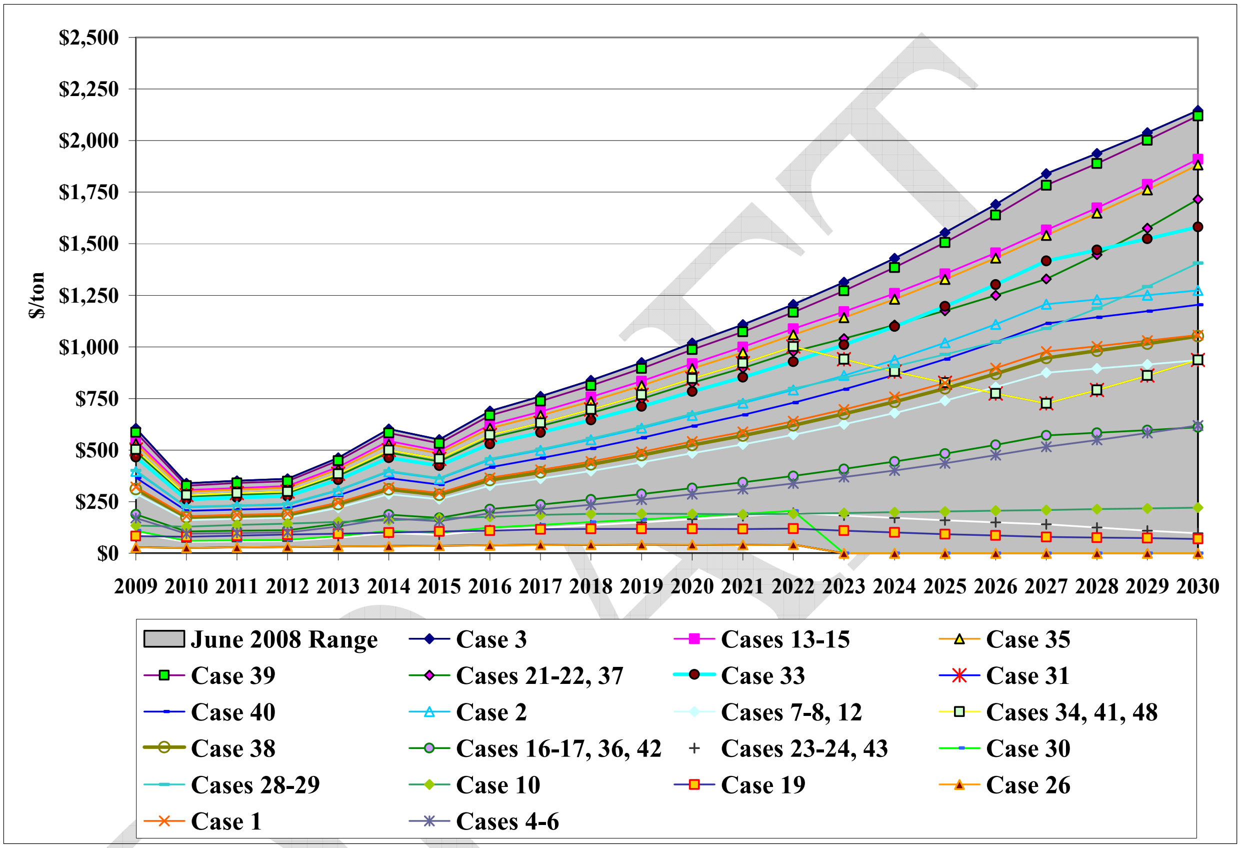
Given the tremendous uncertainty in the $SO_2$ allowance market and considering that current prices have departed from a fundamentals-view of future compliance costs, two sets of reference $SO_2$ allowance price forecasts were developed for this IRP. The two reference $SO_2$ allowance price forecasts are adjusted in response to the specific variables for any given case in much the same way that the underlying gas price forecasts are adjusted. As case variables are changed, IPM® is used to produce an associated $SO_2$ allowance price response, which in turn is used to make adjustments to the appropriate reference price forecasts. Table 7.7 summarizes $SO_2$ allowance prices developed for the two reference forecasts.

**Table 7.7 – Reference $SO_2$ Allowance Price Forecast Summary (nominal $/ton)**

| Forecast Name | 2010 | 2015 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|
| June 2008 | $205 | $333 | $616 | $940 | $1,204 |
| August 2008 | $157 | $206 | $232 | $247 | $271 |

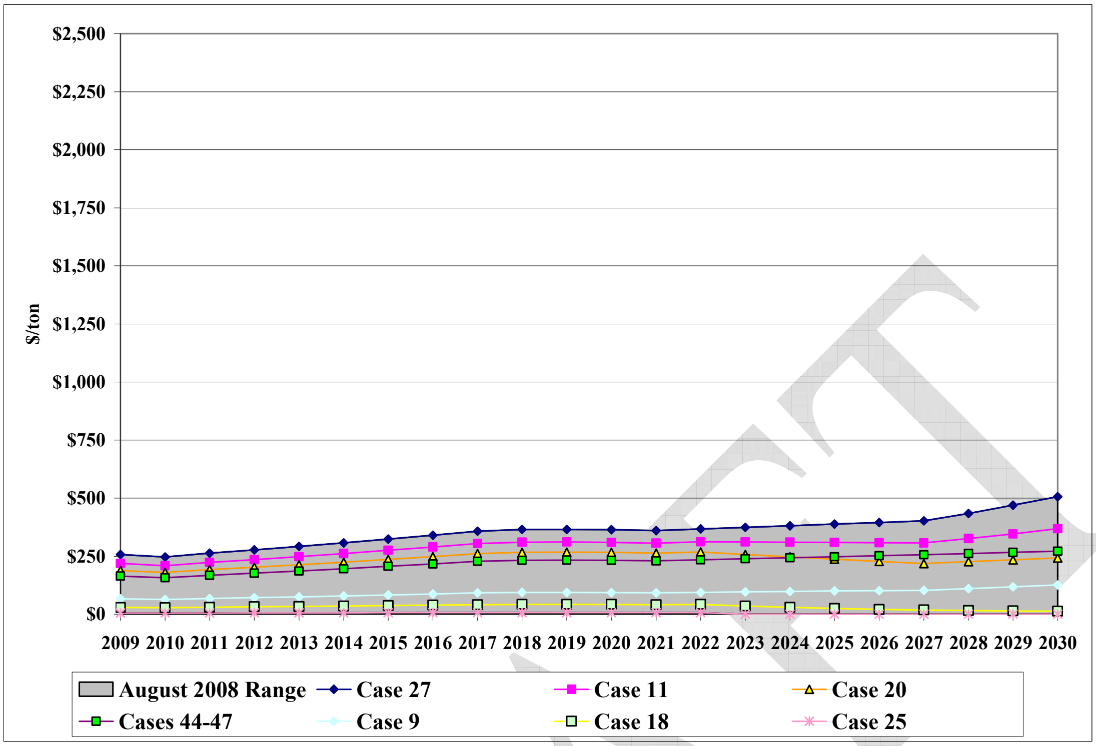
The June 2008 reference forecast reflects a combination of market forwards and a fundamentals-based price forecast. The market portion of the forecast extends through 2012 and reflects forwards as of June 20, 2008. Prices from 2013 through 2015 are derived as a gradual transition from the market forwards to the subsequent fundamentals-based forecast, which is applied starting in 2016. The fundamentals-based forecast is indicative of future compliance costs tied to the marginal cost of installing scrubbers on enough units to achieve the emission reduction targets established under CAIR. Figure 7.16 shows $SO_2$ allowance prices for the forecasts developed around the June 2008 reference price projection.

**Figure 7.16 – $SO_2$ Allowance Prices Developed off of the June 2008 Reference Forecast**




The August 2008 reference $SO_2$ allowance price forecast is based almost entirely upon market forwards as of August 7, 2008. The market is used for prices through 2021 and escalated at inflation thereafter. Under this reference price forecast, it is assumed that the uncertainties plaguing the $SO_2$ allowance market will continue into the foreseeable future. Figure 7.17 shows $SO_2$ allowance prices for the forecasts developed around the August 2008 reference price projection.

**Figure 7.17 – $SO_2$ Allowance Prices Developed off of the August 2008 Reference Forecast**




## OPTIMIZED PORTFOLIO DEVELOPMENT

For Phase 3, the System Optimizer is executed for each set of case assumptions, generating an optimized investment plan and associated real levelized present value of revenue requirements (PVRR) for 2009 through 2028. System Optimizer operates by minimizing for each year the operating costs for existing resources subject to system load balance, reliability and other constraints. Over the 20-year study period, it also optimizes resource additions subject to resource investment and capacity constraints (monthly peak loads plus a planning reserve margin for each load area represented in the model).

To accomplish these optimization objectives, the model performs a time-of-day least-cost dispatch for existing and potential planned generation, contract, demand-side management, and transmission resources. The dispatch is based on a representative-week method. Time-of-day hourly blocks are simulated according to a user-specified day-type pattern representing an entire week. Each month is represented by one week, with results scaled to the number of days in the month and then the number of months in the year. The dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the overall PVRR, consisting of the net present value of contract and spot market purchase costs, generation costs (fuel, fixed and variable operation and maintenance, unserved energy, and unmet capacity), and amortized capital costs for planned resources.

For capital cost derivation, System Optimizer uses annual capital recovery factors to address end-effects issues associated with capital-intensive investments of different durations and in-service dates. PacifiCorp used the real-levelized capital costs produced by the System Optimizer for portfolio cost reporting by the PaR model.

## Representation and Modeling of Renewable Portfolio Standards

PacifiCorp incorporates annual system-wide renewable generation constraints in the System Optimizer model to ensure that each optimized portfolio meets state Renewable Portfolio Standard (RPS) requirements.[35] For the base case RPS requirement, current Oregon, Utah, Washington, and California rules are followed. The resulting system generation requirement, using the state end-use energy forecasts as the starting point, reaches two percent of system load for 2011-2014, five percent for 2015-2019, six percent for 2020-2024, and 15 percent for 2025-2028. A key assumption backing the system-wide RPS representation is that all of PacifiCorp's state jurisdictions will adopt renewable energy credit (REC) trading rules through the Multi-state Process, thus enabling sales and purchase of surplus banked RECs.

RPS modeling is conducted as a two-step process. First, for each case the System Optimizer generates a portfolio without any RPS constraints applied. Determining whether the portfolio meets the RPS constraints is an off-line exercise utilizing a spreadsheet accounting model. The main components of the model include for each applicable state (1) the annual RPS requirement, (2) the annual generation from qualifying existing renewable facilities and resources selected by the System Optimizer, and (3) tracking of annual cumulative surplus REC bank balances. The qualifying generation for the all states, divided by the system load, represents the RPS compliance percentage. If this compliance percentage falls short of the generation requirement for a given year, available surplus banked RECs are applied. A portfolio is RPS-compliant if the RPS compliance percentage exceeds the RPS generation requirement for all years.

For step two, if the portfolio is not RPS-compliant then PacifiCorp re-runs the System Optimizer model with the annual RPS constraints turned on. To the extent the RPS requirement is not met, the model will add eligible resources to ensure compliance. Comparison of the costs for the RPS non-compliant and compliant portfolios indicates the incremental cost of RPS compliance with additional renewable resources.[36]

For each case, an RPS compliance report was generated. This report shows the annual system RPS requirements, REC bank balances, REC-adjusted qualifying generation, RPS compliance percentages, and the system load used in the calculations. The report also includes a line chart comparing the RPS compliance and system generation requirements percentages for both the base and high RPS scenarios. The RPS compliance reports are included in Appendix A.

## Modeling Front Office Transactions and Growth Resources

Front office transactions, described in Chapter 6, are assumed to be transacted on a one-year basis, and are represented as available in each year of the study. For capacity optimization model-

[35] The model currently is designed to treat RPS constraints as a generation percentage of system load. PacifiCorp is working with the model vendor on enhancements that enable representation of load-based RPS requirements for multiple jurisdictions.
[36] This two-step approach is intended to address a Utah commission 2007 IRP acknowledgment order requirement.

ing, System Optimizer engages in market purchase acquisition—both front office transactions and spot market purchases for energy balancing—to the extent it is economic given other available resources. The model can select virtually any quantity of FOT generation up to limits imposed for each case, in any study year, independently of choices in other years. However, once a front office transaction resource is selected, it is treated as a must-run resource for the duration of the transaction period. For this IRP, front office transactions are available for all years in the study period. (In contrast, front office transactions were only modeled through 2018 in the 2007 IRP, after which the model could select only growth resources to meet load growth.)

The front office transactions modeled in the Planning and Risk Module generally have the same characteristics as those modeled in the System Optimizer, except that transaction prices reflect wholesale forward electric market prices that are "shocked" according to a stochastic modeling process prior to simulation execution.

Another resource type included in the IRP models is the *growth resource*. This resource is intended for capacity balancing in each load area to ensure that capacity reserve margins are met in the out years of each simulation (after 2020). The System Optimizer model can select an annual flat or third-quarter heavy load hour energy pattern priced at forward market prices appropriate for each load area. Growth resources are similar to front office transactions, except that they are not transacted at market hubs.

## Modeling Wind Resources

Wind resources are modeled with an hourly generation shape that reflects average hourly wind variability. The shapes are scaled to capacity factors reflecting representative wind resource qualities across PacifiCorp's system. (See Chapter 6 for more details on wind resource options.) The hourly generation shape is repeated for each year of the simulation, and is used in both the System Optimizer and Planning and Risk models.

Because System Optimizer is not a detailed chronological unit commitment and dispatch model, the cost impacts of wind tied to unit commitment are not captured. Also, system costs and reliability effects associated with intra-hour wind variability are not captured.

To capture the costs of integrating wind into the system, PacifiCorp applied a value of \$11.75/MWh (in 2008 dollars) for portfolio modeling. The source of this value was Portland General Electric Company's wind integration study, which assumed penetration of over 1,000 MW of wind capacity with no addition of supporting flexible thermal resources. This value was selected as a reasonable proxy to use until PacifiCorp's own wind integration cost study is completed.

To reflect realistic system resource addition limits tied to transmission availability, System Optimizer was constrained to select up to 500 MW of wind prior to 2014, and 750 MW in 2014 and thereafter.

## Modeling Fossil Fuel Efficiency Improvements

For all IRP modeling, PacifiCorp used forward-looking heat rates for existing fossil fuel plants, which account for plant efficiency improvement plans. Previously the company used four-year historical average heat rates. This change ensures that such planned improvements are factored in the optimized portfolios and stochastic production cost simulations, in line with the goals of the PURPA fossil fuel generation efficiency standard that is part of the 2005 Energy Policy Act.

## MONTE CARLO PRODUCTION COST SIMULATION

Phase 4 entails simulation of each optimized portfolios from Phase 3 using the Planning and Risk model in stochastics mode. The PaR simulation produces a dispatch solution that accounts for chronological commitment and dispatch constraints. Three stochastic simulations were executed for the three $CO_2$ tax levels: $0/ton, $45/ton, and $100/ton. These levels reflect a reasonable middle value along with bookends adopted for portfolio development. All the simulations used the October 2008 forward price curves as the expected gas and electricity price forecast values. This maintains comparability with the price forecast assumptions used for the 2009 business plan, as well as with the business plan reference cases, numbers 46 and 47.

The PaR simulation also incorporates stochastic risk in its production cost estimates by using a stochastic model and Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability for new resources. (For existing thermal units, planned maintenance schedules were used.[37]) Although wind resource generation was not varied in the same way as the other stochastic variables, the hour-to-hour generation does vary throughout the year, but the pattern is repeated identically for all study years (2009-2028) and Monte Carlo iterations.

### The Stochastic Model

The stochastic model used in PaR is a two-factor (a short-run and a long-run factor) short-run mean reverting model. Variable processes assume normality or log-normality as appropriate. Separate volatility and correlation parameters are used for modeling the short-run and long-run factors. The short-run process defines seasonal effects on forward variables, while the long-run factor defines random structural effects on electricity and natural gas markets and retail load regions. The short-run process is designed to capture the seasonal patterns inherent in electricity and natural gas markets and seasonal pressures on electricity demand.

Mean reversion represents the speed at which a disturbed variable will return to its seasonal expectation. With respect to market prices, the long-run factor should be understood as an expected equilibrium, with the Monte Carlo draws defining a possible forward equilibrium state. In the case of regional electricity loads, the Monte Carlo draws define possible forward paths for electricity demand.

### Stochastic Model Parameter Estimation

Stochastic model parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the

[37] Stochastic simulation of existing thermal unit availability is undesirable because it introduces cost variability unassociated with the evaluation of new resources, which confounds comparative portfolio analysis.

mean reversion parameter. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. The econometric analysis uses 48 months of historical data for parameter estimation.

The long-run parameters are derived from a "random-walk with drift" regression. The standard error of the random-walk regression defines the long-run volatility for the regional electricity load variables. In the case of the natural gas and electricity market prices, the standard error of the random walk regression is interpolated with the volatilities from the company's official forward price curves over the twenty-year IRP study period. The long-run regression errors are correlated to capture inter-variable effects from changes to expected market equilibrium for natural gas and electricity markets, as well as the impacts from changes in expected regional electricity loads.

PacifiCorp's econometric analysis is performed for the following stochastic variables:

- Fuel prices (natural gas prices for the company's western and eastern control areas),
- Electricity market prices for Mid-Columbia (Mid C), California – Oregon Border (COB), Four Corners, and Palo Verde (PV),
- Electric transmission area loads (California, Idaho, Oregon, Utah, Washington and Wyoming regions)
- Hydroelectric generation

For outage modeling, PacifiCorp relies on the PaR model's Monte Carlo simulation method to create a distributed outage pattern for new resources. PacifiCorp does not estimate stochastic parameters for plant outages.

**Monte Carlo Simulation**

During model execution, PaR makes time-path-dependent Monte Carlo draws for each stochastic variable based on the input parameters. The Monte Carlo draws are of percentage deviations from the expected forward value of the variables, and are the same for each Monte Carlo simulation. In the case of natural gas prices, electricity prices, and regional loads, PaR applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

The PaR model is configured to conduct 100 Monte Carlo simulation runs for the 20-year study period, so that each of the 100 simulations has its own set of stochastic parameters and shocked forecast values. The end result of the Monte Carlo simulation is 100 production cost runs (iterations) reflecting a wide range of portfolio cost outcomes.

Figures 7.18 through 7.21 show the 100-iteration frequencies for market prices resulting from the Monte Carlo draws for two representative years, 2009 and 2018. Figures 7.22 through 7.26 show the annual loads by load area at different percentiles: 10$^{th}$, 25$^{th}$, 50$^{th}$, 75$^{th}$, and 90$^{th}$. Figure 7.27 shows the 25$^{th}$, 50$^{th}$, and 75$^{th}$ percentiles for hydroelectric generation.

**Figure 7.18 – Frequency of Western (Mid-Columbia) Electricity Market Prices for 2009 and 2018**

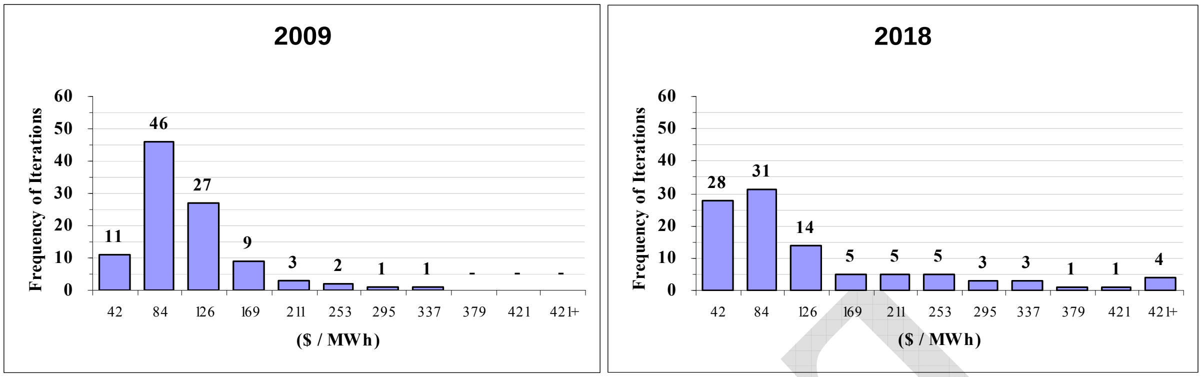



**Figure 7.19 – Frequency of Eastern (Palo Verde) Electricity Market Prices, 2009 and 2018**

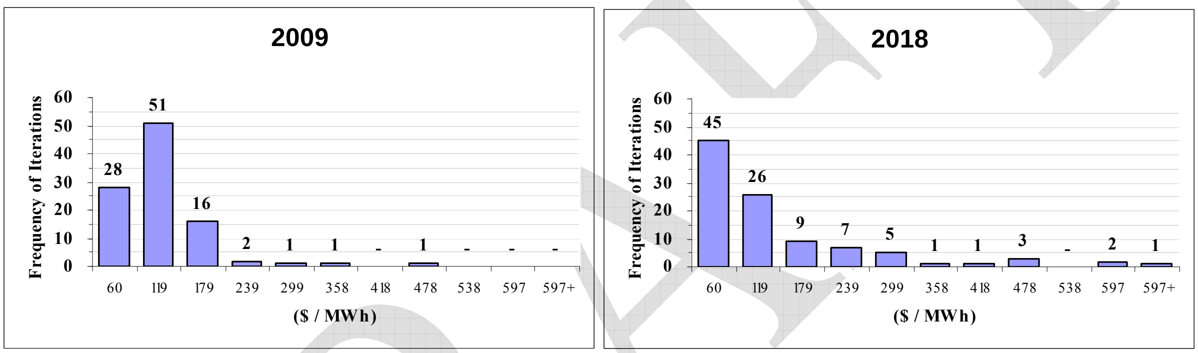



**Figure 7.20 – Frequency of Western Natural Gas Market Prices, 2009 and 2018**

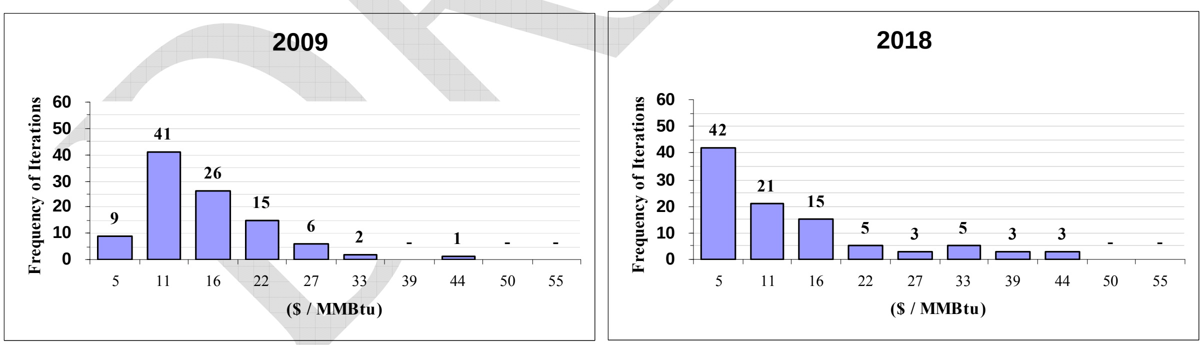
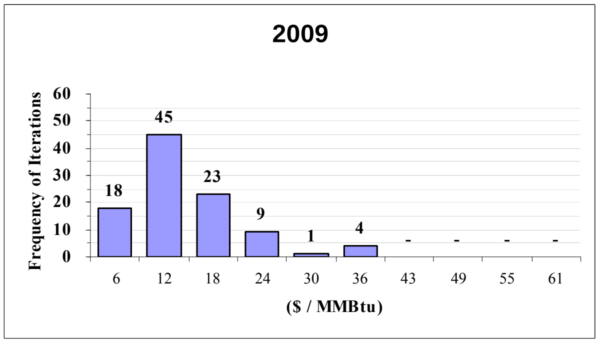


**Figure 7.21 – Frequency of Eastern Natural Gas Market Prices, 2009 and 2018**



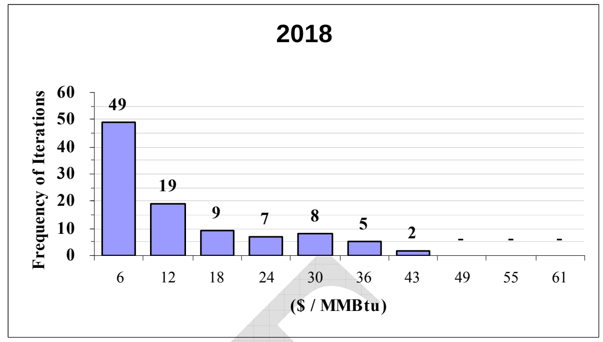




**Figure 7.22 – Frequencies for Idaho (Goshen) Loads**

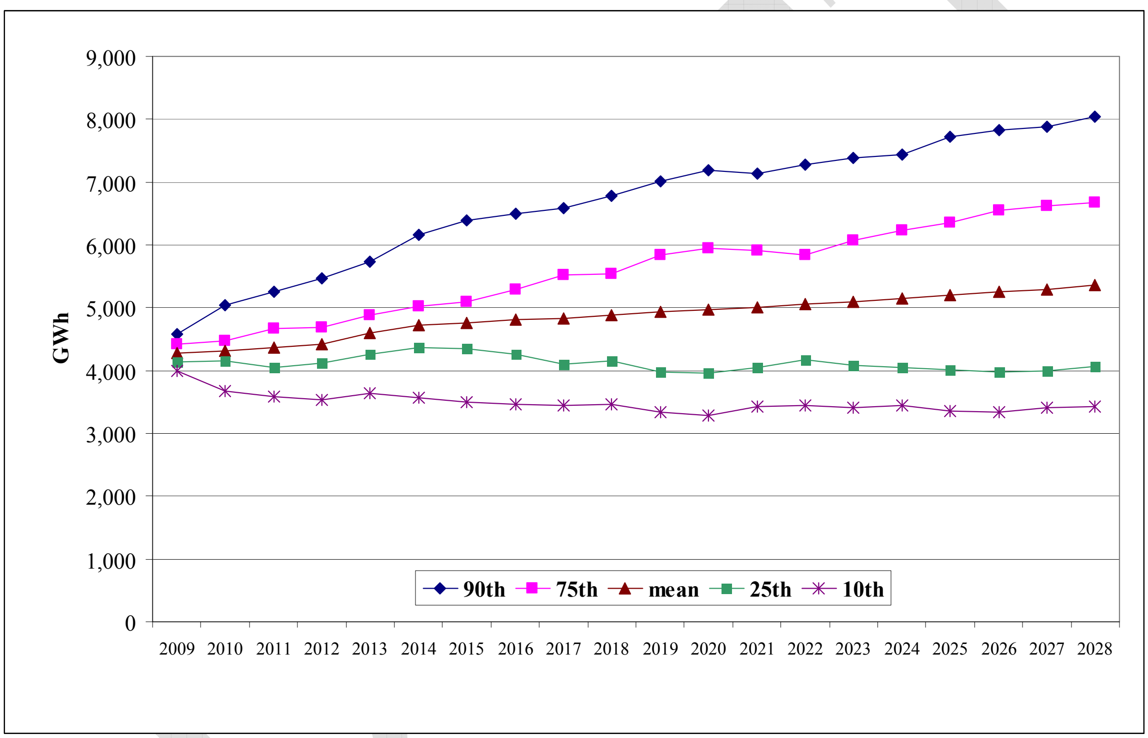


**Figure 7.23 – Frequencies for Utah Loads**

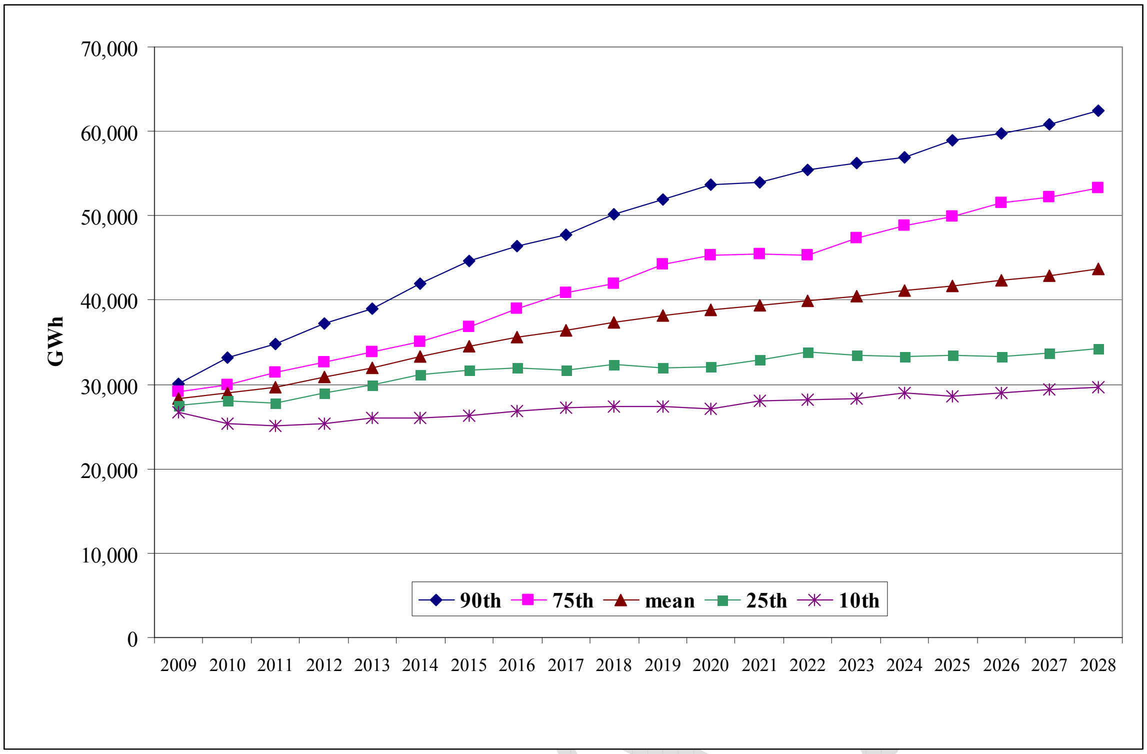



**Figure 7.24 – Frequencies for Washington Loads**

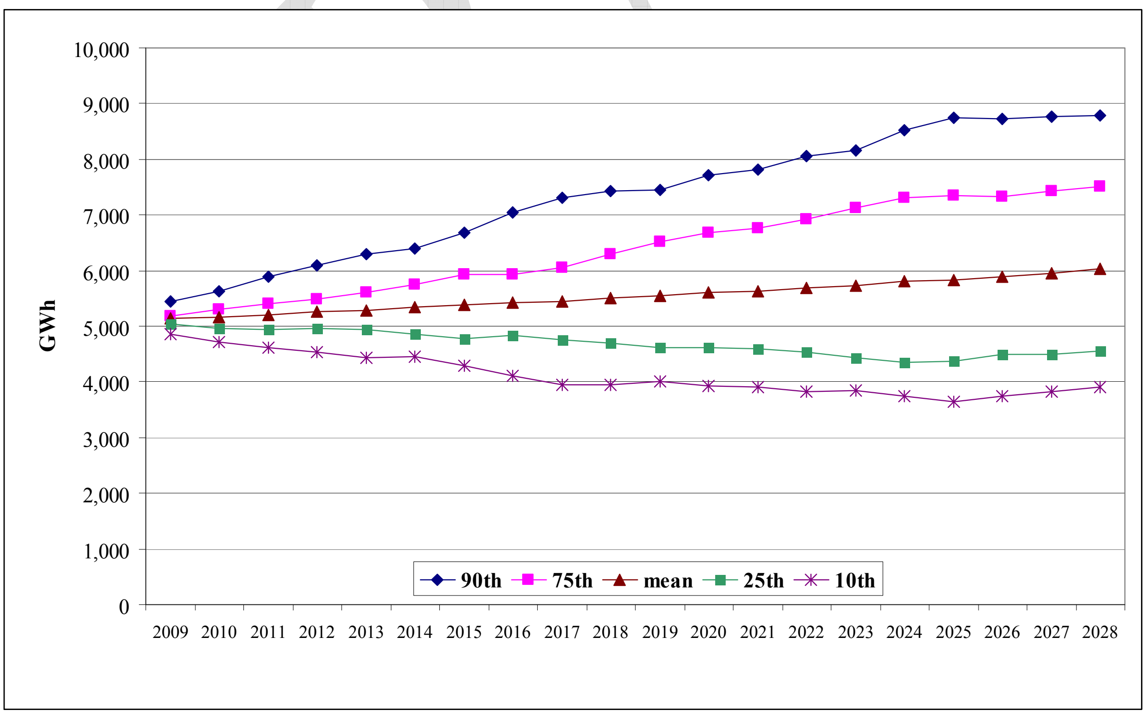


**Figure 7.25 – Frequencies for West Main (California and Oregon) Loads**

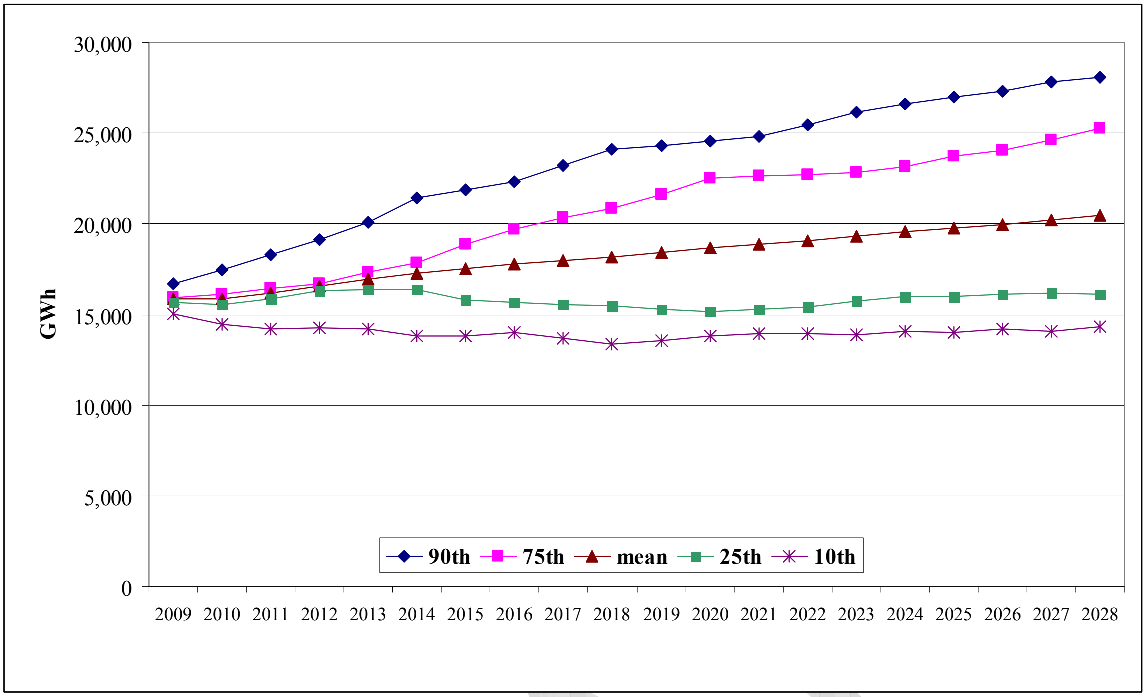



**Figure 7.26 – Frequencies for Wyoming Loads**

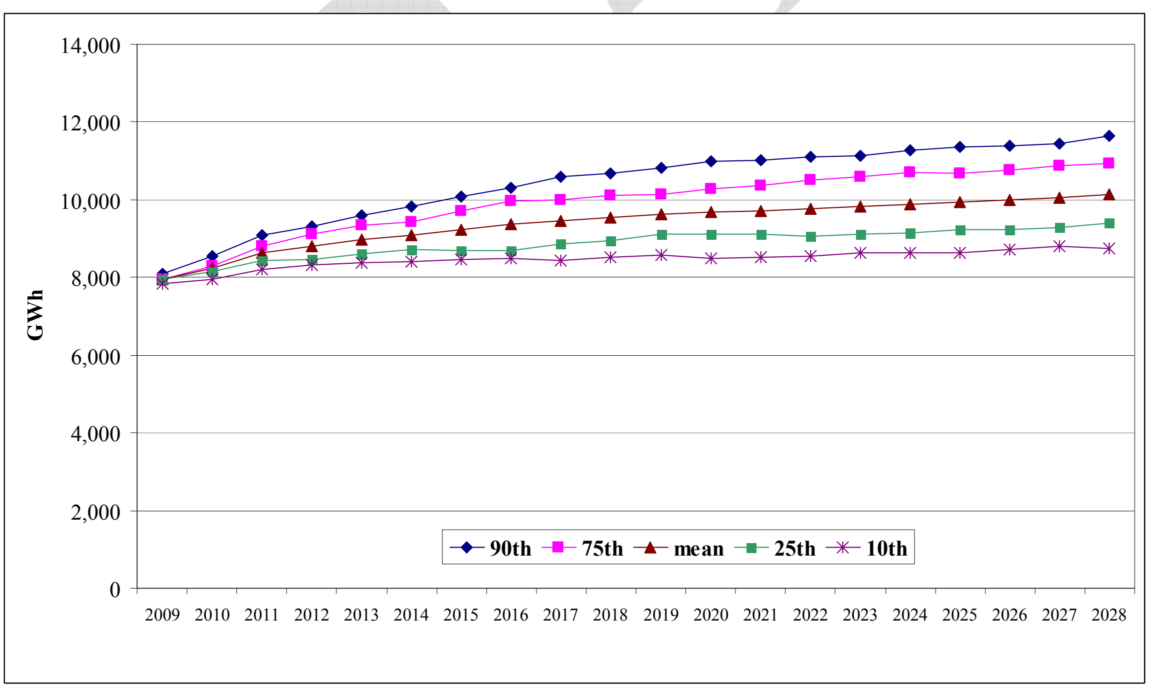
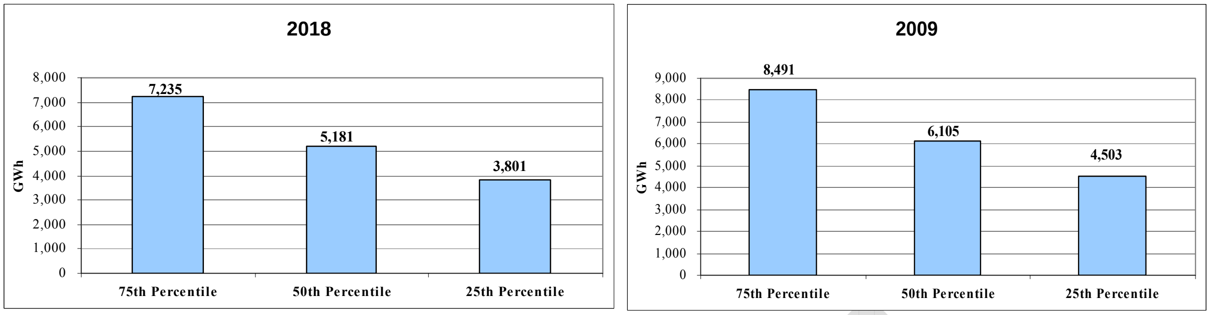


**Figure 7.27 – Hydroelectric Generation Frequency, 2009 and 2018**




PacifiCorp derives expected values for the Monte Carlo simulation by averaging run results across all 100 iterations. The company also looks at subsets of the 100 iterations that signify particularly adverse cost conditions, and derives associated cost measures as indicators of high-end portfolio risk. These cost measures, and others used to rank portfolio performance, are described in the next section.

## PORTFOLIO PERFORMANCE MEASURES

Stochastic simulation results for the optimized portfolios were summarized and compared to determine which portfolios perform best according to a set of performance measures. These measures, grouped by category, include the following:

Cost
- Mean PVRR (Present Value of Revenue Requirements)
- Risk-adjusted mean PVRR
- Minimum PVRR cost exposure under $CO_2$ tax outcomes
- Customer rate impact
- Capital costs for the first ten years of the simulation period (2009-2018) and the total simulation (2009-2028)

Risk
- Upper-tail Mean PVRR
- 95$^{th}$ Percentile PVRR
- Production cost standard deviation

Supply Reliability
- Average annual Energy Not Served (ENS)
- Upper-tail ENS
- Loss of Load Probability (LOLP)

PacifiCorp reports the portfolio results for each $CO_2$ tax simulation, the straight average for the three $CO_2$ tax simulations, and multiple probability-weighted averages. The multiple probability-weighted averages reflect \$5/ton increments of the expected value (EV) $CO_2$ tax, ranging from

$20/ton to $70/ton. This range is in line with long run values that have appeared in federal and state legislative proposals.[38] The average values are converted to a normalized, 1-to-10 scaled score to preserve relative differences between measure results when combining the scores for composite ranking of the portfolios.

In addition to these stochastic measures, PacifiCorp reports fuel source diversity statistics and the emission footprint of each portfolio, focusing on generator emissions.

The following sections describe in detail each of these performance measures as well as the fuel source diversity statistics.

## Mean PVRR

The stochastic mean PVRR for each portfolio is the average of the portfolio's net variable operating costs for 100 iterations of the PaR model in stochastic mode, combined with the real levelized capital costs for new resources determined by the System Optimizer model. The PVRR is reported in 2009 dollars as of January 1, 2009.

The net variable cost from the PaR simulations, expressed as a net present value, includes system costs for fuel, variable plant O&M, unit start-up, market contracts, spot market purchases and sales, and costs associated with making up for generation deficiencies (Energy Not Served costs; see the section on ENS below for background on ENS and the representation of ENS costs in the PaR model.) The variable costs included are not only for new resources but existing system operations as well. The capital additions for new resources (both generation and transmission) are calculated on an escalated "real-levelized" basis to appropriately handle investment end effects. Other components in the stochastic mean PVRR include renewable production tax credits and emission externality costs, such as a $CO_2$ tax.

The PVRR measure captures the total resource cost for each portfolio, including externality costs in the form of $CO_2$ cost adders. Total resource cost includes all the costs to the utility and customer for the variable portion of total system operations and the capital requirements for new supply and Class 1 demand-side resources as evaluated in this IRP.

## Risk-adjusted Mean PVRR

This measure—risk-adjusted PVRR for short—is calculated as the stochastic mean PVRR plus the expected value, EV, of the $95^{th}$ percentile PVRR, where EV = $PVRR_{95}$ x 5%. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on the 100 Monte Carlo simulations conducted for each production cost run.

The rationale behind the risk-adjusted PVRR is to have a consolidated stochastic cost indicator for portfolio ranking, combining expected cost and high-end cost risk concepts without eliciting and applying subjective weights that express the utility of trading one cost attribute for another.

[38] For example, see, Metcalf, G., et al, Analysis of U.S. Greenhouse Gas Tax Proposals (Massachusetts Institute of Technology, Joint Program on the Science and Policy of Global Change, Report No. 160, April 2008). As an example of a state legislative $CO_2$ tax proposal, the Kansas House of Representatives considered a $37/ton $CO_2$ tax to be levied on the state's electric utilities.

PacifiCorp also presents scatter-plot graphs of the stochastic mean PVRR versus upper-tail mean PVRR for portfolios as a means to visualize the tradeoff between expected and high-cost outcomes.

## Minimum Cost Exposure under Alternative Carbon Dioxide Tax Levels

Cost exposure is the difference between a portfolio's risk-adjusted PVRR and the risk-adjusted PVRR of the best-performing portfolio for a given $CO_2$ tax level modeled in the Monte Carlo simulation. Each portfolio is ranked on the basis of the size of its maximum cost exposure realized under the three $CO_2$ tax levels: $0/ton, $45/ton, and $100/ton.

This ranking scheme is based on the Minimax Regret decision criterion, which focuses on avoiding the worst possible consequences that could result when making a decision. In decision theory, "regret" is defined as the exposure between a course of action taken and the best course of action possible given a particular state of nature.[39] If the decision-maker selects the course of action that turns out to be the best possible one, then the regret is zero. Conversely, the maximum regret occurs if the selected course of action results in the worst outcome among the possibilities. The minimax decision rule is to select the course of action that minimizes the maximum regret across the states of nature evaluated. This is a risk-averse stance applicable to decision-making under uncertainty.

To illustrate the application of the decision rule, the following matrix shows the cost outcomes given two alternative actions and two states of nature, designated as $S_1$ and $S_2$. Under state of nature $S_1$, the best possible cost outcome happens under Alternative 2; under state of nature $S_2$, the superior cost outcome happens under Alternative 1.

| | Cost (Billion $) | |
|---|---|---|
| **Alternative** | **$S_1$** | **$S_2$** |
| **1** | 18.00 | 23.00 |
| **2** | 10.00 | 28.00 |
| **Lowest Cost** | **10.00** | **23.00** |

To determine the maximum regret for the two alternatives, a loss matrix is constructed:

**Loss Table (Billion $)**

| Alternative | $S_1$ | $S_2$ | Maximum Regret |
|---|---|---|---|
| **1** | 8.00 | 0.00 | **8.00** |
| **2** | 0.00 | 5.00 | **5.00** |

The maximum regret for alternative 1 under state of nature $S_1$ is $8 billion, while the maximum regret for alternative 2 under state of nature $S_2$ is $5 billion. By applying the minimax decision

[39] Regret is also called "opportunity loss", or the amount that would be lost by not picking the best alternative.

rule, alternative 2 would be selected because it has the lowest maximum loss under the two states of nature.

For PacifiCorp's minimax evaluation, the states of nature are the stochastic cost outcomes given the three $CO_2$ tax levels modeled in the Monte Carlo simulations ($0/ton, $45/ton, and $100/ton). The alternatives are the resource portfolios developed from the 21 core cases with the medium load growth assumption.

## Customer Rate Impact

PacifiCorp calculates the customer rate impact associated with each of the portfolios based on the stochastic production cost results and capital costs reported for the portfolio by the System Optimizer model. The rate impact measure is the change in the customer dollar-per-megawatt-hour price for the period 2010 through 2028, expressed on a levelized net present value basis.

The dollars in the rate numerator consist of the stochastic mean system operating cost (fuel cost, environmental cost, and variable O&M costs of all resources), combined with the fixed O&M and capital costs of the new supply-side and transmission resources.[40] The rate denominator is the retail load.

It should be noted that this measure provides an indication of the comparative rate impacts across risk analysis portfolios, but is not intended to accurately capture projected total system revenue requirements. For example, planned upgrades for current stations such as pollution controls added under PacifiCorp's Clean Air Initiative, as well as hydro relicensing costs, are not included in the calculations. Likewise, the IRP impacts assume immediate ratemaking treatment and make no distinction between current or proposed multi-jurisdictional allocation methodologies.

## Capital Cost

The total capital cost measure is the sum of the capital costs for generation resources and transmission, expressed as a net present value. The capital costs are reported by the System Optimizer for each portfolio. Capital costs for the first 10 years of the simulation period, as well as the entire simulation period, are reported. The ten-year capital cost view (for resources added in 2009-2018), is intended to indicate the relative rate impact of the portfolios attributable to resource construction costs during the period considered in PacifiCorp's business plan.

## Risk Measures

For this IRP, PacifiCorp relies on four stochastic cost risk measures: upper-tail mean PVRR, 5th and 95th percentile PVRR, and the standard deviation of production costs.

[40] New IRP resource capital costs are represented in 2008 dollars and grow with inflation, and start in the year the resource added. This method is used so resources having different lives can be evaluated on a comparable basis. The customer rate impacts will be lower in the early years and higher in the later years when compared to customer rate impacts computed under a rate-making formula.

**Upper-Tail Mean PVRR**

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the five highest production costs on a net present value basis. The portfolio's real levelized fixed costs are added to these five production costs, and the arithmetic average of the resulting PVRRs is computed.

**95th and 5th Percentile PVRR**

The fifth and ninety-fifth percentile stochastic PVRRs are also reported. These PVRR values correspond to the iteration out of the 100 that represents the fifth and ninety-fifth percentiles on the basis of production costs (net present value basis), respectively. These measures represent snapshot indicators of low-risk and high-risk stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted PVRR measure.

**Production Cost Standard Deviation**

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost for the 100 Monte Carlo simulation iterations. The production cost is expressed as a net present value for the annual costs for 2009 through 2028.

**Supply Reliability**

**Average and Upper-Tail Energy Not Served**

Certain iterations of a PaR stochastic simulation will have "energy not served" or ENS.[41] Energy Not Served is a condition where there is insufficient generation available to meet load because of physical constraints or market conditions. This occurs when an iteration has one or more stochastic variables with large random shocks that prevent the model from fully balancing the system for the simulated hour. Typically large load shocks and simultaneous unplanned plant outages are implicated in ENS events. (Deterministic PaR simulations do not experience ENS because there is no random behavior of model parameters; for example, loads increase in a smooth fashion over time.) Consequently, ENS, when averaged across all 100 iterations, serves as a measure of the stochastic reliability risk for a portfolio's resources.

For reporting of the ENS statistics, PacifiCorp calculates an average annual value for 2009 through 2028 in gigawatt-hours, as well as the upper-tail ENS (average of the five iterations with the highest ENS). Results using the $45/ton $CO_2$ tax are reported, as the tax level does not have a material influence on ENS amounts.

One change from previous IRPs related to the handling of ENS is the estimation of ENS costs included in the portfolio stochastic PVRR. In previous IRPs, PacifiCorp applied a single ENS cost for the PaR model, using the FERC price cap as a reasonable cost proxy for acquiring emergency power. PacifiCorp recognizes that, in practice, the planning response to significant ENS is different for short-run versus long-run ENS expectations. In the short-run, the company would have recourse to few remedial options, and would expect to pay a large premium for emergency power. On the other hand, the company has more planning options with which to respond to long-term forecasted ENS growth, including acquisition of peaking resources. Consequently, a

[41] Also referred to as Expected Unserved Energy, or EUE.

tiered pricing scheme has been applied to ENS quantities generated by the Planning and Risk model. The ENS cost is set to $400/MWh (real dollars) for the first 50 GWh/yr of ENS, $200/MWh for the next 100 GWh/yr, and $100/MWh for all quantities above 150 GWh/yr. For large forecasted ENS quantities that occur in the out years of the study period, the acquisition of peaking generation would become cost-effective, with the $100/MWh reflecting the long-run all-in cost for such generation.

**Loss of Load Probability**

Loss of Load Probability is a term used to describe the probability that the combinations of online and available energy resources cannot supply sufficient generation to serve the load peak during a given interval of time.

Mathematically, LOLP defined as:

$$\mathbf{LOLP} = \text{Prob}(\mathbf{S} < \mathbf{L})$$

*where **S** is a random variable representing the available power supply, and **L** is the daily load peak where the peak load is regarded as known.*

Traditionally LOLP was calculated for each hour of the year, converted to a measure of statistically expected outage times or number of outage events (depending on the model), and summed for the year. The annual measure estimates the generating system's reliability. A high LOLP generally indicates a resource shortage, which can be due to generator outages, insufficient installed capacity, or both. Target values for annual system LOLP depend on the utilities' degree of risk aversion, but a level equivalent of one day per ten years is typical.

For reporting LOLP, PacifiCorp calculates the probability of ENS events, where the magnitude of the ENS exceeds given threshold levels. PacifiCorp is strongly interconnected with the regional network; therefore, only events that occur at the time of the regional peak are the ones likely to have significant consequences. Of those events, small shortfalls are likely to be resolved with a quick (though expensive) purchase. In Chapter 8, the proportion of iterations with ENS events in July exceeding selected threshold levels are reported for each optimized portfolio simulated with the PaR model. The LOLP is reported as a study average as well as year-by-year results for an example threshold level of 25,000 MWh. This threshold methodology follows the lead of the Pacific Northwest Resource Adequacy Forum, which reports the probability of a "significant event" occurring the winter season.

**<u>Fuel Source Diversity</u>**

For assessing fuel source diversity on a summary basis for each portfolio, PacifiCorp calculated the new resource generation shares for four broad fuel-type categories as reflected in the System Optimizer expansion plan:

- Renewables and DSM ("no fuel" generation plus a small quantity of biomass fuel)
- Natural gas
- Market
- Coal, including all types of coal-based technologies selected for the expansion plan
- Nuclear

To account for the timing impact of the assumed availability of coal and nuclear resources in the portfolios, the generation shares are reported for years 2013, 2020, and 2028. Conventional supercritical coal plants are picked up in the 2020 and 2028 snapshots, while nuclear and clean coal resources are picked up in the 2028 snapshot.

Another perspective on fuel diversity is the nameplate capacity mix for the portfolios. Appendix A contains area charts for all portfolios developed that show the resource nameplate capacity mix by year. Nameplate capacity for resources selected by the System Optimizer is grouped into the following new resource categories: gas, DSM, distributed generation, wind, other renewables, clean coal, conventional coal, energy storage, other renewables, market purchases, and growth resources.

## TOP-PERFORMING PORTFOLIO SELECTION

For this IRP, PacifiCorp has instituted a weighted scoring scheme that combines selected portfolio performance measures into an overall composite preference score. The cases selected for performance ranking include the core cases defined with the medium load growth assumption (to maintain cost comparability with respect to the amount of resources required) as well as cases 46 and 47 (the two business plan reference portfolios).

The measures used in the weighted scoring scheme, along with their importance weights (which sum to 1), include the following:

**Table 7.8 – Measure Importance Weights for Portfolio Ranking**

| Cost Measures | Weight |
|---|---|
| Risk-adjusted PVRR | 45% |
| Customer Rate Impact | 20% |
| Capital Cost for 2009-2018 | 5% |
| **Risk Measures** | **Weight** |
| $CO_2$ Cost Exposure | 15% |
| Production Cost Standard Deviation | 5% |
| Average annual ENS | 5% |
| Average Annual Probability of ENS events for July exceeding 25 GWh | 5% |
| **Total** | **100%** |

Risk-adjusted PVRR represents the long-run cost performance for a portfolio, accounting for the potential for a high-cost outcome and its associated cost on an expected value basis. Consequently, this criterion is given the largest weight among the performance measures. The customer rate impact measure gauges long-run retail rate variability for a portfolio; given two portfolios with equivalent long-run costs, the portfolio that has lower retail rate variability is preferred. The 10-year capital cost criterion reflects the role that near-term capital expenditures plays in determining portfolio affordability and financeability for purposes of business plan preparation.

For portfolio risk measures, cost exposure under alternative $CO_2$ tax levels reflects a portfolio's potential for avoiding worst-case cost outcomes given $CO_2$ regulatory policy uncertainty; it is a measure of $CO_2$ cost risk, and has been given the largest weight among risk measures included in the preference scoring process. The three other risk measures reflect variable cost variability and supply reliability attributes, and have been given a combined weight of 15 percent for preference scoring.

Table 7.9 shows a sample of the preference-scoring grid for the optimized portfolios. To determine the preference scores for the portfolios, PacifiCorp conducted the following steps:

1. Calculate the normalized (scaled from 1 to 10) rankings for the probability-weighted average stochastic cost measures (risk-adjusted PVRR, customer rate impact, $CO_2$ cost exposure, and the standard deviation of production costs). Rankings are determined for each of 12 expected value $CO_2$ tax levels, ranging from $15 to $70.
2. Calculate the normalized rankings for the 10-year capital costs, average annual ENS, and July event LOLP.
3. Populate the portfolio preference-scoring grid with the normalized rankings. The weighted ranking for each portfolio is the sum of each individual performance ranking multiplied by its importance weight. These weighted rankings are then converted to final preference scores by scaling the rankings to a 1 to 10 range.



**Table 7.9 – Portfolio Preference Scoring Grid**

| | Cost Measures | | | Risk Measures | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Case 1/ | Risk-adjusted PVRR | Rate Impact | Capital Cost | CO2 Cost Exposure | Production Cost Standard Deviation | Ave. Annual Energy Not Served | LOLP, Annual Ave. for July Event > 25 GWh | Weighted Rankings | Normalized Scores (1 to 10) |
| 1 | | | | | | | | 0.0 | 0.0 |
| 2 | | | | | | | | 0.0 | 0.0 |
| 3 | | | | | | | | 0.0 | 0.0 |
| 5 | | | | | | | | 0.0 | 0.0 |
| 8 | | | | | | | | 0.0 | 0.0 |
| 9 | | | | | | | | 0.0 | 0.0 |
| 10 | | | | | | | | 0.0 | 0.0 |
| 11 | | | | | | | | 0.0 | 0.0 |
| 14 | | | | | | | | 0.0 | 0.0 |
| 17 | | | | | | | | 0.0 | 0.0 |
| 18 | | | | | | | | 0.0 | 0.0 |
| 19 | | | | | | | | 0.0 | 0.0 |
| 20 | | | | | | | | 0.0 | 0.0 |
| 22 | | | | | | | | 0.0 | 0.0 |
| 24 | | | | | | | | 0.0 | 0.0 |
| 25 | | | | | | | | 0.0 | 0.0 |
| 26 | | | | | | | | 0.0 | 0.0 |
| 27 | | | | | | | | 0.0 | 0.0 |
| 29 | | | | | | | | 0.0 | 0.0 |
| 46 | | | | | | | | 0.0 | 0.0 |
| 47 | | | | | | | | 0.0 | 0.0 |
| Importance Weights | 45% | 20% | 5% | 15% | 5% | 5% | 5% | | |

The net result was a set of 12 preference-scoring grids, one for each expected value $CO_2$ tax level. For determining the top-performing portfolios, PacifiCorp calculated the average of the preference scores across the $CO_2$ tax levels, as well as inspected the variability of the scores as the $CO_2$ level increased.

The top three portfolios on the basis of the preference scores were selected as final preferred portfolio candidates. Three portfolios represent a manageable number in light of the data processing and model run-time requirements associated with phase 6, deterministic risk assessment of the top-performing portfolios.

## SCENARIO RISK ASSESSMENT

The purpose of phase 6 is to determine the range of deterministic costs that could result given a fixed set of resources under varying gas/electricity price and $CO_2$ cost assumptions, the two main sources of portfolio risk. The Public Service Commission of Utah, in its acknowledgment order for PacifiCorp's 2007 IRP, directed the company to consider this step for the 2008 IRP.

PacifiCorp used the System Optimizer to determine PVRRs for the three top-performing portfolios under a subset of the core cases (Scenario Risk Cases). For these runs, the System Optimizer dispatches the fixed set of portfolio resources as part of its least-cost portfolio solution. The PVRR comparisons thus indicate the production cost differences under the alternative cost scenarios.

As with the performance ranking process, PacifiCorp selected only those cases with the medium load growth assumption. Cases were also restricted to those using the June 2008 forward price curve. These selection rules resulted in 10 cases and total of 30 System Optimizer runs to support this analysis as shown in Table 7.10.

**Table 7.10 – Cases Selected for Deterministic Risk Assessment**

| Case | $CO_2$ Tax Level (2008 dollars) | Base Gas Cost |
|---|---|---|
| 1 | $0/ton | Low |
| 2 | $0/ton | Medium |
| 3 | $0/ton | High |
| 5 | $45/ton | Low |
| 8 | $45/ton | Medium |
| 14 | $45/ton | High |
| 17 | $70/ton | Medium |
| 22 | $70/ton | High |
| 24 | $100/ton | Medium |
| 29 | $100/ton | High |

In parallel with the stochastic risk analysis, PacifiCorp reports a measure of central tendency (mean PVRR) and variation (PVRR standard deviation) for the portfolio results, as well as ranked each portfolio and computed the rank sum as an overall performance indicator.

## PREFERRED PORTFOLIO SELECTION AND ACQUISITION RISK ANALYSIS

The preferred portfolio is selected from the three top-performing portfolios on the basis of the portfolio preference scores, and then consideration of resource risks and fuel source diversity.

Using the preferred portfolio as the starting point, PacifiCorp conducts a next best alternative (NBA) analysis that applied a number of procurement risk scenarios to determine optimal portfolios in the event of unplanned circumstances. The focus of the NBA analysis is on key firm-planned and new resources reflected in the preferred portfolio.

# 8. MODELING AND PORTFOLIO SELECTION RESULTS

## INTRODUCTION

This chapter reports modeling and portfolio performance evaluation results for the portfolios developed with alternate input assumptions using the System Optimizer model. The preferred portfolio is presented, along with a discussion of the relative advantages and risks associated with the top-performing portfolios.

Discussion of the portfolio evaluation results falls into the following 12 sections.
Portfolio Development Results – This section presents the System Optimizer resource portfolios, describing resource preferences as a function of the model input assumptions and profiling resource utilization patterns for each portfolio. Analysis results for several sensitivity case portfolios are also presented.

- Stochastic Simulation Results - Candidate Portfolios – This section reports the stochastic modeling results and cost/risk measure ranking results for each of the 21 candidate portfolios.
- Load Growth Impact on Resource Choice – This section compares the stochastic modeling results for portfolios developed with alternative load growth assumptions.
- Capacity Planning Reserve Margin – This section describes the stochastic cost and risk analysis of portfolios developed with 12 and 15 percent capacity planning reserve margins.
- Probability-weighted Stochastic Cost Results – This section reports the stochastic cost measures as probability-weighted averages of the results for the three $CO_2$ tax simulations: $0, $45, and $100/ton in 2008 dollars. These results are key inputs in the overall portfolio preference scoring process.
- Fuel Source Diversity – This section provides statistics on generation shares by fuel type for all the portfolios; three snap shot years are profiled: 2013, 2020, and 2028.
- Emissions Footprint – This section reports for each portfolio the annual emission quantities of $CO_2$, sulfur dioxide, nitrous oxides, and mercury for 2009-2028.
- Top-performing Portfolio Selection – This section describes the results of the portfolio cost/risk measure ranking and preference scoring, and identifies the three top-performing portfolios chosen as final candidates for preferred portfolio selection.
- Scenario Risk Assessment – This section describes the deterministic scenario analysis conducted for the three top-performing portfolios, concluding with a critique of the value of this type of analysis for the IRP.
- Portfolio Impact of the 2012 Gas Resource Deferral Decision – This section describes the portfolio analysis conducted to reflect the removal of the Lake Side 2 combined-cycle plant as a planned resource for 2012.
- Portfolio Impact of PacifiCorp's February 2009 Load Forecast – This section presents the portfolio developed to account for a new load forecast prepared in February 2009.
- Preferred Portfolio Selection – This section compares the top-performing portfolios, profiling their relative advantages and risks and pulling in the portfolio analysis conducted for the

Lake Side 2 construction cancellation and revised load forecast. The portfolio that is the most desirable after considering cost, risk and uncertainty is then presented.

## PORTFOLIO DEVELOPMENT RESULTS

Tables 8.1 and 8.2 show the cumulative capacity additions by resource type for the portfolios for years 2009-2018 and 2009-2028, respectively. Megawatt amounts for front office transactions and growth resources represent annual averages: 20 years for FOT, and eight years for growth resources. (The detailed portfolio resource tables are included in Appendix A.)

# Table 8.1 – Portfolio Capacity Additions by Resource Type, 2009 – 2018

| | | | | Cumulative Megawatt Nameplate Capacity by Resource Type (Annual Average for Market Resources) [1/] | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Case | PVRR | Gas Scenario / FPC | CO2 Price | SCPC | Gas | Wind | Dist. Gen | Market Purchases (10-yr Avg) | Other Renewables | DSM Class 1 | DSM Class 2 |
| **Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)** | | | | | | | | | | | |
| 1 | $20,045 | Low - June 2008 | $0 | | 261 | | 124 | 748 | | 108 | 716 |
| 2 | $21,512 | Medium - June 2008 | $0 | 600 | 261 | 140 | 85 | 646 | 35 | 2 | 890 |
| 3 | $19,503 | High - June 2008 | $0 | 790 | | 3,291 | 95 | 530 | 155 | 7 | 982 |
| 5 | $40,526 | Low - June 2008 | $45 | | 261 | 1,050 | 95 | 691 | 35 | 2 | 901 |
| 8 | $41,372 | Medium - June 2008 | $45 | | | 2,400 | 147 | 663 | 120 | 7 | 955 |
| 9 | $40,204 | Low - Oct 2008 | $45 | | 261 | 1,280 | 95 | 690 | 35 | 2 | 899 |
| 10 | $40,319 | Medium - Oct 2008 | $45 | | | 2,400 | 117 | 679 | 155 | 7 | 949 |
| 11 | $40,559 | High - Oct 2008 | $45 | 600 | | 4,814 | 103 | 546 | 155 | 7 | 1,001 |
| 14 | $39,949 | High - June 2008 | $45 | 600 | | 5,355 | 107 | 500 | 155 | 7 | 1,018 |
| 17 | $51,207 | Medium - June 2008 | $70 | | | 3,900 | 110 | 613 | 155 | 7 | 985 |
| 18 | $49,745 | Low - Oct 2008 | $70 | | | 3,900 | 110 | 640 | 155 | 7 | 954 |
| 19 | $50,102 | Medium - Oct 2008 | $70 | | | 4,100 | 110 | 620 | 155 | 7 | 975 |
| 20 | $50,536 | High - Oct 2008 | $70 | | | 5,250 | 104 | 602 | 155 | 7 | 1,007 |
| 22 | $49,983 | High - June 2008 | $70 | 600 | | 5,750 | 101 | 514 | 155 | 7 | 1,048 |
| 24 | $60,693 | Medium - June 2008 | $100 | | | 5,739 | 112 | 565 | 155 | 7 | 1,009 |
| 25 | $58,838 | Low - Oct 2008 | $100 | | | 5,250 | 112 | 742 | 155 | 7 | 1,000 |
| 26 | $59,660 | Medium - Oct 2008 | $100 | | | 5,250 | 112 | 661 | 155 | 7 | 1,007 |
| 27 | $60,484 | High - Oct 2008 | $100 | | | 5,750 | 110 | 648 | 155 | 7 | 1,045 |
| 29 | $57,635 | High - June 2008 | $100 | | | 5,750 | 158 | 538 | 155 | 110 | 1,079 |
| 46 | $21,532 | Medium - Oct 2008 | $8, C&T | | 174 | 600 | 136 | 641 | | 19 | 906 |
| 47 | $20,863 | Medium - Oct 2008 | $8, C&T | | 174 | 822 | 136 | 646 | | 29 | 903 |
| **Low Load Growth Core Cases** | | | | | | | | | | | |
| 4 | $34,612 | Low - June 2008 | $45 | | | 300 | 91 | 216 | 35 | | 882 |
| 7 | $34,582 | Medium - June 2008 | $45 | | | 1,800 | 91 | 172 | 85 | | 920 |
| 13 | $31,076 | High - June 2008 | $45 | 600 | | 4,610 | 95 | 121 | 155 | | 1,004 |
| 16 | $43,523 | Medium - June 2008 | $70 | | | 3,599 | 109 | 116 | 155 | | 962 |
| 21 | $40,517 | High - June 2008 | $70 | | | 5,750 | 95 | 134 | 155 | | 1,017 |
| 23 | $51,692 | Medium - June 2008 | $100 | | | 5,559 | 111 | 101 | 155 | | 1,005 |
| 28 | $47,806 | High - June 2008 | $100 | | | 5,750 | 95 | 242 | 155 | | 1,017 |
| **High Load Growth Core Cases** | | | | | | | | | | | |
| 6 | $48,140 | Low - June 2008 | $45 | | 1,363 | 904 | 192 | 755 | 155 | 126 | 957 |
| 12 | $50,146 | Medium - June 2008 | $45 | 600 | 888 | 1,907 | 151 | 748 | 155 | 107 | 994 |
| 15 | $50,914 | High - June 2008 | $45 | 600 | 261 | 5,750 | 153 | 771 | 655 | 114 | 1,079 |
| **Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth** | | | | | | | | | | | |
| 30 | $48,541 | Medium - June 2008 | $45 to $179 | | | 4,400 | 110 | 621 | 155 | 7 | 1,003 |
| 31 | $47,552 | High - June 2008 | $45 to $179 | | | 5,750 | 110 | 533 | 155 | 7 | 1,072 |
| **Sensitivity Case - High Cost Outcome** | | | | | | | | | | | |
| 33 | $69,949 | High - June 2008 | $100 | 600 | 577 | 5,750 | 158 | 662 | 655 | 126 | 1,113 |
| **Sensitivity Cases - Clean Base-Load Generation Availability** | | | | | | | | | | | |
| 34 | $40,564 | Medium - June 2008 | $45 | | | 3,183 | 138 | 647 | 85 | 7 | 950 |
| 35 | $39,853 | High - June 2008 | $45 | 600 | | 5,000 | 97 | 528 | 120 | 7 | 1,015 |
| 36 | $51,242 | Medium - June 2008 | $70 | | | 4,200 | 147 | 681 | 120 | 7 | 1,002 |
| 37 | $48,949 | High - June 2008 | $70 | | | 5,750 | 95 | 595 | 120 | 7 | 1,019 |
| **Sensitivity Cases - High Plant Construction Costs** | | | | | | | | | | | |
| 38 | $41,974 | Medium - June 2008 | $45 | | | 1,605 | 138 | 665 | 85 | 64 | 968 |
| 39 | $34,791 | High - June 2008 | $45 | 600 | | 3,182 | 142 | 493 | 120 | 109 | 1,020 |
| **Sensitivity Case - System-wide Oregon CO2 Reduction Targets** | | | | | | | | | | | |
| 40 | $24,761 | Medium - June 2008 | Hard Cap | | | 1,241 | 124 | 677 | 85 | 104 | 920 |
| **Sensitivity Cases - Planning Reserve Margin, 15%** | | | | | | | | | | | |
| 41 | $41,542 | Medium - June 2008 | $45 | | 261 | 1,934 | 151 | 776 | 155 | 25 | 954 |
| 42 | $51,420 | Medium - June 2008 | $70 | | 261 | 3,600 | 110 | 764 | 155 | | 983 |
| 43 | $60,905 | Medium - June 2008 | $100 | | | 5,750 | 154 | 713 | 155 | 105 | 1,036 |
| **Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)** | | | | | | | | | | | |
| 44 | $21,249 | Medium - Oct 2008 | $8, C&T | 600 | | 1,746 | 132 | 632 | 85 | 109 | 900 |
| 45 | $20,875 | Medium - Oct 2008 | $8, C&T | 600 | 261 | 721 | 89 | 654 | 35 | 2 | 877 |
| **Sensitivity Case - Class 3 DSM for Peak Load Reduction** | | | | | | | | | | | |
| 48 | $41,268 | Medium - June 2008 | $45 | | | 2,400 | 107 | 643 | 85 | 121 | 945 |

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

# Table 8.2 – Portfolio Capacity Additions by Resource Type, 2009 – 2028

| | | | | Cumulative Megawatt Nameplate Capacity by Resource Type (Annual Average for Market and Growth Resources) [1/] | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Case | PVRR | Gas Scenario / FPC | CO2 Price | SCPC | SCPC w/ CCS | IGCC w/ CCS | Gas | Wind | Dist. Gen | Nuclear | Market Purchases (20-yr Avg) | Growth Resource (8-yr Avg, 2021-2028) | Other Renewables | DSM Class 1 | DSM Class 2 |
| **Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)** | | | | | | | | | | | | | | | |
| 1 | $20,045 | Low - June 2008 | $0 | | | | 261 | | 130 | | 1,102 | 859 | | 108 | 1,537 |
| 2 | $21,512 | Medium - June 2008 | $0 | 600 | | | 261 | 941 | 109 | | 880 | 524 | 35 | 2 | 1,815 |
| 3 | $19,503 | High - June 2008 | $0 | 790 | | | | 4,003 | 95 | | 713 | 437 | 155 | 7 | 1,992 |
| 5 | $40,526 | Low - June 2008 | $45 | | 346 | | 261 | 1,600 | 110 | | 1,089 | 734 | 35 | 2 | 1,835 |
| 8 | $41,372 | Medium - June 2008 | $45 | | | | | 2,400 | 160 | | 1,090 | 624 | 120 | 7 | 1,942 |
| 9 | $40,204 | Low - Oct 2008 | $45 | | 346 | | 261 | 1,600 | 110 | | 1,133 | 623 | 35 | 2 | 1,834 |
| 10 | $40,319 | Medium - Oct 2008 | $45 | | | | | 2,600 | 129 | | 1,124 | 513 | 155 | 7 | 1,936 |
| 11 | $40,559 | High - Oct 2008 | $45 | 600 | | | | 5,000 | 114 | | 717 | 651 | 155 | 7 | 2,024 |
| 14 | $39,949 | High - June 2008 | $45 | 600 | | 466 | | 6,287 | 120 | | 711 | 272 | 155 | 7 | 2,066 |
| 17 | $51,207 | Medium - June 2008 | $70 | | 876 | | | 3,900 | 122 | | 1,084 | 609 | 155 | 7 | 2,020 |
| 18 | $49,745 | Low - Oct 2008 | $70 | | 876 | | | 3,900 | 122 | | 1,089 | 667 | 155 | 7 | 1,974 |
| 19 | $50,102 | Medium - Oct 2008 | $70 | | 876 | | | 4,100 | 122 | | 1,094 | 610 | 155 | 7 | 2,009 |
| 20 | $50,536 | High - Oct 2008 | $70 | | 876 | | | 6,600 | 114 | 1,600 | 842 | 651 | 155 | 7 | 2,035 |
| 22 | $49,983 | High - June 2008 | $70 | 600 | 876 | | | 7,200 | 101 | 1,600 | 616 | 161 | 155 | 7 | 2,115 |
| 24 | $60,693 | Medium - June 2008 | $100 | | 876 | | | 6,600 | 122 | 3,200 | 802 | 280 | 155 | 7 | 2,076 |
| 25 | $58,838 | Low - Oct 2008 | $100 | | 876 | | | 6,175 | 122 | | 1,070 | 777 | 155 | 7 | 2,035 |
| 26 | $59,660 | Medium - Oct 2008 | $100 | | 876 | | | 6,600 | 122 | 3,200 | 783 | 311 | 155 | 7 | 2,042 |
| 27 | $60,484 | High - Oct 2008 | $100 | | 876 | | | 6,680 | 120 | 3,200 | 972 | 650 | 155 | 7 | 2,098 |
| 29 | $57,635 | High - June 2008 | $100 | | 876 | 466 | | 7,200 | 167 | 3,200 | 575 | 450 | 155 | 110 | 2,183 |
| 46 | $21,532 | Medium - Oct 2008 | $8, C&T | 600 | | | 174 | 1,388 | 151 | | 897 | 468 | | 19 | 1,825 |
| 47 | $20,863 | Medium - Oct 2008 | $8, C&T | 600 | | | 174 | 1,344 | 151 | | 892 | 469 | | 29 | 1,822 |
| **Low Load Growth Core Cases** | | | | | | | | | | | | | | | |
| 4 | $34,612 | Low - June 2008 | $45 | | 346 | | | 300 | 110 | | 269 | 125 | 35 | | 1,801 |
| 7 | $34,582 | Medium - June 2008 | $45 | | 346 | | | 1,800 | 110 | | 185 | 115 | 85 | | 1,857 |
| 13 | $31,076 | High - June 2008 | $45 | 600 | | | | 4,800 | 95 | | 71 | 81 | 155 | | 2,038 |
| 16 | $43,523 | Medium - June 2008 | $70 | | 876 | | | 3,599 | 122 | | 108 | 111 | 155 | | 1,990 |
| 21 | $40,517 | High - June 2008 | $70 | | 876 | | | 6,202 | 95 | 1,600 | 124 | 70 | 155 | | 2,058 |
| 23 | $51,692 | Medium - June 2008 | $100 | | 876 | | | 6,600 | 122 | 3,200 | 157 | 85 | 155 | | 2,045 |
| 28 | $47,806 | High - June 2008 | $100 | | 876 | | | 5,800 | 95 | 3,200 | 150 | 67 | 155 | | 2,036 |
| **High Load Growth Core Cases** | | | | | | | | | | | | | | | |
| 6 | $48,140 | Low - June 2008 | $45 | | | | 1,838 | 1,600 | 209 | | 1,181 | 1,125 | 155 | 126 | 1,983 |
| 12 | $50,146 | Medium - June 2008 | $45 | 600 | | | 888 | 2,299 | 169 | | 1,186 | 1,125 | 155 | 126 | 2,082 |
| 15 | $50,914 | High - June 2008 | $45 | 600 | | 466 | 261 | 6,599 | 169 | 1,600 | 1,148 | 572 | 655 | 125 | 2,163 |
| **Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth** | | | | | | | | | | | | | | | |
| 30 | $48,541 | Medium - June 2008 | $45 to $179 | | 876 | 466 | | 7,000 | 122 | 3,200 | 743 | 126 | 155 | 7 | 2,091 |
| 31 | $47,552 | High - June 2008 | $45 to $179 | | 876 | | | 7,200 | 122 | 3,200 | 815 | 130 | 155 | 7 | 2,159 |
| **Sensitivity Case - High Cost Outcome** | | | | | | | | | | | | | | | |
| 33 | $69,949 | High - June 2008 | $100 | 600 | | | 1,100 | 7,200 | 169 | | 762 | 1,125 | 655 | 126 | 2,294 |
| **Sensitivity Cases - Clean Base-Load Generation Availability** | | | | | | | | | | | | | | | |
| 34 | $40,564 | Medium - June 2008 | $45 | | | | | 3,900 | 152 | | 1,109 | 539 | 85 | 7 | 1,937 |
| 35 | $39,853 | High - June 2008 | $45 | 600 | | | | 5,000 | 97 | | 778 | 479 | 120 | 7 | 2,022 |
| 36 | $51,242 | Medium - June 2008 | $70 | | 876 | | | 4,200 | 169 | | 1,127 | 762 | 120 | 110 | 2,046 |
| 37 | $48,949 | High - June 2008 | $70 | | 876 | | | 5,762 | 95 | 3,200 | 468 | 150 | 120 | 7 | 2,061 |
| **Sensitivity Cases - High Plant Construction Costs** | | | | | | | | | | | | | | | |
| 38 | $41,974 | Medium - June 2008 | $45 | | | | | 2,118 | 151 | | 1,114 | 535 | 85 | 64 | 1,970 |
| 39 | $34,791 | High - June 2008 | $45 | 600 | | | | 3,255 | 149 | | 641 | 580 | 120 | 109 | 2,113 |
| **Sensitivity Case - System-wide Oregon CO2 Reduction Targets** | | | | | | | | | | | | | | | |
| 40 | $24,761 | Medium - June 2008 | Hard Cap | | 876 | | | 2,200 | 124 | | 999 | 1,000 | 85 | 104 | 1,880 |
| **Sensitivity Cases - Planning Reserve Margin, 15%** | | | | | | | | | | | | | | | |
| 41 | $41,542 | Medium - June 2008 | $45 | | | | 261 | 1,934 | 163 | | 1,168 | 590 | 155 | 25 | 1,941 |
| 42 | $51,420 | Medium - June 2008 | $70 | | 876 | | 261 | 3,600 | 122 | | 1,160 | 679 | 155 | | 2,017 |
| 43 | $60,905 | Medium - June 2008 | $100 | | 876 | | | 6,600 | 163 | 3,200 | 907 | 291 | 155 | 105 | 2,104 |
| **Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)** | | | | | | | | | | | | | | | |
| 44 | $21,249 | Medium - Oct 2008 | $8, C&T | 600 | | | | 5,673 | 149 | | 948 | 161 | 155 | 109 | 1,811 |
| 45 | $20,875 | Medium - Oct 2008 | $8, C&T | 600 | | | 261 | 881 | 110 | | 904 | 430 | 120 | 2 | 1,795 |
| **Sensitivity Case - Class 3 DSM for Peak Load Reduction** | | | | | | | | | | | | | | | |
| 48 | $41,268 | Medium - June 2008 | $45 | | | | | 2,400 | 122 | | 1,037 | 679 | 85 | 121 | 1,932 |

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

## Wind Resource Selection

Wind resource selection varied considerably across the portfolios, ranging from no resources in one portfolio (case 1, with no $CO_2$ tax and low gas prices) to 7,200 MW in five portfolios (cases 11, 29, 30, 31, and 33—all based on high gas prices and a $CO_2$ tax of $70 or greater). For the $45 $CO_2$ tax core cases with medium load growth, the amount of wind capacity averaged over 3,200 MW. For the $70 and $100 $CO_2$ tax core cases with medium load growth, the amount of wind capacity averaged over 5,100 MW and 6,600 MW, respectively. System Optimizer found wind to be cost-effective for displacing gas generation under high gas price scenarios, reducing $CO_2$ taxes, and selling to markets during off-peak periods.

Regarding the timing of wind additions, the model generally started adding wind capacity early in the study period, from 2010 to 2012, with large and constant amounts included in response to high gas prices, high $CO_2$ tax values, or both. For these cases, the model often selected amounts up to the limit allowed in a year (500 MW prior to 2014, and 750 MW in 2014 and thereafter). In only a few of the cases was wind added after 2020, generally to help meet RPS requirements owing to less wind investment made earlier in the study period (for example, cases 2 and 5). The expiration of the renewable PTC in 2013 (case 45) was found to significantly impact the amount and timing of wind additions; no wind was added after 2012.

An important caveat to these results is that System Optimizer does not account for reliability impacts and associated costs from adding large amounts of wind to the system.

## Gas Resource Selection

Intercooled aeroderivative (IC aero) SCCT plants were the most common gas resource included in the portfolios, occurring in cases having low gas prices combined with either the $0 or $45 $CO_2$ tax, or medium gas prices combined with no $CO_2$ tax. The SCCT plant (261 MW) was always selected in 2016.

Combined-cycle gas plants were selected infrequently, only appearing in three scenario situations: high load growth and either the low or medium gas price assumptions (cases 6 and 12), and the high-cost bookend scenario (case 33). The model chose only west-side CCCT units with a 2015 in-service date.

## Class 1 Demand-side Management Resource Selection

The model selected a small amount of Class 1 DSM capacity, 2 to 7 MW, for most of the portfolios, favoring Idaho dispatchable irrigation over other programs. This capacity was added most commonly between 2016 and 2018, with the earliest additions in 2013 for portfolios with no wind capacity chosen in the early years. Additions reached over 100 MW for high load growth scenarios, while no capacity was added in any of the portfolios developed with the low load growth scenario. Of the core cases with medium load growth, only two cases—numbers 1 and 29—included more than 100 MW. For case 1, which was based on no $CO_2$ tax and low gas prices, Class 1 DSM appears to substitute for renewables capacity added in most other portfolios. For case 29, the selection of Class 1 DSM is driven by low utilization of gas plants stemming from the combination of the $100 $CO_2$ tax and high gas prices.

## Class 2 Demand-side Management Resource Selection

The model selected a sizable amount of Class 2 DSM in all portfolios by 2028, ranging from 1,537 MW to 2,183 MW, and adding this DSM on a relatively constant basis for every year of the simulation period. For the medium load growth portfolios, the average amount included was 1,970 MW. The variation of the DSM among these portfolios, as measured by the standard deviation, was only about 130 MW.

## Supercritical Pulverized Coal Resource Selection

The model selected supercritical coal plants in response to the following set of conditions:

- No $CO_2$ tax combined with medium or high gas prices (cases 2 and 3)
- The \$8 $CO_2$ cap-and-trade allowance price (cases 44 and 45, and business plan reference cases 46 and 47)
- The \$45 $CO_2$ tax combined with high gas prices (cases 11, 14, 35, and 39)
- The \$45 $CO_2$ tax with low load growth, combined with high gas prices (case 13)
- The \$45 $CO_2$ tax with high load growth, combined with either medium or high gas prices (cases 12 and 15)
- The \$70 $CO_2$ tax combined with high gas prices (case 22)

Only one coal plant was included in these portfolios. The plant was always selected in 2018, except for the two business plan reference cases, where it was added in 2019.

The combination of scenario inputs for which supercritical coal plants were chosen indicates that determining a $CO_2$ cost trigger point at which coal plants are no longer cost-effective has limited value without considering the impact of gas prices.

## Geothermal Resource Selection

Geothermal was included in a large majority of the case portfolios, and generally selected in 2013—the first year of availability. The Blundell 3 project appeared in all portfolios where this resource was configured as an option, except for case 1 (defined with no $CO_2$ tax and low gas prices). The green-field projects in both the east and west were not cost-effective in low load growth scenarios, but frequently appeared in the portfolios developed with all other combinations of scenario input values.

An interesting result of enforcing the high renewable portfolio standard requirement for case 44 was that the geothermal resources were deferred from their typical 2013 in-service dates: the Blundell 3 project was added in 2015, while the east and west green-field resources were added in 2020 and 2025, respectively. The model followed a similar deferral strategy for case 45, where the production tax credit expired in 2013. For this portfolio, Blundell 3 was deferred to 2016, while the west green-field resource was deferred to 2023.

## Nuclear Resource Selection

Nuclear plants become cost-effective resource alternatives under high gas price and $CO_2$ tax scenarios; they are also always selected in 2025, the earliest in-service year. A 1,600 MW unit was chosen with a \$70 $CO_2$ tax combined with high gas prices. The model selected a 3,200 MW unit given a \$100 $CO_2$ tax and medium or high gas prices. There is no clear preference for nuclear resources given the level of load growth assumed.

**Clean Coal Resource Selection**

Clean coal technologies appear under the \$45 $CO_2$ tax in limited circumstances; only in combination with low gas and electricity prices. Under medium gas price scenarios, renewables, energy efficiency, and distributed generation substitute for a single pulverized coal CCS retrofit project. Only under the highest gas/electricity prices (June 2008 forward price curve) does IGCC become cost-effective with a \$45 $CO_2$ tax.

Multiple pulverized coal CCS retrofit units are added in all portfolios specified with the \$70 and \$100 $CO_2$ tax. IGCC capacity is only added under the June 2008 high gas price scenario.

**Short-term Market Purchase Selection**

Reliance on front office transactions varies substantially among the portfolios. They are utilized more heavily under the low and medium gas price scenarios. In contrast, portfolios with large quantities of wind or base-load coal tend to rely less on them. The portfolios do not exhibit a correlation between the $CO_2$ tax level and the amount of front office transactions.

**Distributed Generation Selection**

Distributed generation resources—CHP and standby generation—was selected in all the portfolios, and ranged from 95 MW in case 3 (medium load growth, no $CO_2$ tax, and high June 2008 gas price scenario) to 209 MW in case 6 (high load growth, \$45 $CO_2$ tax, and low June 2008 gas price scenario).

Standby generation, biomass CHP, and the Kern River Recovered Energy Generation projects were most commonly selected. Standby generation and biomass always appeared in the first year of availability (2009), while the Kern River REG units appeared between 2011 and 2015. The low biomass fuel price assumed for the CHP resource explains why it appears in all the portfolios. Quantities were typically added in constant amounts each year until 2018. Kern River REG units were not selected under low load growth scenarios, or a combination of the \$45 $CO_2$ tax and low gas price scenarios. Additions of reciprocating engine CHP were less common, and are sensitive to the gas prices assumed. System optimizer generally started adding this type of CHP resource in the 2012-2013 time frame, with constant amounts (typically 1 or 2 MW) appearing in each year.

There is no single factor that accounts for the amount of distributed generation capacity selected; rather, a combination of low or medium gas price scenarios and higher $CO_2$ tax levels appear associated with larger quantities added.

**Emerging Technology Resource Selection**

Emerging technologies—solar, energy storage, and fuel cells—were rarely selected by the model, and appear in no more than one portfolio. The portfolio for case 15 includes 500 MW of solar thermal with natural gas backup (250 MW in 2014 and 2015), added in response to a \$45 $CO_2$ tax and high load growth and gas prices. Compressed air energy storage and battery storage appear in case 12 as a response to a \$45 $CO_2$ tax combined with high load growth and medium gas prices. (CAES air compression is fueled by simple-cycle combustion turbines). These technologies are added late in the simulation period, after 2025. Finally, fuel cells appear in the portfolio for case 6 in 2016 (40 MW in the east side), developed with high load growth, low gas prices, and the \$45 $CO_2$ tax.

## Transmission Option Selection

PacifiCorp included three transmission resource options in System Optimizer:

- An Energy Gateway West expansion totaling 750 MW (Path C to West Main) available in 2015
- A Walla Walla to West Main transmission project available beginning in 2014, with capacity options of 200 MW and 400 MW

System Optimizer did not these transmission options in any of the portfolios.

## Incremental Resource Selection under Alternative Load Growth Scenarios

Observations concerning the incremental resources selected as load growth increases are as follows:

\$45/ton $CO_2$ Tax and Low Gas Prices

- Moving from low to medium load growth, System Optimizer chose front office transactions as the dominant resource for meeting load. Mead and Mona FOT were relied on heavily beginning in 2013 and 2017, respectively. Additionally, the model added an IC aero SCCT in 2016 (261 MW), a significant amount of east-side wind (750 MW by 2018, and another 450 MW by 2021), and a small quantity of east-side Class 2 DSM.
- Moving from medium to high load growth, the model added a diverse mix of resource types. Incremental resources included: combined-cycle (1,100 MW by 2018 and another CCCT plant added in 2020); 123 MW of Class 1 DSM by 2014; 131 MW of Class 2 DSM by 2028, 40 MW of fuel cell capacity by 2016, 50 MW of utility-scale biomass by 2016, and west-side front office transactions in the out-years. No incremental wind capacity was added.

\$45/ton $CO_2$ Tax and Medium Gas Prices

- Moving from low to medium load growth, System Optimizer relied mostly on front office transactions and wind to serve the higher loads. The incremental resource mix included 600 MW of wind, CHP, distributed standby generation, west-side geothermal, and Class 2 DSM.
- Moving from medium to high load growth, the optimal resource mix shifted to conventional thermal resources and fewer wind additions. A coal plant and IC aero SCCT plant were added in the east during the first 10 years of the study period, with a consequent reduction in east-side wind (about 500 MW), while a combined cycle plant was added in the west. A significant amount of Class 1 DSM was also added (118 MW), along with Class 2 DSM.

\$45/ton $CO_2$ Tax and High Gas Prices

- Moving from low to medium load growth, the model chose wind and, despite the high gas prices, front office transactions, as the primary resources needed to serve load. By 2021, the model added about 1,500 MW of wind. From 2017 through 2028, the model selected Mead front office transactions, averaging 460 MW per year. An IGCC plant was also added in 2025.

- Moving from medium to high load growth, System Optimizer added 250 MW of solar in both 2014 and 2015, and added an east-side IC Aero SCCT in 2016. Other resource additions include: front office transactions (Mead and Mid-Columbia); 84 MW of Class 1 DSM by 2020; 96 MW of Class 2 DSM by 2025; over 300 MW of wind (400 MW added in the east—accelerated by two years—along with a 100 MW reduction in the west); 47 MW of distributed standby generation, and; a 1,600 MW nuclear unit in 2015.

$70/ton $CO_2$ Tax and Low Gas Prices

Moving from low to medium load growth, the dominant resources for meeting the higher loads are wind and front office transactions. The model added 300 MW of wind by 2018. Selection of all available Mead and Mona front office transactions began in 2018, while use of Mid-Columbia transactions ramped up from 2013 to full utilization by 2020 and beyond. Additional Class 2 DSM was also selected, reaching 86 MW by 2023.

$70/ton $CO_2$ Tax and Medium Gas Prices

Moving from low to medium load growth, the model chose a conventional pulverized coal plant in 2018 and additional wind. On the east-side, it added 911 MW of wind from 2018 through 2020, and deferred west-wide wind additions to 2019 and 2020. This wind resource timing suggests that the model's strategy was to dilute the coal plant's $CO_2$ tax impact by adding wind.

$100/ton $CO_2$ Tax and Medium Gas Prices

Moving from low to medium load growth, System Optimizer relied on wind and front office transactions to address the higher load growth. Unlike the $70/ton scenario, the model did not find it cost-effective to add a conventional coal resource and offset it with wind or other renewables. In the out-years, the portfolio relied on both front office transactions (primarily Mid-Columbia) and growth resources to meet load.

$100/ton $CO_2$ Tax and High Gas Prices

Moving from low to medium load growth, System Optimizer depended heavily on wind resources to meet load, adding 1,351 MW in two years: 2019 and 2020. Additionally, the model increased reliance on front office transactions, although this reliance was temporary in the east side (2018 through 2020). The model also chose addition DSM, including 110 MW of Class 1 DSM and 147 MW of Class 2 DSM.

## Thermal Resource Utilization

Table 8.3 shows for gas and coal resources the average annual capacity factors for each portfolio, reflecting both existing and new resources. The capacity factors are reported for the entire simulation period, as well as for the following periods: 2009-2012 (capturing plant operations before a $CO_2$ tax goes into effect), 2013-2020, and 2021-2028.

The impact of the $CO_2$ tax on plant dispatch is shown by comparing the capacity factors for the 2009-2012 and 2013-2020 periods for the various gas price scenarios. Low gas prices cause the tax burden to fall on the coal plants, which realize a typical 10-percentage-point utilization decrease under a \$45 $CO_2$ tax, a 20-percentage-point utilization decrease under a \$70 $CO_2$ tax, and a 50 percentage point decrease under the \$100 $CO_2$ tax. With a \$100 $CO_2$ tax, a number of coal plants become uneconomic to operate, dispatching with a capacity factor in the single digits.

As gas prices increase in combination with a $CO_2$ tax, the tax burden shifts to the gas plants, which see a large drop-off in utilization. Under a \$100 $CO_2$ tax and high gas price scenarios, coal plant utilization drops by 10 to 16 percentage points.

## Table 8.3 – Average Annual Thermal Resource Capacity Factors by Portfolio

| | | | Gas Plant Capacity Factors (%) | | | | Coal Plant Capacity Factors (%) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Case** | **Gas Price Scenario / FPC** | **CO2 Price** | **Average, 2009-2012** | **Average, 2013-2020** | **Average, 2021-2028** | **Average, 2009-2028** | **Average, 2009-2012** | **Average, 2013-2020** | **Average, 2021-2028** | **Average, 2009-2028** |
| **Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)** | | | | | | | | | | |
| 1 | Low - June 2008 | $0 | 33 | 39 | 61 | 47 | 86 | 87 | 88 | 87 |
| 2 | Medium - June 2008 | $0 | 30 | 30 | 40 | 34 | 86 | 87 | 88 | 87 |
| 3 | High - June 2008 | $0 | 34 | 17 | 16 | 20 | 86 | 87 | 88 | 87 |
| 5 | Low - June 2008 | $45 | 35 | 40 | 59 | 46 | 86 | 73 | 71 | 75 |
| 8 | Medium - June 2008 | $45 | 31 | 28 | 46 | 36 | 86 | 86 | 86 | 86 |
| 9 | Low - Oct 2008 | $45 | 42 | 40 | 64 | 50 | 86 | 76 | 73 | 77 |
| 10 | Medium - Oct 2008 | $45 | 57 | 34 | 57 | 48 | 85 | 86 | 87 | 86 |
| 11 | High - Oct 2008 | $45 | 38 | 14 | 18 | 21 | 86 | 86 | 85 | 86 |
| 14 | High - June 2008 | $45 | 25 | 11 | 13 | 15 | 86 | 86 | 87 | 86 |
| 17 | Medium - June 2008 | $70 | 30 | 29 | 48 | 37 | 86 | 72 | 68 | 73 |
| 18 | Low - Oct 2008 | $70 | 42 | 42 | 75 | 55 | 86 | 54 | 46 | 57 |
| 19 | Medium - Oct 2008 | $70 | 57 | 33 | 62 | 49 | 85 | 71 | 64 | 71 |
| 20 | High - Oct 2008 | $70 | 37 | 12 | 14 | 18 | 86 | 82 | 77 | 81 |
| 22 | High - June 2008 | $70 | 25 | 10 | 11 | 14 | 86 | 84 | 81 | 83 |
| 24 | Medium - June 2008 | $100 | 28 | 31 | 48 | 37 | 86 | 52 | 37 | 53 |
| 25 | Low - Oct 2008 | $100 | 41 | 43 | 69 | 53 | 86 | 34 | 29 | 42 |
| 26 | Medium - Oct 2008 | $100 | 56 | 36 | 57 | 48 | 85 | 49 | 37 | 51 |
| 27 | High - Oct 2008 | $100 | 36 | 13 | 10 | 16 | 86 | 71 | 60 | 69 |
| 29 | High - June 2008 | $100 | 20 | 5 | 6 | 8 | 86 | 76 | 57 | 71 |
| 46 | Medium - Oct 2008 | $8, C&T | 35 | 35 | 58 | 44 | 86 | 87 | 88 | 87 |
| 47 | Medium - Oct 2008 | $8, C&T | 35 | 35 | 58 | 44 | 86 | 87 | 88 | 87 |
| **Low Load Growth Core Cases** | | | | | | | | | | |
| 4 | Low - June 2008 | $45 | 34 | 39 | 63 | 48 | 86 | 71 | 68 | 73 |
| 7 | Medium - June 2008 | $45 | 30 | 24 | 38 | 31 | 86 | 86 | 86 | 86 |
| 13 | High - June 2008 | $45 | 25 | 9 | 10 | 13 | 86 | 84 | 83 | 84 |
| 16 | Medium - June 2008 | $70 | 29 | 24 | 41 | 32 | 86 | 70 | 64 | 70 |
| 21 | High - June 2008 | $70 | 25 | 8 | 8 | 12 | 86 | 83 | 78 | 82 |
| 23 | Medium - June 2008 | $100 | 27 | 28 | 40 | 33 | 86 | 48 | 32 | 49 |
| 28 | High - June 2008 | $100 | 20 | 4 | 3 | 7 | 86 | 72 | 49 | 65 |
| **High Load Growth Core Cases** | | | | | | | | | | |
| 6 | Low - June 2008 | $45 | 36 | 40 | 55 | 45 | 86 | 73 | 71 | 75 |
| 12 | Medium - June 2008 | $45 | 32 | 27 | 42 | 34 | 86 | 86 | 87 | 86 |
| 15 | High - June 2008 | $45 | 26 | 14 | 16 | 17 | 86 | 86 | 87 | 86 |
| **Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth** | | | | | | | | | | |
| 30 | Medium - June 2008 | $45 to $179 | 31 | 31 | 58 | 42 | 86 | 83 | 53 | 72 |
| 31 | High - June 2008 | $45 to $179 | 28 | 14 | 21 | 19 | 86 | 86 | 66 | 78 |
| **Sensitivity Case - High Cost Outcome** | | | | | | | | | | |
| 33 | High - June 2008 | $100 | 24 | 8 | 9 | 11 | 85 | 85 | 86 | 85 |
| **Sensitivity Cases - Clean Base-Load Generation Availability** | | | | | | | | | | |
| 34 | Medium - June 2008 | $45 | 32 | 27 | 44 | 35 | 86 | 85 | 86 | 86 |
| 35 | High - June 2008 | $45 | 30 | 17 | 16 | 19 | 86 | 86 | 83 | 85 |
| 36 | Medium - June 2008 | $70 | 19 | 29 | 48 | 34 | 86 | 73 | 67 | 73 |
| 37 | High - June 2008 | $70 | 25 | 10 | 6 | 12 | 86 | 82 | 73 | 79 |
| **Sensitivity Cases - High Plant Construction Costs** | | | | | | | | | | |
| 38 | Medium - June 2008 | $45 | 33 | 32 | 48 | 38 | 86 | 87 | 88 | 87 |
| 39 | High - June 2008 | $45 | 24 | 10 | 11 | 13 | 85 | 80 | 84 | 82 |
| **Sensitivity Case - System-wide Oregon CO2 Reduction Targets** | | | | | | | | | | |
| 40 | Medium - June 2008 | Hard Cap | 30 | 11 | 10 | 15 | 86 | 77 | 67 | 75 |
| **Sensitivity Cases - Planning Reserve Margin, 15%** | | | | | | | | | | |
| 41 | Medium - June 2008 | $45 | 31 | 26 | 41 | 33 | 86 | 86 | 86 | 86 |
| 42 | Medium - June 2008 | $70 | 29 | 27 | 43 | 34 | 86 | 72 | 68 | 73 |
| 43 | Medium - June 2008 | $100 | 28 | 31 | 48 | 37 | 86 | 52 | 36 | 52 |
| **Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)** | | | | | | | | | | |
| 44 | Medium - Oct 2008 | $8, C&T | 35 | 33 | 49 | 40 | 86 | 87 | 88 | 87 |
| 45 | Medium - Oct 2008 | $8, C&T | 34 | 33 | 58 | 43 | 85 | 86 | 88 | 87 |
| **Sensitivity Case - Class 3 DSM for Peak Load Reduction** | | | | | | | | | | |
| 48 | Medium - June 2008 | $45 | 32 | 29 | 47 | 37 | 86 | 86 | 86 | 86 |

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

## Sensitivity Case Results

### $CO_2$ Tax Real Cost Escalation and Demand Response

Cases 30 and 31 were designed to test a real escalating $CO_2$ tax and assumed decrease in load growth attributable to the price response. The $CO_2$ tax begins in 2013 and is increased at a real straight-line escalation rate resulting in $7.86/ton increases per year starting in 2014. Load growth is maintained at a medium level through 2020, after which the growth converts to a low forecast for the remainder of the simulation period.

For the two cases, all factors were held constant with the exception of the gas price forecast used: case 30 was based on the June 2008 medium gas price while case 31 was based on the June 2008 high gas price forecast. The case 30 portfolio included 5,498 MW of wind added by 2028, a nuclear plant in 2025, and four carbon capture and sequestration plants in 2025, including an IGCC resource. The case 31 portfolio included more wind and front office transactions, but excluded the IGCC resource.

The PVRR for case 31 was $989 million lower than case 30, an unintuitive result. Several factors contributed to this PVRR difference:

- The 466 MW Utah IGCC with CCS unit added in the case 30 portfolio was not included in case 31. Instead, higher on-peak spot purchases and DSM programs costs were incurred in case 31.
- Case 31 included 750 MW more wind than case 30 in the first ten years. As a result of the additional wind, existing station fuel costs in case 31 were $1.1 billion lower than in case 30.
- While the capital costs for case 31 were $2.4 billion higher than in case 30, the difference was offset by higher spot market sales in case 31.

Normally the System Optimizer model will build to the 12% planning reserve margin level; however, it may exceed that if it is economic to add extra capacity and sell excess energy to the market. For example, in cases 30 and 31, the model added resources in excess of the planning reserve margin in 2025 through 2028 with the addition of a 3,200 MW nuclear plant. Significant excess energy is sold to market, contributing to $27.6 and $30.0 billion PVRR reductions for cases 30 and 31, respectively

### Early Clean Base-load Resource Availability

Cases 34 through 37 were designed to test early availability of clean base-load generation resources by allowing System Optimizer to select such resources as early as 2020 rather than 2025 as specified for all other case definitions. Cases 34 and 35 were specified with a $45/ton $CO_2$ tax and varying gas price forecasts (medium and high June 2008), while cases 36 and 37 were based on a $70 $CO_2$ tax with the same gas price forecasts.

For cases 34 and 35, no clean base-load technology was selected; however, the high gas price forecast used in case 35 caused the model to select about 1,000 MW of additional wind in the west and a 600 MW pulverized coal plant in Utah. Case 34 favored front office transactions.

For cases 36 and 37 (both with the \$70 $CO_2$ tax), three clean coal resources were selected in 2020. For case 37, the model also selected a 3,200 MW nuclear station in 2020 as an alternative to market purchases in the out years. The PVRR for case 37 is about \$2.3 billion lower than case 36, and this cost relationship exists between cases 34 and 35 as well. As indicated above, the cost difference is attributable to the model selling excess energy to the market.

**High Construction Costs**
For cases 38 and 39, resource construction costs were uniformly increased by 20 percent. Both were based on a \$45 $CO_2$ tax, medium load growth, and medium and high gas price forecasts, respectively.

Comparing case 38 to case 8 (which used the same input assumptions except for construction costs) indicates that the uniform percentage cost increase caused the model to select additional DSM programs along with dispatching existing units more often. Similarly, a comparison between cases 39 and 14 indicate that the construction cost increase, combined with a higher gas price forecast, caused the model to build about 3,000 MW less wind in case 39 than for case 14. The reduced wind build in case 39 was a major contributor to the lower PVRR relative to that for case 14 (a \$5.16 billion difference). In addition, the Utah IGCC unit picked in case 14 was not chosen in case 39. For case 39, the model preferred to buy from the market and relied more heavily on growth resources in the out years. In case 39, units were not dispatched as often as in case 14 and there was consequently less power to sell to the market.

**Carbon Dioxide Emissions Hard Cap**
Case 40 was designed to determine the optimal resource mix given a system-wide $CO_2$ emissions hard cap patterned after the Oregon $CO_2$ reduction targets from House Bill 3543 (10 percent below 1990 levels by 2020, and at least 75% below 1990 levels by 2050). The specific allowances per year reflected in the System Optimizer model are reported in Table 8.4. The cap is assumed to go into effect beginning in 2013. With these system emission constraints in place, the model optimizes the resource mix such that the system-wide average emissions stay at or below the annual caps.

**Table 8.4 – Hard Cap $CO_2$ Emission Allowances**

| Year | Hard Cap CO2 Allowances (Million Short Tons) |
|---|---|
| 2009 | 53.484 |
| 2010 | 53.484 |
| 2011 | 55.192 |
| 2012 | 56.077 |
| 2013 | 54.244 |
| 2014 | 52.412 |
| 2015 | 50.579 |
| 2016 | 48.746 |
| 2017 | 46.913 |
| 2018 | 45.081 |
| 2019 | 43.248 |
| 2020 | 41.415 |
| 2021 | 40.418 |
| 2022 | 39.421 |

| Year | Hard Cap CO2 Allowances (Million Short Tons) |
|---|---|
| 2023 | 38.424 |
| 2024 | 37.427 |
| 2025 | 36.430 |
| 2026 | 35.433 |
| 2027 | 34.436 |
| 2028 | 33.439 |

For this sensitivity study, front office transactions and growth resources were assigned a proxy $CO_2$ emission rate. The rate is that for a Utah combined-cycle gas plant (F type 2x1), reflecting a presumed long term reduction in the WECC $CO_2$ footprint attributable to the penetration of gas, wind and other renewable resources in the resource stack. Additionally, the June 2008 \$0 $CO_2$ tax forward price forecasts were used to ensure that the model's capacity expansion solution was constrained by the hard cap only, and not impacted by $CO_2$ costs reflected in market prices.

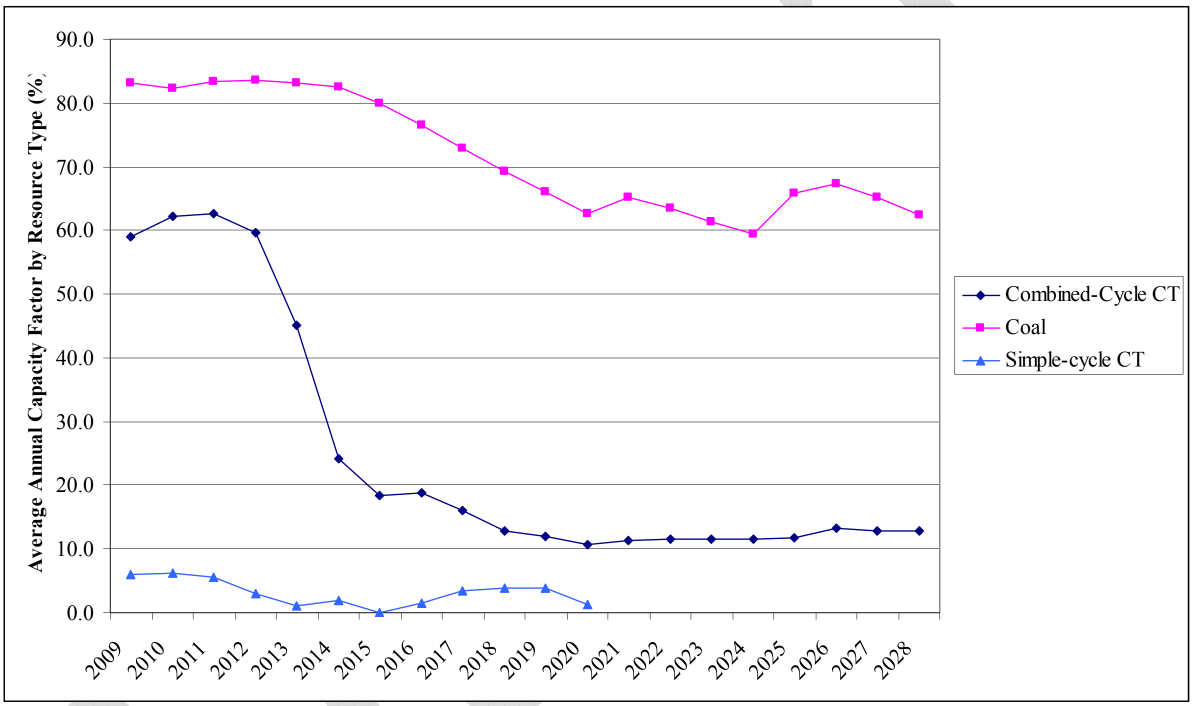
Table 8.5 compares the total emissions generated in case 40 to the three medium load, medium gas forecast core cases (Case 8, 17, and 24). The results indicate that the hard cap portfolio is most comparable to the \$70 $CO_2$ tax portfolio, having total cumulative emissions of 900 and 931 million tons, respectively.

**Table 8.5 – Portfolio Comparison, System Optimizer Total $CO_2$ Emissions by Year**

| Year | CO2 emissions (Millions Short Tons) | | | |
|---|---|---|---|---|
| | Case 40 System Hard Cap | Case 8 \$45/ton CO2 tax | Case 17 \$70/ton CO2 Tax | Case 24 \$100/ton CO2 Tax |
| **2009** | 54.0 | 54.5 | 54.4 | 54.4 |
| **2010** | 53.7 | 54.0 | 53.8 | 53.6 |
| **2011** | 54.5 | 54.1 | 54.0 | 53.6 |
| **2012** | 56.1 | 54.2 | 53.6 | 52.5 |
| **2013** | 54.2 | 54.1 | 51.5 | 46.3 |
| **2014** | 52.4 | 53.4 | 49.3 | 43.9 |
| **2015** | 50.6 | 54.3 | 47.8 | 38.3 |
| **2016** | 48.7 | 54.2 | 44.5 | 33.7 |
| **2017** | 46.9 | 55.3 | 47.6 | 35.7 |
| **2018** | 45.1 | 55.3 | 50.0 | 37.7 |
| **2019** | 43.2 | 55.7 | 50.5 | 37.7 |
| **2020** | 41.4 | 55.6 | 50.9 | 37.9 |
| **2021** | 40.4 | 54.1 | 50.0 | 37.6 |
| **2022** | 39.4 | 54.1 | 49.2 | 36.3 |
| **2023** | 38.4 | 54.0 | 47.9 | 32.6 |
| **2024** | 37.4 | 54.0 | 45.8 | 27.1 |
| **2025** | 36.4 | 53.6 | 36.2 | 12.3 |
| **2026** | 35.4 | 52.7 | 33.0 | 11.9 |
| **2027** | 34.4 | 52.3 | 30.8 | 11.3 |
| **2028** | 33.4 | 51.9 | 29.8 | 10.8 |
| **Cumulative Total** | 896.4 | 1081.3 | 930.6 | 705.4 |

With the combination of medium June 2008 market prices and the hard cap, a significant reduction in combined-cycle gas plant capacity factors happens from 2013 through 2015, followed by a gradual decrease through 2020. Figure 8.1 compares the average annual capacity factors for combined-cycle, coal, and simple-cycle combustion turbine resources reflected in the model. Capacity factors for certain coal plants begin to drop off in 2015, while others are unaffected, reflecting the relative dispatch cost differences among the plants. As noted earlier in the chapter, the impact of $CO_2$ costs on plant dispatch cannot be assessed in isolation from fuel prices; utilization of thermal resource types in response to $CO_2$ costs will vary considerably based on the fuel price forecasts used for the simulations.

**Figure 8.1 – Average Annual Capacity Factors by Resource Type, $CO_2$ Hard Cap Portfolio**




A number of current IRP model limitations come into play for analyzing a hard cap scenario. First, the System Optimizer model does not allow emission rates to be assigned to spot market balancing transactions. This limitation is being addressed in an enhanced version of the model being developed for PacifiCorp by the model vendor. Second, the Planning and Risk model is limited in that hard caps cannot be directly enforced. To simulate the effect of a hard cap, the shadow cost for the last ton of incremental emissions calculated from System Optimizer can be entered into the Planning and Risk model. PacifiCorp is in the process of experimenting and validating this work-around approach. The test simulation resulted in annual $CO_2$ emissions that were consistently below the hard cap. The stochastic costs results for the test simulation are as follows: mean PVRR of \$41.0 billion, upper-tail mean PVRR of \$76.4 billion, and production cost standard deviation of \$11.7 billion.

**Alternative Renewable Policy Assumptions**

Case 44 is designed with a System Optimizer constraint that imposes a system-wide renewable generation requirement that reaches 25 percent of system load by 2028. Case 44 parallels case 8 in terms of other input assumptions; i.e., an \$8 $CO_2$ tax and medium June 2008 gas and electricity prices.

In order to satisfy the higher RPS requirement, the model selected a large amount of wind and some geothermal resources, especially in the mid and later years of the simulation period. With nearly 6,000 MW of wind resources built, this scenario attributes a relatively small PVRR to sales of clean energy to markets.[42]

The second alternative renewable policy scenario was established to determine the best resource mix without the renewable production tax credit after 2012. Case 45 was created from case 44 with the base case RPS requirement, but the costs of resources qualifying for the PTC were adjusted to remove the incentive after 2012. Without the PTC, the model selected:

- No wind resources after 2012
- A west geothermal resource in 2023
- An IC Aero SCCT in 2016 instead of wind resources
- More growth resource capacity in the out years

## STOCHASTIC SIMULATION RESULTS - CANDIDATE PORTFOLIOS

This section presents stochastic cost, stochastic supply reliability risk, and capital cost performance results for the 21 portfolios that constitute the group from which the preferred portfolio was selected. For the stochastic cost measures, results are first shown for the three individual $CO_2$ tax simulations, along with the straight average across the $CO_2$ tax results. The section concludes with tables that show the stochastic cost results as probability-weighted values. These values reflect \$5/ton increments of the expected value (EV) $CO_2$ tax, ranging from \$20/ton to \$70/ton.

### Stochastic Mean PVRR

Table 8.6 reports the stochastic mean PVRR for each of the candidate portfolios by $CO_2$ tax level, along with average values and associated rankings. Cases 8, 5, and 9 rank the highest based on the average of the CO2 tax results.

**Table 8.6 – Stochastic Mean PVRR by Candidate Portfolio**

| Case | CO2 Tax Level, Million Dollars (2009\$) | | | | Rank |
|---|---|---|---|---|---|
| | \$0/ton | \$45/ton | \$100/ton | Average | |
| 1 | 21,873 | 39,893 | 61,299 | 41,022 | 10 |
| 2 | 21,642 | 39,542 | 60,098 | 40,427 | 4 |

[42] The cost results presume a regulatory world with both a \$45/ton $CO_2$ tax and an aggressive RPS requirement. In this situation, the markets would be flooded with excess clean energy, driving market prices down. This dynamic is not captured in the scenario. Also, the reliability impacts and costs of such large amounts of wind being added to the system are not factored into the IRP simulations.

| Case | CO2 Tax Level, Million Dollars (2009$) | | | | Rank |
|---|---|---|---|---|---|
| | $0/ton | $45/ton | $100/ton | Average | |
| 3 | 24,844 | 40,745 | 57,781 | 41,123 | 11 |
| 5 | 22,417 | 39,289 | 58,700 | 40,136 | 2 |
| 8 | 23,092 | 39,244 | 57,311 | 39,882 | 1 |
| 9 | 22,532 | 39,398 | 58,800 | 40,244 | 3 |
| 10 | 23,723 | 39,872 | 58,198 | 40,598 | 6 |
| 11 | 25,664 | 41,035 | 57,496 | 41,398 | 12 |
| 14 | 27,620 | 42,481 | 57,954 | 42,685 | 16 |
| 17 | 25,267 | 40,134 | 56,369 | 40,590 | 5 |
| 18 | 25,092 | 40,185 | 56,822 | 40,700 | 7 |
| 19 | 25,600 | 40,513 | 56,870 | 40,994 | 9 |
| 20 | 28,412 | 42,127 | 56,620 | 42,386 | 15 |
| 22 | 29,751 | 43,576 | 57,813 | 43,713 | 20 |
| 24 | 30,393 | 43,496 | 57,094 | 43,661 | 19 |
| 25 | 27,178 | 41,317 | 56,419 | 41,638 | 13 |
| 26 | 30,056 | 43,417 | 57,485 | 43,653 | 18 |
| 27 | 30,367 | 43,477 | 57,105 | 43,650 | 17 |
| 29 | 32,601 | 45,626 | 59,042 | 45,757 | 21 |
| 46 | 23,336 | 40,975 | 61,146 | 41,819 | 14 |
| 47 | 22,345 | 40,058 | 60,378 | 40,927 | 8 |

Table 8.7 reports the incremental mean PVRR associated with imposing the $45/ton and $100/ton $CO_2$ taxes, as well as the average cost for the two tax levels. Table 8.8 reports the net power cost (variable cost less market sales revenue) and fixed cost by portfolio for the three $CO_2$ tax simulations.

**Table 8.7 – Incremental Mean PVRR by $CO_2$ Tax Level**

| Case | Incremental Mean PVRR (Million $) | | |
|---|---|---|---|
| | $45/ton | $100/ton | Average |
| 1 | 18,019 | 39,426 | 28,723 |
| 2 | 17,900 | 38,456 | 28,178 |
| 3 | 15,901 | 32,937 | 24,419 |
| 5 | 16,872 | 36,284 | 26,578 |
| 8 | 16,152 | 34,219 | 25,186 |
| 9 | 16,866 | 36,268 | 26,567 |
| 10 | 16,149 | 34,476 | 25,312 |
| 11 | 15,371 | 31,831 | 23,601 |
| 14 | 14,861 | 30,334 | 22,597 |
| 17 | 14,867 | 31,102 | 22,984 |
| 18 | 15,093 | 31,730 | 23,411 |
| 19 | 14,913 | 31,270 | 23,092 |
| 20 | 13,715 | 28,208 | 20,962 |
| 22 | 13,825 | 28,062 | 20,943 |
| 24 | 13,103 | 26,700 | 19,902 |
| 25 | 14,139 | 29,241 | 21,690 |
| 26 | 13,361 | 27,429 | 20,395 |
| 27 | 13,110 | 26,738 | 19,924 |

| Case | Incremental Mean PVRR (Million $) | | |
|---|---|---|---|
| | $45/ton | $100/ton | Average |
| 29 | 13,025 | 26,440 | 19,733 |
| 46 | 17,639 | 37,811 | 27,725 |
| 47 | 17,713 | 38,032 | 27,873 |

### Table 8.8 – PVRR Net Power Costs and Fixed Costs by $CO_2$ Tax Level

| Case | $0/ton CO2 Tax | | | | $45/ton CO2 Tax | | | | $100/ton CO2 Tax | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Net Power Cost (Bil$) | Rank | Fixed Cost (Bil$) | Rank | Net Power Cost (Bil$) | Rank | Fixed Cost (Bil$) | Rank | Net Power Cost (Bil$) | Rank | Fixed Cost (Bil$) | Rank |
| 1 | 20.0 | 21 | 1.8 | 1 | 38.1 | 21 | 1.8 | 1 | 59.5 | 21 | 1.8 | 1 |
| 2 | 18.3 | 18 | 3.4 | 2 | 36.2 | 20 | 3.4 | 2 | 56.7 | 20 | 3.4 | 2 |
| 3 | 14.1 | 9 | 10.7 | 12 | 30.0 | 10 | 10.7 | 12 | 47.1 | 11 | 10.7 | 12 |
| 5 | 18.3 | 20 | 4.1 | 3 | 35.2 | 17 | 4.1 | 3 | 54.6 | 17 | 4.1 | 3 |
| 8 | 16.8 | 14 | 6.3 | 7 | 33.0 | 14 | 6.3 | 7 | 51.0 | 14 | 6.3 | 7 |
| 9 | 18.3 | 19 | 4.2 | 5 | 35.2 | 16 | 4.2 | 5 | 54.6 | 16 | 4.2 | 5 |
| 10 | 17.4 | 15 | 6.4 | 8 | 33.5 | 15 | 6.4 | 8 | 51.8 | 15 | 6.4 | 8 |
| 11 | 13.9 | 8 | 11.8 | 13 | 29.2 | 9 | 11.8 | 13 | 45.7 | 9 | 11.8 | 13 |
| 14 | 12.7 | 5 | 14.9 | 15 | 27.6 | 7 | 14.9 | 15 | 43.0 | 7 | 14.9 | 15 |
| 17 | 15.7 | 11 | 9.6 | 10 | 30.5 | 11 | 9.6 | 10 | 46.8 | 10 | 9.6 | 10 |
| 18 | 16.1 | 13 | 9.0 | 9 | 31.2 | 13 | 9.0 | 9 | 47.8 | 13 | 9.0 | 9 |
| 19 | 15.8 | 12 | 9.8 | 11 | 30.7 | 12 | 9.8 | 11 | 47.1 | 12 | 9.8 | 11 |
| 20 | 13.2 | 7 | 15.2 | 16 | 26.9 | 6 | 15.2 | 16 | 41.4 | 6 | 15.2 | 16 |
| 22 | 12.1 | 1 | 17.6 | 18 | 25.9 | 4 | 17.6 | 18 | 40.2 | 4 | 17.6 | 18 |
| 24 | 12.4 | 4 | 18.0 | 20 | 25.5 | 3 | 18.0 | 20 | 39.1 | 2 | 18.0 | 20 |
| 25 | 14.1 | 10 | 13.0 | 14 | 28.3 | 8 | 13.0 | 14 | 43.4 | 8 | 13.0 | 14 |
| 26 | 13.1 | 6 | 17.0 | 17 | 26.4 | 5 | 17.0 | 17 | 40.5 | 5 | 17.0 | 17 |
| 27 | 12.4 | 3 | 18.0 | 19 | 25.5 | 2 | 18.0 | 19 | 39.1 | 3 | 18.0 | 19 |
| 29 | 12.2 | 2 | 20.4 | 21 | 25.3 | 1 | 20.4 | 21 | 38.7 | 1 | 20.4 | 21 |
| 46 | 17.9 | 16 | 5.4 | 6 | 35.6 | 18 | 5.4 | 6 | 55.7 | 18 | 5.4 | 6 |
| 47 | 18.2 | 17 | 4.1 | 4 | 35.9 | 19 | 4.1 | 4 | 56.2 | 19 | 4.1 | 4 |



## Risk-adjusted PVRR

As discussed in Chapter 7, risk-adjusted PVRR is calculated as the stochastic mean PVRR plus five percent of the 95$^{th}$ percentile PVRR, with the latter term representing a cost premium reflecting the tail risk for the portfolio. This measure constitutes 45 percent of the overall composite portfolio preference score for each candidate portfolio.

Table 8.9 reports the risk-adjusted PVRR values for each of the portfolios by $CO_2$ tax level, along with average values and associated rankings. Cases 8, 5, and 9 rank the highest in line with the stochastic mean PVRR values reported in Table 8.3. Figure 8.2 shows the range of risk-adjusted PVRRs for each portfolio by $CO_2$ tax level, matched up with the amount of incremental wind capacity included. It is apparent from the chart that the variation in risk-adjusted PVRR across the $CO_2$ tax levels generally decreases as the amount of portfolio wind capacity increases.

Figures 8.3 through 8.7 show capacity by resource type for each portfolio, ranked by risk-adjusted PVRR averaged across the $CO_2$ tax simulations. The resource types include wind, energy efficiency, average annual front office transactions, clean base load coal, and IC aero SCCT resources. These charts indicate the correlation between the amount of primary resource type added to the portfolios and the risk-adjusted cost. As can be seen from Figure 8.3, the positive correlation between risk-adjusted PVRR and amount of wind capacity added is clearly evident. Similarly the negative correlation between risk-adjusted PVRR and the volume of front office transactions is evident in Figure 8.4.

**Table 8.9 – Risk-adjusted PVRR by Portfolio**

| Case | CO2 Tax Level, Million Dollars (2009$) | | | Average | Rank |
|---|---|---|---|---|---|
| | $0/Ton | $45/Ton | $100/Ton | | |
| 1 | 23,992 | 43,093 | 66,090 | 44,392 | 12 |
| 2 | 23,506 | 42,492 | 64,586 | 43,528 | 4 |
| 3 | 26,610 | 43,555 | 61,952 | 44,039 | 9 |
| 5 | 24,365 | 42,270 | 63,154 | 43,263 | 2 |
| 8 | 24,942 | 42,138 | 61,628 | 42,903 | 1 |
| 9 | 24,489 | 42,387 | 63,261 | 43,379 | 3 |
| 10 | 25,676 | 42,815 | 62,585 | 43,692 | 6 |
| 11 | 27,472 | 43,856 | 61,646 | 44,324 | 11 |
| 14 | 29,422 | 45,340 | 62,046 | 45,603 | 16 |
| 17 | 27,173 | 43,021 | 60,574 | 43,589 | 5 |
| 18 | 27,009 | 43,093 | 61,077 | 43,726 | 7 |
| 19 | 27,533 | 43,427 | 61,111 | 44,024 | 8 |
| 20 | 30,314 | 44,957 | 60,666 | 45,312 | 15 |
| 22 | 31,599 | 46,442 | 61,886 | 46,642 | 20 |
| 24 | 32,292 | 46,363 | 61,088 | 46,581 | 18 |
| 25 | 29,107 | 44,193 | 60,544 | 44,615 | 13 |
| 26 | 31,986 | 46,290 | 61,528 | 46,602 | 19 |
| 27 | 32,251 | 46,338 | 61,087 | 46,559 | 17 |
| 29 | 34,596 | 48,571 | 63,133 | 48,767 | 21 |
| 46 | 25,255 | 43,973 | 65,681 | 44,970 | 14 |
| 47 | 24,233 | 43,022 | 64,885 | 44,047 | 10 |

**Figure 8.2 – Risk-adjusted PVRR Range and Wind Nameplate Capacity by Portfolio**

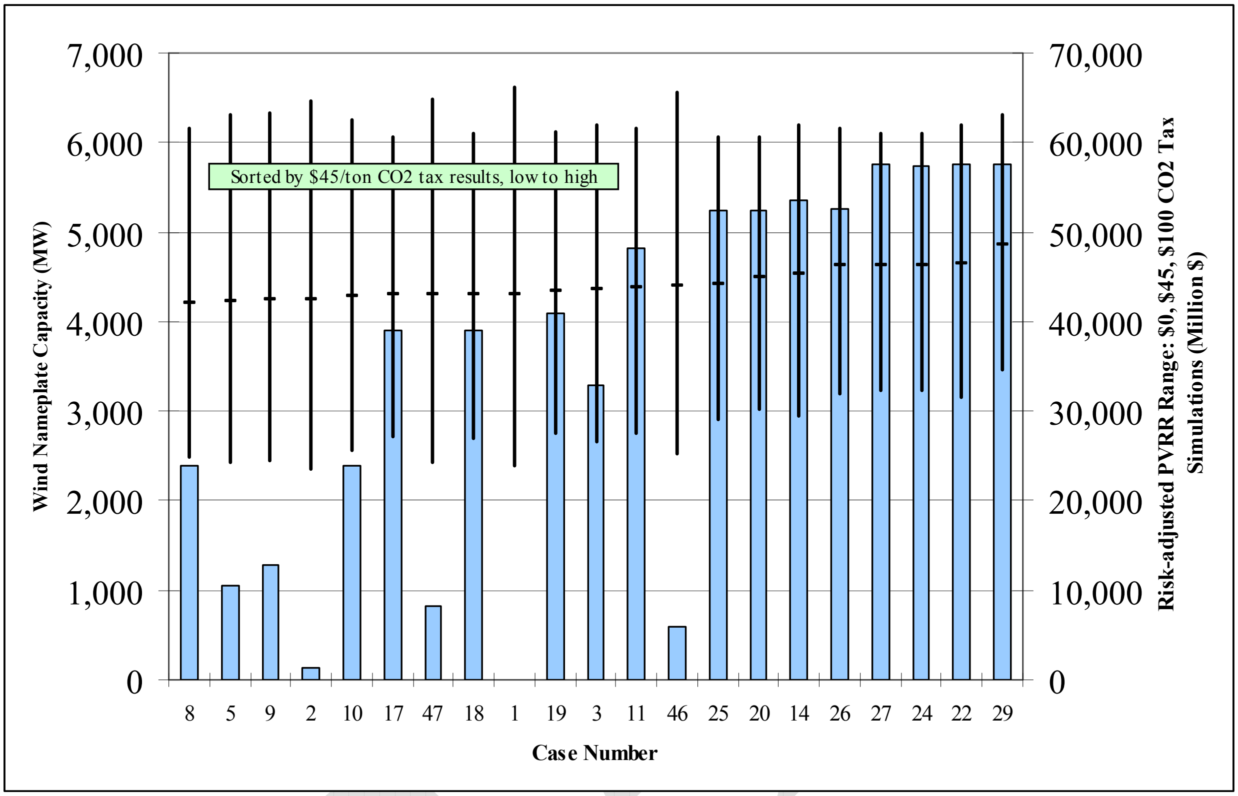



**Figure 8.3 – Wind Capacity for Portfolios Ranked by Risk-adjusted PVRR**

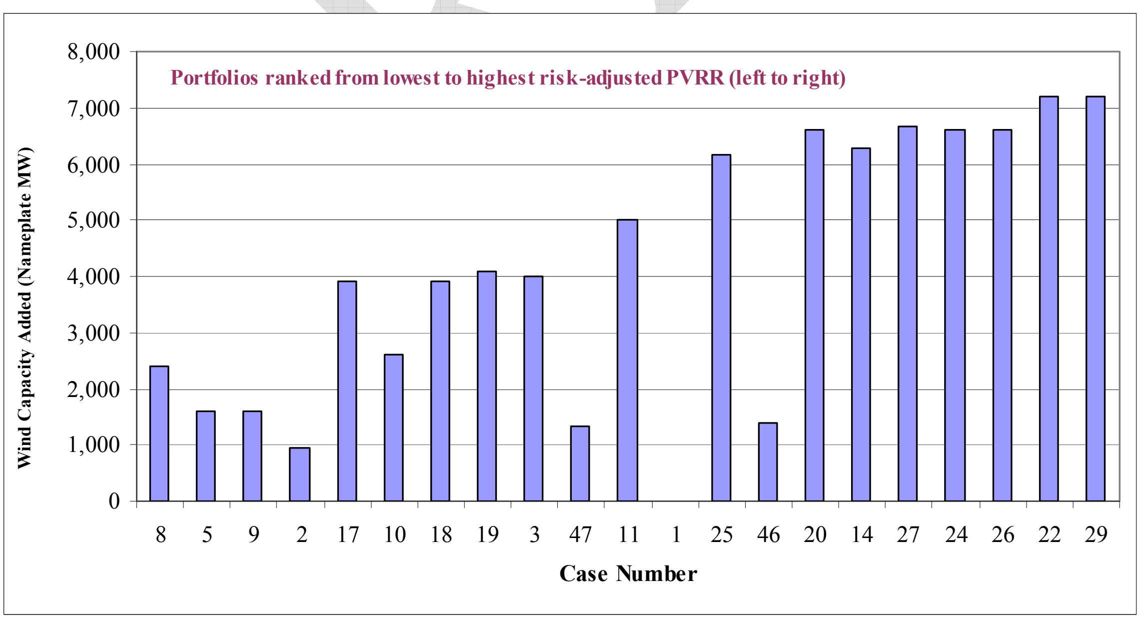


**Figure 8.4 – Energy Efficiency Capacity for Portfolios Ranked by Risk-adjusted PVRR**

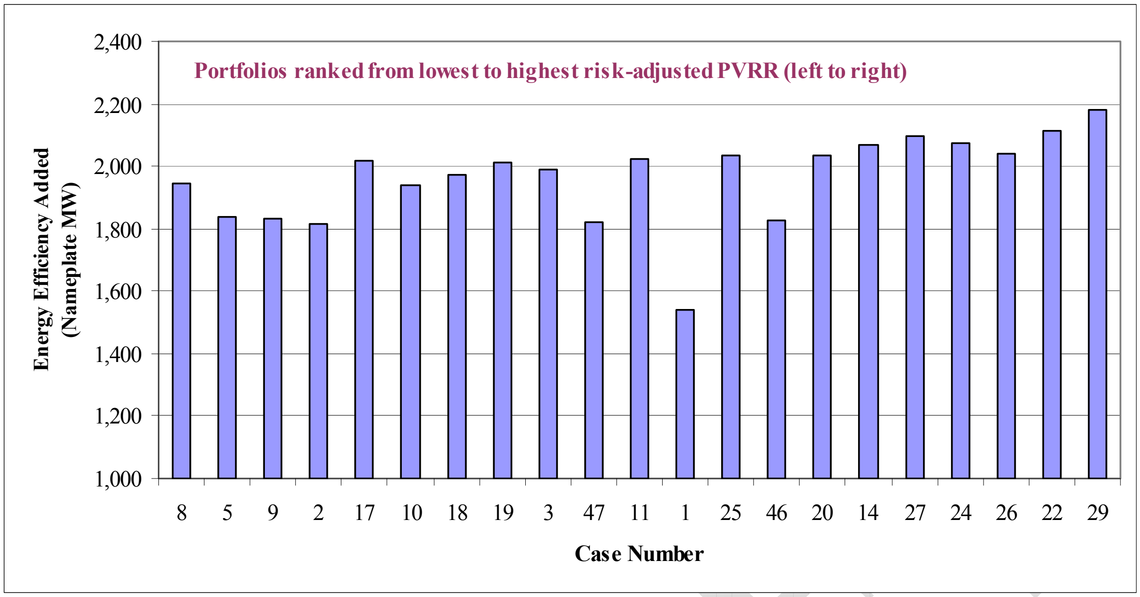



**Figure 8.5 – Annual Average Front Office Transaction Capacity for Portfolios Ranked by Risk-adjusted PVRR**

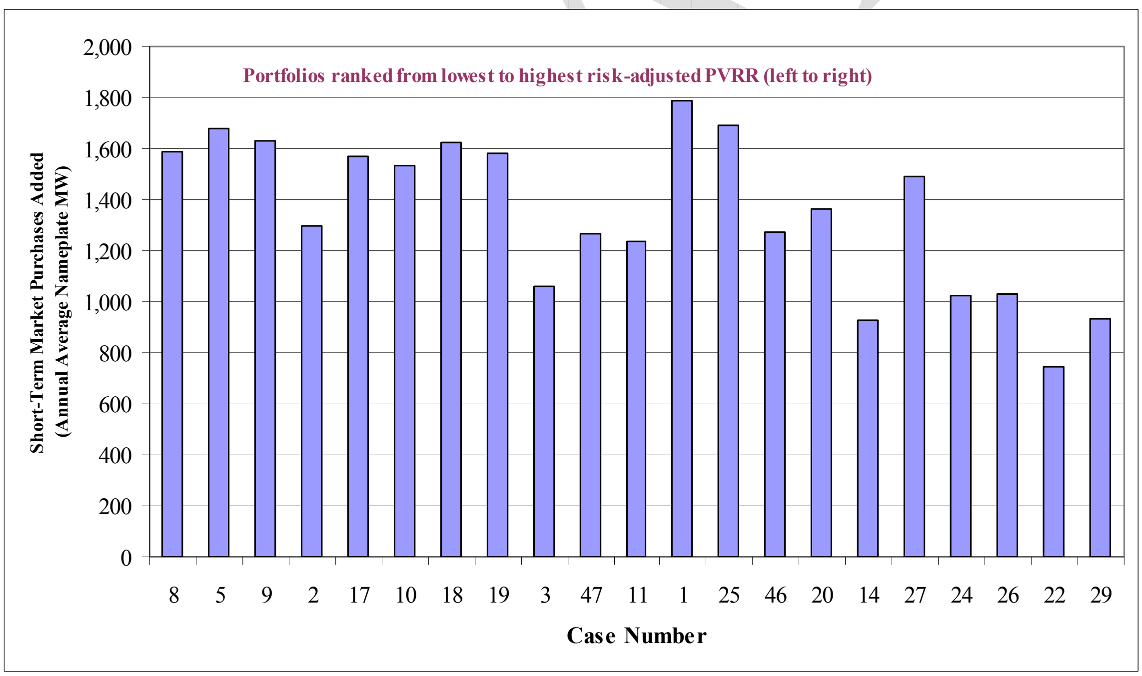


**Figure 8.6 – Clean Base Load Coal Capacity for Portfolios Ranked by Risk-adjusted PVRR**

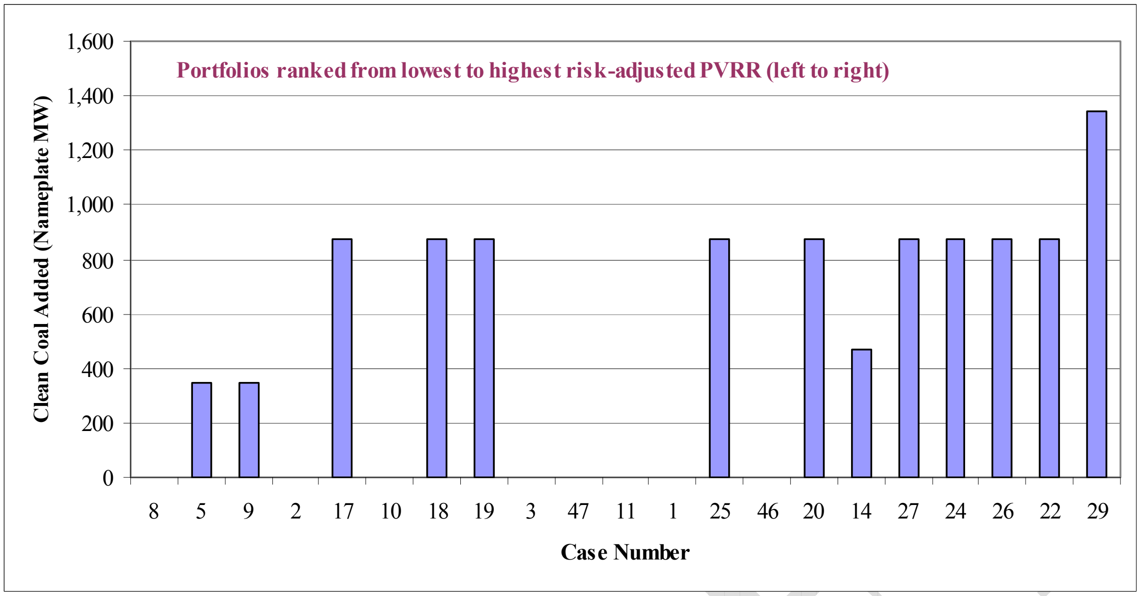
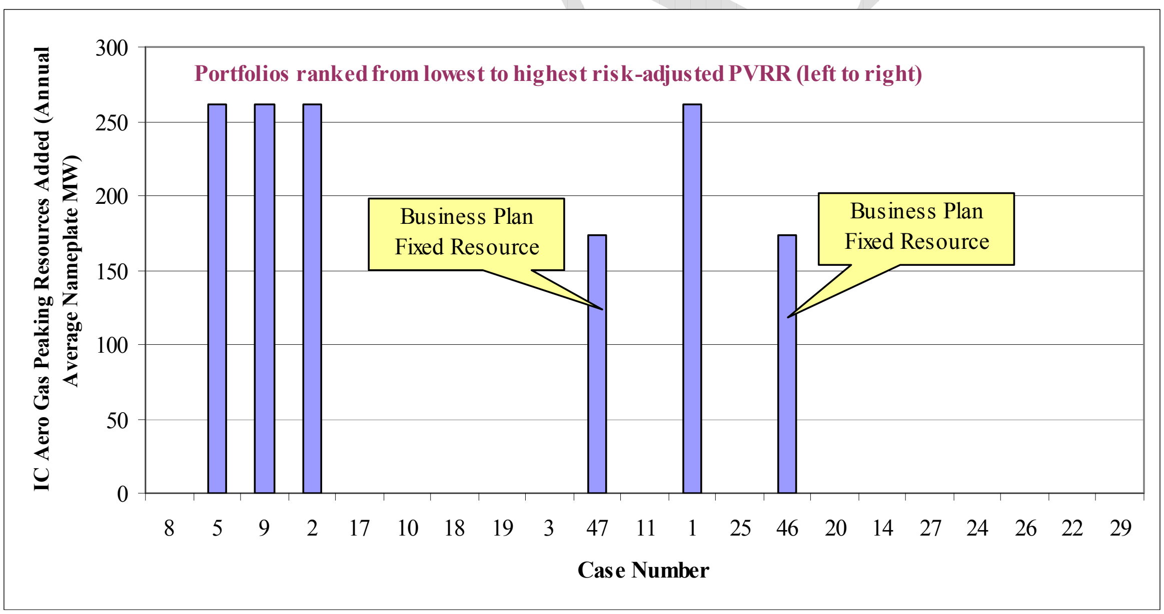



**Figure 8.7 – IC Aeroderivative SCCT Capacity for Portfolios Ranked by Risk-adjusted PVRR**




## Customer Rate Impact

The portfolio customer rate impacts for each $CO_2$ tax simulation, and averaged across the simulations, are reported in Table 8.10. This measure is given a 20 percent weight for determining the overall portfolio preference scores.

With no $CO_2$ tax, the portfolios for cases 1 and 2 perform the best due to the lack of wind investment. Case 1, which has the lowest rate impact, has no wind additions other than the firm planned resources in 2009 and 2010. Case 2, which ranked second, has only 338 MW of wind added by 2018, but includes a 600 MW super-critical coal plant in 2018. Under the \$45 $CO_2$ tax, the top performers are the portfolios for cases 9 and 5. Case 9 has slightly more wind resources than case 5 (by 230 MW) and less front office transactions. Under the \$100 $CO_2$ tax, the top performers are cases 20 and 17. Case 20 relies on a nuclear plant in 2025 and more wind than for case 17.

When averaging the results across the $CO_2$ tax levels, cases 9 and 5 fare the best; they rank first and second, respectively.

**Table 8.10 – Customer Rate Impacts by Portfolio**

| Case | $CO_2$ Tax Level (2009$) | | | Average | Rank |
|---|---|---|---|---|---|
| | $0/ton | $45/ton | $100/ton | | |
| 1 | 2.82 | 6.28 | 10.16 | 6.42 | 8 |
| 2 | 2.89 | 6.31 | 10.06 | 6.42 | 7 |
| 3 | 3.49 | 6.58 | 9.74 | 6.61 | 14 |
| 5 | 2.95 | 6.11 | 9.54 | 6.20 | 2 |
| 8 | 3.08 | 6.19 | 9.48 | 6.25 | 5 |
| 9 | 2.93 | 6.09 | 9.52 | 6.18 | 1 |
| 10 | 3.24 | 6.31 | 9.64 | 6.40 | 6 |
| 11 | 3.34 | 6.22 | 9.11 | 6.22 | 3 |
| 14 | 4.09 | 6.97 | 9.80 | 6.95 | 16 |
| 17 | 3.48 | 6.22 | 9.03 | 6.24 | 4 |
| 18 | 3.61 | 6.41 | 9.33 | 6.45 | 9 |
| 19 | 3.66 | 6.43 | 9.28 | 6.46 | 10 |
| 20 | 4.24 | 6.62 | 8.92 | 6.59 | 13 |
| 22 | 4.78 | 7.30 | 9.70 | 7.26 | 18 |
| 24 | 5.22 | 7.51 | 9.70 | 7.48 | 20 |
| 25 | 3.95 | 6.57 | 9.20 | 6.58 | 12 |
| 26 | 5.09 | 7.41 | 9.66 | 7.39 | 19 |
| 27 | 4.99 | 7.19 | 9.27 | 7.15 | 17 |
| 29 | 5.71 | 7.96 | 10.07 | 7.91 | 21 |
| 46 | 3.16 | 6.55 | 10.22 | 6.64 | 15 |
| 47 | 2.99 | 6.39 | 10.09 | 6.49 | 11 |

## Cost Exposure under Alternative Carbon Dioxide Tax Levels

As discussed in Chapter 7, cost exposure is the difference between a portfolio's risk-adjusted PVRR and the risk-adjusted PVRR of the best-performing portfolio for a given $CO_2$ tax level. Portfolio performance under this measure is gauged by the size of the worst loss that could be realized under the three $CO_2$ tax levels if the chosen portfolio turns out to not be the optimal one based on risk-adjusted PVRR. This measure was assigned a 15 percent weight for determining the overall portfolio preference scores.

Table 8.11 presents the cost exposure results for the $CO_2$ tax simulations, with no probability weights applied. As indicated in the table, the potential cost exposure is large for portfolios built in response to an extreme $CO_2$ tax value, and where the realized $CO_2$ tax turns out to be at the other extreme. The cost exposures range from $30 million for case 17 under a realized $100/ton tax, to $11 billion for case 29 given no $CO_2$ tax. (Note that portfolios with no cost exposure value reported have the lowest cost at that $CO_2$ tax level.)

To be consistent with the probability-weighted approach used to rank portfolio performance, the maximum loss values are probability-weighted as well.

**Table 8.11 – Portfolio Cost Exposures for Carbon Dioxide Tax Outcomes**

| Case | CO2 Tax Level, Million Dollars (2009$) | | | | Rank |
|---|---|---|---|---|---|
| | $0/ton | $45/ton | $100/ton | Maximum Loss | |
| 1 | 486 | 956 | 5,546 | 5,546 | 13 |
| 2 | - | 354 | 4,042 | 4,042 | 10 |
| 3 | 3,104 | 1,417 | 1,408 | 3,104 | 5 |
| 5 | 859 | 132 | 2,610 | 2,610 | 3 |
| 8 | 1,436 | - | 1,084 | 1,436 | 1 |
| 9 | 983 | 249 | 2,717 | 2,717 | 4 |
| 10 | 2,170 | 678 | 2,040 | 2,170 | 2 |
| 11 | 3,965 | 1,718 | 1,102 | 3,965 | 8 |
| 14 | 5,916 | 3,202 | 1,502 | 5,916 | 15 |
| 17 | 3,667 | 883 | 30 | 3,667 | 7 |
| 18 | 3,503 | 955 | 533 | 3,503 | 6 |
| 19 | 4,026 | 1,290 | 566 | 4,026 | 9 |
| 20 | 6,808 | 2,819 | 122 | 6,808 | 16 |
| 22 | 8,093 | 4,304 | 1,342 | 8,093 | 17 |
| 24 | 8,786 | 4,225 | 543 | 8,786 | 20 |
| 25 | 5,601 | 2,055 | - | 5,601 | 14 |
| 26 | 8,480 | 4,152 | 984 | 8,480 | 18 |
| 27 | 8,745 | 4,200 | 543 | 8,745 | 19 |
| 29 | 11,090 | 6,433 | 2,588 | 11,090 | 21 |
| 46 | 1,749 | 1,835 | 5,137 | 5,137 | 12 |
| 47 | 727 | 885 | 4,341 | 4,341 | 11 |

## Portfolio Capital Costs

Figures 8.8 and 8.9 show the capital costs for each portfolio, expressed on a net present value basis for costs accrued for 2009-2018 and 2009-2028, respectively. (The 2009-2018 capital cost measure was assigned a five percent weight for determining the portfolio preference scores.)

The portfolios with the lowest capital costs are for cases 1, 2, and 5. Case 1, with a capital cost of $0.5 billion, relies more heavily on market purchases, distributed generation, and Class 1 DSM than the other low capital cost portfolios, and reflects no incremental wind investment past 2010.

In contrast, the high-cost portfolios—such as cases 29, 22, 27, and 24—reflect large investments in wind, clean coal, and nuclear plants to mitigate the $CO_2$ tax liabilities.

**Figure 8.8 – Portfolio Capital Costs, 2009-2018**

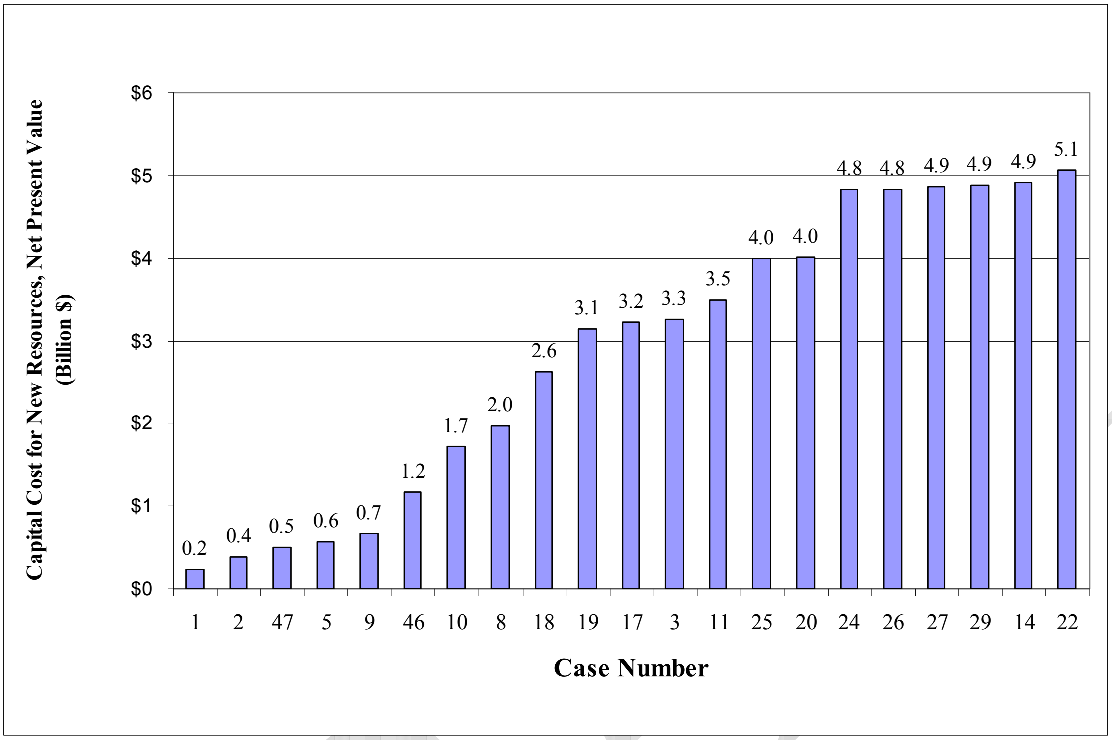
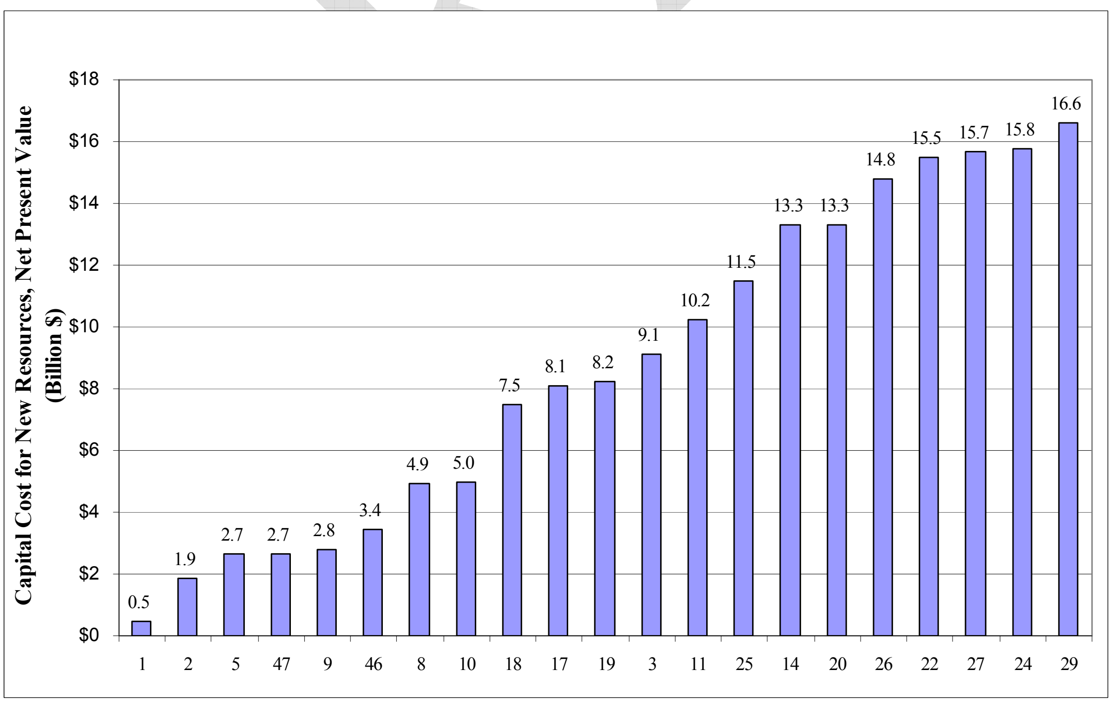
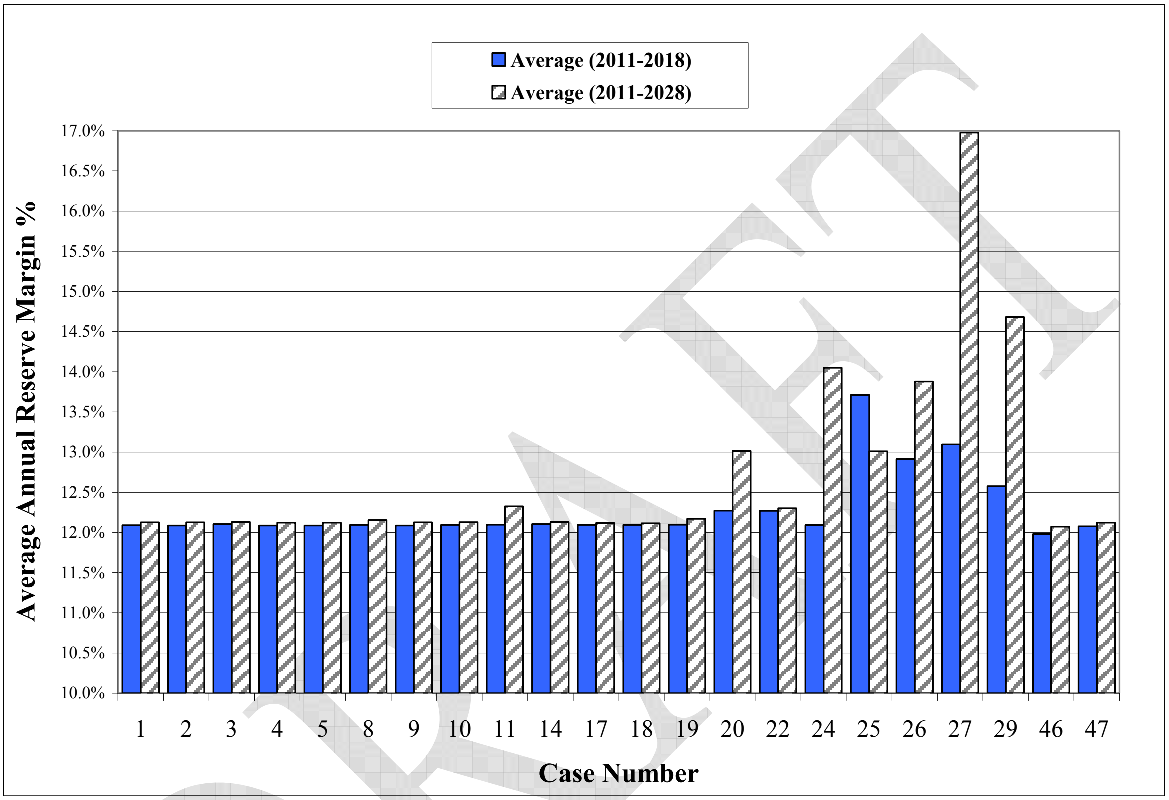



**Figure 8.9 – Portfolio Capital Costs, 2009-2028**



The impact of such investments on capacity planning reserve margins, particularly in the out years, is indicated in Figure 8.10. This figure shows average annual reserve margins for 2011 to 2018 (reflecting the start of the system capacity short position) as well as for 2011 to 2028. The association between extensive clean generation investment and excess planning reserve margins is clearly seen with margins far exceeding the 12 percent requirement reflected in the model.[43]

**Figure 8.10 – Average Annual Planning Reserve Margins**

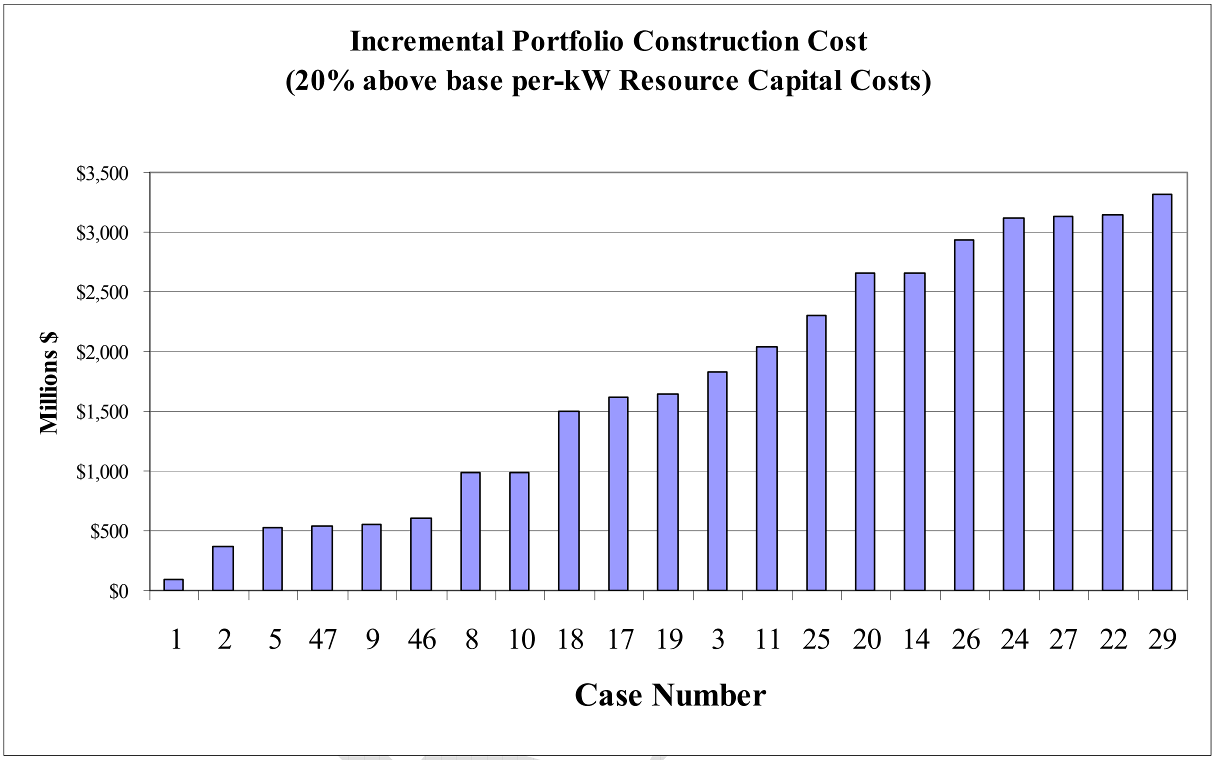





[43] The 2011-2028 average annual planning reserve margins for case 11, which was based on a $45/ton $CO_2$ tax, is higher than for the other core cases with this tax level. Unlike the other $45 tax cases, case 11 was modeled with high gas prices. This case experienced greater west-east transfers than the other cases for 2026-2028, supported by a relatively larger amount of growth resources and front office transactions on the west side.

Figure 8.11 shows the impact on portfolio capital costs given a 20 percent increase in the per-kilowatt capital cost for all resources.

**Figure 8.11 – Incremental Portfolio Capital Costs (20% increase from Base per-kW values)**




## Upper-tail Mean PVRR

Table 8.12 reports the upper-tail mean PVRR results for the individual $CO_2$ tax simulations and the average.

Cases 22 and 14 perform the best. Case 22 includes both pulverized coal and nuclear plants in response to a $70/ton $CO_2$ tax and high gas/electricity prices. Case 14 also includes pulverized coal as well as an IGCC plant in 2025. Both portfolios feature heavy reliance on wind resources (7,200 MW for case 22 and 6,300 MW for case 14), and consequently rely on less front office transactions and gas plant dispatch.

**Table 8.12 – Upper-tail Mean PVRR by Portfolio**

| Case | CO2 Tax Level, Million Dollars (2009$) | | | | Rank |
|---|---|---|---|---|---|
| | $0/ton | $45/ton | $100/ton | Average | |
| 1 | 57,487 | 80,005 | 114,973 | 84,155 | 21 |
| 2 | 51,169 | 73,646 | 107,193 | 77,336 | 16 |
| 3 | 44,084 | 65,519 | 94,991 | 68,198 | 5 |

| Case | CO2 Tax Level, Million Dollars (2009$) | | | | Rank |
|---|---|---|---|---|---|
| | $0/ton | $45/ton | $100/ton | Average | |
| 5 | 53,047 | 74,487 | 106,969 | 78,168 | 19 |
| 8 | 49,843 | 70,581 | 101,048 | 73,824 | 14 |
| 9 | 53,347 | 74,736 | 107,163 | 78,415 | 20 |
| 10 | 52,335 | 72,023 | 102,956 | 75,771 | 15 |
| 11 | 44,638 | 65,642 | 94,453 | 68,244 | 6 |
| 14 | 44,778 | 65,453 | 93,021 | 67,751 | 2 |
| 17 | 49,328 | 68,766 | 96,941 | 71,678 | 11 |
| 18 | 50,209 | 69,834 | 98,591 | 72,878 | 13 |
| 19 | 50,320 | 69,705 | 98,022 | 72,682 | 12 |
| 20 | 46,767 | 66,084 | 92,486 | 68,446 | 7 |
| 22 | 45,569 | 65,404 | 91,170 | 67,381 | 1 |
| 24 | 46,980 | 65,939 | 91,142 | 68,020 | 4 |
| 25 | 48,112 | 66,967 | 94,182 | 69,754 | 10 |
| 26 | 47,587 | 66,665 | 92,520 | 68,924 | 8 |
| 27 | 46,732 | 65,701 | 90,907 | 67,780 | 3 |
| 29 | 48,734 | 67,670 | 92,365 | 69,590 | 9 |
| 46 | 52,224 | 74,442 | 107,516 | 78,061 | 18 |
| 47 | 51,559 | 73,905 | 107,252 | 77,572 | 17 |

The following charts present the megawatt capacities for the portfolios ranked by upper-tail mean PVRR, focusing on the resource types most consequential for determining upper-tail cost risk. Figures 8.12 and 8.13 show the portfolio wind and energy efficiency capacities, indicating that upper-tail cost risk is inversely proportional to the amount of these resources added. Figures 8.14 and 8.15 show the front office transactions (on an average annual basis) and peaking gas capacities, respectively. Portfolios with more of these resource types tend to exhibit higher upper-tail cost risk.

**Figure 8.12 – Wind Capacity for Portfolios Ranked by Upper-tail Mean PVRR**

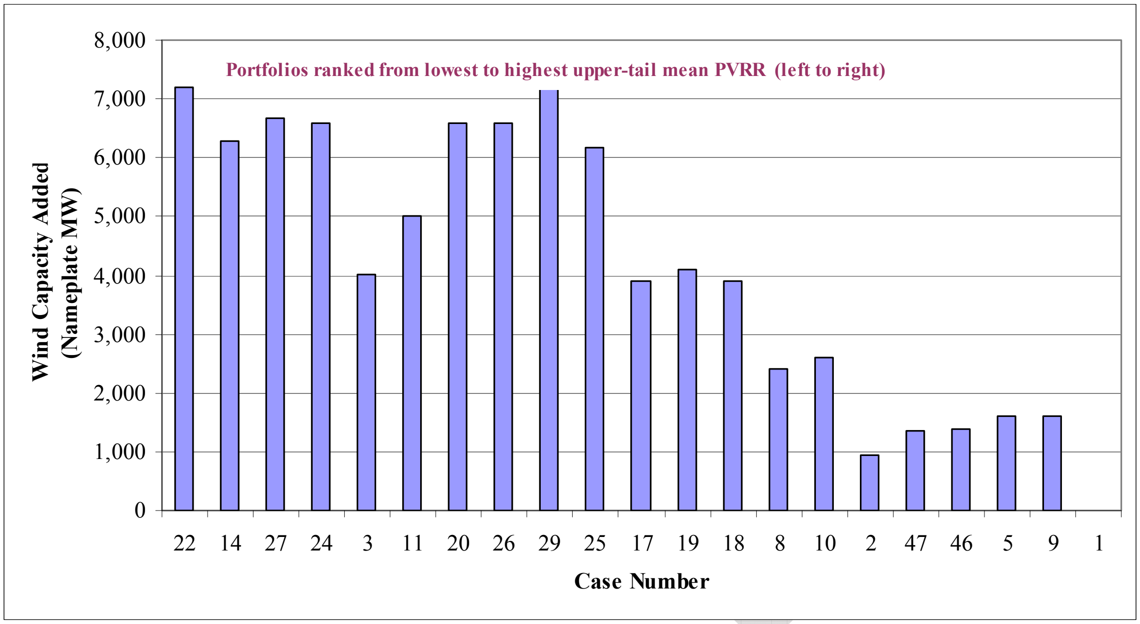



**Figure 8.13 – Energy Efficiency Capacity for Portfolios Ranked by Upper-tail Mean PVRR**

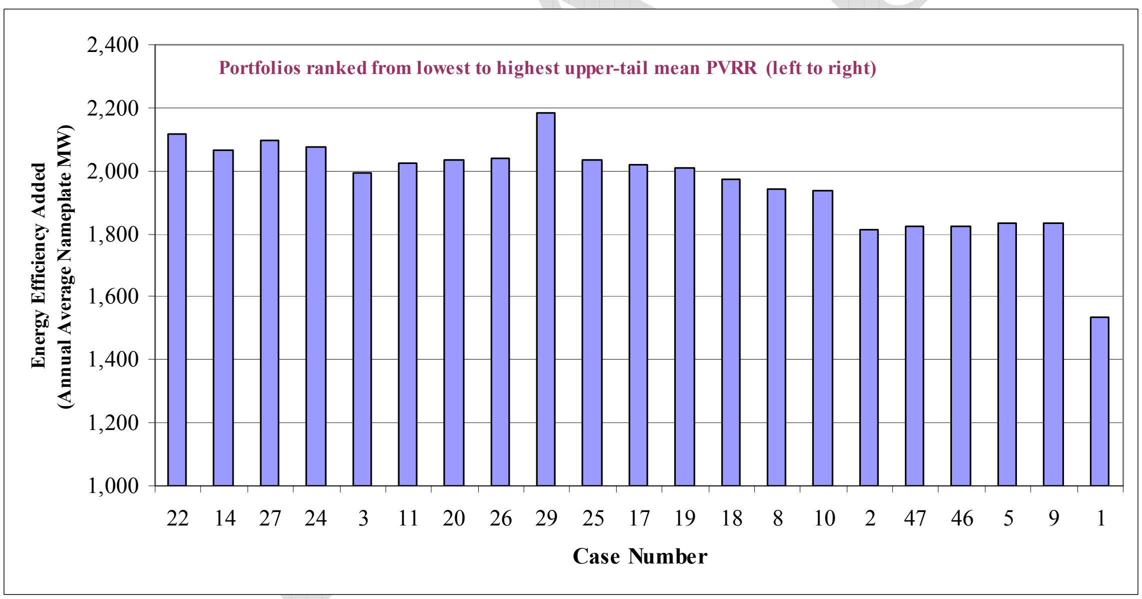


**Figure 8.14 – Front Office Transaction Capacity for Portfolios Ranked by Upper-tail Mean PVRR**

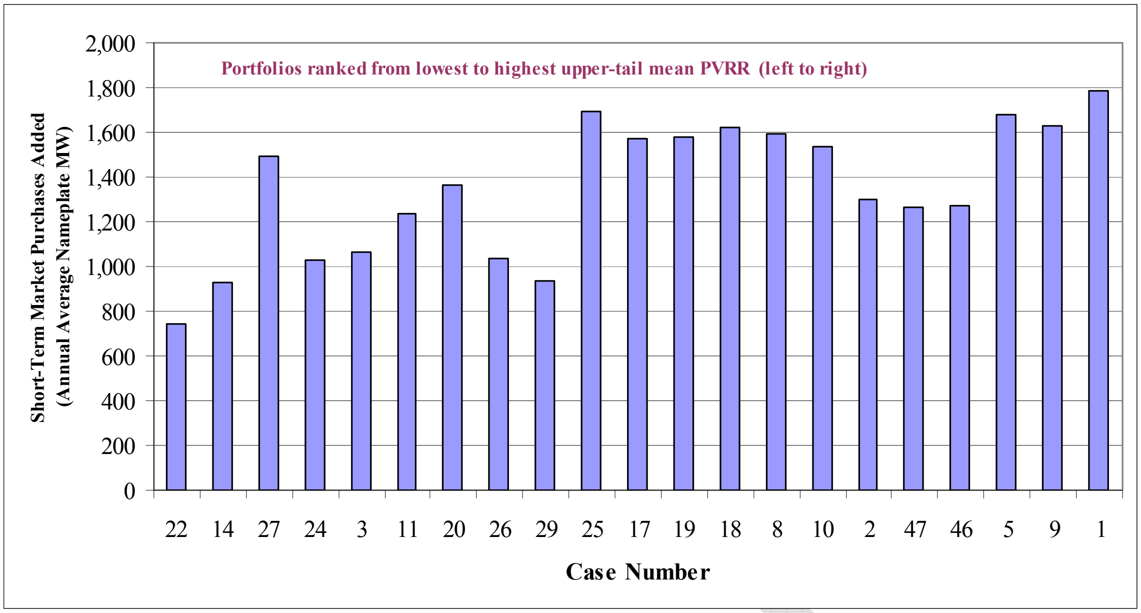
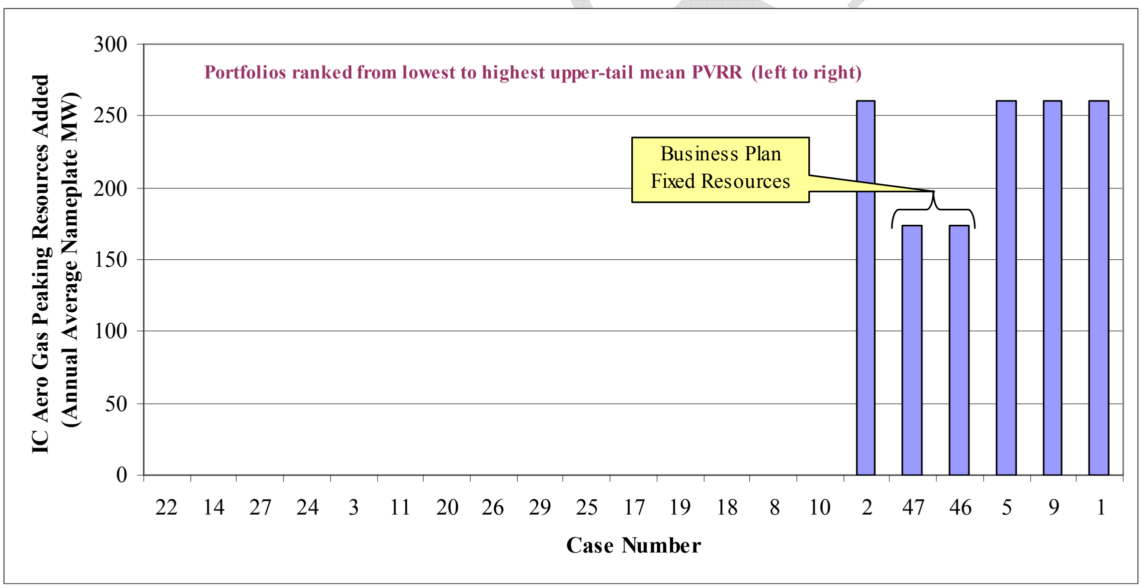



**Figure 8.15 – Intercooled Aeroderivative SCCT Capacity for Portfolios Ranked by Upper-tail Mean PVRR**



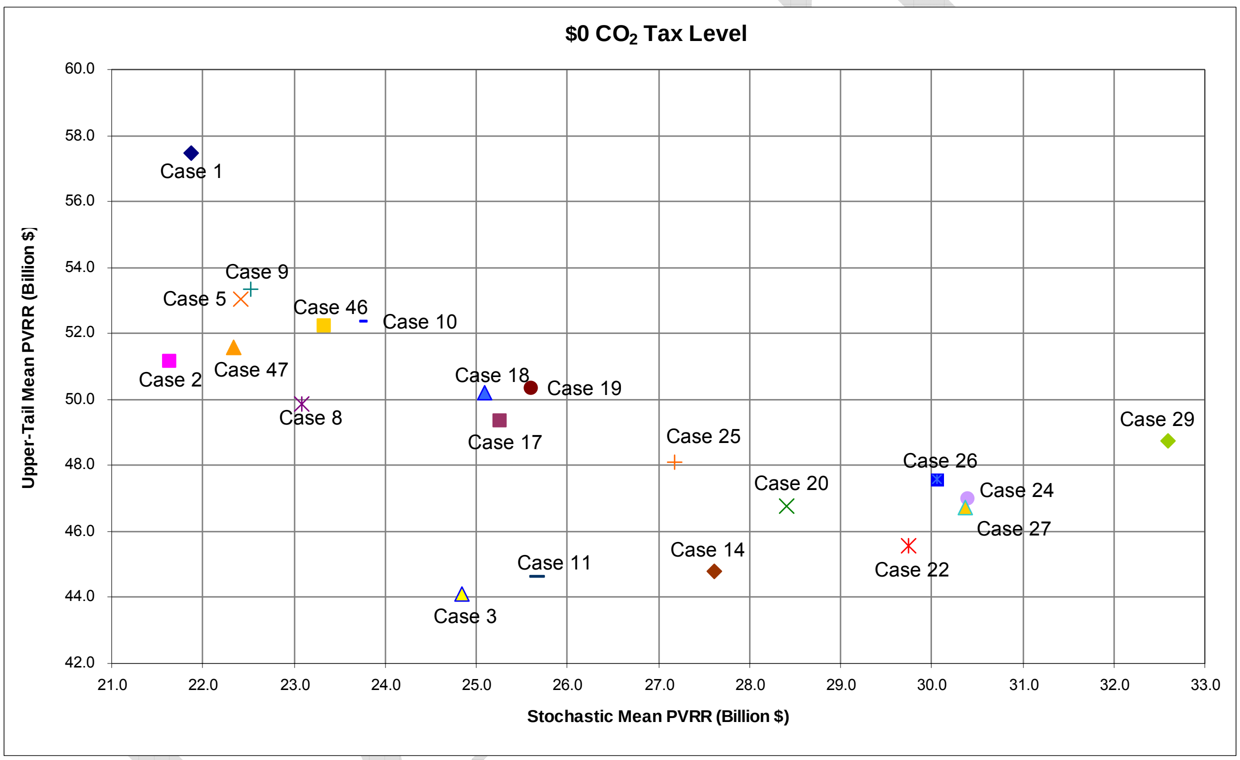

## <u>Mean/Upper-Tail Cost Scatter Plots</u>

Figures 8.16 through 8.18 are scatter plots of portfolio cost (mean PVRR) versus high-end cost risk as represented by the upper-tail mean PVRR. These scatter plots show the trade-off between cost and risk at the different $CO_2$ tax levels.

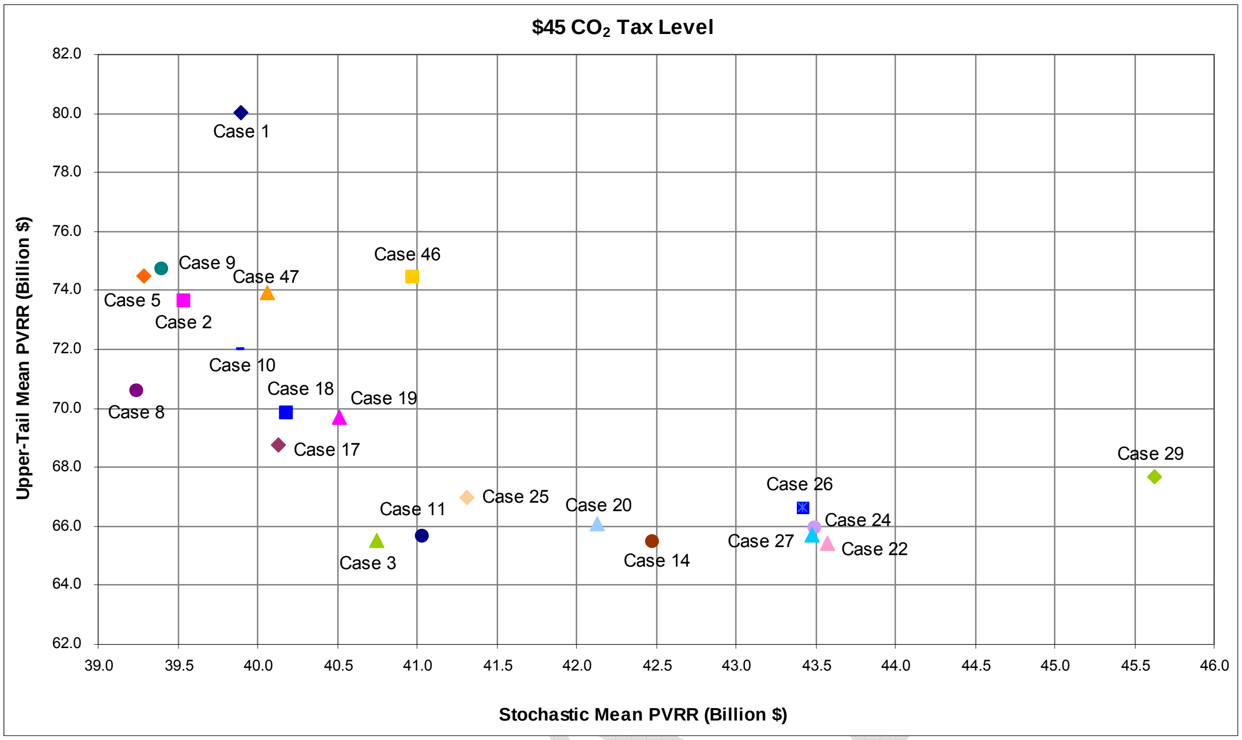
Across the $CO_2$ tax levels, there are no portfolios that dominate all others for both mean PVRR and upper-tail mean PVRR. For the $0/ton tax, the case 2 and 3 portfolios dominate all others for mean PVRR and upper-tail mean PVRR, respectively. For the $45/ton tax, the dominant (or nearly dominant) portfolios are represented by cases 8 and 5 for mean PVRR, and cases 22, 14, and 3 for the upper-tail mean. For the $100/ton tax, the dominating portfolios include cases 17 and 25 for mean PVRR, and 27, 22, and 24 for upper-tail mean PVRR.

Figure 8.19 is the scatter plot for the cost and risk measures expressed as averages across the $CO_2$ tax simulations. Cases 8 and 5 dominate on mean PVRR, while cases 22, 27, and 14 dominate on upper-tail mean PVRR.

**Figure 8.16 – Stochastic Cost versus Upper-tail Risk, $0 $CO_2$ Tax**



## Figure 8.17 – Stochastic Cost versus Upper-tail Risk, \$45 $CO_2$ Tax




## Figure 8.18 – Stochastic Cost versus Upper-tail Risk, \$100 $CO_2$ Tax

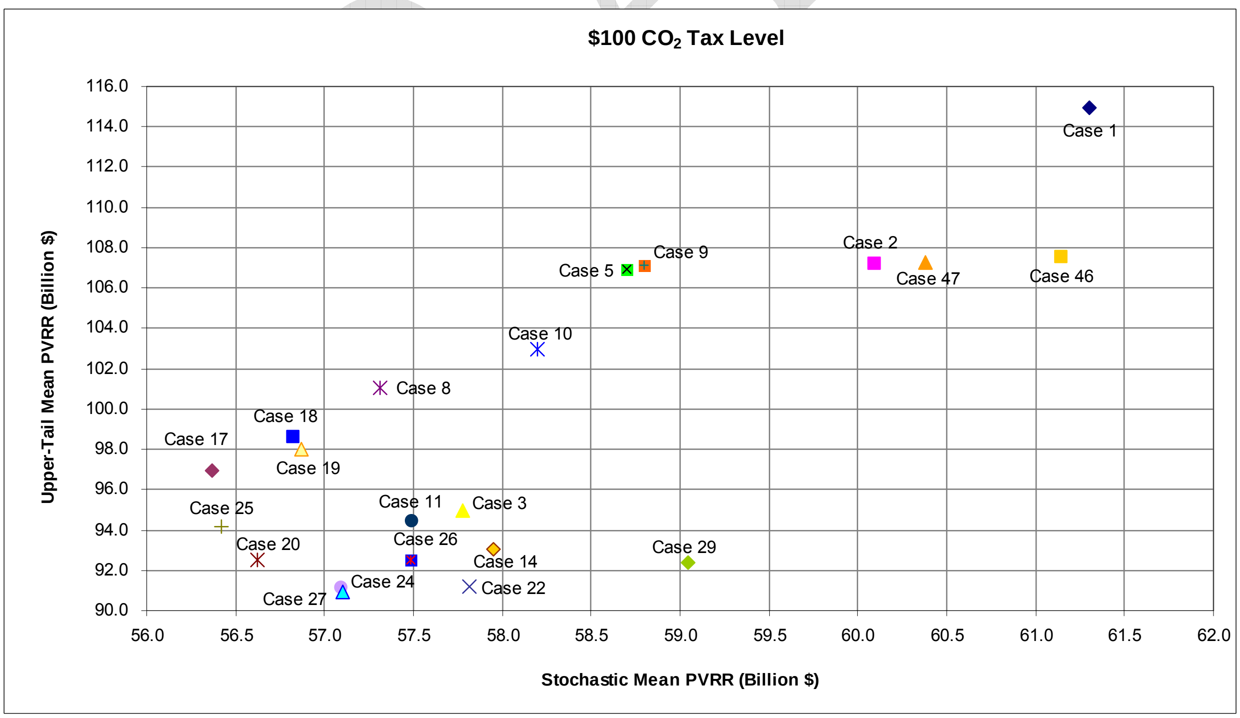
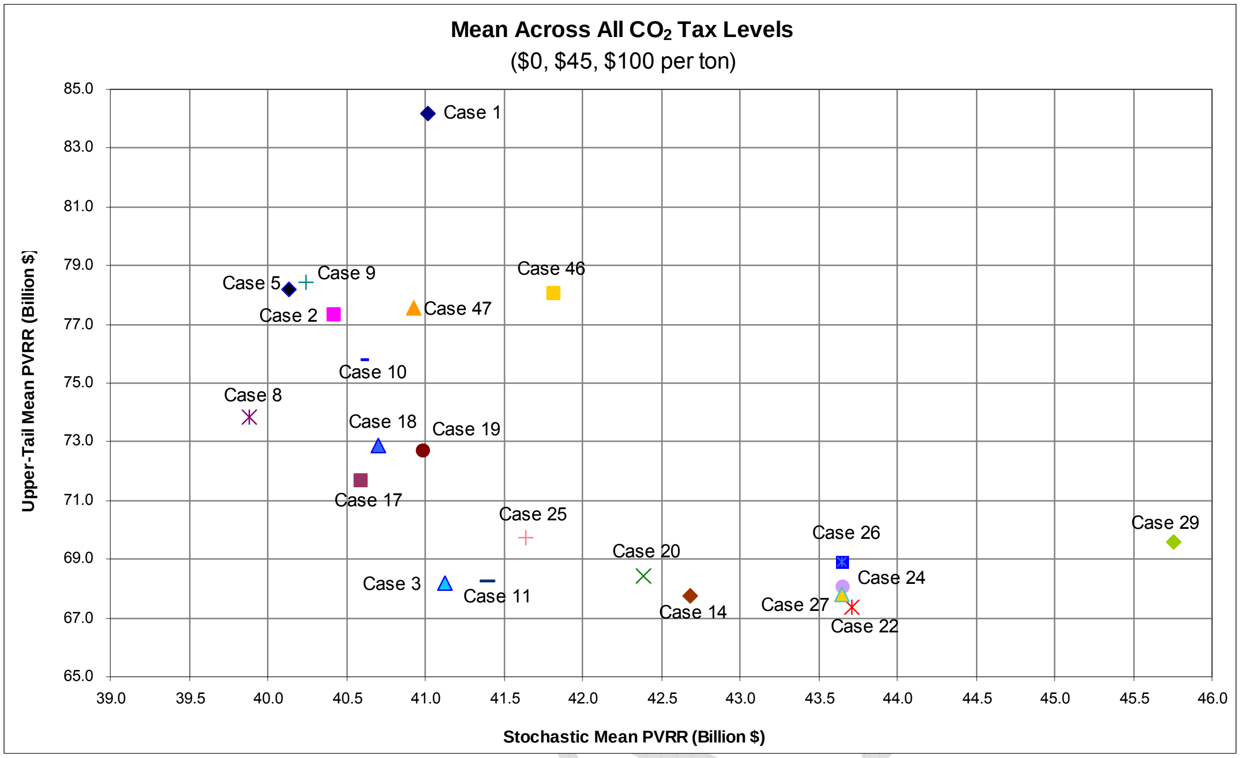


**Figure 8.19 – Stochastic Cost versus Upper-tail Risk, Average for $CO_2$ Tax Levels**




## Fifth and Ninety-Fifth Percentile PVRR

Table 8.13 reports the 5th and 95th percentile PVRR results for each of the $CO_2$ tax simulations. Straight averages across the simulations are also shown. The 95th percentile PVRRs are incorporated into the risk-adjusted PVRR results shown above.

**Table 8.13 – 5th and 95th Percentile PVRR by Portfolio**

| Case | CO2 Tax Level, Million Dollars (2009$) | | | | | | Average 5th Percentile | Average 95th Percentile |
|---|---|---|---|---|---|---|---|---|
| | $0/ton | | $45/ton | | $100/ton | | | |
| | 5th Percentile | 95th Percentile | 5th Percentile | 95th Percentile | 5th Percentile | 95th Percentile | | |
| 1 | 12,783 | 42,378 | 25,788 | 64,012 | 37,447 | 95,821 | 25,339 | 67,404 |
| 2 | 13,242 | 37,288 | 26,367 | 58,989 | 38,006 | 89,768 | 25,872 | 62,015 |
| 3 | 16,195 | 35,313 | 28,995 | 56,205 | 39,187 | 83,429 | 28,126 | 58,316 |
| 5 | 13,824 | 38,965 | 26,143 | 59,619 | 36,667 | 89,078 | 25,544 | 62,554 |
| 8 | 15,227 | 37,008 | 25,594 | 57,877 | 36,925 | 86,354 | 25,916 | 60,413 |
| 9 | 13,845 | 39,135 | 26,254 | 59,775 | 36,833 | 89,222 | 25,644 | 62,711 |
| 10 | 15,530 | 39,069 | 26,786 | 58,877 | 37,377 | 87,726 | 26,564 | 61,890 |
| 11 | 16,042 | 36,143 | 29,664 | 56,410 | 38,989 | 83,010 | 28,232 | 58,521 |
| 14 | 18,323 | 36,047 | 31,913 | 57,172 | 39,748 | 81,853 | 29,995 | 58,357 |
| 17 | 17,939 | 38,113 | 27,689 | 57,738 | 37,331 | 84,101 | 27,653 | 59,984 |
| 18 | 17,497 | 38,334 | 27,366 | 58,161 | 37,552 | 85,095 | 27,472 | 60,530 |
| 19 | 18,038 | 38,656 | 27,945 | 58,283 | 37,923 | 84,818 | 27,968 | 60,586 |
| 20 | 19,002 | 38,039 | 31,958 | 56,595 | 38,589 | 80,918 | 29,849 | 58,518 |
| 22 | 20,516 | 36,950 | 32,172 | 57,320 | 39,783 | 81,455 | 30,823 | 58,575 |

| Case | CO2 Tax Level, Million Dollars (2009$) | | | | | | Average 5th Percentile | Average 95th Percentile |
|---|---|---|---|---|---|---|---|---|
| | $0/ton | | $45/ton | | $100/ton | | | |
| | 5th Percentile | 95th Percentile | 5th Percentile | 95th Percentile | 5th Percentile | 95th Percentile | | |
| 24 | 21,323 | 37,971 | 33,686 | 57,338 | 39,783 | 79,882 | 31,597 | 58,397 |
| 25 | 18,385 | 38,596 | 29,912 | 57,527 | 38,267 | 82,511 | 28,855 | 59,545 |
| 26 | 21,408 | 38,599 | 33,688 | 57,464 | 40,050 | 80,862 | 31,715 | 58,975 |
| 27 | 21,363 | 37,689 | 33,220 | 57,212 | 40,064 | 79,636 | 31,549 | 58,179 |
| 29 | 23,269 | 39,889 | 34,029 | 58,893 | 42,020 | 81,822 | 33,106 | 60,201 |
| 46 | 15,085 | 38,385 | 27,953 | 59,954 | 39,326 | 90,703 | 27,455 | 63,014 |
| 47 | 14,048 | 37,753 | 26,881 | 59,283 | 38,290 | 90,150 | 26,406 | 62,395 |

## Production Cost Standard Deviation

The standard deviation of stochastic production costs for each portfolio and the average is shown in table 8.14. (Probability-weighted average values based on alternative expected value $CO_2$ tax levels are reported in Table 8.27.) This risk measure was assigned a five percent weight for determination of the portfolio preference scores.

As expected, portfolios that rely on coal, wind, and nuclear resources exhibit the lowest levels of production cost variability.

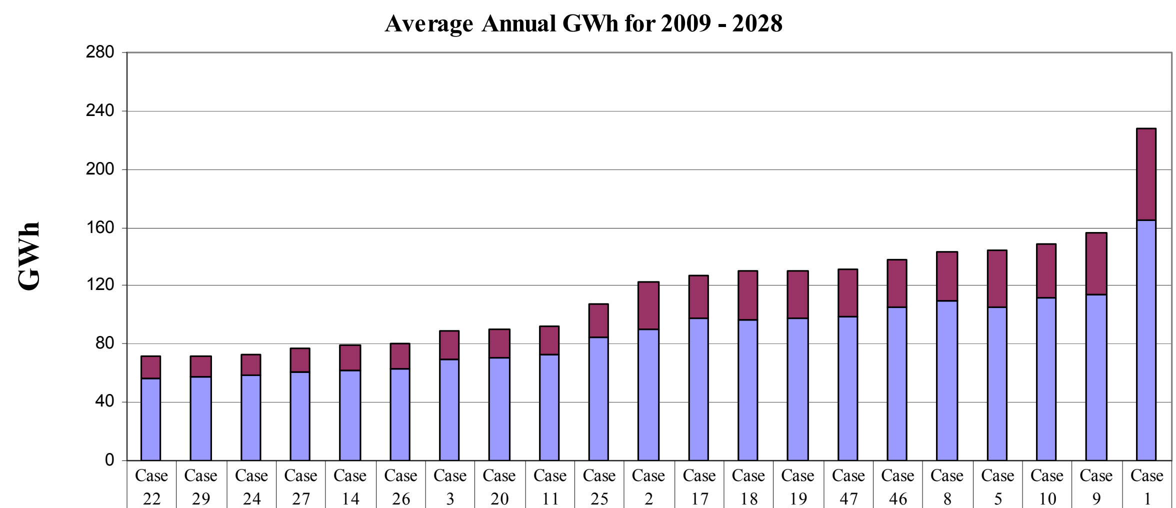
**Table 8.14 – Production Cost Standard Deviation**

| Case | CO2 Tax Level, Million Dollars (2009$) | | | | Rank |
|---|---|---|---|---|---|
| | $0/ton | $45/ton | $100/ton | Average | |
| 1 | 10,486 | 12,939 | 18,966 | 14,130 | 21 |
| 2 | 8,795 | 11,312 | 17,234 | 12,447 | 18 |
| 3 | 6,484 | 8,845 | 14,129 | 9,819 | 9 |
| 5 | 9,067 | 11,549 | 17,422 | 12,679 | 19 |
| 8 | 8,083 | 10,534 | 16,156 | 11,591 | 14 |
| 9 | 9,104 | 11,565 | 17,412 | 12,694 | 20 |
| 10 | 8,552 | 10,733 | 16,424 | 11,903 | 15 |
| 11 | 6,499 | 8,778 | 13,958 | 9,745 | 8 |
| 14 | 6,106 | 8,256 | 13,205 | 9,189 | 6 |
| 17 | 7,438 | 9,799 | 15,133 | 10,790 | 11 |
| 18 | 7,655 | 10,033 | 15,439 | 11,042 | 13 |
| 19 | 7,566 | 9,906 | 15,238 | 10,904 | 12 |
| 20 | 6,336 | 8,460 | 13,255 | 9,350 | 7 |
| 22 | 5,860 | 7,854 | 12,459 | 8,724 | 2 |
| 24 | 5,904 | 7,955 | 12,530 | 8,796 | 4 |
| 25 | 6,808 | 9,041 | 14,090 | 9,980 | 10 |
| 26 | 6,094 | 8,201 | 12,880 | 9,058 | 5 |
| 27 | 5,893 | 7,909 | 12,434 | 8,745 | 3 |
| 29 | 5,920 | 7,844 | 12,242 | 8,669 | 1 |
| 46 | 8,628 | 11,142 | 17,029 | 12,266 | 16 |
| 47 | 8,708 | 11,251 | 17,188 | 12,382 | 17 |

## Energy Not Served (ENS)

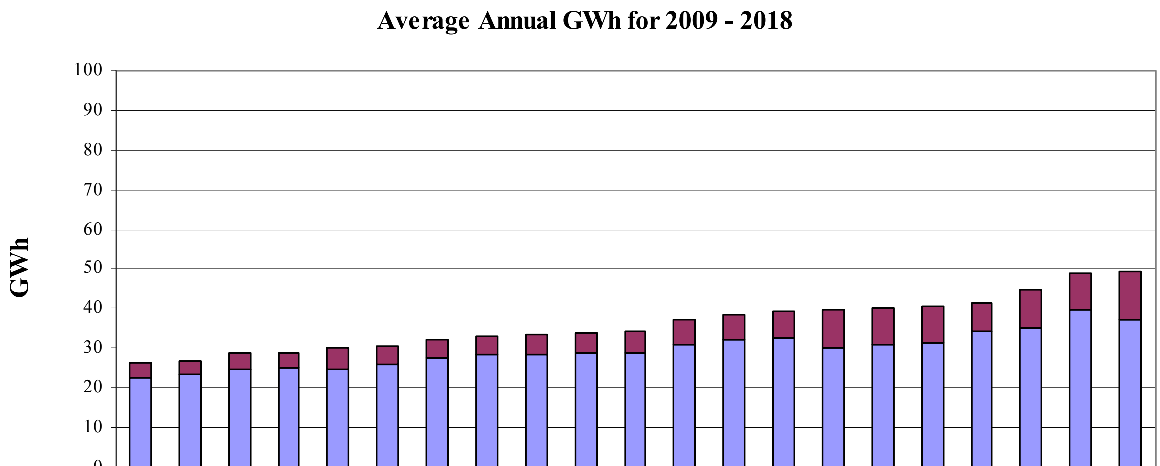
Figures 8.20 and 8.21 below show, respectively, the average annual amount of Energy Not Served (ENS) for the periods 2009-2028 and 2009-2018. Figure 8.22 shows the upper-tail mean ENS by portfolio. As explained in Chapter 7, these are measures of high-end supply reliability risk. Portfolios with low ENS include coal and nuclear, as well as relatively large quantities of wind. Portfolios with relatively high amounts of ENS rely to a greater degree on front office transactions, and in the out-years, growth resources.

**Figure 8.20 – Average Annual Energy Not Served, 2009-2028 ($45 $CO_2$ Tax)**



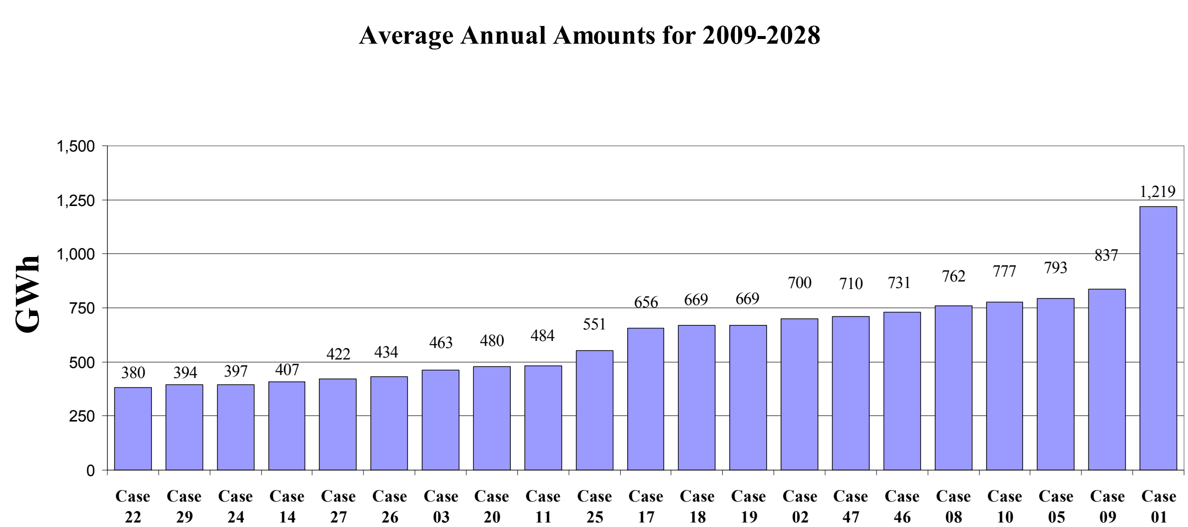

| | Case 22 | Case 29 | Case 24 | Case 27 | Case 14 | Case 26 | Case 3 | Case 20 | Case 11 | Case 25 | Case 2 | Case 17 | Case 18 | Case 19 | Case 47 | Case 46 | Case 8 | Case 5 | Case 10 | Case 9 | Case 1 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| West | 15 | 14 | 15 | 15 | 17 | 17 | 20 | 19 | 19 | 23 | 32 | 30 | 33 | 33 | 33 | 33 | 34 | 40 | 37 | 42 | 64 |
| East | 56 | 58 | 58 | 61 | 62 | 63 | 69 | 71 | 73 | 85 | 90 | 97 | 97 | 97 | 98 | 105 | 109 | 105 | 112 | 114 | 165 |

**Figure 8.21 – Average Annual Energy Not Served, 2009-2018 ($45 $CO_2$ Tax)**




| | Case 14 | Case 22 | Case 24 | Case 29 | Case 3 | Case 27 | Case 11 | Case 25 | Case 20 | Case 26 | Case 17 | Case 19 | Case 18 | Case 8 | Case 2 | Case 5 | Case 9 | Case 10 | Case 47 | Case 46 | Case 1 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| West | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 7 | 9 | 9 | 9 | 7 | 9 | 9 | 13 |
| East | 23 | 23 | 25 | 25 | 25 | 26 | 28 | 28 | 29 | 29 | 29 | 31 | 32 | 33 | 30 | 31 | 31 | 34 | 35 | 40 | 37 |

**Figure 8.22 – Upper-tail Energy Not Served, $45 $CO_2$ Tax**




## Loss of Load Probability

As discussed in Chapter 7, Loss of Load Probability (LOLP) is represented by the probability of an occurrence of Energy Not Served. Table 8.12 displays the average LOLP for each of the candidate portfolios during the summer peak at various ENS event thresholds, modeled using the \$45 $CO_2$ tax assumption. The first block of data is the average LOLP for the first ten years of the study period. The second block of data shows the same information calculated for the entire 20 years. The LOLP values in the second block are significantly higher than the first because the variability of the random draws for the stochastic variable draws increases over time, causing greater extremes in the out-years of the study period.

Table 8.15 displays the year-by-year results for the threshold value of 25,000 MWh. For each year, the LOLP value represents the proportion of the 100 simulation iterations where the July ENS was greater than 25,000 MWh. This is the equivalent of 2,500 megawatts for 10 hours. The annual average LOLPs from Table 8.13 constitute one of the supply reliability risk measures used for overall portfolio preference scoring, and is given a five percent weight for this purpose.

**Table 8.15 – Average Loss of Load Probability by Event Size During Summer Peak**

| Average for operating years 2009 through 2018 | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Event Size (MWh) | Case Number | | | | | | | | | |
| | 1 | 2 | 3 | 5 | 8 | 9 | 10 | 11 | 14 | 17 |
| > 0 | 40% | 39% | 38% | 39% | 42% | 39% | 42% | 39% | 36% | 41% |
| > 1,000 | 32% | 32% | 30% | 32% | 35% | 31% | 34% | 33% | 29% | 34% |
| > 10,000 | 19% | 18% | 16% | 18% | 20% | 18% | 20% | 18% | 15% | 18% |
| > 25,000 | 13% | 11% | 10% | 12% | 13% | 12% | 13% | 11% | 9% | 12% |
| > 50,000 | 8% | 7% | 6% | 7% | 8% | 7% | 8% | 7% | 6% | 7% |
| > 100,000 | 5% | 4% | 4% | 5% | 5% | 5% | 5% | 4% | 3% | 4% |
| > 500,000 | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| > 1,000,000 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Average for operating years 2009 through 2028 | | | | | | | | | | |
| Event Size (MWh) | Case Number | | | | | | | | | |
| | 1 | 2 | 3 | 5 | 8 | 9 | 10 | 11 | 14 | 17 |
| > 0 | 42% | 39% | 42% | 39% | 45% | 41% | 45% | 43% | 41% | 44% |
| > 1,000 | 37% | 33% | 35% | 34% | 38% | 35% | 38% | 36% | 34% | 37% |
| > 10,000 | 26% | 21% | 23% | 22% | 25% | 23% | 27% | 24% | 22% | 25% |
| > 25,000 | 21% | 16% | 16% | 17% | 19% | 18% | 20% | 16% | 15% | 19% |
| > 50,000 | 16% | 12% | 12% | 13% | 14% | 14% | 15% | 12% | 11% | 14% |
| > 100,000 | 12% | 9% | 8% | 10% | 10% | 11% | 11% | 8% | 7% | 10% |
| > 500,000 | 4% | 3% | 2% | 3% | 3% | 3% | 3% | 2% | 2% | 3% |
| > 1,000,000 | 2% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |

| Average for operating years 2009 through 2018 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Event Size (MWh) | Case Number | | | | | | | | | | |
| | 18 | 19 | 20 | 22 | 24 | 25 | 26 | 27 | 29 | 46 | 47 |
| > 0 | 42% | 41% | 39% | 37% | 37% | 40% | 40% | 37% | 37% | 44% | 42% |
| > 1,000 | 34% | 34% | 33% | 30% | 30% | 33% | 33% | 30% | 30% | 37% | 35% |
| > 10,000 | 20% | 19% | 18% | 16% | 16% | 18% | 18% | 16% | 16% | 23% | 21% |
| > 25,000 | 13% | 12% | 11% | 10% | 10% | 11% | 11% | 10% | 10% | 14% | 13% |
| > 50,000 | 8% | 8% | 7% | 6% | 6% | 7% | 7% | 7% | 6% | 9% | 8% |
| > 100,000 | 4% | 4% | 4% | 3% | 3% | 4% | 4% | 3% | 3% | 6% | 5% |
| > 500,000 | 1% | 1% | 1% | 0% | 1% | 0% | 1% | 0% | 0% | 1% | 1% |

| Event Size (MWh) | Average for operating years 2009 through 2018 | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Case Number | | | | | | | | | | |
| | 18 | 19 | 20 | 22 | 24 | 25 | 26 | 27 | 29 | 46 | 47 |
| > 1,000,000 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

| Event Size (MWh) | Average for operating years 2009 through 2028 | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Case Number | | | | | | | | | | |
| | 18 | 19 | 20 | 22 | 24 | 25 | 26 | 27 | 29 | 46 | 47 |
| > 0 | 45% | 45% | 43% | 42% | 42% | 43% | 43% | 42% | 42% | 47% | 45% |
| > 1,000 | 38% | 38% | 37% | 35% | 35% | 37% | 37% | 35% | 35% | 41% | 38% |
| > 10,000 | 26% | 26% | 24% | 22% | 22% | 24% | 24% | 23% | 23% | 27% | 26% |
| > 25,000 | 19% | 19% | 17% | 15% | 15% | 18% | 17% | 16% | 16% | 20% | 19% |
| > 50,000 | 14% | 14% | 12% | 11% | 11% | 13% | 12% | 11% | 11% | 14% | 14% |
| > 100,000 | 10% | 10% | 8% | 7% | 7% | 9% | 8% | 7% | 7% | 11% | 10% |
| > 500,000 | 3% | 3% | 2% | 2% | 1% | 3% | 2% | 2% | 2% | 3% | 3% |
| > 1,000,000 | 1% | 1% | 1% | 0% | 0% | 1% | 0% | 0% | 0% | 1% | 1% |

## Table 8.16 – Year-by-Year Loss of Load Probability

Probability of ENS Event > 25,000 MWh in July

| Year | Case Number | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 5 | 8 | 9 | 10 | 11 | 14 | 17 |
| 2009 | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 2010 | 14% | 12% | 10% | 12% | 12% | 12% | 12% | 11% | 9% | 11% |
| 2011 | 9% | 9% | 8% | 9% | 9% | 9% | 9% | 9% | 8% | 9% |
| 2012 | 7% | 7% | 5% | 7% | 7% | 7% | 7% | 7% | 5% | 7% |
| 2013 | 17% | 14% | 10% | 14% | 12% | 17% | 16% | 13% | 10% | 12% |
| 2014 | 18% | 17% | 8% | 17% | 17% | 19% | 17% | 10% | 8% | 16% |
| 2015 | 17% | 15% | 10% | 15% | 15% | 15% | 15% | 10% | 10% | 10% |
| 2016 | 11% | 11% | 13% | 11% | 15% | 11% | 15% | 13% | 11% | 13% |
| 2017 | 8% | 6% | 12% | 6% | 14% | 6% | 14% | 11% | 11% | 14% |
| 2018 | 23% | 19% | 19% | 20% | 23% | 20% | 23% | 19% | 17% | 21% |
| 2019 | 21% | 12% | 16% | 15% | 18% | 15% | 18% | 15% | 15% | 17% |
| 2020 | 22% | 15% | 19% | 19% | 23% | 19% | 23% | 19% | 19% | 22% |
| 2021 | 24% | 17% | 22% | 19% | 20% | 21% | 24% | 22% | 22% | 23% |
| 2022 | 26% | 12% | 15% | 17% | 16% | 17% | 22% | 16% | 15% | 21% |
| 2023 | 30% | 25% | 25% | 25% | 30% | 28% | 30% | 25% | 24% | 30% |
| 2024 | 30% | 23% | 21% | 22% | 23% | 25% | 27% | 23% | 21% | 24% |
| 2025 | 39% | 27% | 27% | 36% | 39% | 36% | 35% | 30% | 27% | 36% |
| 2026 | 30% | 25% | 25% | 27% | 29% | 26% | 29% | 26% | 25% | 29% |
| 2027 | 26% | 21% | 22% | 25% | 27% | 25% | 27% | 23% | 22% | 23% |
| 2028 | 35% | 25% | 25% | 26% | 29% | 29% | 31% | 20% | 23% | 28% |

| Year | Case Number | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 18 | 19 | 20 | 22 | 24 | 25 | 26 | 27 | 29 | 46 | 47 |
| 2009 | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| 2010 | 12% | 12% | 11% | 9% | 9% | 11% | 11% | 11% | 10% | 12% | 12% |
| 2011 | 9% | 9% | 9% | 8% | 8% | 9% | 9% | 8% | 8% | 9% | 9% |
| 2012 | 7% | 7% | 7% | 5% | 5% | 7% | 7% | 5% | 5% | 7% | 7% |
| 2013 | 17% | 14% | 12% | 10% | 10% | 13% | 13% | 10% | 10% | 12% | 12% |

| Year | Case Number | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 18 | 19 | 20 | 22 | 24 | 25 | 26 | 27 | 29 | 46 | 47 |
| 2014 | 18% | 18% | 13% | 8% | 8% | 13% | 13% | 10% | 9% | 17% | 17% |
| 2015 | 15% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 15% | 15% |
| 2016 | 13% | 13% | 13% | 13% | 13% | 13% | 13% | 13% | 13% | 16% | 15% |
| 2017 | 14% | 14% | 13% | 11% | 11% | 12% | 13% | 12% | 12% | 21% | 14% |
| 2018 | 21% | 21% | 21% | 17% | 20% | 20% | 21% | 21% | 19% | 26% | 23% |
| 2019 | 17% | 17% | 16% | 15% | 15% | 15% | 16% | 16% | 15% | 21% | 18% |
| 2020 | 22% | 22% | 21% | 19% | 21% | 21% | 21% | 21% | 21% | 24% | 23% |
| 2021 | 23% | 23% | 23% | 22% | 23% | 23% | 23% | 23% | 23% | 25% | 23% |
| 2022 | 20% | 21% | 17% | 15% | 16% | 19% | 17% | 18% | 17% | 20% | 18% |
| 2023 | 30% | 30% | 28% | 25% | 25% | 28% | 29% | 30% | 27% | 31% | 29% |
| 2024 | 25% | 24% | 24% | 21% | 21% | 22% | 22% | 24% | 21% | 24% | 24% |
| 2025 | 36% | 36% | 29% | 23% | 24% | 33% | 24% | 24% | 23% | 34% | 33% |
| 2026 | 29% | 31% | 27% | 25% | 24% | 29% | 24% | 24% | 24% | 29% | 28% |
| 2027 | 23% | 22% | 21% | 21% | 20% | 22% | 20% | 20% | 20% | 25% | 24% |
| 2028 | 29% | 28% | 23% | 22% | 22% | 28% | 22% | 18% | 20% | 27% | 26% |

## LOAD GROWTH IMPACT ON RESOURCE CHOICE

Table 8.17 reports selected stochastic cost and risk results for the cases developed with low and high load growth assumptions. Comparable medium load growth cases are included for reference purposes. The results are also grouped by gas price scenario to highlight the influence of gas and associated electricity prices on portfolio cost as load growth increases.

One observation gleaned from Table 8.17 is that the mix of resource added in response to higher load growth reduces high-end cost risk and Energy Not Served. The System Optimizer model tended to add wind and base-load resources (or CCCT capacity under low gas price scenarios), which reduced upper-tail costs. Much of the cost reduction is seen in the form of net revenue gains from spot market balancing transactions.

**Table 8.17 – Stochastic Performance Results for Alternative Load Growth Scenario Cases**

| Case | Load Growth | Gas Price Scenario / FPC | Mean | 5th Percentile | 95th Percentile | Upper-Tail Mean | Production Cost Standard Deviation | Ave. Annual ENS (GWh/yr, 2009-2028) |
|---|---|---|---|---|---|---|---|---|
| $45/ton CO2 Tax | | | | | | | | |
| 4 | Low | Low - June 2008 | 40,270 | 26,484 | 63,634 | 79,735 | 12,725 | 345.3 |
| 5 | Med | Low - June 2008 | 39,289 | 26,143 | 59,619 | 74,487 | 9,067 | 144.6 |
| 6 | High | Low - June 2008 | 39,635 | 27,311 | 58,044 | 71,364 | 10,639 | 37.7 |
| | | | | | | | | |
| 7 | Low | Medium - June 2008 | 39,877 | 26,747 | 59,769 | 74,618 | 11,395 | 255.1 |
| 8 | Med | Medium - June 2008 | 39,244 | 25,594 | 57,877 | 70,581 | 10,534 | 143.4 |
| 12 | High | Medium - June 2008 | 40,027 | 27,513 | 56,698 | 67,054 | 9,462 | 38.3 |
| | | | | | | | | |
| 13 | Low | High - June 2008 | 42,040 | 30,546 | 57,924 | 67,240 | 8,940 | 117.5 |
| 14 | Med | High - June 2008 | 42,481 | 31,913 | 57,172 | 65,453 | 8,256 | 79.0 |

| Case | Load Growth | Gas Price Scenario / FPC | Mean | 5th Percentile | 95th Percentile | Upper-Tail Mean | Production Cost Standard Deviation | Ave. Annual ENS (GWh/yr, 2009-2028) |
|---|---|---|---|---|---|---|---|---|
| 15 | High | High - June 2008 | 43,893 | 33,105 | 56,816 | 64,247 | 7,392 | 26.2 |
| **$70/ton CO2 Tax** | | | | | | | | |
| 16 | Low | Medium - June 2008 | 40,654 | 27,584 | 59,033 | 71,420 | 10,300 | 193.3 |
| 17 | Med | Low - June 2008 | 42,481 | 27,689 | 57,738 | 68,766 | 7,438 | 127.1 |
| | | | | | | | | |
| 21 | Low | High - June 2008 | 43,038 | 32,516 | 58,082 | 67,686 | 8,677 | 107.6 |
| 22 | Med | High - June 2008 | 43,576 | 32,172 | 57,320 | 65,404 | 7,854 | 71.3 |
| **$100/ton CO2 Tax** | | | | | | | | |
| 23 | Low | Medium - June 2008 | 43,624 | 33,987 | 57,827 | 66,798 | 8,177 | 88.6 |
| 24 | Med | Medium - June 2008 | 43,496 | 33,686 | 57,338 | 65,939 | 7,955 | 72.7 |
| | | | | | | | | |
| 28 | Low | High - June 2008 | 43,602 | 32,764 | 58,070 | 67,305 | 8,376 | 94.0 |
| 29 | Med | High - June 2008 | 45,626 | 34,029 | 58,893 | 67,670 | 7,844 | 72.1 |
| | | | | | | | | |
| 33 | High | High - June 2008 | 46,285 | 27,463 | 61,638 | 76,361 | 11,731 | 22.2 |

## CAPACITY PLANNING RESERVE MARGIN

PacifiCorp compared stochastic cost and risk measures for portfolios built to meet 12 percent and 15 percent capacity planning reserve margins. This comparative analysis also examined the impact of the resource mix as the cost of $CO_2$ emission compliance increases, since resources added in response to high $CO_2$ costs, such as wind and energy efficiency programs, are not subject to fuel price volatility.[44] The relevant comparisons are cases 8 and 41 ($45 $CO_2$ tax), cases 17 and 42 ($70 $CO_2$ tax), and cases 24 and 43 ($100 $CO_2$ tax). Stochastic simulations were only conducted with the $45 $CO_2$ tax since ENS is not materially affected by differences in emission cost.

For the $45 $CO_2$ tax cases, increasing the planning reserve margin from 12 percent to 15 percent resulted in additional wind (135 MW) and east-side geothermal (35 MW) resources, as well as increased reliance on front office transactions on both the east and west sides, prior to 2016. The System Optimizer model added an IC aero SCCT in 2016 (261 MW) and subsequently cut back on additional wind resources and front office transactions. Table 8.18 shows the stochastic cost and risk results for the two case portfolios (cases 8 and 41), while Table 8.19 shows the detailed PVRR cost breakdown.

Building to the 15-percent PRM level increased costs and high-end cost risk due to higher fuel and market purchase costs. Partially offsetting these higher operating costs was reduced system balancing costs and lower capital expenditures from the smaller wind investment. (The contribution of the ENS cost as a proportion of total variable costs is less than that reported in the 2007 IRP due to the tiered cost approach applied for this IRP. See the discussion on ENS in Chapter 7 for details.)

[44] The IRP modeling of wind does not capture the stochastic behavior of wind generation, so related supply reliability risks are not captured in the stochastic analysis.

As expected, with the higher PRM, supply reliability is enhanced as measured by average annual ENS and significant-event LOLP during July. Dividing the incremental portfolio cost by the reduced amount of ENS (487 GWh for 2009-2028) associated with adopting the 15-percent PRM portfolio results in a cost premium of $659/MWh for the ENS reduction.

### Table 8.18 – Cost versus Risk for 12% and 15% Planning Reserve Margin Portfolios

| | | | | Stochastic Risk, Million $ | | | | Supply Reliability | |
|---|---|---|---|---|---|---|---|---|---|
| Planning Reserve Margin (%) | Case | $CO_2$ Tax | Stochastic Mean PVRR (Million $) | 5th Percentile | 95th Percentile | Upper Tail (mean of 5 Highest) | Standard Deviation | Annual Ave. ENS (GWh/yr) | Probability of ENS Event > 25 GWh in July (Annual average) |
| 12 | 8 | 45 | 39,244 | 25,594 | 57,877 | 70,581 | 10,534 | 143.4 | 19.1% |
| 15 | 41 | 45 | 39,565 | 26,113 | 58,265 | 71,649 | 10,715 | 119.1 | 15.5% |
| Difference, 15% less 12% | | | 321 | 518 | 388 | 1,068 | 181 | (24) | -3.7% |
| 12 | 17 | 70 | 40,134 | 27,689 | 57,738 | 68,766 | 9,799 | 127.1 | 18.5% |
| 15 | 42 | 70 | 40,166 | 27,722 | 57,591 | 69,029 | 9,843 | 98.6 | 14.3% |
| Difference, 15% less 12% | | | 32 | 33 | (147) | 263 | 44 | (28) | -4.2% |
| 12 | 24 | 100 | 43,496 | 33,686 | 57,338 | 65,939 | 7,955 | 72.7 | 15.5% |
| 15 | 43 | 100 | 43,486 | 33,736 | 57,316 | 65,874 | 7,936 | 69.3 | 15.1% |
| Difference, 15% less 12% | | | (10) | 50 | (22) | (65) | (19) | (3) | -0.4% |

### Table 8.19 – PVRR Cost Details ($45/ton CO2 Tax), 12% and 15% Planning Reserve Margin Portfolios

| Cost Component ($ 000) | 12% PRM Case 8 | 15% PRM Case 41 | Difference (Case 41 less 8) |
|---|---|---|---|
| **Variable Cost** | | | |
| Total Fuel Cost | 14,191,867 | 14,418,506 | 226,640 |
| Variable O&M Cost | 1,222,685 | 1,241,622 | 18,937 |
| Total Emission Cost | 14,691,301 | 14,751,942 | 60,641 |
| Long Term Contracts and Front Office Transactions | 8,978,705 | 9,650,090 | 671,386 |
| DSM | 3,015,434 | 3,019,019 | 3,586 |
| **Spot Market Balancing** | | | |
| Sales | (13,089,333) | (13,482,889) | (393,557) |
| Purchases | 3,714,988 | 3,514,149 | (200,839) |
| Energy Not Served | 184,495 | 152,058 | (32,436) |
| Dump Power | (12,366) | (10,982) | 1,384 |
| Reserve Deficiency | 73,920 | 63,886 | (10,034) |
| **Total Variable Net Power Costs** | **32,971,694** | **33,317,402** | **345,707** |
| | | | |
| **Real Levelized Fixed Costs** | **6,272,174** | **6,247,502** | **(24,672)** |
| | | | |
| **Total PVRR** | **39,243,869** | **39,564,904** | **321,036** |

**Table 8.20 – PVRR Cost Details ($70/ton CO2 Tax), 12% and 15% Planning Reserve Margin Portfolios**

| Cost Component ($ 000) | 12% PRM Case 17 | 15% PRM Case 42 | Difference (Case 42 less 17) |
|---|---|---|---|
| **Variable Cost** | | | |
| Total Fuel Cost | 13,625,227 | 13,740,869 | 115,642 |
| Variable O&M Cost | 1,204,222 | 1,215,560 | 11,339 |
| Total Emission Cost | 13,469,668 | 13,455,115 | (14,553) |
| Long Term Contracts and Front Office Transactions | 8,669,522 | 9,330,643 | 661,121 |
| DSM | 3,186,054 | 3,180,545 | (5,509) |
| **Spot Market Balancing** | | | |
| Sales | (13,388,006) | (13,854,964) | (466,958) |
| Purchases | 3,546,102 | 3,284,808 | (261,294) |
| Energy Not Served | 168,279 | 130,139 | (38,141) |
| Dump Power | (21,406) | (19,997) | 1,409 |
| Reserve Deficiency | 63,344 | 52,524 | (10,820) |
| **Total Variable Net Power Costs** | **30,523,005** | **30,515,242** | **(7,764)** |
| | | | |
| **Real Levelized Fixed Costs** | **9,610,984** | **9,651,213** | **40,229** |
| | | | |
| **Total PVRR** | **40,133,989** | **40,166,454** | **32,465** |

Under a $70 $CO_2$ tax, increasing the PRM results in a similar build pattern as that for the $45 $CO_2$ tax cases—including the addition of an IC Aero SCCT in 2016—except that System Optimizer removes less wind and increases front office transactions once the peaking resource is added. As can be seen from Table 8.20, the gap in cost and cost risk narrows between the two portfolios, while supply reliability improves slightly. Table 8.21 shows the PVRR cost detail comparison for the two portfolios. Fuel, net system balancing, and emission costs are reduced due to the extra wind included in the 15-percent PRM portfolio and decreased dispatch of thermal units. The cost premium associated with an ENS reduction of 569 GWh drops to $57/MWh.

For the $100 $CO_2$ tax cases, increasing the PRM to 15 percent results in a larger amount of DSM (125 MW), particularly Class 1 programs, and distributed standby generation (42 MW), and a slight increase in front office transactions. No peaking gas resources were added in either portfolio. As indicated in Table 8.21, costs and cost risk actually decrease slightly due to this resource mix.[45] The supply reliability benefit is negligible, and there is effectively a positive cost benefit for reducing the 69 GWh of ENS.

[45] The System Optimizer's deterministic PVRR for case 43 was slightly greater than that for case 24: $60.905 billion versus $60.693 billion. The extrinsic (or real option value) of generation units affected by stochastic variation in fuel and market prices is not accounted in the deterministic capacity optimization solutions.

**Table 8.21 – PVRR Cost Details (\$100/ton $CO_2$ Tax), 12% and 15% Planning Reserve Margin Portfolios**

| Cost Component ($ 000) | 12% PRM Case 24 | 15% PRM Case 43 | Difference (Case 43 less 24) |
|---|---|---|---|
| **Variable Cost** | | | |
| Total Fuel Cost | 12,231,023 | 12,159,435 | (71,587) |
| Variable O&M Cost | 1,099,133 | 1,094,393 | (4,741) |
| Total Emission Cost | 12,068,839 | 12,009,121 | (59,718) |
| Long Term Contracts and Front Office Transactions | 7,533,865 | 8,332,267 | 798,403 |
| DSM | 3,342,009 | 3,443,037 | 101,028 |
| **Spot Market Balancing** | | | |
| Sales | (13,956,020) | (14,423,822) | (467,802) |
| Purchases | 3,073,137 | 2,851,243 | (221,894) |
| Energy Not Served | 117,336 | 112,439 | (4,897) |
| Dump Power | (27,096) | (27,081) | 15 |
| Reserve Deficiency | 35,439 | 32,499 | (2,940) |
| **Total Variable Net Power Costs** | **25,517,664** | **25,583,531** | **65,866** |
| | | | |
| **Real Levelized Fixed Costs** | **17,978,326** | **17,902,669** | **(75,657)** |
| | | | |
| **Total PVRR** | **43,495,990** | **43,486,200** | **(9,790)** |

The main conclusions to be drawn from this analysis are as follows:

- With low to moderately high $CO_2$ tax assumptions (less than \$70/ton), planning to a higher PRM results in a significant cost premium for avoiding unserved energy. Whether this cost premium is worth paying is a subjective determination. However, from a stochastic modeling perspective, it is not cost-effective to invest in incremental generating capacity for reserves given that the cost premium for such investment is above the assumed ENS cost.
- In a high $CO_2$ cost environment, the incremental resources acquired for the larger capacity reserve requirement shifts to low $CO_2$-emitting options, which is beneficial from an overall stochastic cost perspective. However, the supply reliability improvement from adding these incremental resources appears to reach a point of diminishing returns between \$70/ton and \$100/ton.

## FUEL SOURCE DIVERSITY

Tables 8.22 through 8.24 show the generation shares by fuel type category for selected years (2013, 2020, and 2028) for new resources in each of the 21 portfolios. The generation mix profile for each portfolio changes over time reflecting the availability of conventional and emerging technologies over the 20-year study period.

All the portfolios increase fuel diversity by reducing the generation share of the company's coal-fired plants. This result is a consequence of the System Optimizer being allowed to select from a diverse range of resource types in response to various price scenarios that in some scenarios make investment in new conventional thermal generation less cost-effective in the future. In this respect, each portfolio has the optimal fuel mix based on it associated input scenario.

While the portfolios increase overall generation fleet fuel and technology diversity, at the same time, concentration of any one fuel or technology for new resource investment has been found to be suboptimal when considering risk and uncertainty. As an example, portfolios for cases 22 and 24 include relatively large investment in wind resources to mitigate correspondingly large $CO_2$ compliance costs.

**Table 8.22 – Generation Shares for New Resources by Fuel Type for 2013**

| 2013 Generation Shares, New Resources (%) | | | |
|---|---|---|---|
| Case | Renewable/DSM | Natural Gas | Market |
| 1 | 25% | 16% | 59% |
| 2 | 36% | 14% | 50% |
| 3 | 70% | 8% | 23% |
| 5 | 36% | 14% | 50% |
| 8 | 58% | 10% | 32% |
| 9 | 36% | 14% | 50% |
| 10 | 49% | 11% | 40% |
| 11 | 67% | 8% | 25% |
| 14 | 76% | 6% | 17% |
| 17 | 68% | 8% | 24% |
| 18 | 59% | 9% | 31% |
| 19 | 65% | 9% | 26% |
| 20 | 68% | 7% | 25% |
| 22 | 77% | 6% | 17% |
| 24 | 77% | 6% | 17% |
| 25 | 68% | 7% | 25% |
| 26 | 68% | 7% | 25% |
| 27 | 73% | 6% | 21% |
| 29 | 77% | 7% | 16% |
| 46 | 41% | 23% | 36% |
| 47 | 33% | 26% | 41% |
| Average | 58% | 11% | 31% |

**Table 8.23 – Generation Shares for New Resources by Fuel Type for 2020**

| 2020 Generation Shares, New Resources (%) | | | | |
|---|---|---|---|---|
| Case | Coal | Renewable/DSM | Natural Gas | Market |
| 1 | 0% | 34% | 17% | 49% |
| 2 | 16% | 41% | 14% | 29% |
| 3 | 11% | 75% | 3% | 11% |
| 5 | 0% | 57% | 11% | 33% |
| 8 | 0% | 67% | 5% | 27% |
| 9 | 0% | 58% | 10% | 32% |
| 10 | 0% | 69% | 4% | 26% |
| 11 | 7% | 79% | 3% | 11% |
| 14 | 7% | 81% | 3% | 10% |
| 17 | 0% | 76% | 4% | 21% |
| 18 | 0% | 75% | 4% | 21% |
| 19 | 0% | 76% | 3% | 20% |
| 20 | 0% | 83% | 3% | 15% |
| 22 | 6% | 84% | 2% | 8% |

| 2020 Generation Shares, New Resources (%) | | | | |
|---|---|---|---|---|
| **Case** | **Coal** | **Renewable/DSM** | **Natural Gas** | **Market** |
| **24** | 0% | 83% | 3% | 14% |
| **25** | 0% | 81% | 3% | 16% |
| **26** | 0% | 82% | 3% | 15% |
| **27** | 0% | 83% | 3% | 14% |
| **29** | 0% | 86% | 3% | 12% |
| **46** | 14% | 50% | 11% | 25% |
| **47** | 14% | 50% | 11% | 25% |
| **Average** | 4% | 70% | 6% | 20% |

### Table 8.24 – Generation Shares for New Resources by Fuel Type for 2028

| 2028 Generation Shares, New Resources (%) | | | | | |
|---|---|---|---|---|---|
| **Case** | **Coal** | **Nuclear** | **Renewable/DSM** | **Natural Gas** | **Market** |
| **1** | 0% | 0% | 34% | 11% | 55% |
| **2** | 10% | 0% | 47% | 8% | 35% |
| **3** | 9% | 0% | 68% | 3% | 20% |
| **5** | 5% | 0% | 50% | 7% | 38% |
| **8** | 0% | 0% | 61% | 4% | 35% |
| **9** | 5% | 0% | 50% | 7% | 38% |
| **10** | 0% | 0% | 63% | 3% | 34% |
| **11** | 6% | 0% | 71% | 2% | 21% |
| **14** | 9% | 0% | 76% | 2% | 13% |
| **17** | 9% | 0% | 61% | 2% | 28% |
| **18** | 9% | 0% | 61% | 2% | 28% |
| **19** | 8% | 0% | 62% | 2% | 28% |
| **20** | 6% | 11% | 62% | 2% | 19% |
| **22** | 11% | 12% | 70% | 2% | 6% |
| **24** | 6% | 23% | 64% | 2% | 6% |
| **25** | 7% | 0% | 69% | 2% | 22% |
| **26** | 6% | 23% | 66% | 2% | 3% |
| **27** | 5% | 20% | 56% | 2% | 17% |
| **29** | 9% | 21% | 66% | 2% | 2% |
| **46** | 9% | 0% | 51% | 7% | 33% |
| **47** | 9% | 0% | 51% | 7% | 33% |
| **Average** | 7% | 6% | 60% | 4% | 23% |

## GENERATOR EMISSIONS FOOTPRINT

### Carbon Dioxide

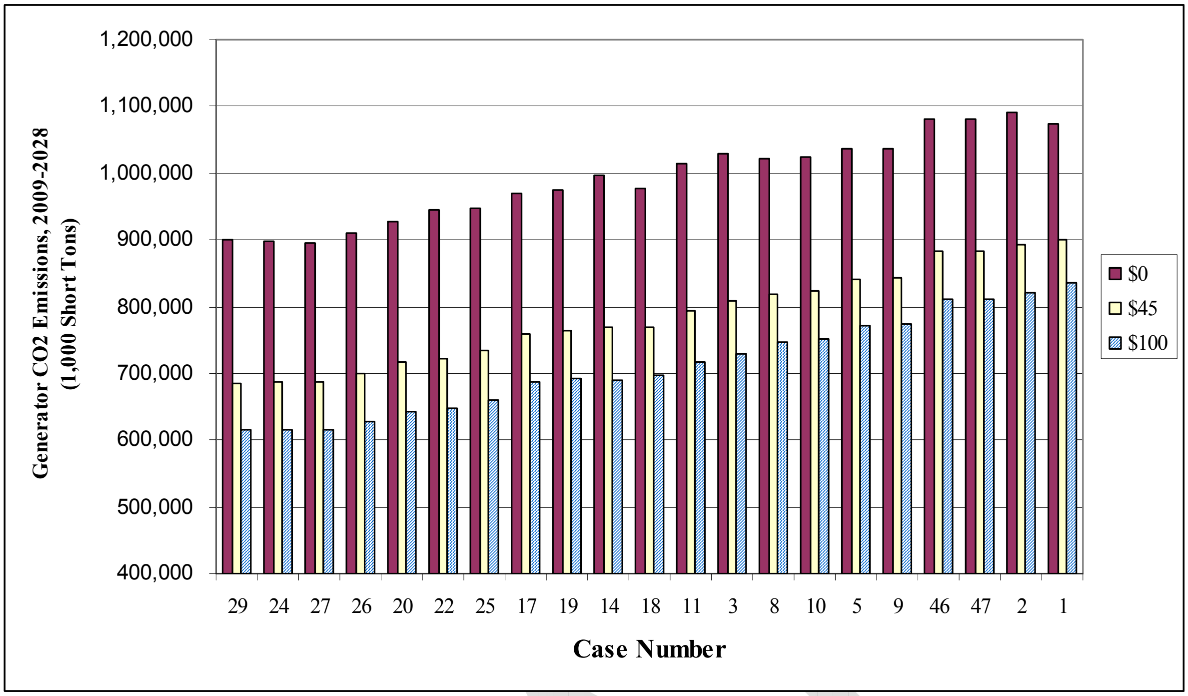
The portfolio cumulative generator $CO_2$ emissions for the simulation period are presented in Table 8.25 by $CO_2$ tax level and the average across tax levels. Figure 8.23 shows the emissions footprint in bar chart form by tax level, with portfolios ranked from lowest to highest emissions (left to right) for the $45 tax.

The portfolios with the lowest cumulative $CO_2$ emissions are those optimized in response to both the $100 $CO_2$ tax and high gas price scenarios. At the other extreme, portfolios optimized with no $CO_2$ tax have the highest emissions. A notable exception is the portfolio for case 3. This portfolio was optimized with the high June 2008 gas price scenario, and as a consequence, includes both a pulverized coal plant in 2018 and about 3,900 MW of wind by 2028. This resource combination lowered the $CO_2$ emissions to less than the amount produced by a number of portfolios optimized with the $45 $CO_2$ tax; specifically, those for cases 5, 8, 9, and 10.

**Table 8.25 – Cumulative Generator Carbon Dioxide Emissions, 2009-2028**

| Case | Cumulative Generator CO2 Emissions, 2009-2028 (1,000 Short Tons) | | | Average |
|---|---|---|---|---|
| | CO2 Tax Level | | | |
| | $0 | $45 | $100 | |
| 1 | 1,073,510 | 899,802 | 835,943 | 936,418 |
| 2 | 1,089,942 | 892,740 | 821,440 | 934,707 |
| 3 | 1,028,918 | 807,954 | 730,560 | 855,811 |
| 5 | 1,036,052 | 841,758 | 772,358 | 883,389 |
| 8 | 1,020,539 | 818,050 | 746,063 | 861,551 |
| 9 | 1,037,463 | 843,569 | 774,282 | 885,105 |
| 10 | 1,025,000 | 823,005 | 751,041 | 866,349 |
| 11 | 1,014,089 | 794,324 | 716,885 | 841,766 |
| 14 | 997,347 | 768,352 | 688,991 | 818,230 |
| 17 | 969,127 | 759,332 | 687,261 | 805,240 |
| 18 | 977,559 | 769,036 | 696,885 | 814,493 |
| 19 | 973,843 | 764,943 | 692,880 | 810,555 |
| 20 | 928,315 | 715,884 | 643,360 | 762,520 |
| 22 | 944,887 | 722,610 | 647,183 | 771,560 |
| 24 | 897,912 | 686,454 | 615,226 | 733,197 |
| 25 | 948,159 | 733,850 | 660,573 | 780,861 |
| 26 | 909,892 | 699,942 | 628,852 | 746,228 |
| 27 | 895,656 | 686,694 | 616,273 | 732,874 |
| 29 | 899,919 | 686,052 | 615,523 | 733,831 |
| 46 | 1,080,785 | 882,033 | 810,307 | 924,375 |
| 47 | 1,081,815 | 883,284 | 811,541 | 925,547 |

**Figure 8.23 – Generator Carbon Dioxide Emissions by $CO_2$ Tax Level**




## Other Pollutants

Table 8.26 reports for each case portfolio the emissions footprint for sulfur dioxide ($SO_2$), nitrous oxides ($NO_X$), and mercury (Hg). On an average basis across each $CO_2$ tax level, the portfolio for case 24 has the lowest emissions of $SO_2$. For $NO_X$, the lowest-emitting portfolio was for case 27, while for mercury, the lowest-emitting portfolio was case 14.

**Table 8.26 – Generator Carbon Dioxide Emissions by $CO_2$ Tax Level**

| Case | Emission Types and Units | | | Emission Types and Units | | | Emission Types and Units | | |
|---|---|---|---|---|---|---|---|---|---|
| | SO2 | NOx | Hg | SO2 | NOx | Hg | SO2 | NOx | Hg |
| | 1000 Tons | 1000 Tons | Pounds | 1000 Tons | 1000 Tons | Pounds | 1000 Tons | 1000 Tons | Pounds |
| | $0 CO2 Tax | | | $45 CO2 Tax | | | $100 CO2 Tax | | |
| **1** | 917 | 1,214 | 14,190 | 735 | 979 | 11,665 | 670 | 905 | 10,652 |
| **2** | 922 | 1,207 | 14,149 | 717 | 947 | 11,330 | 647 | 865 | 10,244 |
| **3** | 877 | 1,148 | 13,648 | 653 | 865 | 10,531 | 580 | 776 | 9,440 |
| **5** | 900 | 1,191 | 14,266 | 698 | 933 | 11,591 | 629 | 851 | 10,535 |
| **8** | 883 | 1,171 | 13,719 | 676 | 908 | 10,831 | 606 | 825 | 9,752 |
| **9** | 900 | 1,192 | 14,281 | 699 | 934 | 11,616 | 630 | 853 | 10,564 |
| **10** | 886 | 1,175 | 13,766 | 679 | 912 | 10,898 | 609 | 829 | 9,821 |
| **11** | 869 | 1,142 | 13,473 | 649 | 863 | 10,400 | 577 | 775 | 9,322 |
| **14** | 856 | 1,124 | 13,329 | 630 | 836 | 10,168 | 558 | 746 | 9,089 |
| **17** | 852 | 1,143 | 13,971 | 642 | 865 | 11,356 | 574 | 779 | 10,382 |
| **18** | 859 | 1,151 | 14,086 | 649 | 874 | 11,476 | 580 | 789 | 10,495 |
| **19** | 855 | 1,147 | 14,037 | 646 | 870 | 11,430 | 577 | 784 | 10,458 |
| **20** | 822 | 1,102 | 13,423 | 610 | 824 | 10,831 | 543 | 738 | 9,893 |
| **22** | 825 | 1,095 | 13,426 | 605 | 807 | 10,724 | 537 | 720 | 9,780 |

| Case | Emission Types and Units | | | Emission Types and Units | | | Emission Types and Units | | |
|---|---|---|---|---|---|---|---|---|---|
| | SO2 | NOx | Hg | SO2 | NOx | Hg | SO2 | NOx | Hg |
| | 1000 Tons | 1000 Tons | Pounds | 1000 Tons | 1000 Tons | Pounds | 1000 Tons | 1000 Tons | Pounds |
| | $0 CO2 Tax | | | $45 CO2 Tax | | | $100 CO2 Tax | | |
| 24 | 796 | 1,069 | 13,049 | 586 | 793 | 10,437 | 521 | 709 | 9,526 |
| 25 | 835 | 1,123 | 13,720 | 621 | 841 | 11,070 | 552 | 754 | 10,100 |
| 26 | 805 | 1,081 | 13,181 | 597 | 806 | 10,605 | 532 | 722 | 9,697 |
| 27 | 795 | 1,067 | 12,954 | 588 | 793 | 10,403 | 523 | 710 | 9,507 |
| 29 | 799 | 1,072 | 13,092 | 590 | 792 | 10,462 | 526 | 710 | 9,562 |
| 46 | 917 | 1,202 | 14,091 | 710 | 941 | 11,241 | 639 | 857 | 10,153 |
| 47 | 918 | 1,203 | 14,103 | 712 | 942 | 11,264 | 641 | 858 | 10,177 |

## TOP-PERFORMING PORTFOLIO SELECTION

Chapter 7 outlined the portfolio preference scoring approach for selecting the top portfolios. Preference-scoring grids were prepared for 12 expected value $CO_2$ tax levels, ranging from $15 to $70 at $5 increments. Table 8.27 shows the expected value $CO_2$ tax levels and associated probabilities. Stochastic cost results for the three $CO_2$ tax production cost simulations were weighted with these probabilities. These probability-weighted results are reported in Appendix B, and include risk-adjusted PVRR, customer rate impact, $CO_2$ cost exposure, upper-tail mean PVRR, and standard deviation of production costs. The 12 preference-scoring grids are also reported in Appendix B. A preference-scoring grid sample—for the $45 expected value $CO_2$ tax—is shown as Table 8.28.

**Table 8.27 – Probability Weights for Calculating Expected Value $CO_2$ Tax Levels**

| Expected Value CO2 Tax | Probability (%) | | |
|---|---|---|---|
| | $0/ton | $45/ton | $100/ton |
| $15 | 66 | 34 | 0 |
| $20 | 55 | 45 | 0 |
| $25 | 45 | 55 | 0 |
| $30 | 40 | 55 | 5 |
| $35 | 35 | 55 | 10 |
| $40 | 30 | 55 | 15 |
| $45 | 25 | 55 | 20 |
| $50 | 20 | 55 | 25 |
| $55 | 15 | 55 | 30 |
| $60 | 10 | 55 | 35 |
| $65 | 5 | 55 | 40 |
| $70 | 0 | 55 | 45 |

## Table 8.28 – Measure Rankings and Preference Scores, \$45/ton Expected-value $CO_2$ Tax

| | Cost Measures | | | Risk Measures | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Case | Risk-adjusted PVRR | Rate Impact | Capital Cost | CO2 Cost Exposure | Production Cost Standard Deviation | Ave. Annual Energy Not Served | LOLP, Annual Ave. for July Event > 25 GWh | Weighted Rankings | Normalized Scores (1 to 10) |
| 1 | 2.7 | 2.0 | 1.0 | 2.7 | 10.0 | 10.0 | 10 | 3.6 | 3.2 |
| 2 | 1.6 | 2.1 | 1.3 | 1.6 | 7.2 | 3.9 | 2.1 | 2.1 | 1.2 |
| 3 | 2.8 | 3.2 | 6.7 | 2.8 | 2.8 | 2.0 | 2.1 | 3.0 | 2.4 |
| 5 | 1.3 | 1.1 | 1.6 | 1.3 | 7.6 | 5.2 | 4.6 | 2.0 | 1.0 |
| 8 | 1.0 | 1.4 | 4.3 | 1.0 | 5.8 | 5.1 | 7.6 | 2.0 | 1.1 |
| 9 | 1.5 | 1.0 | 1.8 | 1.5 | 7.6 | 5.9 | 5.8 | 2.2 | 1.3 |
| 10 | 2.1 | 2.1 | 3.8 | 2.1 | 6.2 | 5.5 | 8.9 | 2.9 | 2.2 |
| 11 | 3.3 | 1.4 | 7.1 | 3.3 | 2.7 | 2.2 | 2.9 | 3.0 | 2.4 |
| 14 | 5.3 | 5.1 | 9.7 | 5.3 | 1.8 | 1.4 | 1.3 | 4.9 | 4.9 |
| 17 | 2.2 | 1.5 | 6.6 | 2.2 | 4.5 | 4.2 | 6.6 | 2.7 | 2.0 |
| 18 | 2.3 | 2.5 | 5.4 | 2.3 | 4.9 | 4.4 | 7.8 | 3.0 | 2.4 |
| 19 | 2.8 | 2.6 | 6.4 | 2.8 | 4.7 | 4.4 | 7.1 | 3.3 | 2.8 |
| 20 | 4.9 | 3.4 | 8.0 | 4.9 | 2.1 | 2.1 | 4.3 | 4.4 | 4.3 |
| 22 | 6.9 | 6.7 | 10.0 | 6.9 | 1.1 | 1.0 | 1.0 | 6.1 | 6.6 |
| 24 | 6.8 | 7.8 | 9.6 | 6.8 | 1.2 | 1.1 | 1.5 | 6.3 | 6.9 |
| 25 | 3.8 | 3.3 | 8.0 | 3.8 | 3.1 | 3.1 | 5.1 | 3.9 | 3.6 |
| 26 | 6.8 | 7.4 | 9.6 | 6.8 | 1.6 | 1.5 | 3.4 | 6.4 | 6.9 |
| 27 | 6.8 | 6.2 | 9.6 | 6.8 | 1.1 | 1.3 | 2.6 | 6.1 | 6.5 |
| 29 | 10.0 | 10.0 | 9.7 | 10.0 | 1.0 | 1.0 | 1.7 | 8.7 | 10.0 |
| 46 | 3.7 | 3.2 | 2.7 | 3.7 | 6.9 | 4.8 | 9.0 | 4.1 | 3.8 |
| 47 | 2.4 | 2.4 | 1.5 | 2.4 | 7.1 | 4.5 | 6.9 | 2.9 | 2.3 |

| Importance Weights | 45% | 20% | 5% | 15% | 5% | 5% | 5% |
|---|---|---|---|---|---|---|---|

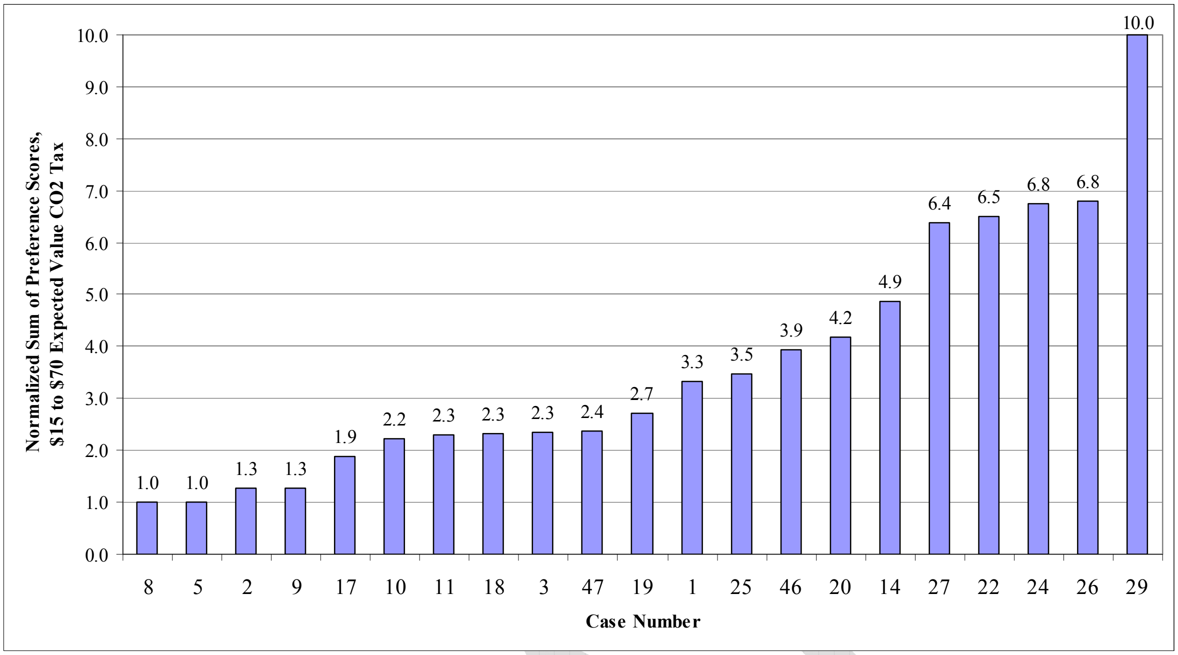
Table 8.29 reports the portfolio preference scores for each of the 12 expected value $CO_2$ tax levels. When summing the normalized preference scores across the expected value $CO_2$ tax levels, the portfolios for cases 5 and 8 have the best scores, followed by cases 9 and 2. (These portfolios are shown highlighted in the table.) These four portfolios were therefore selected as the candidates for preferred portfolio selection.

## Table 8.29 – Portfolio Preference Scores

| | Expected Value CO2 Tax | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Case | \$15 | \$20 | \$25 | \$30 | \$35 | \$40 | \$45 | \$50 | \$55 | \$60 | \$65 | \$70 | Rank Sum | Normalized Score |
| 1 | 2.40 | 2.43 | 2.47 | 2.56 | 2.67 | 2.82 | 3.15 | 3.61 | 4.19 | 4.88 | 5.71 | 6.81 | 43.7 | 3.33 |
| 2 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.19 | 1.50 | 1.93 | 2.43 | 3.03 | 3.96 | 20.0 | 1.26 |
| 3 | 3.14 | 3.07 | 3.00 | 2.86 | 2.69 | 2.49 | 2.41 | 2.39 | 2.44 | 2.49 | 2.56 | 2.90 | 32.4 | 2.35 |
| 5 | 1.63 | 1.53 | 1.43 | 1.31 | 1.17 | 1.01 | 1.00 | 1.09 | 1.27 | 1.49 | 1.76 | 2.37 | 17.0 | 1.00 |
| 8 | 2.21 | 2.06 | 1.92 | 1.72 | 1.48 | 1.21 | 1.07 | 1.00 | 1.00 | 1.00 | 1.02 | 1.35 | 17.0 | 1.00 |
| 9 | 1.83 | 1.74 | 1.64 | 1.53 | 1.40 | 1.25 | 1.25 | 1.35 | 1.54 | 1.77 | 2.06 | 2.67 | 20.0 | 1.26 |
| 10 | 2.98 | 2.86 | 2.75 | 2.61 | 2.45 | 2.28 | 2.23 | 2.26 | 2.36 | 2.47 | 2.63 | 3.07 | 30.9 | 2.22 |
| 11 | 3.51 | 3.39 | 3.27 | 3.07 | 2.85 | 2.56 | 2.38 | 2.25 | 2.17 | 2.09 | 2.01 | 2.20 | 31.8 | 2.29 |
| 14 | 5.46 | 5.42 | 5.38 | 5.27 | 5.15 | 4.99 | 4.91 | 4.88 | 4.88 | 4.88 | 4.89 | 5.08 | 61.2 | 4.86 |
| 17 | 3.69 | 3.49 | 3.29 | 3.01 | 2.68 | 2.30 | 2.01 | 1.75 | 1.53 | 1.28 | 1.00 | 1.00 | 27.0 | 1.87 |
| 18 | 3.81 | 3.64 | 3.46 | 3.23 | 2.96 | 2.64 | 2.43 | 2.25 | 2.12 | 1.96 | 1.80 | 1.90 | 32.2 | 2.33 |
| 19 | 4.18 | 4.02 | 3.85 | 3.62 | 3.35 | 3.04 | 2.82 | 2.64 | 2.49 | 2.33 | 2.15 | 2.22 | 36.7 | 2.72 |
| 20 | 5.93 | 5.75 | 5.56 | 5.30 | 5.00 | 4.64 | 4.32 | 4.02 | 3.71 | 3.37 | 2.99 | 2.81 | 53.4 | 4.18 |
| 22 | 7.24 | 7.18 | 7.11 | 7.00 | 6.87 | 6.70 | 6.58 | 6.47 | 6.37 | 6.26 | 6.14 | 6.13 | 80.1 | 6.51 |
| 24 | 7.91 | 7.79 | 7.67 | 7.51 | 7.31 | 7.08 | 6.87 | 6.65 | 6.43 | 6.17 | 5.87 | 5.67 | 82.9 | 6.76 |
| 25 | 5.15 | 4.97 | 4.79 | 4.54 | 4.24 | 3.89 | 3.60 | 3.33 | 3.08 | 2.79 | 2.47 | 2.37 | 45.2 | 3.46 |
| 26 | 7.80 | 7.69 | 7.58 | 7.43 | 7.26 | 7.06 | 6.89 | 6.72 | 6.55 | 6.35 | 6.12 | 6.00 | 83.5 | 6.81 |
| 27 | 7.72 | 7.58 | 7.44 | 7.25 | 7.02 | 6.75 | 6.50 | 6.24 | 5.97 | 5.67 | 5.32 | 5.10 | 78.6 | 6.38 |
| 29 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 10.00 | 120.0 | 10.00 |
| 46 | 3.01 | 3.07 | 3.14 | 3.24 | 3.35 | 3.49 | 3.80 | 4.22 | 4.75 | 5.38 | 6.13 | 7.13 | 50.7 | 3.94 |
| 47 | 1.91 | 1.93 | 1.95 | 1.97 | 2.01 | 2.05 | 2.27 | 2.60 | 3.06 | 3.58 | 4.22 | 5.15 | 32.7 | 2.37 |

Figure 8.24 shows the portfolio preference scores from Table 8.36 sorted from best to worst.

**Figure 8.24 – Portfolio Preference Scores, sorted from Best to Worst**




## Sensitivity of Portfolio Preference Rankings to Measure Importance Weights

To test the sensitivity of the preference scores to changes in measure importance weights—particularly for the top-performing portfolios—PacifiCorp constructed a preference-scoring grid for the expected value \$45 $CO_2$ tax level with an alternate set of weights. The alternate weights reflect a combination of comments and recommendations made by participants at PacifiCorp's February 2, 2009 public meeting, and place more importance on risk-adjusted PVRR and $CO_2$ cost risk, but none on capital costs. These alternative weights are shown in Table 8.30.

**Table 8.30 – Alternate Measure Importance Weights**

| Measures | Weight |
|---|---|
| **Cost** | |
| Risk-adjusted PVRR | 50% |
| Customer Rate Impact | 10% |
| Capital Cost for 2009-2018 | 0% |
| **Risk** | |
| $CO_2$ Cost Exposure | 25% |
| Production Cost Standard Deviation | 5% |
| Average annual ENS | 5% |
| Average Annual Probability of ENS events for July exceeding 25 GWh | 5% |

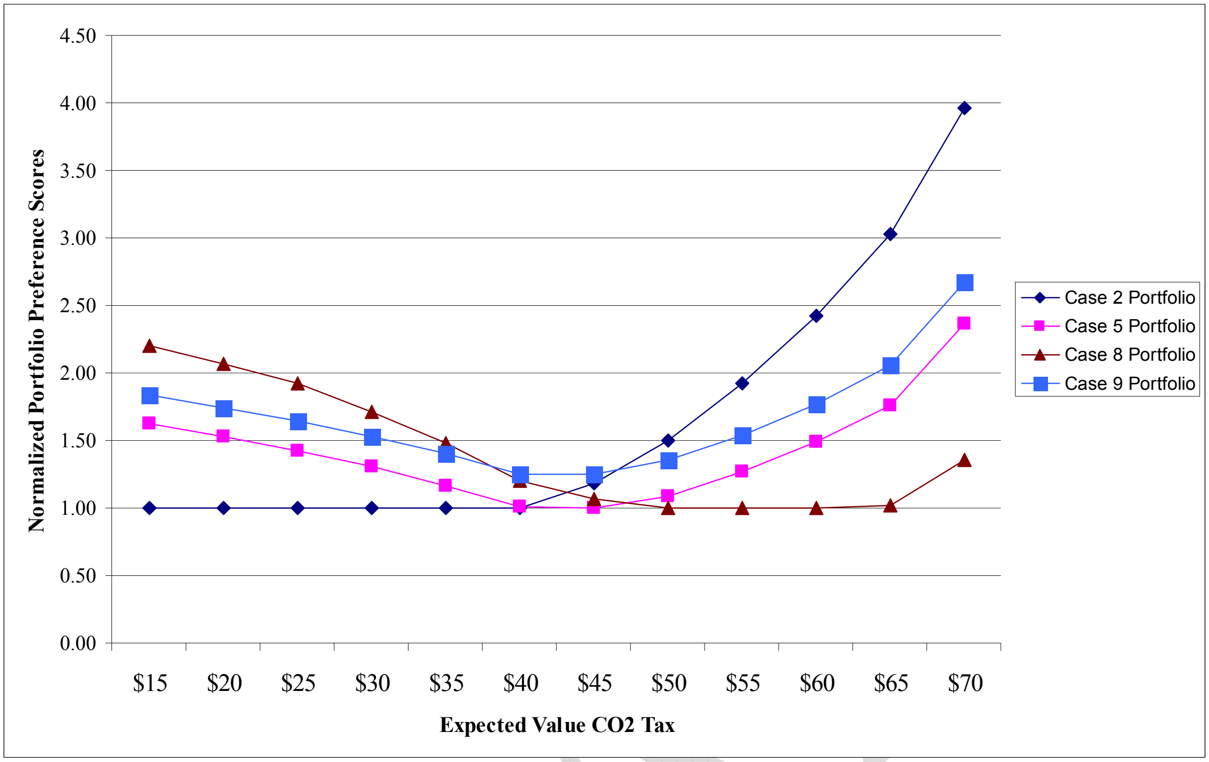
The resulting measure rankings and preference scores based on these alternate weightings are reported in Table 8.31. The alternate weights result in changes to scores of no more than two-tenths of a point. The score for case 8 registers a slight improvement relative to the score for case 5, resulting in a switch in ranking. However, portfolios 8, 5, 2, and 9 remain the top ranked under both weighting schemes. Based on this result, PacifiCorp concludes that the top-performing portfolios are robust choices given variations in the measure weighting schemes.

### Table 8.31 – Measure Rankings and Preference Scores with Alternative Measure Importance Weights, $45/ton Expected-value $CO_2$ Tax

| | Cost Measures | | | Risk Measures | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Case | Risk-adjusted PVRR | Rate Impact | Capital Cost | CO2 Cost Exposure | Production Cost Standard Deviation | Ave. Annual Energy Not Served | LOLP, Annual Ave. for July Event > 25 GWh | Weighted Rankings | Normalized Scores (1 to 10) |
| 1 | 2.7 | 2.0 | 1.0 | 2.7 | 10.0 | 10.0 | 10 | 3.7 | 3.5 |
| 2 | 1.6 | 2.1 | 1.3 | 1.6 | 7.2 | 3.9 | 2.1 | 2.1 | 1.3 |
| 3 | 2.8 | 3.2 | 6.7 | 2.8 | 2.8 | 2.0 | 2.1 | 2.8 | 2.3 |
| 5 | 1.3 | 1.1 | 1.6 | 1.3 | 7.6 | 5.2 | 4.6 | 2.0 | 1.2 |
| 8 | 1.0 | 1.4 | 4.3 | 1.0 | 5.8 | 5.1 | 7.6 | 1.8 | 1.0 |
| 9 | 1.5 | 1.0 | 1.8 | 1.5 | 7.6 | 5.9 | 5.8 | 2.2 | 1.5 |
| 10 | 2.1 | 2.1 | 3.8 | 2.1 | 6.2 | 5.5 | 8.9 | 2.8 | 2.3 |
| 11 | 3.3 | 1.4 | 7.1 | 3.3 | 2.7 | 2.2 | 2.9 | 3.0 | 2.5 |
| 14 | 5.3 | 5.1 | 9.7 | 5.3 | 1.8 | 1.4 | 1.3 | 4.7 | 4.8 |
| 17 | 2.2 | 1.5 | 6.6 | 2.2 | 4.5 | 4.2 | 6.6 | 2.6 | 2.0 |
| 18 | 2.3 | 2.5 | 5.4 | 2.3 | 4.9 | 4.4 | 7.8 | 2.9 | 2.4 |
| 19 | 2.8 | 2.6 | 6.4 | 2.8 | 4.7 | 4.4 | 7.1 | 3.2 | 2.8 |
| 20 | 4.9 | 3.4 | 8.0 | 4.9 | 2.1 | 2.1 | 4.3 | 4.4 | 4.4 |
| 22 | 6.9 | 6.7 | 10.0 | 6.9 | 1.1 | 1.0 | 1.0 | 6.0 | 6.5 |
| 24 | 6.8 | 7.8 | 9.6 | 6.8 | 1.2 | 1.1 | 1.5 | 6.1 | 6.6 |
| 25 | 3.8 | 3.3 | 8.0 | 3.8 | 3.1 | 3.1 | 5.1 | 3.8 | 3.5 |
| 26 | 6.8 | 7.4 | 9.6 | 6.8 | 1.6 | 1.5 | 3.4 | 6.2 | 6.7 |
| 27 | 6.8 | 6.2 | 9.6 | 6.8 | 1.1 | 1.3 | 2.6 | 6.0 | 6.4 |
| 29 | 10.0 | 10.0 | 9.7 | 10.0 | 1.0 | 1.0 | 1.7 | 8.7 | 10.0 |
| 46 | 3.7 | 3.2 | 2.7 | 3.7 | 6.9 | 4.8 | 9.0 | 4.2 | 4.1 |
| 47 | 2.4 | 2.4 | 1.5 | 2.4 | 7.1 | 4.5 | 6.9 | 3.0 | 2.5 |
| Importance Weights | 50% | 10% | 0% | 25% | 5% | 5% | 5% | | |

As indicated above, the portfolios developed under cases 2, 5, 8, and 9 performed the best according to the final preference scores. For selecting the preferred portfolio, of interest is how the preference scores for these portfolios vary across the $CO_2$ tax levels. Figure 8.25 shows the scores at each expected value $CO_2$ tax level. The case 2 portfolio scores the best with tax levels below $40, while the case 8 portfolio scores the best with tax levels at $50 and above. Case 5 appears to represent the "least-regrets" portfolio with respect to the range of preference scores, avoiding the highest scores like the case 2 and 8 portfolios, and always dominating the case 9 portfolio.

**Figure 8.25 – Preference Scores by Expected Value $CO_2$ Tax, Top-performing Portfolios**




Based on the preference scores and the analysis above, PacifiCorp dropped cases 2 and 9 from further consideration as the preferred portfolio. A discussion of the comparative advantages, disadvantages, and risks for the two remaining portfolios is provided below.

**Case 5 versus Case 8 Portfolio Assessment**

Both case 5 and case 8 are equally strong contenders to be the preferred portfolio. The main difference between the two portfolios is that case 8 includes 1,150 MW more wind in the first 10 years (600 MW more overall), and lacks a gas peaking resource in 2016. Case 5 also includes more east-side front office transactions in the first 10 years than case 8.

The assumed $CO_2$ cost is the key determinant for overall portfolio performance: case 8 out-performs case 5 with $CO_2$ taxes at $45 and above, but the reverse is true with $CO_2$ taxes below $45. Noteworthy is that case 5 out-performs case 8 on customer rate impact for all $CO_2$ tax levels.

In terms of relative advantages independent of the operational cost impact of a $CO_2$ price, case 5 has a smaller capital cost (by $2.2 billion), as well as a lower probability of a major ENS event during the system peak month. In contrast, case 8 has a lower upper-tail cost and upper-tail ENS, reflecting the variable operating cost savings benefits of the additional wind and its selected location in load areas that exhibit relatively higher ENS.

A disadvantage for case 8 is the amount of wind investment in the first 10 years, which reaches 2,600 MW. The average annual capacity added for 2012 through 2018 exceeds 300 MW, which is a concern from procurement, rate impact, construction project management, and operational perspectives. This wind is not needed for RPS compliance purposes, and its economic desirability hinges on continuation of a production tax credit (or comparable financial incentive), a significant $CO_2$ cost penalty benefiting clean energy alternatives, and a robust market for sales of excess energy, particularly during off-peak hours. On the other hand, the incremental wind provides added price hedge benefits due to the lack of fuel costs and exposure to future $CO_2$ compliance costs. The respective wind expansion patterns for cases 5 and 8 suggest that the optimal wind strategy is to identify a wind capacity floor and upper value that are updated as aspects of future federal $CO_2$ compliance cost and renewable energy policies becomes clearer. This strategy takes advantage of the relatively short development lead-time and modular construction of wind resources. PacifiCorp's action plan discusses this wind strategy in more detail.

Both portfolios have heavier reliance on market purchases relative to most other portfolios, which increases the risk of a high-end cost outcome. Case 8 does better than case 5, due to more renewable resources and east-side Class 2 DSM, but both appear in the bottom quartile of ranking results for upper-tail risk measures. This higher tail risk must be evaluated in the context of the timing of when the tail risk is most pronounced, and other risks that these portfolios help mitigate. For example, Table 8.32 compares the 95$^{th}$ percentile PVRRs for the case 5, 8 and 22 portfolios given a 10-year span (2009-2018) and 20-year span (2009-2028). The case 22 portfolio ranks at the top for upper-tail mean PVRR.

**Table 8.32 – Short- and Long-term 95$^{th}$ Percentile PVRR Comparisons**

| Case | 95th Percentile, Million $ $45/ton CO2 Tax | |
|---|---|---|
| | 10-Year 2009-2018 | 20-Year 2009-2028 |
| **5** | 24,832 | 59,619 |
| **8** | 23,952 | 57,877 |
| **22** | 24,453 | 57,320 |
| | | |
| Case 5 less 22 | 379 | 2,299 |
| Case 8 less 22 | (501) | 558 |

As the comparison shows, differences in upper-tail mean PVRR are significantly lower under the 10-year view. Case 8 actually performs better than case 22, owing primarily to the high capital costs associated with a pulverized coal plant and 4,500 MW of wind included in case 22. The portfolios that do well on the 20-year upper-tail cost measures rely on large amounts of wind resources, as well as base-load resources such as conventional pulverized coal and nuclear in the out-years—resources with their own significant risks. This comparison again illustrates the tradeoff between expected costs and high-end cost risk.

As emphasized in PacifiCorp's 2007 IRP, PacifiCorp believes that firm market purchases benefit the preferred portfolio by increasing planning flexibility and resource diversity at a time of considerable regulatory uncertainty. The current economic recession, coupled with the company's need for grid infrastructure and clean air investments, magnifies the importance of such flexibility for maintaining affordable customer rates. Nevertheless, PacifiCorp recognizes the risks associated with market reliance, and has in place a price hedging strategy to mitigate these risks. A description of PacifiCorp's price hedging strategy is provided in Chapter 9.

Regarding fuel source diversity, the case 8 portfolio has a greater proportion of renewable generation—and generation reduction in the case of Class 2 DSM—than for case 5, particularly in the near term. On the other hand, case 5 has a greater share of gas generation, and for the first 10 years, more reliance on generation from market purchases. By 2028, the generation mix for the two portfolios look similar. The significant difference is that case 5 includes a clean coal resource in 2025, while case 8 depends on much earlier wind investment to meet $CO_2$ and RPS compliance requirements.

## Scenario Risk Assessment

### Risk Scenario Development

In accordance with the Public Service Commission of Utah's acknowledgement order for PacifiCorp's last IRP, the company followed the Commission's instruction to "examine the cost consequences of the superior portfolios with respect to uncertainty by subjecting them to evaluation under the initial set of relatively broad input assumptions".[46] PacifiCorp selected the three top-performing portfolios—cases 5, 8, and 9—for this analysis (Case 2 had a. were fixed in the System Optimizer capacity expansion model. The model was then executed to solve for the deterministic PVRR under each selected input scenario. The input scenarios consisted of the following case assumptions:

- Medium load growth forecast
- June 2008 forward price curves and high/low variations
- Varying $CO_2$ tax levels: \$0, \$45, \$70, and \$100

The resulting ten risk scenarios, along with the represented cases, are listed in Table 8.33. A total of 30 deterministic PVRRs therefore represent the outcome of the scenario risk modeling.

**Table 8.33 – Scenario Risk Case Definitions**

| Risk Scenario Number | Case Number | $CO_2$ tax (\$/ton) | Gas Price Forecast | Load Growth Scenario |
|---|---|---|---|---|
| 1 | 1 | \$0 | Low | Medium |
| 2 | 2 | \$0 | Medium | Medium |
| 3 | 3 | \$0 | High | Medium |
| 4 | 5 | \$45 | Low | Medium |
| 5 | 8 | \$45 | Medium | Medium |
| 6 | 14 | \$45 | High | Medium |
| 7 | 17 | \$70 | Medium | Medium |
| 8 | 22 | \$70 | High | Medium |

[46] Public Service Commission of Utah, Report and Order, In the Matter of the PacifiCorp 2006 Integrated Resource Plan, Docket No. 07-2035-01, February 6, 2008, p. 40.

| Risk Scenario Number | Case Number | $CO_2$ tax ($/ton) | Gas Price Forecast | Load Growth Scenario |
|---|---|---|---|---|
| 9 | 24 | $100 | Medium | Medium |
| 10 | 29 | $100 | High | Medium |

The analysis did not include alternative load growth scenarios because the portfolios were developed with the same load growth forecast. Therefore, applying alternative load forecasts would have no value for cost comparison purposes. The selection of only the June 2008 price forecast assumptions reflects a practical decision to help limit the number of additional model runs to a manageable number.

**Risk Scenario Modeling Results**

Table 8.34 shows the deterministic PVRR results for the 30 System Optimizer runs, along with the PVRR average and the standard deviation for each portfolio across the risk scenarios. The portfolio for case 8 has both the lowest PVRR and the smallest PVRR variability across the risk scenarios. The case 8 and 5 portfolios are nearly equal with respect to both PVRR average and standard deviation, owing to the similarity of the portfolios.

**Table 8.34 – Scenario Risk PVRR Results**

| Risk Scenario Number | Case | Deterministic PVRR (Million 2008$) | | |
|---|---|---|---|---|
| | | Portfolio Case 5 | Portfolio Case 8 | Portfolio Case 9 |
| 1 | 1 | 21,025 | 21,972 | 21,048 |
| 2 | 2 | 22,176 | 22,305 | 22,188 |
| 3 | 3 | 22,550 | 21,288 | 22,481 |
| 4 | 5 | 40,542 | 40,730 | 40,542 |
| 5 | 8 | 41,691 | 41,389 | 41,672 |
| 6 | 14 | 44,243 | 42,430 | 44,146 |
| 7 | 17 | 52,533 | 51,782 | 52,489 |
| 8 | 22 | 55,159 | 53,144 | 55,049 |
| 9 | 24 | 64,853 | 63,379 | 64,768 |
| 10 | 29 | 65,123 | 62,913 | 64,915 |
| **Average** | | 42,990 | 42,133 | 42,930 |
| **Standard Deviation** | | 15,968 | 15,278 | 15,920 |

Table 8.35 reports the portfolio PVRR rankings for each risk scenario. Case 8 ranks first on the basis of having the lowest rank sum (16). Case 9 comes in second with a rank sum of 19, followed by case 5 with a rank sum of 24.

**Table 8.35 – Portfolio PVRR Rankings**

| Risk Scenario Number | Case | Portfolio Rankings based on Deterministic PVRR | | |
|---|---|---|---|---|
| | | Portfolio Case 5 | Portfolio Case 8 | Portfolio Case 9 |
| 1 | 1 | 1 | 3 | 2 |

| Risk Scenario Number | Case | Portfolio Rankings based on Deterministic PVRR | | |
|---|---|---|---|---|
| | | Portfolio Case 5 | Portfolio Case 8 | Portfolio Case 9 |
| 2 | 2 | 1 | 3 | 2 |
| 3 | 3 | 3 | 1 | 2 |
| 4 | 5 | 1 | 3 | 1 |
| 5 | 8 | 3 | 1 | 2 |
| 6 | 14 | 3 | 1 | 2 |
| 7 | 17 | 3 | 1 | 2 |
| 8 | 22 | 3 | 1 | 2 |
| 9 | 24 | 3 | 1 | 2 |
| 10 | 29 | 3 | 1 | 2 |
| **Rank Sum** | | 24 | 16 | 19 |

Table 8.36 shows differences between the original deterministic PVRR and those obtained for the risk scenario runs.[47]

**Table 8.36 – PVRR Differences, Portfolio Development Case less Risk Scenario Results**

| Risk Scenario Number | Case | Deterministic PVRR (Million 2008$) | | |
|---|---|---|---|---|
| | | Portfolio Case 5 | Portfolio Case 8 | Portfolio Case 9 |
| Original PVRR | | 40,526 | 41,372 | 40,204 |
| 1 | 1 | (19,501) | (19,400) | (19,156) |
| 2 | 2 | (18,350) | (19,067) | (18,016) |
| 3 | 3 | (17,976) | (20,084) | (17,723) |
| 4 | 5 | 16 | (642) | 338 |
| 5 | 8 | 1,165 | 17 | 1,468 |
| 6 | 14 | 3,717 | 1,058 | 3,942 |
| 7 | 17 | 12,007 | 10,410 | 12,285 |
| 8 | 22 | 14,633 | 11,772 | 14,845 |
| 9 | 24 | 24,327 | 22,007 | 24,564 |
| 10 | 29 | 24,597 | 21,541 | 24,711 |

These results indicate that Portfolio 5 performed best in low gas/low $CO_2$ tax scenarios and performed worst in high gas price and high $CO_2$ tax cases. Portfolio 8 performed best under the medium/high gas price and medium/high $CO_2$ tax scenarios, but performed worst in low gas/low $CO_2$ scenarios.

**Conclusions**

The scenario risk assessment yielded findings similar to the stochastic mean cost analysis regarding the top-performing portfolio, case 8. However, case 9 performed slightly ahead of case 5 in the scenario risk analysis, whereas case 5 performed ahead of case 9 under the stochastic mean

[47] Fixing of resources in System Optimizer for the risk scenario runs entailed rounding capacity values of the smaller resources, such as class 2 DSM amounts by topology bubble, price tier, and year. The result was a small PVRR difference with respect to the PVRR obtained in the original portfolio development run.

cost analysis. Given this outcome, the question is whether the risk scenario analysis, as formulated above, provides any added value for preferred portfolio selection over that provided by the stochastic analysis. PacifiCorp concludes that it does not. The reasons are as follows. First, the stochastic Monte Carlo simulations provide 100 combinations of input invariables, accounting for variable correlations. The scenario risk assessment is essentially a manually formulated and limited version of the Monte Carlo simulation. It is impractical to emulate this range of input variability using System Optimizer or the Planning and Risk model in deterministic mode.

Second, the scenario risk assessment introduces a confounding aspect to the preferred portfolio selection process given the situation where the analysis yields performance conclusions contradictory to those obtained from the stochastic analysis—such as with the case 5 and 9 portfolios.

In summary, PacifiCorp believes that the stochastic risk analysis is sufficient for exploring portfolio cost outcomes given a range of input assumptions reflecting uncertainty and risk. The only value that the scenario risk assessment provides is to confirm the degree that stochastic and deterministic costs are consistent for portfolio ranking purposes. On the other hand, the company finds value with subjecting a portfolio to resource-specific scenarios as part of the acquisition path analysis, and using System Optimizer to determine the optimal resource mix under those alternate resource assumptions.

## PORTFOLIO IMPACT OF THE 2012 GAS RESOURCE DEFERRAL DECISION

Based on the portfolio preference scores and consideration of relative resource risks, the company would have chosen the case 5 portfolio as the basis for its preferred portfolio. However, due to the company's February 2009 decision to terminate the construction contract for the Lake Side 2 CCCT resource, PacifiCorp conducted additional portfolio analysis to determine a revised preferred portfolio that takes this decision into account, as well as new transmission and market assumptions that supported that decision.

PacifiCorp conducted two types of portfolio studies reflecting the removal of Lake Side 2 as a planned resource in 2012. The first type involved fixing a combined-cycle gas plant in 2014 and running System Optimizer to select other resources using the case 5 input assumptions. Two portfolios were created: one had a 570 MW (July capacity) wet-cooled CCCT located at the Lake Side site in Utah North, while the second had a 536 MW dry-cooled CCCT located in the Currant Creek site. This was followed by stochastic production cost modeling runs using the PaR model with \$0, \$45, and \$100 $CO_2$ tax levels. These two portfolios reflect a CCCT deferral strategy that assumes, conservatively, that CCCT capital costs do not change from the generic values assumed for the 2008 IRP, after adjusting for inflation.[48] The rationale for fixing CCCTs in System Optimizer is that this model does not account for resource optionality and reserve holding value captured through stochastic production cost modeling, and tends to favor SCCTs over CCCTs for meeting capacity planning reserve margins as a result.

[48] PacifiCorp expects that lower commodity costs and the effects of the world-wide economic downturn should eventually start to impact plant construction prices. However, the Company did not see price reductions in the bids received in response to its 2008 All-Source RFP issued in October 2008.

The second portfolio study type consisted of the removal of the Lake Side 2 plant in the top eight portfolios selected on the basis of the preference scores (Table 8.36), and having System Optimizer select the portfolios to fill the resource gap using the case definitions associated with these portfolios. Stochastic production cost simulations with multiple $CO_2$ tax levels were also conducted for these 10 portfolios.

The portfolios modeled without Lake Side 2 reflect a number of assumption changes documented in Chapters 6 and 7. Table 8.37 profiles the 10 portfolios and the associated input assumptions.

**Table 8.37 – Additional Portfolios Modeled to Support a 2012 Gas Resource Deferral Strategy**

<table>
<tr><th>Portfolio Name</th><th>Case Definition Used</th><th>Additional Fixed Resources</th><th>Common Assumption Changes</th></tr>
<tr><td>2B</td><td>2</td><td>None</td><td rowspan="10">• Lake Side 2 CCCT removed as a planned resource<br>• West Main/West Main to Yakima topology updates (See Figure 7.2)<br>• Mona to Utah South topology update (See Figure 7.2)<br>• Mid-Columbia market depth updates for 2012 and 2013 (See Table 6.22)<br>• Mona market depth updates for 2012 and 2013, including Nevada Utah Border (See Table 6.22)</td></tr>
<tr><td>5B</td><td>5</td><td>None</td></tr>
<tr><td>5B_CCCT_Dry</td><td>5</td><td>Dry-cooled CCCT fixed in 2014</td></tr>
<tr><td>5B_CCCT_Wet</td><td>5</td><td>Wet-cooled CCCT fixed in 2014</td></tr>
<tr><td>8B</td><td>8</td><td>None</td></tr>
<tr><td>9B</td><td>9</td><td>None</td></tr>
<tr><td>10B</td><td>10</td><td>None</td></tr>
<tr><td>17B</td><td>17</td><td>None</td></tr>
<tr><td>18B</td><td>18</td><td>None</td></tr>
<tr><td>47B</td><td>47</td><td>None</td></tr>
</table>

PacifiCorp developed a full set of performance measures for these portfolios and ranked them using the same preference-scoring scheme applied for the original 21 portfolios. These additional portfolios are shown in Appendix A. The stochastic performance measures are reported in Appendix B.

Table 8.38 compares the cumulative nameplate capacities by major resource type for the original and "B series" portfolios. The B series portfolios include more front office transaction and energy efficiency program capacity than their original portfolio counterparts, and—with the exception of the two fixed CCCT portfolios (5B_CCCT_Dry and 5B_CCCT_Dry)—include more IC Aero SCCT capacity. On the other hand, just four of the 10 portfolios include more wind capacity (2B, 10B, 17B, and 47B), while two portfolios have less wind than the original portfolios (8B and 18B). Portfolio tables showing the resource capacity differences between the ten B series portfolios and the corresponding originals are included in Appendix A.

**Table 8.38 – Resource Capacity Comparisons, Original and B Series Portfolios**

| Case | Cumulative Nameplate Capacity for 2009-2028 (MW) by Resource Type | | | | | | |
|---|---|---|---|---|---|---|---|
| | Wind | CCCT | IC Aero SCCT | FOT [1/] | DSM, Class 2 | Dist Gen [2/] | Clean Coal Retrofit |
| **2** | 1,204 | 607 | 261 | 646 | 1,815 | 50 | 0 |
| **2B** | 1,863 | 0 | 548 | 775 | 1,866 | 92 | 0 |
| **5** | 1,863 | 607 | 261 | 691 | 1,835 | 50 | 346 |
| **5B** | 1,863 | 0 | 391 | 829 | 1,896 | 132 | 0 |
| **5B_CCCT_Dry** | 1,863 | 536 | 261 | 821 | 1,839 | 78 | 346 |
| **5B_CCCT_Wet** | 1,863 | 570 | 261 | 820 | 1,838 | 50 | 346 |
| **8** | 2,663 | 607 | 0 | 663 | 1,942 | 88 | 0 |
| **8B** | 2,563 | 0 | 261 | 811 | 1,989 | 129 | 0 |
| **9** | 1,863 | 607 | 261 | 690 | 1,834 | 50 | 346 |
| **9B** | 1,863 | 0 | 391 | 829 | 1,893 | 132 | 0 |
| **10** | 2,863 | 607 | 0 | 679 | 1,936 | 57 | 0 |
| **10B** | 2,952 | 0 | 261 | 820 | 1,985 | 127 | 0 |
| **17** | 4,163 | 607 | 0 | 613 | 2,020 | 50 | 346 |
| **17B** | 4,363 | 0 | 261 | 796 | 2,063 | 127 | 346 |
| **18** | 4,163 | 607 | 0 | 640 | 1,974 | 50 | 346 |
| **18B** | 3,863 | 0 | 261 | 808 | 2,023 | 127 | 346 |
| **47** | 1,607 | 607 | 174 | 646 | 1,822 | 92 | 0 |
| **47B** | 2,383 | 0 | 609 | 797 | 1,855 | 92 | 0 |

[1/] Annual average front office transactions capacity for 2009-2018 shown.

[2/] Distributed generation consists of customer standby generation and combined heat and power facilities.

General findings for this additional portfolio analysis are as follows.

- The combination of revised input assumptions and deferral of a 2012 gas resource resulted in lower PVRRs compared with those reported for the original portfolios. For example, as shown in Table 8.39, the stochastic mean PVRR of portfolio 5B (averaged across the three $CO_2$ tax simulations) is \$570 million less than the PVRR for the original case 5 portfolio.[49]

- The portfolio with a wet-cooled CCCT located at the Lake Side 2 site ("5B_CCCT Wet") had the lowest risk-adjusted PVRR, $CO_2$ cost exposure, and rate impact (Table 8.40). The other two case 5 portfolios ranked second and third.

- The wet-cooled CCCT deferral portfolio also had the best overall preference score, ranking at the top for expected value $CO_2$ tax levels of \$20 through \$60. Table 8.41 presents the portfolio preference scores for $CO_2$ tax expected values from \$15 to \$70.

[49] The PVRRs for the original case 5 portfolio reported in Table 8.41 are adjusted to include 2012 CCCT capital costs for comparability with the gas resource deferral portfolios. Because the Lake Side 2 CCCT was treated as an existing resource in all the original portfolios, associated capital costs were not included in the PVRR calculations.

- The three portfolios developed with the case 5 input assumptions had the highest preference scores (Table 8.41). This portfolio analysis strengthens the assertion that case 5 is relatively robust at producing the optimal portfolios on the basis of overall preference scoring.

- Fixing a CCCT in 2014 rather than allowing System Optimizer to fully optimize resource selection resulted in improved stochastic costs. For example, fixing a wet-cooled CCCT in 2014 yielded a $115 million improvement in risk-adjusted PVRR (averaged across the $0, $45, and $100 $CO_2$ tax simulations) relative to portfolio 5B, which has no CCCT. Fixing a dry-cooled CCCT in 2014 resulted in a $51 million risk-adjusted PVRR improvement.

- The tail risk (upper-tail mean PVRR) for seven of the B series portfolios—2B, 5, 5B_CCCT_Dry, 5B_CCCT_Wet, 9, 17, and 47—is lower than that for the original portfolio counterparts. This is due to more wind, DSM, and distributed generation in these new portfolios. The two CCCT deferral portfolios had the highest upper-tail risk and production cost standard deviation. Figure 8.26 is a scatter-plot graph of the stochastic mean PVRR versus upper-tail mean PVRR for the three $CO_2$ tax levels.

**Table 8.39 – Stochastic Mean PVRR for 2012 Gas Resource Deferral Strategy Portfolios**

| Case | CO2 Tax Level | | | Average | Rank |
|---|---|---|---|---|---|
| | $0/Ton | $45/Ton | $100/Ton | | |
| **2B** | 22,126 | 40,062 | 60,448 | 40,879 | 8 |
| **5B** | 22,554 | 39,452 | 58,664 | 40,224 | 3 |
| **5B_CCCT_Dry** | 22,462 | 39,369 | 58,751 | 40,194 | 2 |
| **5B_CCCT_Wet** | 22,457 | 39,315 | 58,639 | 40,137 | 1 |
| **8B** | 23,402 | 39,673 | 57,809 | 40,295 | 4 |
| **9B** | 22,778 | 39,725 | 59,031 | 40,511 | 5 |
| **10B** | 23,921 | 40,261 | 58,542 | 40,908 | 8 |
| **17B** | 25,569 | 40,539 | 56,798 | 40,968 | 9 |
| **18B** | 25,102 | 40,353 | 57,136 | 40,864 | 6 |
| **47B** | 22,658 | 40,507 | 60,872 | 41,346 | 10 |
| **5** 1/ | 23,075 | 39,947 | 59,358 | 40,794 | |

1/ The PVRRs for the original case 5 portfolio are adjusted to include 2012 CCCT capital costs for comparability with the gas resource deferral portfolios.

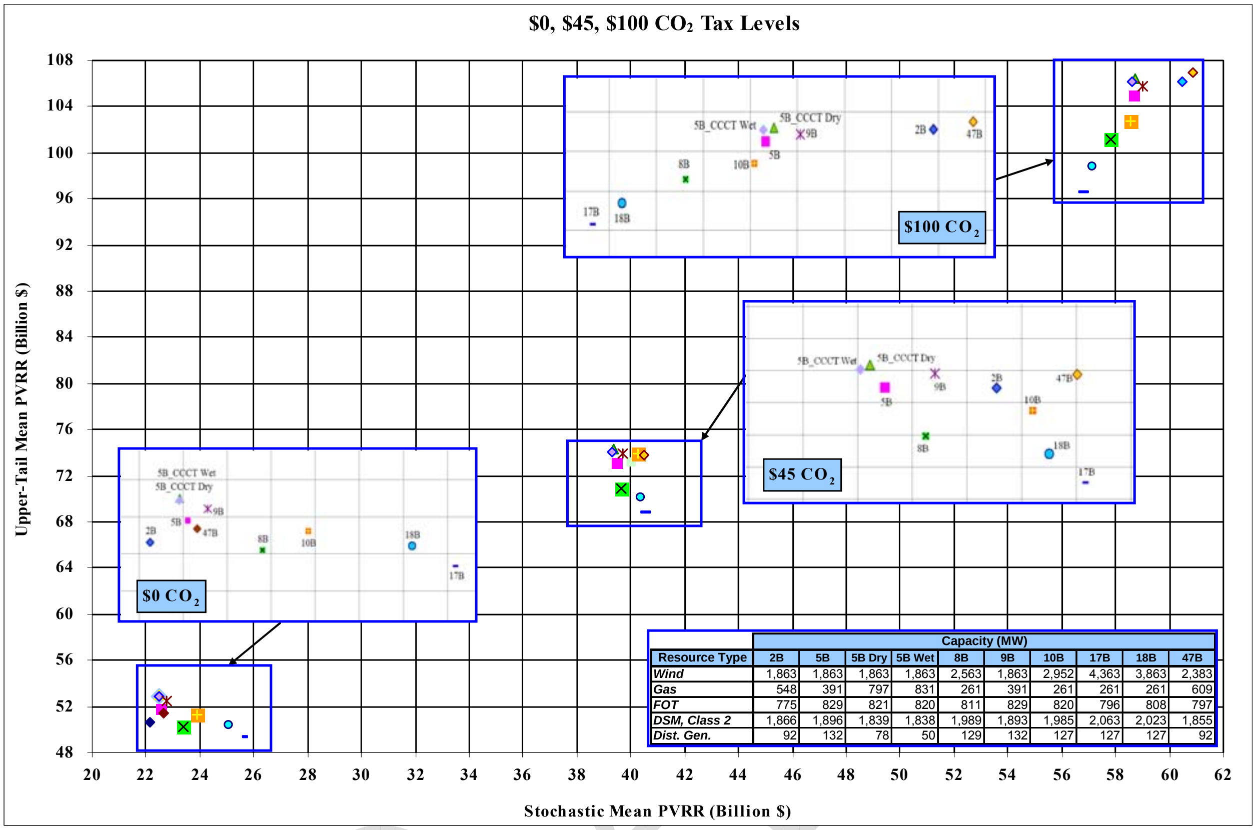
## Table 8.40 – Measure Rankings and Preference Scores for 2012 Gas Resource Deferral Strategy Portfolios, \$45/ton Expected-value $CO_2$ Tax

| | Cost Measures | | | | Risk Measures | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Case | Risk-adjusted PVRR | Rate Impact | Minimum Cost Exposure for CO2 Tax | Capital Cost | Upper-Tail Mean PVRR | Production Cost Standard Deviation | Ave. Annual Energy Not Served | LOLP, Annual Average for July Event > 25 GWh | Weighted Rankings | Normalized Scores (1 to 10) |
| 2B | 6.7 | 8.9 | 6.0 | 1.0 | 8.2 | 8.0 | 1.2 | 1 | **6.0** | **6.8** |
| 5B | 2.2 | 2.8 | 3.0 | 3.0 | 8.2 | 8.5 | 7.5 | 6.3 | **3.2** | **2.9** |
| 5B_CCCT Dry | 1.5 | 1.6 | 2.0 | 1.5 | 10.0 | 10.0 | 4.8 | 4.9 | **2.3** | **1.7** |
| 5B_CCCT Wet | 1.0 | 1.0 | 1.0 | 1.5 | 9.6 | 9.7 | 4.6 | 4.7 | **1.8** | **1.0** |
| 8B | 3.6 | 5.1 | 4.0 | 6.4 | 4.6 | 5.2 | 4.9 | 4.5 | **4.1** | **4.2** |
| 9B | 4.3 | 2.4 | 5.0 | 3.2 | 9.4 | 9.0 | 10.0 | 10.0 | **4.6** | **4.9** |
| 10B | 8.2 | 10.0 | 7.0 | 5.7 | 6.6 | 5.9 | 5.3 | 6.8 | **7.6** | **9.0** |
| 17B | 9.7 | 9.3 | 9.0 | 10.0 | 1.0 | 1.0 | 1.1 | 2.2 | **7.8** | **9.3** |
| 18B | 8.5 | 8.3 | 8.0 | 8.2 | 3.2 | 2.9 | 3.3 | 2.2 | **7.1** | **8.4** |
| 47B | 10.0 | 9.2 | 10.0 | 1.2 | 9.3 | 8.3 | 1.0 | 7.4 | **8.3** | **10.0** |
| **Importance Weights** | **40%** | **20%** | **15%** | **5%** | **5%** | **5%** | **5%** | **5%** | | |

## Table 8.41 – Measure Rankings and Preference Scores for 2012 Gas Resource Deferral Strategy Portfolios

| | Expected Value CO2 Tax | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Case | 15 | 20 | 25 | 30 | 35 | 40 | 45 | 50 | 55 | 60 | 65 | 70 | Rank Sum | Normalized Score |
| 2B | 1.2 | 1.8 | 2.3 | 2.9 | 4.2 | 5.4 | 6.7 | 7.6 | 7.8 | 7.9 | 8.0 | 8.3 | 63.9 | 6.8 |
| 5B | 2.2 | 2.1 | 2.2 | 2.3 | 2.4 | 2.6 | 2.8 | 2.8 | 2.9 | 2.8 | 3.2 | 3.9 | 32.2 | 3.2 |
| 5B_CCCT Dry | 1.3 | 1.3 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.7 | 1.6 | 1.7 | 2.1 | 2.9 | 20.1 | 1.8 |
| 5B_CCCT Wet | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 2.3 | 13.3 | 1.0 |
| 8B | 4.5 | 4.6 | 4.4 | 4.4 | 4.3 | 4.1 | 4.0 | 3.4 | 2.7 | 1.7 | 1.3 | 2.1 | 41.7 | 4.3 |
| 9B | 3.3 | 3.4 | 3.5 | 3.7 | 3.8 | 4.4 | 4.8 | 4.6 | 4.5 | 4.8 | 4.7 | 5.3 | 50.8 | 5.3 |
| 10B | 6.6 | 6.8 | 7.1 | 7.4 | 7.9 | 8.4 | 8.9 | 8.2 | 7.4 | 6.7 | 6.2 | 6.2 | 87.8 | 9.6 |
| 17B | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 9.3 | 6.9 | 5.1 | 3.1 | 1.5 | 1.0 | 86.9 | 9.5 |
| 18B | 8.9 | 8.9 | 8.9 | 8.9 | 8.9 | 9.0 | 8.4 | 6.2 | 4.8 | 3.4 | 1.9 | 1.7 | 79.8 | 8.7 |
| 47B | 3.3 | 3.8 | 4.5 | 5.3 | 6.4 | 8.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 91.4 | 10.0 |

**Figure 8.26 - Stochastic Cost versus Upper-tail Risk: \$0, \$45, and \$100 $CO_2$ Tax Levels**




| Resource Type | Capacity (MW) 2B | 5B | 5B Dry | 5B Wet | 8B | 9B | 10B | 17B | 18B | 47B |
|---|---|---|---|---|---|---|---|---|---|---|
| *Wind* | 1,863 | 1,863 | 1,863 | 1,863 | 2,563 | 1,863 | 2,952 | 4,363 | 3,863 | 2,383 |
| *Gas* | 548 | 391 | 797 | 831 | 261 | 391 | 261 | 261 | 261 | 609 |
| *FOT* | 775 | 829 | 821 | 820 | 811 | 829 | 820 | 796 | 808 | 797 |
| *DSM, Class 2* | 1,866 | 1,896 | 1,839 | 1,838 | 1,989 | 1,893 | 1,985 | 2,063 | 2,023 | 1,855 |
| *Dist. Gen.* | 92 | 132 | 78 | 50 | 129 | 132 | 127 | 127 | 127 | 92 |

## WIND RESOURCE ACQUISITION SCHEDULE DEVELOPMENT

Based on the 2012 gas resource deferral modeling results, PacifiCorp chose the "5B_CCCT_Wet" portfolio as the basis for the preferred portfolio. An issue with this portfolio, and wind resource optimization in general, is that the capacity expansion model adds a large amount of wind capacity in certain years and little or none in others. Such a pattern, while optimal from the model's perspective, is not desirable from a business planning perspective.

As noted in Chapter 7, PacifiCorp applied annual wind capacity constraints to reflect realistic system limits. However, additional constraints are required to emulate a long-term procurement program that ideally accounts for rate stability/financial impacts, anticipated demand for construction and equipment resources, flexibility to respond to changing market and regulatory conditions, construction management requirements, and location-specific considerations not factored into the IRP models. The company believes that given the current sophistication of capacity expansion optimization models, development of a suitable wind acquisition schedule that takes these various factors into account is best handled outside of the model. Consequently, PacifiCorp manually developed a wind acquisition schedule based on the aggregate wind amount from the 5B_CCCT_Wet portfolio, and then ran System Optimizer with this fixed wind schedule and the 5B_CCCT_Wet input assumptions. The resulting portfolio, presented in the next section, constitutes PacifiCorp's preferred portfolio. Table 8.42 shows the wind acquisition schedule and original wind additions from the 5B_CCCT_Wet portfolio.

**Table 8.42 – Revised Wind Resource Acquisition Schedule**

| Wind Resource Acquisition Schedule (Nameplate MW) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total (2009-2018) | Total (2009-2021) |
| East | 198 | 150 | | 100 | 100 | 100 | 150 | 100 | 100 | 50 | 200 | 200 | 150 | 1,048 | 1,598 |
| West | 45 | 20 | 200 | | | | | | | | | | | 265 | 265 |
| Total | 243 | 170 | 200 | 100 | 100 | 100 | 150 | 100 | 100 | 50 | 200 | 200 | 150 | 1,313 | 1,863 |
| Wind Additions for Case 5B_CCCT_Wet (Nameplate MW) | | | | | | | | | | | | | | | |
| East | 99 | 99 | | | | | 300 | | | 750 | 550 | | | 598 | 1,798 |
| West | 45 | 20 | | | | | | | | | | | | 65 | 65 |
| Total | 342 | 119 | | | | 140 | 460 | 100 | | 750 | | | | 1,261 | 1,863 |

The strategy behind this acquisition schedule is to distribute wind quantities across all years of the business planning period (2009-2018) and through 2021, keeping annual amounts at 200 MW or less. Planning to relatively level annual wind additions provides the following customer and company benefits:

- Helps to support rate and capital spending stability
- Strikes a balance between the risk of (1) front-loading wind development and then experiencing lower-than-expected $CO_2$ costs, and (2) deferring wind development and then experiencing higher-than-expected $CO_2$ costs, termination of the PTC after 2012, or both
- Reduces the risk of RPS compliance penalty costs stemming from procurement delays for projects needed to meet percentage-of-sales requirements in a given year
- Helps in maintaining efficiently sized construction management, engineering, and support teams

The wind schedule also reflects the addition of 200 MW of west-side wind resources in 2011 to take advantage of regional wind diversity benefits that are not captured in the IRP models.

## THE IRP PREFERRED PORTFOLIO

Table 8.43 presents the detailed view of the preferred portfolio resources. This portfolio reflects the wind schedule described in the preceding section. Since Class 1 DSM other than the Utah Cool Keeper program was found to be cost-effective in all the portfolios modeled, the preferred portfolio includes up to 120 MW of additional cost-effective Class 1 DSM to be identified through competitive Requests for Proposals and procured in the 2009-2016 time frame. (For the non-CCCT “B series” cases, the capacity expansion model typically selected 91 MW of various Class 1 DSM programs in the east—predominantly irrigation load control and load curtailment—and 34 MW in the west.) This amount is in line with the corporate objective of aggressively pursuing DSM opportunities, and exceeds the 2009 business plan goal by 15 MW. Acquiring the additional Class 1 DSM amounts would reduce the need for front office transactions.

Below are explanatory notes for the portfolio table.

- Swift 1 Upgrades – The three Swift upgrade projects (25 MW each) are shown under the year for which they enter commercial service (2012, 2013, and 2014); however, the planned in-service dates occur after the system peaks for these years. They are available to support the summer peak load in 2013, 2014, and 2015, respectively.
- High Plains and Duke PPA Wind Projects – The High Plains wind project has an October December 2009 in-service date, and is therefore shown under the year for which it enters commercial service (2009); the Duke project has a December 2009 in-service date, but is modeled with a start date of January 1, 2010, and is therefore shown in the year it is available to support the summer peak load (2010).
- Gas resource MW capacities reflect average annual capability rather than the generator nameplate. For the CCCT, the value shown approximates the July maximum capability.
- Class 2 DSM resource capacities reflect summer peak values.
- The capacities shown for the coal plant CCS (carbon capture and sequestration) retrofit resources represent replacement capacities for the existing units. The replacement capacity is smaller than the original unit size, which is due to a capacity penalty for capturing the $CO_2$.
- Short-term resource totals comprise the sum of front office transactions and growth resources.

Table 8.44 shows the resulting capacity load and resource balance for 2009-2018 with preferred portfolio resources included. Figures 8.27 and 8.28 consist of pie charts showing the energy and capacity mixes of the portfolio for 2009, 2014, and 2018.

# Table 8.43 – Preferred Portfolio, Detail Level

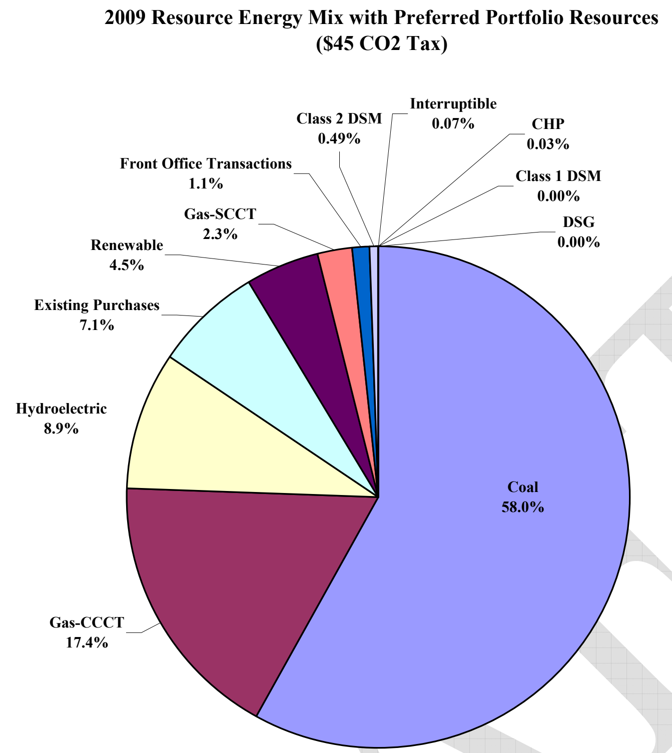
| | | Capacity, MW | | | | | | | | | | | | | | | | | | | | Resource Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Resource** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **10 Year** | **20 Year** |
| **East** | | | | | | | | | | | | | | | | | | | | | | | |
| | CCS Hunter - Unit 3 (Replaces Original Unit) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 346 | - | - | - | - | 346 |
| | CCCT F 2x1 | - | - | - | - | - | 570 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 570 | 570 |
| | IC Aero SCCT | - | - | - | - | - | - | - | 261 | - | - | - | - | - | - | - | - | - | - | - | - | 261 | 261 |
| | East PPA | - | - | - | 201 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 201 | 201 |
| | Coal & Gas Capacity Upgrades | 3 | 44 | 33 | 25 | 2 | 14 | - | 8 | - | - | - | - | - | - | - | - | - | - | - | - | 128 | 128 |
| | Blundell Geothermal 3 | - | - | - | - | 35 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 35 | 35 |
| | Wind, Duke Energy PPA | - | 99 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 99 | 99 |
| | Wind, High Plains | 99 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 99 | 99 |
| | Wind, WYSW, 35% Capacity Factor | - | 150 | - | 100 | 100 | 100 | 150 | 100 | 100 | 50 | 200 | 200 | 150 | - | - | - | - | - | - | - | 850 | 1,400 |
| | **Total Wind** | **99** | **249** | **-** | **100** | **100** | **100** | **150** | **100** | **100** | **50** | **200** | **200** | **150** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **1,048** | **1,598** |
| | CHP - Biomass | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | - | - | - | - | - | - | - | - | - | - | 20 | 20 |
| | CHP - Reciprocating Engine | - | - | - | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | - | - | - | - | 10 | 21 |
| | Distributed Standby Generation | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | - | - | - | - | - | - | - | - | - | - | 38 | 38 |
| | DSM, Class 1, Utah-Cool Keeper | 25 | 50 | 40 | 30 | 10 | 10 | 10 | 10 | 10 | 10 | - | - | - | - | - | - | - | - | - | - | 205 | 205 |
| | DSM, Class 1, Other | * | * | * | * | * | * | * | * | * | * | - | - | - | - | - | - | - | - | - | - | Up to 90 | Up to 90 |
| | DSM, Class 2, Goshen | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 17 | 38 |
| | DSM, Class 2, Utah | 40 | 46 | 42 | 42 | 45 | 45 | 46 | 45 | 47 | 48 | 47 | 48 | 49 | 51 | 52 | 52 | 59 | 55 | 57 | 55 | 447 | 971 |
| | DSM, Class 2, Wyoming | - | 3 | 6 | 8 | 8 | 8 | 8 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 10 | 10 | 68 | 164 |
| | **DSM, Class 2 Total** | **42** | **51** | **49** | **52** | **55** | **55** | **56** | **56** | **58** | **59** | **58** | **59** | **60** | **62** | **64** | **64** | **71** | **67** | **69** | **67** | **532** | **1,173** |
| | FOT Utah, 3rd Qtr HLH | - | - | - | 44 | 50 | - | 2 | 28 | - | - | - | 7 | 50 | 50 | 50 | 50 | - | - | 50 | - | | |
| | FOT Mead, 3rd Qtr HLH | - | - | - | - | - | - | - | - | 517 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | | |
| | FOT Mona/Nevada Utah Border, 3rd Qtr HLH | 75 | 50 | 150 | 350 | 443 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | - | - | - | - | - | - | - | - | | |
| | **FOT East Total** | **75** | **50** | **150** | **394** | **493** | **200** | **202** | **228** | **717** | **800** | **800** | **807** | **650** | **650** | **650** | **650** | **600** | **600** | **650** | **600** | | |
| | Growth Resource - Goshen | - | - | - | - | - | - | - | - | - | - | - | - | 204 | 187 | 198 | 219 | - | - | 192 | - | | |
| | Growth Resource - Utah North | - | - | - | - | - | - | - | - | - | - | - | - | 212 | 308 | 238 | 242 | - | - | - | - | | |
| | Growth Resource - Wyoming | - | - | - | - | - | - | - | - | - | - | - | - | 73 | 79 | 126 | 167 | - | - | 196 | - | | |
| **West** | | | | | | | | | | | | | | | | | | | | | | | |
| | Coal Plant Turbine Upgrades | - | 9 | 9 | 12 | 12 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 42 | 42 |
| | Swift Hydro Upgrades | - | - | - | 25 | 25 | 25 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 75 | 75 |
| | Wind PPA | 45 | 20 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 65 | 65 |
| | Wind, Yakima, 29% Capacity Factor PPA | - | - | 100 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 100 | 100 |
| | Wind, Walla Walla, 29% Capacity Factor PPA | - | - | 100 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 100 | 100 |
| | **Total Wind** | **45** | **20** | **200** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **265** | **265** |
| | Utility Biomass | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 25 | - | 25 | - | - | 50 |
| | CHP - Biomass | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | - | - | - | - | - | - | - | - | - | - | 12 | 12 |
| | CHP - Reciprocating Engine | - | - | - | - | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | - | - | - | - | - | - | 4 | 6 |
| | Distributed Standby Generation | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | - | - | - | - | - | - | - | - | - | - | 12 | 12 |
| | DSM, Class 1, Other | * | * | * | * | * | * | * | * | * | * | - | - | - | - | - | - | - | - | - | - | Up to 30 | Up to 30 |
| | DSM, Class 2, Washington | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 30 | 59 |
| | DSM, Class 2, West Main | 28 | 28 | 30 | 30 | 30 | 31 | 31 | 31 | 31 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 289 | 492 |
| | DSM, Class 2, Yakima | 5 | 6 | 5 | 5 | 5 | 5 | 6 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 53 | 114 |
| | **DSM, Class 2 Total** | **35** | **36** | **39** | **39** | **38** | **39** | **39** | **39** | **39** | **29** | **29** | **29** | **30** | **29** | **29** | **30** | **29** | **30** | **30** | **30** | **372** | **665** |
| | FOT COB, Flat Annual | - | - | 59 | 389 | - | 389 | 289 | 239 | 239 | 239 | 338 | 338 | 338 | 338 | 338 | 338 | 338 | 338 | 338 | - | | |
| | FOT COB, 3rd Qtr HLH | - | - | - | - | 389 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 338 | | |
| | FOT Mid-Columbia, Flat Annual | - | - | - | - | - | - | - | - | - | 171 | 228 | 228 | 37 | 67 | 71 | 63 | 68 | 87 | 109 | 165 | | |
| | FOT Mid-Columbia, 3rd Qtr HLH | - | - | - | 400 | 400 | 300 | 400 | 400 | - | 121 | 105 | 160 | - | - | - | 7 | 308 | 313 | 291 | 235 | | |
| | FOT West Main, 3rd Qtr HLH | - | - | - | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | | |
| | **FOT West Total** | **-** | **-** | **59** | **839** | **839** | **739** | **739** | **689** | **289** | **582** | **721** | **776** | **424** | **454** | **459** | **457** | **764** | **788** | **788** | **788** | | |
| | Growth Resource - Walla Walla | - | - | - | - | - | - | - | - | - | - | - | - | 106 | 97 | 134 | 135 | 127 | 128 | 396 | 403 | | |
| | Growth Resource - West Main | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 607 | 660 | 67 | 666 | | |
| | Growth Resource - Yakima | - | - | - | - | - | - | - | - | - | - | - | - | 157 | 163 | 268 | 271 | 215 | 294 | 315 | 317 | | |
| | **Annual Additions, Long Term Resources** | **257** | **467** | **378** | **491** | **286** | **823** | **266** | **485** | **218** | **158** | **289** | **291** | **243** | **94** | **94** | **95** | **471** | **97** | **123** | **97** | | |
| | **Annual Additions, Short Term Resources** | **75** | **50** | **209** | **1,234** | **1,332** | **939** | **942** | **918** | **1,006** | **1,382** | **1,521** | **1,583** | **1,825** | **1,937** | **2,074** | **2,141** | **2,313** | **2,470** | **2,603** | **2,773** | | |
| | **Total Annual Additions** | **332** | **517** | **587** | **1,725** | **1,618** | **1,762** | **1,208** | **1,402** | **1,224** | **1,540** | **1,811** | **1,873** | **2,068** | **2,031** | **2,168** | **2,236** | **2,785** | **2,567** | **2,727** | **2,870** | | |

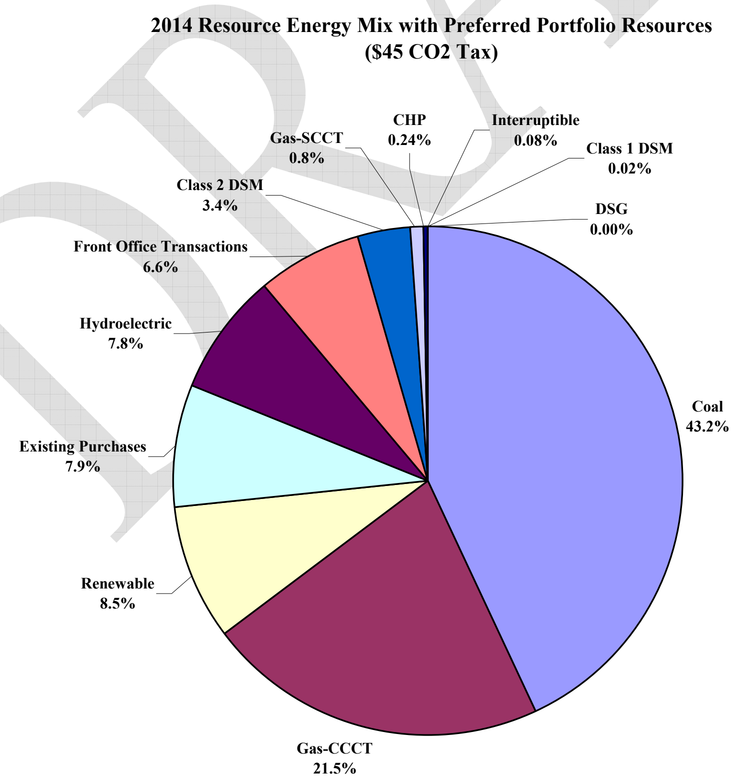
* Up to 120 MW of additional cost-effective Class 1 DSM programs (90 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2016. Firm market purchases (3rd quarter products) would be reduced accordingly.

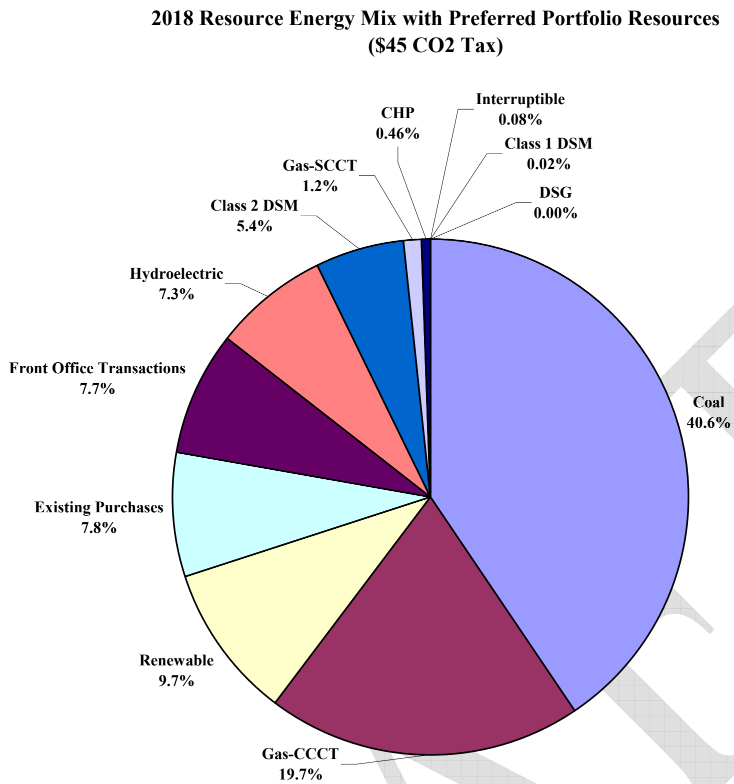
## Table 8.44 - Preferred Portfolio Load and Resource Balance (2009-2018)

| Calendar Year | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| **East** | | | | | | | | | | |
| Thermal | 5,983 | 5,998 | 6,025 | 6,066 | 6,066 | 6,078 | 6,079 | 6,087 | 6,088 | 5,863 |
| Hydroelectric Generation | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 |
| Demand-side Management | 345 | 395 | 435 | 465 | 475 | 485 | 495 | 505 | 515 | 525 |
| Renewable | 157 | 157 | 157 | 157 | 157 | 157 | 154 | 154 | 154 | 154 |
| Purchase | 751 | 546 | 541 | 341 | 341 | 341 | 341 | 320 | 320 | 320 |
| Qualifying Facilities | 151 | 151 | 151 | 151 | 151 | 151 | 151 | 151 | 151 | 151 |
| Interruptible Contracts | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 |
| Transfers | 854 | 914 | 794 | 685 | 737 | 565 | 769 | 737 | 231 | 519 |
| **East Existing Resources** | **8,614** | **8,534** | **8,476** | **8,238** | **8,300** | **8,149** | **8,361** | **8,326** | **7,831** | **7,905** |
| | | | | | | | | | | |
| Combined Heat and Power | 2 | 4 | 6 | 9 | 11 | 14 | 18 | 22 | 26 | 30 |
| Distributed Standby Generation | 4 | 8 | 12 | 15 | 19 | 23 | 27 | 31 | 35 | 38 |
| DSM, Class 2 | 36 | 79 | 119 | 160 | 205 | 249 | 294 | 338 | 384 | 431 |
| Front Office Transactions | 75 | 50 | 150 | 394 | 493 | 200 | 202 | 228 | 717 | 800 |
| Gas | 0 | 0 | 0 | 201 | 201 | 771 | 771 | 1,032 | 1,032 | 1,032 |
| Geothermal | 0 | 0 | 0 | 0 | 35 | 35 | 35 | 35 | 35 | 35 |
| Wind | 9 | 12 | 12 | 15 | 17 | 20 | 23 | 26 | 28 | 29 |
| Growth Resource | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **East Planned Resources** | **126** | **153** | **299** | **794** | **980** | **1,310** | **1,369** | **1,711** | **2,255** | **2,395** |
| | | | | | | | | | | |
| **East Total Resources** | **8,740** | **8,687** | **8,774** | **9,032** | **9,280** | **9,460** | **9,730** | **10,037** | **10,086** | **10,300** |
| | | | | | | | | | | |
| Load (Coincident Peak) | 6,757 | 6,949 | 7,150 | 7,404 | 7,643 | 7,779 | 8,029 | 8,303 | 8,491 | 8,696 |
| Sale | 781 | 768 | 758 | 747 | 745 | 745 | 745 | 745 | 659 | 659 |
| **East Obligation** | **7,538** | **7,717** | **7,908** | **8,151** | **8,388** | **8,524** | **8,774** | **9,048** | **9,150** | **9,355** |
| | | | | | | | | | | |
| Planning reserves (12%) | 731 | 769 | 771 | 786 | 797 | 841 | 865 | 890 | 837 | 845 |
| Non-owned reserves | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| **East Reserves** | **802** | **840** | **841** | **857** | **867** | **912** | **935** | **961** | **908** | **915** |
| | | | | | | | | | | |
| **East Obligation + Reserves** | **8,339** | **8,556** | **8,749** | **9,007** | **9,255** | **9,436** | **9,709** | **10,009** | **10,058** | **10,271** |
| **East Position** | **401** | **131** | **25** | **25** | **25** | **24** | **21** | **28** | **29** | **29** |
| **East Reserve Margin** | **17.3%** | **13.7%** | **12.3%** | **12.3%** | **12.3%** | **12.3%** | **12.2%** | **12.3%** | **12.3%** | **12.3%** |
| | | | | | | | | | | |
| **West** | | | | | | | | | | |
| Thermal | 2,550 | 2,559 | 2,568 | 2,579 | 2,591 | 2,591 | 2,591 | 2,591 | 2,577 | 2,577 |
| Hydroelectric Generation | 1,315 | 1,218 | 1,216 | 980 | 1,009 | 1,046 | 1,157 | 1,150 | 1,149 | 1,146 |
| Demand-side Management | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 90 | 96 | 96 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| Purchase | 1,310 | 1,203 | 753 | 115 | 144 | 111 | 111 | 111 | 111 | 139 |
| Qualifying Facilities | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 |
| Transfers | (855) | (914) | (795) | (686) | (738) | (565) | (769) | (737) | (231) | (520) |
| **West Existing Resources** | **4,530** | **4,281** | **3,958** | **3,198** | **3,217** | **3,392** | **3,300** | **3,325** | **3,815** | **3,551** |
| | | | | | | | | | | |
| Combined Heat and Power | 1 | 2 | 4 | 5 | 7 | 9 | 10 | 12 | 14 | 16 |
| Distributed Standby Generation | 1 | 2 | 4 | 5 | 6 | 7 | 8 | 9 | 11 | 12 |
| DSM, Class 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DSM, Class 2 | 26 | 54 | 83 | 112 | 140 | 169 | 199 | 228 | 257 | 279 |
| Front Office Transactions | 0 | 0 | 59 | 839 | 839 | 739 | 739 | 689 | 289 | 582 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Growth Resource | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **West Planned Resources** | **29** | **58** | **157** | **969** | **1,000** | **933** | **965** | **947** | **580** | **896** |
| | | | | | | | | | | |
| **West Total Resources** | **4,559** | **4,340** | **4,115** | **4,167** | **4,217** | **4,325** | **4,265** | **4,272** | **4,395** | **4,448** |
| | | | | | | | | | | |
| Load (Coincident Peak) | 3,393 | 3,422 | 3,490 | 3,587 | 3,638 | 3,722 | 3,769 | 3,824 | 3,893 | 3,978 |
| Sale | 499 | 490 | 290 | 258 | 258 | 258 | 158 | 108 | 108 | 108 |
| **West Obligation** | **3,892** | **3,912** | **3,780** | **3,845** | **3,896** | **3,980** | **3,927** | **3,932** | **4,001** | **4,086** |
| | | | | | | | | | | |
| Planning reserves (12%) | 307 | 319 | 346 | 334 | 333 | 355 | 345 | 348 | 401 | 370 |
| Non-owned reserves | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| **West Reserves** | **313** | **325** | **353** | **340** | **339** | **362** | **352** | **355** | **408** | **377** |
| | | | | | | | | | | |
| **West Obligation + Reserves** | **4,199** | **4,230** | **4,126** | **4,179** | **4,229** | **4,335** | **4,272** | **4,280** | **4,402** | **4,456** |
| **West Position** | **360** | **110** | **(11)** | **(12)** | **(12)** | **(10)** | **(7)** | **(8)** | **(7)** | **(9)** |
| **West Reserve Margin** | **21.1%** | **14.6%** | **11.5%** | **11.5%** | **11.5%** | **11.6%** | **11.7%** | **11.6%** | **11.7%** | **11.6%** |
| | | | | | | | | | | |
| **System** | | | | | | | | | | |
| **Total Resources** | **13,299** | **13,027** | **12,889** | **13,199** | **13,497** | **13,785** | **13,995** | **14,309** | **14,481** | **14,747** |
| **Obligation** | **11,430** | **11,628** | **11,687** | **11,996** | **12,284** | **12,504** | **12,701** | **12,980** | **13,151** | **13,441** |
| **Reserves** | **1,115** | **1,165** | **1,194** | **1,197** | **1,206** | **1,274** | **1,287** | **1,316** | **1,315** | **1,292** |
| **Obligation + Reserves** | **12,544** | **12,793** | **12,882** | **13,192** | **13,490** | **13,777** | **13,988** | **14,296** | **14,466** | **14,733** |
| **System Position** | **754** | **234** | **7** | **7** | **6** | **7** | **8** | **13** | **15** | **14** |

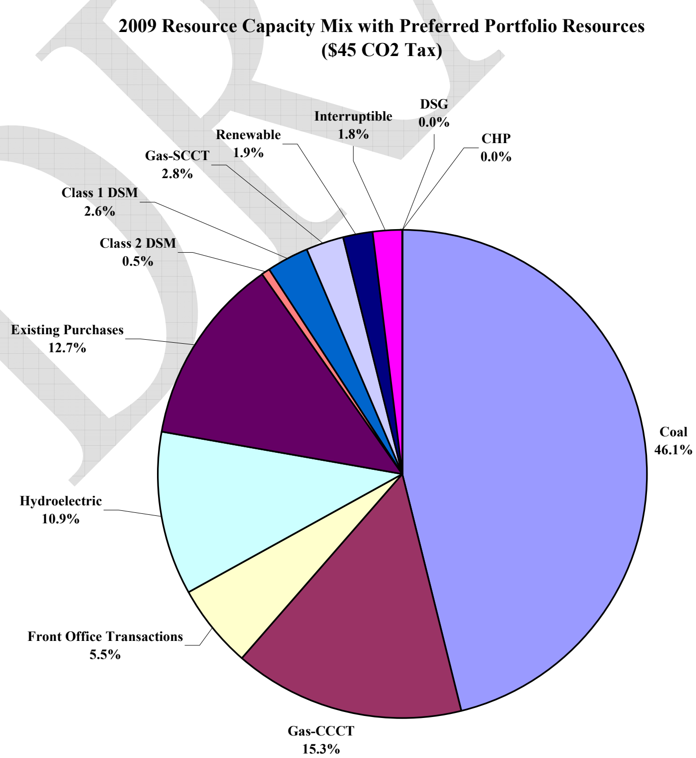
## Figure 8.27 – Current and Projected PacifiCorp Resource Energy Mix



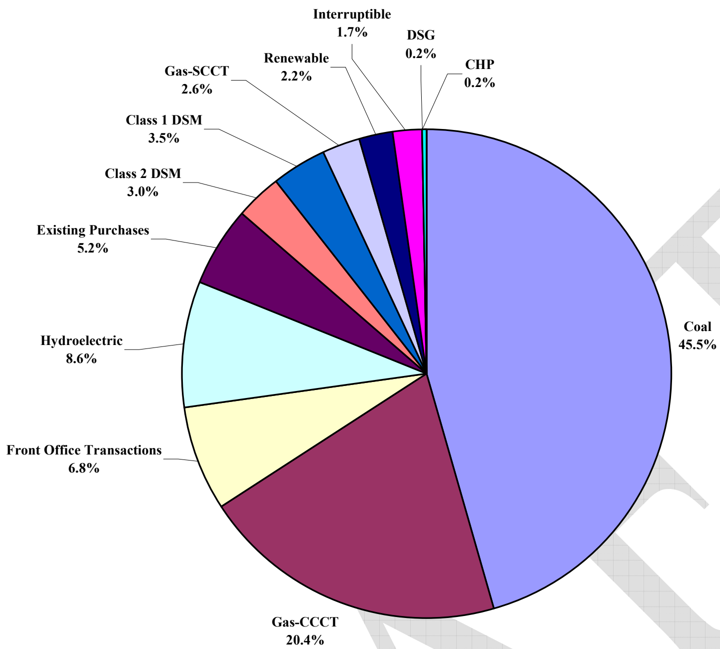





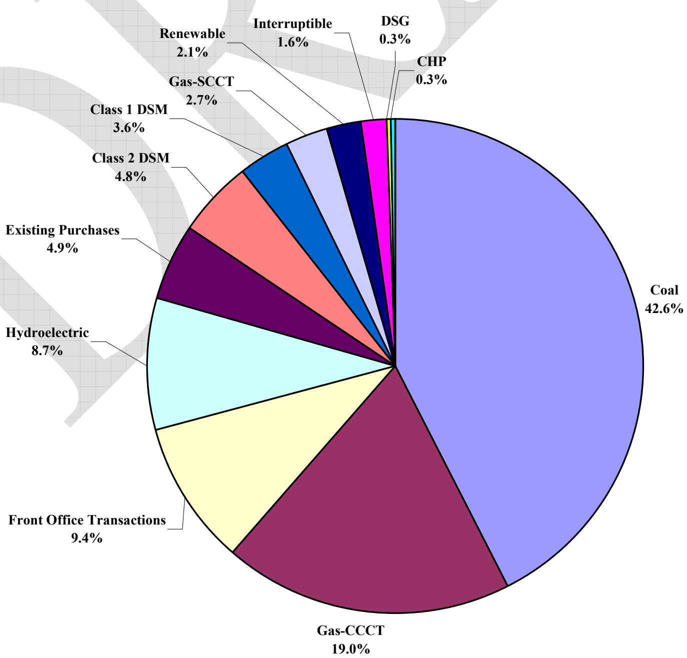

# Figure 8.28 – Current and Projected PacifiCorp Resource Capacity Mix



**2014 Resource Capacity Mix with Preferred Portfolio Resources**
**($45 CO2 Tax)**




**2018 Resource Capacity Mix with Preferred Portfolio Resources**
**($45 CO2 Tax)**



## PORTFOLIO IMPACT OF PACIFICORP'S FEBRUARY 2009 LOAD FORECAST

PacifiCorp prepared a new load forecast in February 2009 after reviewing actual loads through January 2009. This forecast is being used to support corporate planning efforts including the acquisition path analysis outlined in the next Chapter, as well as recent regulatory filings.

Table 8.45 compares the coincident peak loads for the two load forecasts. For the 2009 business plan, the load forecast was adjusted to include the expected impact of historical Class 2 DSM programs, which are assumed to contribute incremental load reductions in the future as equipment and appliances are replaced with higher-efficiency alternatives. This load forecast adjustment was not included in previous IRP modeling, but is factored into the portfolio modeling using the February 2009 load forecast. As with the federal lighting standards adjustment described in Chapter 5, this DSM adjustment has the effect of increasing the load forecast for capacity expansion modeling only, so that the model can select additional DSM to fill the load gap. Including this adjustment also ensures that sufficient resource capacity is added in case the full amount of estimated future load reductions from existing Class 2 DSM programs is not realized. This adjustment, which partially offsets the recession-related load reductions, ranges from 34 MW in 2009 to 337 MW by 2018. Appendix E reports the detailed February 2008 forecast net of expected future load reductions attributable to existing Class 2 DSM programs and federal lighting standards.



**Table 8.45 – Coincident Peak Load Forecast Comparison**

| Nov. 2008 Forecast | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| East | 6,757 | 6,949 | 7,150 | 7,404 | 7,643 | 7,779 | 8,029 | 8,303 | 8,491 | 8,696 |
| West | 3,393 | 3,422 | 3,490 | 3,587 | 3,638 | 3,722 | 3,769 | 3,824 | 3,893 | 3,978 |
| System | 10,150 | 10,371 | 10,640 | 10,991 | 11,281 | 11,501 | 11,798 | 12,127 | 12,384 | 12,674 |
| **Feb. 2009 Forecast** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| East | 6,722 | 6,924 | 7,220 | 7,483 | 7,741 | 7,905 | 8,173 | 8,410 | 8,664 | 8,886 |
| West | 3,265 | 3,324 | 3,379 | 3,447 | 3,491 | 3,554 | 3,608 | 3,624 | 3,719 | 3,793 |
| System | 9,987 | 10,248 | 10,599 | 10,930 | 11,232 | 11,459 | 11,781 | 12,034 | 12,383 | 12,679 |
| **Difference** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| East | (35) | (25) | 70 | 79 | 98 | 126 | 144 | 107 | 173 | 190 |
| West | (128) | (98) | (111) | (140) | (147) | (168) | (161) | (200) | (174) | (185) |
| System | (163) | (123) | (41) | (61) | (49) | (42) | (17) | (93) | (1) | 5 |

PacifiCorp developed a portfolio using this new DSM-adjusted load forecast and the case 5 input assumptions ($45/ton $CO_2$ tax and low June 2008 forward price curves) with the CCCT fixed in 2014. As indicated in table 8.45, the peak load reductions are not sufficient to eliminate or defer a gas combined-cycle plant.

The resource impacts of applying the new load forecast with the DSM adjustment described above, relative to the 5B_CCCT_Wet portfolio, are as follows:

- The IC aero SCCT originally added in 2016 is no longer needed

- Front office transactions are deferred in both the east and west, and decrease overall by about 100 MW by 2020; the east experiences a net increase of about 90 MW while the west experiences a net decrease of 185 MW in line with the lower loads
- To make up for the loss of the IC aero SCCT and front office transactions, the model added 41 MW of customer standby generation (30 MW in the east; 12 MW in the west), 50 MW of utility-scale biomass capacity in 2015-2016, and moved up 243 MW of wind from 2019 to 2017

Table 8.46 shows the resource capacity differences through 2020 between the portfolio produced using the new load forecast and the wet-cooled CCCT portfolio (5B_CCCT_Wet).

**Table 8.46 – Resource Capacity Differences, February 2009 Load Forecast Portfolio less Wet-Cooled CCCT Portfolio**

| | | Capacity, MW | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Resource | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| East | | | | | | | | | | | | | |
| | CCS Hunter3 | - | - | - | - | - | - | - | - | - | - | - | - |
| | IC Aero | - | - | - | - | - | - | - | (261) | - | - | - | - |
| | Total Wind | - | - | - | - | - | - | - | - | 243 | - | (243) | - |
| | CHP - Reciprocating Engine | - | - | 1 | - | - | - | - | - | - | - | - | - |
| | Distributed Standby Generation | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | - | - | - | - |
| | DSM, Class 1 Total | - | - | - | - | (2.1) | - | - | - | - | - | - | - |
| | DSM, Class 2 Total | 0.3 | - | - | 1.9 | 0.6 | 0.8 | 0.4 | - | - | - | - | - |
| | FOT Utah, 3rd Qtr HLH | - | - | - | (30) | - | - | (17) | 5 | - | 50 | 47 | 50 |
| | FOT Mead, 3rd Qtr HLH | - | - | - | - | - | - | - | - | 64 | - | - | - |
| | FOT Mona/Nevada Utah Border, 3rd Qtr HLH | - | - | - | (7) | (74) | - | - | - | - | - | - | - |
| | Growth Resource Goshen | - | - | - | - | - | - | - | - | - | - | - | - |
| | Growth Resource Utah North | - | - | - | - | - | - | - | - | - | - | - | - |
| | Growth Resource Wyoming | - | - | - | - | - | - | - | - | - | - | - | - |
| West | | | | | | | | | | | | | |
| | Total Wind | - | - | - | - | - | - | - | - | - | - | - | - |
| | Utility Biomass | - | - | - | - | - | - | 25 | 25 | - | - | - | - |
| | CHP - Reciprocating Engine | - | - | - | 1 | - | - | - | - | - | - | - | - |
| | Distributed Standby Generation | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | - | - | - | - |
| | DSM, Class 1 Total | - | - | - | - | - | - | - | 1.9 | - | - | - | - |
| | DSM, Class 2 Total | - | - | - | - | 1.1 | 0.5 | - | - | - | - | - | - |
| | FOT Mid-Columbia, Flat Annual | - | - | (55) | - | - | - | - | - | - | - | - | - |
| | FOT Mid-Columbia, 3rd Qtr HLH | - | - | - | - | - | - | - | - | 26 | (17) | (22) | (19) |
| | FOT West Main, 3rd Qtr HLH | - | - | - | (44) | - | (71) | (58) | - | - | 64 | 54 | (42) |
| | Growth Resource Walla Walla | - | - | - | - | - | - | - | - | - | - | - | - |
| | Growth Resource West Main | - | - | - | - | - | - | - | - | - | - | - | - |
| | Growth Resource Yakima | - | - | - | - | - | - | - | - | - | - | - | - |

Since the relative resource impact of the new DSM-adjusted load forecast is minimal until 2016, no changes to the preferred portfolio are warranted for this period. The uncertainty over the timing and pace of an economy recovery, combined with the short lead-time for a gas peaking resource and the potential need for such resources to support wind integration, also prompted the company to retain the IC aero SCCT in the preferred portfolio.

# 9. ACTION PLAN AND RESOURCE RISK MANAGEMENT

## INTRODUCTION

This chapter presents the company's 2008 IRP action plan, which identifies the steps the company will take during the next two to four years to implement the plan covering the 10-year resource acquisition time frame, 2009-2018. Associated with the action plan is an acquisition path analysis that anticipates major regulatory actions expected during the action plan time horizon and other events that could materially impact resource acquisition strategies.

The resources included in the preferred portfolio were used to help define the actions included in the action plan, focusing on the size, timing, and type of resources needed to meet load obligations and state regulatory requirements. This resource combination was determined to be the lowest cost on a risk-adjusted basis and accounting for (1) several cost, risk and supply reliability measures, (2) significant regulatory uncertainty, and (3) the company's recent decision to not pursue a 2012 combined-cycle gas plant and acquire alternative resources to address the resulting capacity deficits.

The IRP action plan is based upon the latest and most accurate information available at the time the integrated resource plan is filed. Through increased IRP and business planning alignment, resource information used in the IRP, such as capital and operating costs, is now consistent with that used for the business plan. Nevertheless, the resources identified in the plan are proxy resources and act as a guide for resource procurement. Resources evaluated as part of procurement initiatives may vary from the proxy resource identified in the plan with respect to resource type, timing, size, and location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition.

In addition to the action plan and acquisition path analysis, this chapter addresses a number of topics associated with resource risk management. These topics include the following:

- Managing carbon risk for existing plants
- The use of physical and financial hedging for electricity price risk
- Managing gas supply risk
- The treatment of customer and investor risks for resource planning

## THE INTEGRATED RESOURCE PLAN ACTION PLAN

Table 9.1 is a summary of the annual MW capacities and timing for specific resources contained in the preferred portfolio. A more comprehensive summary of portfolio resources can be found in Chapter 8.

## Table 9.1 – Preferred Portfolio, Summary Level

| | Resource | Capacity, MW 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Cumulative Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **East** | | | | | | | | | | | | |
| | CCCT F 2x1, Utah North | - | - | - | - | - | 570 | - | - | - | - | 570 |
| | IC Aero SCCT | - | - | - | - | - | - | - | 261 | - | - | 261 |
| | East PPA | - | - | - | 200 | - | - | - | - | - | - | 200 |
| | Coal & Gas Capacity Upgrades | 3 | 44 | 33 | 25 | 2 | 14 | - | 8 | - | - | 128 |
| | Blundell Geothermal 3 | - | - | - | - | 35 | - | - | - | - | - | 35 |
| | Wind | 99 | 249 | - | 100 | 100 | 100 | 150 | 100 | 100 | 50 | 1,048 |
| | CHP | 2 | 2 | 2 | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 30 |
| | Distributed Standby Generation | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 38 |
| | DSM, Class 1, Utah Cool Keeper Load Control | 25 | 50 | 40 | 30 | 10 | 10 | 10 | 10 | 10 | 10 | 205 |
| | DSM, Class 1, Other | * | * | * | * | * | * | * | * | - | - | Up to 90 |
| | DSM Class 2 | 42 | 51 | 49 | 52 | 55 | 55 | 56 | 56 | 58 | 59 | 532 |
| | FOT East | 75 | 50 | 150 | 394 | 493 | 200 | 202 | 228 | 717 | 800 | |
| **West** | | | | | | | | | | | | |
| | Coal Plant Turbine Upgrades | - | 9 | 9 | 12 | 12 | - | - | - | - | - | 42 |
| | Swift Hydro Upgrades [2/] | - | - | - | 25 | 25 | 25 | - | - | - | - | 75 |
| | Wind | 45 | 20 | 200 | - | - | - | - | - | - | - | 265 |
| | CHP | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 16 |
| | Distributed Standby Generation | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| | DSM, Class 1, Other | * | * | * | * | * | * | * | * | * | * | Up to 30 |
| | DSM, Class 2 | 35 | 36 | 39 | 39 | 38 | 39 | 39 | 39 | 39 | 29 | 372 |
| | FOT West | - | - | 59 | 839 | 839 | 739 | 739 | 689 | 289 | 582 | |
| | **Annual Additions, Long Term Resources** | **257** | **467** | **378** | **491** | **286** | **823** | **266** | **485** | **218** | **158** | |
| | **Annual Additions, Short Term Resources** | **75** | **50** | **209** | **1,234** | **1,332** | **939** | **942** | **918** | **1,006** | **1,382** | |
| | **Total Annual Additions** | **332** | **517** | **587** | **1,724** | **1,618** | **1,762** | **1,208** | **1,402** | **1,224** | **1,540** | |

[1/] The 99 MW amount in 2009 is the High Plains project; the 249 MW in 2010 includes the 99 MW Duke Energy PPA.

[2/] The Swift 1 hydro updates are shown in the years that they enter into commercial service.

* Up to 120 MW of additional cost-effective Class 1 DSM programs (100 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2016. Firm market purchases (3rd quarter products) would be reduced by roughly comparable amounts.

The IRP action plan, detailed in Table 9.2, provides the company with a road map for moving forward with new resource acquisitions, including major transmission projects needed to support the preferred portfolio and other company objectives. (More detail on transmission expansion action items is provided in Chapter 10.)

**Table 9.2 – 2008 IRP Action Plan**

Action items anticipated to extend beyond the next two years, or occur after the next two years, are indicated in italics

| Action Item | Category | Timing | Action(s) |
|---|---|---|---|
| 1 | Renewables | 2009 - 2018 | Acquire 1,400 MW of renewables by 2018<br>• Successfully add 144 MW of wind resources in 2009 that are currently in the project pipeline, including PacifiCorp's 99 MW High Plains facility in Wyoming, and 45 MW of power purchase agreement capacity<br>• Successfully add 269 MW of wind resources in 2010 that are currently in the project pipeline, including 119 MW of power purchase agreement capacity already contracted<br>• Procure up to an additional 500 MW of cost-effective resources for commercial operation, subject to transmission availability, starting in the 2009 to 2011 time frame under the currently active renewables RFP (2008R-1) and the next renewables RFP (2009R-1) expected to be issued in the second quarter of 2009<br>– The company is expected to submit company resources (self build or ownership transfers) in the 2009R-1 RFP<br>• *Procure up to an additional 500 MW of cost-effective resources for commercial operation, subject to transmission availability, starting in the 2012 to 2018 time frame via one or more shelf RFP issuances*<br>– *Seek to obtain at least 35 MW of viable and cost-effective geothermal or other base-load renewables*<br>• *Monitor solar technologies, government financial incentives, and viable project opportunities for potential cost-effective acquisition during the 10-year investment horizon*<br>• *Continue to evaluate the prospects and impacts of Renewable Portfolio Standard rules at the state and federal levels, and adjust the renewable acquisition timeline accordingly* |
| 2 | Firm Market Purchases | 2009 - 2013 | Implement a resource bridging strategy to support acquisition of long-term intermediate/base-load resource(s) in the east control area by the summer of 2014<br>• Acquire the following resources:<br>– Up to 1,400 MW of economic front office transactions on an annual basis as needed through 2013, taking advantage of favorable market conditions<br>– Pursue at least 200 MW of long-term power purchases<br>– Pursue customer interruptible load contract opportunities (targeting Utah)<br>• Resources will be procured through multiple means: (1) reactivation of the suspended 2008 All-Source RFP in late 2009, which seeks third quarter summer products and customer physical curtailment contracts among other resource types, (2) periodic mini-RFPs, and (3) bilateral negotiations |

| Action Item | Category | Timing | Action(s) |
|---|---|---|---|
| | | | • Closely monitor the near-term need for front office transactions and reduce acquisitions as appropriate if load forecasts indicate stable or worsening recessionary impacts relative to the February 2009 load forecast<br>• *Acquire incremental transmission through Transmission Service Requests to support resource acquisition* |
| 3 | Peaking / Intermediate / Base-load Supply-side Resources | 2012 - 2016 | Procure long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame<br>• The proxy resources included in the preferred portfolio consist of (1) a Utah wet-cooled gas combined-cycle plant with a summer capacity rating of 570 MW, acquired by the summer of 2014, and (2) a 261 MW east-side intercooled aeroderivative simple-cycle gas plant acquired by the summer of 2016<br>• Procure through activation of the suspended 2008 all-source RFP in late 2009, thereby obtaining refreshed and new bids reflecting more favorable bid prices than obtained when the RFP was initially issued in October 2008<br>– The company will submit company resources (base-load and/or intermediate load self-build or ownership transfers) once the suspension is removed<br>• *Continue to update load forecasts based on the company's economic recession/recovery outlook, and modify acquisition plans for resources appropriately; closely monitor the need for a simple-cycle gas plant in 2016, and seek alternative peaking resources if load forecasts indicate stable or worsening recessionary impacts relative to the February 2009 load forecast* |
| 4 | Plant Efficiency Improvements | 2009-2018 | Pursue economic plant upgrade projects—such as turbine system improvements and retrofits—and unit availability improvements to lower operating costs and help meet the company's future $CO_2$ and other environmental compliance requirements<br>• *Successfully complete the dense-pack coal plant turbine upgrade projects by 2016, currently planned to add 129 MW of zero-emission generating capacity in the east and 42 MW in the West*<br>• *Seek to meet the company's aggregate coal plant net heat rate improvement goal of 213 Btu/kWh by 2018*[50]<br>• *Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules* |
| 5 | Class 1 DSM | 2009-2018 | Acquire at least 200 - 300 MW of cost-effective Class 1 demand-side management programs for implementation in the 2009-2018 time frame<br>• *Pursue up to 200 MW of expanded Utah Cool Keeper program participation by 2018*<br>• *Pursue up to 130 MW of additional cost-effective class 1 DSM products(100 MW in the east side and 30* |

[50] Pacificorp Energy Heat Rate Improvement Plan, March 31, 2009.

| Action Item | Category | Timing | Action(s) |
|---|---|---|---|
| | | | *MW in the west side) to hedge against the risk of higher gas prices and a faster-than-expected rebound in load growth resulting from economic recovery Procure through the currently active all-source 2008 DSM RFP and subsequent RFPs*<br>• For 2009-2010, implement a standardized Class 1 DSM system benefit estimation methodology for products modeled in the IRP. The modeling will compliment the supply curve work by providing additional resource value information to be used to evolve current Class 1 products and evaluate new products with similar operational characteristics that may be identified between plans. |
| 6 | Class 2 DSM | 2009-2018 | Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2018 (peak capacity), equivalent to about 430 to 480 MWa<br>• *Procure through the currently active all-source DSM RFP and subsequent RFPs* |
| 7 | Class 3 DSM | 2009-2018 | Acquire cost-effective Class 3 DSM programs by 2018<br>• *Procure programs through the currently active all-source DSM RFP and subsequent RFPs*<br>• *Continue to evaluate program attributes, size/diversity, and customer behavior profiles to determine the extent that such programs provide a sufficiently reliable firm resource for long-term planning*<br>• *Portfolio analysis with Class 3 DSM programs included as resource options indicated that at least 100 MW may be cost-effective; continue to evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling* |
| 8 | Distributed Generation | 2009-2018 | Pursue at least 100 MW of distributed generation resources by 2018<br>• *Acquire at least 50 MW of combined heat and power (CHP) generation: 30 MW for the east side and 20 MW for the west side, to include purchase of facility output pursuant to PURPA regulations and from supply-side RFPs (renewable shelf RFPs and All Source RFPs, which provide for QFs with a capacity of 10 MW or greater); focus on renewable fuel and other "clean" facilities to the extent that federal and state Renewable Production Tax credit rules provide additional Renewable Energy Credit value to such facilities*<br>• *Acquire at least 50 MW of customer standby generation: 38 MW for the east side and 12 MW for the west side. Procurement to be handled by competitive RFP for demand response network service and/or individual customer agreements*<br>• Seek up to an additional 40 MW of customer standby generation if the economic recession and market conditions continue to support elimination of simple-cycle gas units or other peaking resources as indicated by IRP portfolio modeling for the 2010 business plan/2008 IRP update |
| 9 | Planning Process Improvements | 2009-2010 | Portfolio modeling improvements<br>• Complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of $CO_2$ and RPS regulatory requirements at the jurisdictional level |

| Action Item | Category | Timing | Action(s) |
|---|---|---|---|
| | | | • Continue to improve wind resource modeling by refining the representation of wind resources; attributes to consider include incremental reserve requirements and other components tied to system integration, geographical diversity impacts, and peak load carrying capability estimation<br>• Refine modeling techniques for DSM supply curves/program valuation, and distributed generation<br>• Investigate and implement, if beneficial, the Loss of Load Probability (LOLP) reliability constraint functionality in the System Optimizer capacity expansion model<br>• Continue to coordinate with PacifiCorp's transmission planning department on improving transmission investment analysis using the IRP models<br>• Continue to investigate the formulation of satisfactory proxy intermediate-term market purchase resources for portfolio modeling, contingent on acquiring suitable market data<br>Establish additional portfolio development scenarios for the 2010 business plan and 2008 IRP update<br>• A federal $CO_2$ cap-and-trade policy scenario along the lines originally proposed for this IRP<br>• Consider developing one or more scenarios incorporating plug-in electric vehicles and Smart Grid technologies |
| 10 | Transmission | 2009-2011 | Obtain Certificates of Public Convenience and Necessity for Utah/Wyoming/Northwest segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief<br>• Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Mona To Oquirrh<br>• Obtain Certificate of Public Convenience and Necessity for 230 kV and 500 kV line between Windstar and Populus<br>• Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Populus and Hemingway |
| 11 | Transmission | 2010 | Permit and build Utah/Idaho/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief<br>• Permit and construct a 345 kV line between Populus to Terminal |
| 12 | Transmission | 2012 | *Permit and build Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief*<br>• *Permit and construct a 500 kV line between Mona and Oquirrh* |
| 13 | Transmission | 2014 | *Permit and build segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief* |

| Action Item | Category | Timing | Action(s) |
|---|---|---|---|
| | | | • *Permit and construct 230 kV and 500 kV line between Windstar and Populus*<br>• *Permit and construct a 345 kV line between Sigurd and Red Butte* |
| 14 | Transmission | 2016 | *Permit and build Northwest/Utah/Nevada segments of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief*<br>• *Permit and construct a 500 kV line between Populus and Hemingway* |
| 15 | Transmission | 2017 | *Permit and build Wyoming/Utah segment of the Energy Gateway Transmission Project to support PacifiCorp load growth, regional resource expansion needs, access to markets, grid reliability, and congestion relief*<br>• *Permit and construct a 500 kV line between Aeolus and Mona* |

## PROGRESS ON PREVIOUS ACTION PLAN ITEMS

This section describes progress that has been made on previous active action plan items documented in the 2007 Integrated Resource Plan Update report filed with the state commissions on June 11, 2008. Most of these action items have been superseded in some form by items identified in the current IRP action plan.

**Action Item 1**: Acquire 2,000 MW of renewables by 2013, including the 1,400 MW outlined in the Renewable Plan. Seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources.

> *Status: This action item has been superseded by Action Item no. 1 in Table 9.2, which cites acquisition of 1,400 MW of cost-effective renewables. The company has acquired, or is in the process of acquiring, 901 MW of owned renewable generating facilities and 479 MW through wind power purchase agreements. PacifiCorp issued two RFPs in 2008 to support renewable energy action items.*

**Action Item 2**: Acquire the base Class 2 DSM (Pacific Power and ETO combined, including energy savings in Oregon beyond that funded by the ETO) of 300 MWa and 200 MWa or more of additional Class 2 DSM if risk-adjusted cost-effective initiatives can be identified. Will work with the ETO to identify such new energy efficiency initiatives and file the necessary tariffs with the Public Utility Commission of Oregon. PacifiCorp will reassess Class 2 objectives upon completion of system-wide DSM potential study. Will incorporate potentials study findings into the 2007 IRP update and 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits. Modeling also will take into account the benefits of conservation in reducing the costs of complying with Renewable Portfolio Standards.

> *Status: This action item has been superseded by Action Item no. 6 in Table 9.2. PacifiCorp issued an all-source DSM RFP in November 2008 to help meet Class 1 DSM acquisition goals.*

**Action Item 3**: Targets were established through potential study work performed for the 2007 IRP. Acquire 100 MW or more of additional Class 1 resources if risk-adjusted cost-effective initiatives can be identified. A new potential study was completed June 2007, and associated findings will be incorporated into the 2007 update and the 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.

> *Status: This action item has been superseded by Action Item no. 5 in Table 9.2. PacifiCorp developed Class 1 DSM supply curves using the DSM potentials study data, and incorporated them into the portfolio modeling for this IRP.*

**Action Item 4**: Although not currently in the base resource stack, the company will seek to leverage Class 3 and 4 resources to improve system reliability during peak load hours. PacifiCorp will incorporate potential study findings into the 2007 update and/or 2008 integrated resource planning processes.

*Status: This action item has been superseded by Action Item no. 7 in Table 9.2. PacifiCorp developed Class 3 DSM supply curves using the DSM potentials study data, and incorporated them into the portfolio modeling for this IRP. The all-source DSM RFP seeks price-responsive product proposals.*

**Action Item 5**: Pursue at least 75 MW of CHP generation for the west-side and 25 MW for the east-side, to include purchase of CHP output pursuant to PURPA regulations and from supply-side RFP outcomes. The potential study results will be incorporated into the 2007 update and 2008 integrated resource planning processes.

*Status: This action item has been superseded by Action Item no. 8 in Table 9.2. PacifiCorp has about 75 MW online of CHP/other distributed generation resources and 30-40 MW in the project pipeline.*

**Action Item 6**: [Distributed Generation] Will incorporate potential study findings into the 2007 update and 2008 integrated resource planning processes.

*Status: This action item has been successfully completed. Chapter 6 describes how PacifiCorp incorporated distributed generation resources in the IRP portfolio modeling.*

**Action Item 7**: Procure base load / intermediate load / summer peak resources system-wide by the summer of 2012 through 2016. This is part of the requirement included in the 2012 Base Load RFP and the 2008 All Source RFP.

*Status: This action item has been superseded by Action Item no. 3 in Table 9.2. PacifiCorp will reactivate the suspended 2008 All-Source RFP in late 2009 to assist in procuring the needed resources*

**Action Items 8 through 12**:

*Status: These action items are no longer active*.

**Action Item 13**: Pursue the addition of transmission facilities or wheeling contracts as identified in the IRP to cost-effectively meet retail load requirements, integrate wind and provide system reliability. Work with other transmission providers to facilitate joint projects where appropriate.

*Status: This action item has been superseded by Action Item nos. 10 through 15 in Table 9.2. Chapter 4 and Chapter 10 outline the company's transmission expansion plans.*

**Action Item 14**: Continue to have dialogue with stakeholders on Global Climate Change issues.

*Status: PacifiCorp continues to participate in numerous forums that address these issues. PacifiCorp's Environmental Policy and Strategy department and Government Affairs de-*

*partment are among the lead organizations within the company that participate in ongoing policy dialogues.*

**Action Item 15**: Evaluate technologies that can reduce the carbon dioxide emissions of the company's resource portfolio in a cost-effective manner, including but not limited to, clean coal, sequestration, and nuclear power. For the 2008 IRP, include IGCC plants with carbon capture and sequestration as a resource option for selection.

**Action Item 16**: Continue to investigate implications of integrating at least 2,000 MW of wind to PacifiCorp's system.

*Status: This action item has been superseded by Action Item Nos. 1 and 9. PacifiCorp is currently updating its wind integration cost estimates, and will include the results as Appendix E in the separate appendix volume for the May 29 IRP filing. PacifiCorp is also pursuing operational improvements for integrating wind resources. This activity is briefly described in the Resource Procurement Strategy section below.*

**Action Item 17**: Update modeling tools and assumptions to reflect policy changes in the area of renewable portfolio standards and carbon dioxide emissions.

*Status: This action item has been superseded by Action Item no. 9 in Table 9.2. PacifiCorp has successfully updated modeling assumptions, including detailed representation of state RPS requirements as system load-based constraints. See Chapter 7 for details on the modeling approach for representing RPS compliance and $CO_2$ costs.*

**Action Item 18**: Work with states to gain acknowledgement or acceptance of the 2008 integrated resource plan and action plan. To the extent state policies result in different acknowledged plans, work with states to achieve state policy goals in a manner that results in full cost recovery of prudently incurred costs.

*Status: Activity under this action item will commence after filing of the IRP with the state commissions.*

**Action Item 19**: In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk.

*Status: This action item has been superseded by Action Item no. 9 in Table 9.2. In formulating market purchase options for the IRP models, the company lacked information with which to discriminate such purchases from the proxy front office transaction (FOT) resources already modeled in this IRP. Lacking such information, the company anticipated using bid information from the 2008 All-Source RFP to inform the development of intermediate-term market purchase resources for modeling purposes. The company received no intermediate-term market purchase bids; therefore, such resources could not be reasonably modeled for this IRP. (See Chapter 6, "Resource Options") PacifiCorp will continue to investigate the formulation of satisfactory intermediate-term market purchases for portfolio modeling contingent on acquiring suitable market data.*

**Action Item 20**: For the 2008 IRP, develop a scenario to meet the $CO_2$ emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.

> *Status: This action item was successfully completed. PacifiCorp designed a portfolio analysis to address this requirement, estimating a system-wide hard cap based on Oregon's HB 3543 emission reduction goals. The company corrected a deficiency with the analysis pointed out by OPUC staff (assigning an emission rate to market purchases). A description of this portfolio scenario ("case 40") is provided in Chapter 7; modeling results are provided in Chapter 8.*

**Action Item 21**: For the 2008 IRP, further develop with stakeholders, use of loss of load probability (LOLP) and energy not served (ENS). Fully develop cost and risk metrics of various LOLP and ENS criteria.

> *Status: This action item has been superseded by Action Item no. 9 in Table 9.2. The company will investigate functionality in the System Optimizer model that allows the application of an LOLP constraint for capacity planning.*

**Action Item 22**: For the 2008 IRP, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their $CO_2$ emissions, under stringent carbon regulation scenarios.

> *Status: This action item has been successfully completed. PacifiCorp incorporated existing plant retrofits with carbon capture and sequestration technology as capacity expansion model resource options. Additionally, portfolios were developed to simulate the effect of forced coal plant back-down through high $CO_2$ costs and emissions hard cap constraints. The associated analysis is provided in Chapter 8.*

**Action Item 23**: Pursue refinement of $CO_2$ emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emission rates to short-term market transactions.

> *Status: This action item has been superseded by Action Item no. 9 Table 9.2, which highlights the $CO_2$ modeling enhancements that PacifiCorp is currently in the process of implementation with its model software vendor, Ventyx Energy, LLC. Completion of the software enhancements are expected in the summer of 2009.*

## IRP ACTION PLAN LINKAGE TO BUSINESS PLANNING

The IRP is not only a regulatory requirement, but is also a driver for PacifiCorp's business planning. As indicated in Chapter 2, the company has made a concerted effort to further align these two planning processes during this IRP cycle. The business planning process addresses the impacts of resources on the company's financial health, electricity rates, and the prospects for successful recovery of shareholder investments. Considerations such as resource affordability and financeability thus serve as checks to make sure that the IRP's long-term planning perspective comports with prudent utility business practices under today's commercial and regulatory environments.

For IRP and business planning alignment purposes, major resource differences between the preferred portfolio and the 2009 business plan approved in December 2008 were analyzed by PacifiCorp Energy's finance department for rate and financial impacts. This analysis also supported credit rating agency review of the business plan. The major resource changes included deferral of the CCCT to 2014, deferral of the IC Aero SCCT to 2016, and the wind acquisition schedule. (The preferred portfolio includes an additional 450 MW through 2018.)

## RESOURCE PROCUREMENT STRATEGY

To acquire resources outlined in the action plan, PacifiCorp intends to continue using a formal and transparent competitive Request for Proposals processes in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to consider project opportunities identified outside of a competitive procurement process that provide clear economic benefits to customers. Regardless of the method for acquiring resources, the company will use its IRP models to support resource evaluation as part of the procurement process, also using up-to-date load, price, and regulatory requirement information available at time that the evaluations occur. This will ensure that the evaluations account for a long-term system benefit view in alignment with the IRP portfolio analysis framework as directed by state procurement regulations, and with business planning goals in mind.

The sections below profiles the general procurement approaches for the key resource categories covered in the action plan: renewables, demand-side management, thermal plants, distributed generation, and market purchases.

### Renewable Resources

The renewables 2008R-1 RFP will be the mechanism under which the company will issue subsequent RFPs to meet most of the renewable resource acquisition goals over the ten-year business planning horizon. The 2008R-1 shelf RFP, to be issued on a periodic basis, will allow the company to react effectively to power supply market developments and changes in the status of RPS requirements, the production tax credit, other financial incentives, and $CO_2$ legislation. The company will seek both cost-effective conventional and emerging renewable technologies through the RFP process, including those coupled with energy storage. Qualifying Facilities under the Public Utilities Regulatory Policy Act (PURPA), at least 10 MW in size, are also treated as eligible resources under this particular RFP program.

The company will pursue renewable resources through means other than the shelf RFP in recognition that strong competition for renewable projects, and the dynamic nature of renewable construction and equipment markets, will require the company to respond quickly and efficiently as resource opportunities arise. Other procurement strategies that PacifiCorp will pursue in parallel include bi-lateral negotiations, PURPA contracting, and self-development.

In addition to supply-side resource acquisition, the company will add transmission infrastructure and flexible generating resources to support wind generation and its integration into the system. PacifiCorp will also work to improve its understanding of how to integrate large amounts of wind into its portfolio in a reliable and cost-effective manner. Areas of focus include wind forecasting, scheduling practices, curtailment tools, and regional coordination activities.

**Demand-side Management**

PacifiCorp uses a variety of business processes to implement DSM programs. The outsourcing model is preferred where the supplier takes the performance risk for achieving DSM results (such as the Cool Keeper program). In other cases, PacifiCorp manages the program and contracts out specific tasks (such as the Energy FinAnswer program). A third method is to operate the program completely in-house as was done with the Idaho Irrigation Load Control program. The business process used for any given program is based on operational expertise, performance risk and cost-effectiveness. With some RFP's, PacifiCorp developed a specific program design, and put that design out to competitive bid. In other cases, as with the currently active 2008 DSM RFP issued in November 2008, PacifiCorp opened up bidding to many types of Class 1, 2, and 3 programs and design options.

To support the DSM procurement program, the IRP models are used for resource valuation purposes to gauge the cost-effectiveness of programs identified for procurement shortlists. In the case of the 2008 DSM RFP, system benefit valuation estimates will be provided for both Class 1 and 2 programs. For Class 2 programs, PacifiCorp will perform a "no cost" load shape decrement analysis to derive program values, similar to what was done for the 2007 IRP. (Although the supply curve modeling approach used for Class 1 and Class 2 DSM programs can provide a gross-level indication of program value, an avoided-cost type of study is necessary to pinpoint precise values suitable for cost-effectiveness assessment.)

**Thermal Plants and Power Purchases**

Prior to the issuance of any supply-side RFP, PacifiCorp will determine whether the RFP should be "all-source" or if the RFP will have limitations as to the amount, proposal structure(s), fuel type, or other resource attributes. The company has lately turned to all-source RFPs in support of IRP fuel-type and technology diversity goals. For example, the 2008 all-source RFP does not specify fuel type requirements, and seeks a range of resources including renewables (greater than 10 MW), Power Purchase Agreements, load curtailment, and QFs.

Company resources will also be determined prior to an RFP being issued and may consist of a self-build option or ownership transfer arrangement. As with other resource categories, the IRP models will be used for bid evaluation, and will reflect the latest market prices, load forecasts, regulatory policies, and other updated information as appropriate.

**Distributed Generation**

Distributed generation, such as CHP and standby generators, were found to be cost-effective resources in the context of IRP portfolio modeling. PacifiCorp's procurement process will continue to provide an avenue for such new or existing resources to participate. These resources will be advantaged by being given a minimum bid amount (MW) eligibility that is appropriate for such an alternative, but that is also consistent with PacifiCorp's then-current and applicable tariff filings (QF tariffs for example). As noted in the action plan, QFs of 10 MW or greater are considered eligible resources in the company's currently active renewables RFP (2008R-1) and the 2008 All Source RFP, which is suspended in February 2009, but is expected to be reactivated late in the year.

PacifiCorp will continue to participate with regulators and advocates in legislative and other regulatory activities that help provide tax or other incentives to renewable and distributed resources. The company will also continue to improve representation of distributed generation resource in the IRP models.

## ASSESSMENT OF OWNING ASSETS VERSUS PURCHASING POWER

As the company acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, the company would be in a better position to control costs, make life extension improvements, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at cost as long as it remains economic. In addition, by owning a plant, the company can hedge itself from the uncertainty of relying on purchasing power from others. On the negative side, owning a facility subjects the company and customers to the risk that the cost of ownership and operation exceeds expectations, the cost of poor performance or early termination, fuel price risk, and the liability of reclamation at the end of the facilities life.

Purchasing power from another party can help mitigate the risk of cost overruns during construction and operation of the plant, can provide certainty of cost and performance, and can avoid any liabilities associated with closure of the plant. Short-term purchased power contracts could allow the company to forgo a long term decision for a period of time if it was deemed appropriate to do so. On the negative side, a purchase power contract could terminate prior to the end of the term, requiring the company to replace the output of the contract at then current market prices. In addition, the company and customers do not receive any of the savings that result from management of the asset, nor do they receive any of the value that arise from the plant after the contract has expired. Finally, credit rating agencies impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation can affect the company's credit ratios and credit rating.

## ACQUISITION PATH ANALYSIS

The acquisition path analysis conducted for this IRP focuses on four risk areas: regulatory events, load growth, gas prices, and procurement delays. The sections below present contingency resource strategies for the company to consider given significant changes in resource planning conditions tied to these four risk areas. The decision mechanism for pursuing the resource strategies is the outcome of the business planning process, which will be informed by portfolio modeling using the IRP models and updated input assumptions.

**Regulatory Events**

Table 9.3 outlines a set of resource acquisition strategies tied to regulatory "trigger" events that have been analyzed for the IRP via input assumption scenarios developed for portfolio analysis. These trigger events include (1) a fairly stringent federal RPS is enacted, (2) the federal renewable PTC expires or is phased out in the next 10 years, and (3) federal $CO_2$ regulation is enacted that results in $CO_2$ cost above and below PacifiCorp's designed $CO_2$ trigger point, which is the $CO_2$ cost that yields significant changes in the resource mix. The Table also lists major risks and implementation constraints for each acquisition strategy.

Public Utility Commission of Oregon IRP guidelines require PacifiCorp to "provide its assessment of whether a $CO_2$ regulatory future that is equally or more stringent than the identified trigger point will be mandated."[51] For this IRP, PacifiCorp defined a trigger point of $45/ton (modeled as a $CO_2$ tax) to demarcate the point at which significant changes to future resource acquisitions take place. Relative to the preferred portfolio, defined with the $45/ton $CO_2$ cost, PacifiCorp defined a trigger point of $70/ton that indicates a reasonable point at which further significant changes to future resource acquisition, as well as major changes to existing fossil fuel resource operations, take place. The company developed numerous portfolios based on these $CO_2$ cost trigger points, along with portfolios defined with even higher costs: a $100 $CO_2$ tax, and a $45 $CO_2$ tax with real escalation that reaches over $160 by 2028. (Chapter 8 provides expected cost and risk performance results as required by the Oregon IRP guidelines.)

The likelihood that $CO_2$ prices would reach or exceed $70/ton depends on the confluence of both federal and state policies that have yet to be determined regarding overall strategic goals, program design, and economic sector/industry responsibilities for helping to attain long-term $CO_2$ reduction objectives. Specifically, governments will need to determine if policies are needed to severely restrict the use of existing fossil fuel resources, and not just discourage new coal plants from being built. Until that policy question is answered, PacifiCorp has no basis to predict whether $CO_2$ costs will exceed any particular level.

Even when this policy question is answered, there are many uncertainties that complicate the task of predicting how high $CO_2$ prices will go at this time. For example, assuming that the U.S. adopts a cap-and-trade system, such open issues as the trajectory of annual $CO_2$ caps, free allowance and offset policies, state/federal interjurisdictional coordination, safety valve provisions, linkages to potential federal RPS requirements, and many other factors, will ultimately determine if $CO_2$ costs exceed $70/ton. Adding to the uncertainty are the following factors:

- The perceived affordability of aggressive $CO_2$ reduction policies in today's economic environment, which could result in a "take it slow" regulatory track
- The pace of technology advancements

[51] Public Utility Commission of Oregon, Order No. 08-339, "Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process", Guideline 8d, June 30, 2008.

- Public policies towards clean coal, advanced nuclear, and other emerging technologies that are currently controversial
- Commitments to reaching international climate change mitigation goals

## Load Growth and Gas Prices

Figure 9.29 shows different resource acquisition paths based on combinations of relative decreases and increases in load growth and gas price projections given the preferred portfolio input assumptions as the starting point. The acquisition paths shown are necessarily high-level, reflecting resource types rather than quantities and timing. The figure also highlights the connection with $CO_2$ regulations, the uncertainty of which greatly complicates any type of contingency resource planning involving other planning variables.

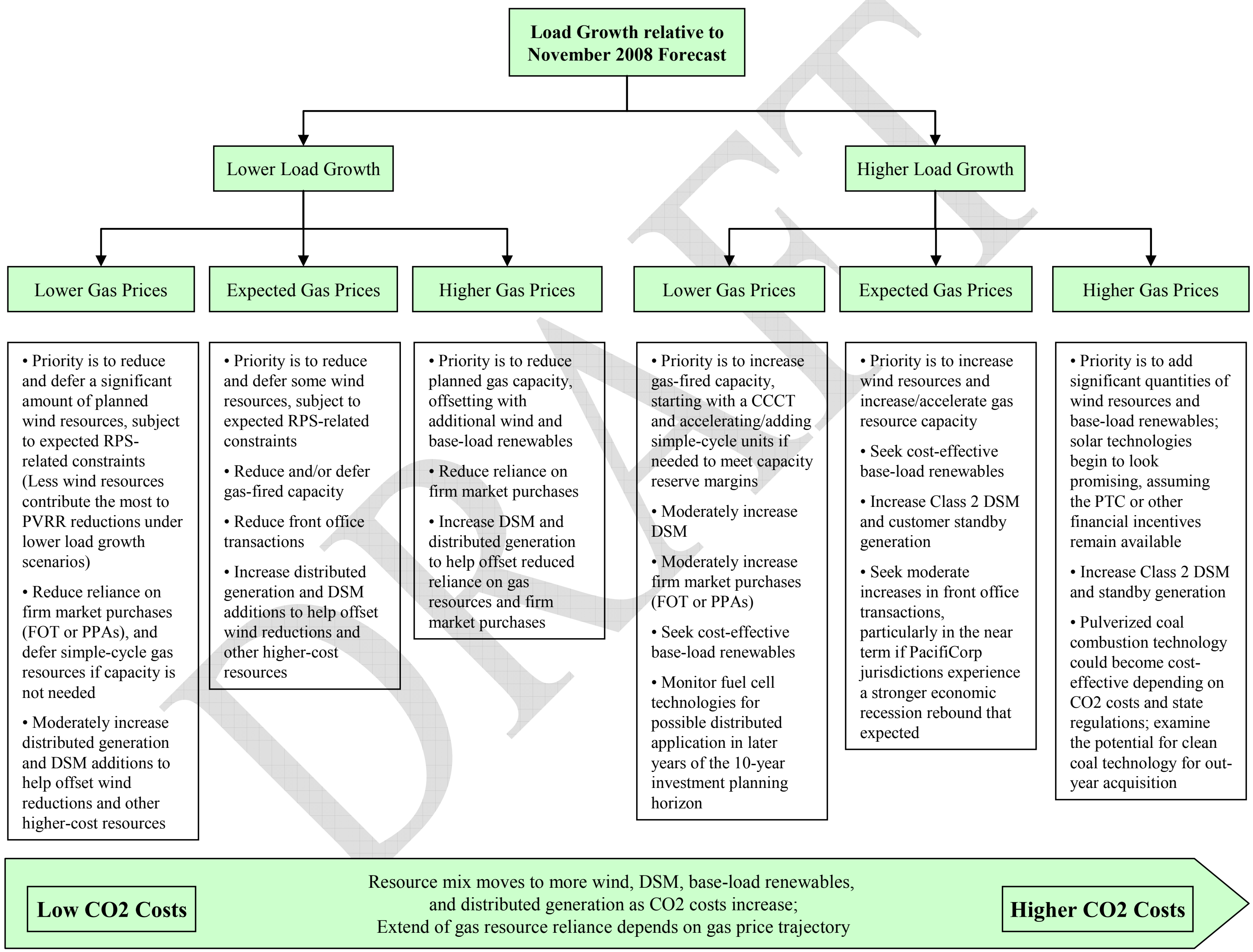
**Table 9.3 – Resource Acquisition Paths Triggered by Major Regulatory Actions**

| Trigger Event | Planning Scenario(s) | Resource Acquisition Strategy | Risks and Constraints |
|---|---|---|---|
| Federal Renewable Portfolio Standard enacted | • A federal RPS is instituted requiring 15% of load to be met with qualifying renewables by 2020, 20% by 2020, and 25% by 2025. | • Cumulative wind capacity totals of 1,600 MW and 3,500 MW are needed by 2020 and 2025, respectively, based on the portfolio developed for the high RPS requirement scenario (case 44).<br>• Spread incremental renewables acquisition according to an annual schedule for procurement flexibility, accelerating as necessary to account for near-term RPS requirements and to take advantage of cost-effective site availability, transmission access, and government financial incentives.<br>• Aggressively diversify the renewables portfolio with other technologies (geothermal, solar, and biomass) as dictated by market conditions and the availability of suitable cost-effective projects.<br>• Continue to issue renewable RFPs under PacifiCorp's shelf RFP program, and step up consideration of unsolicited proposals and multi-participant projects as opportunities arise.<br>• Step up acquisition of demand-side management programs and distributed renewables generation to mitigate cost and procurement risks of utility-scale supply-side projects.<br>• Adjust transmission construction plans and increase regional transmission coordination efforts to facilitate project development activity. | • Ratepayer affordability and company financial impacts associated with a large and protracted renewables acquisition program.<br>• Demand/supply imbalance for wind turbines and labor results in project delays and higher construction costs.<br>• Local environmental and land use concerns/restrictions begin to adversely impact renewable project plans by increasing resource costs and forcing construction delays.<br>• Transmission construction delays.<br>• Compliance burden and costs associated with multi-jurisdictional RPS requirements. |
| Renewable Production Tax Credit expiration or cut-back | • The renewables PTC expires within the 2013-2018 period for wind, or less likely, all renewable resources.<br>• The renewables PTC is phased out over a multi-year period. | • Accelerate renewables acquisition to obtain as much as possible before the PTC expiration date; renewable additions were not found to be cost-effective beyond the PTC expiration date given relatively low $CO_2$ costs during the 2013-2018 period. | • Acceptability of associated rate increases due to the accelerated renewables combined with other resource acquisitions.<br>• Near-term impact on the company's financial situation.<br>• Regulatory requirements (siting and procurement) that could jeopardize meeting required in-service dates. |

| Trigger Event | Planning Scenario(s) | Resource Acquisition Strategy | Risks and Constraints |
|---|---|---|---|
| $CO_2$ emission compliance: low to medium cost impact | • A federal cap-and-trade program or $CO_2$ tax is implemented with an effective production cost impact of up to $70/ton. | • The preferred portfolio is considered a reasonable planning starting point for an uncertain $CO_2$ cost up to $70/ton.<br>• The preferred portfolio would be modified as an outcome of business plan/IRP portfolio modeling to reflect updated assessments of $CO_2$ regulations (start and trajectory of $CO_2$ costs), other energy policies affecting renewable energy acquisition and economics, and forward gas prices. (Natural gas prices affect the quantity of wind to include in the resource portfolio. For example, comparing the preferred portfolio and the portfolio for case 8B, a 20% increase in gas prices was found to result in a 700 MW increase in wind selected by the capacity expansion model.)<br>• Depending on expected $CO_2$ costs and gas prices, step up acquisition of demand-side management programs and high-efficiency distributed generation to help minimize the carbon footprint, continue to diversify the resource mix, and take advantage of any $CO_2$ compliance credits that may be given to these resource types.<br>• Modify the bid evaluation process (which is based on the IRP portfolio modeling framework) to reflect updated $CO_2$ regulatory expectations. | • Ratepayer affordability and company financial impacts associated with $CO_2$ costs that approach the upper end of the cost range ($40 to $70/ton).<br>• Compliance burden and costs associated with multi-jurisdictional $CO_2$ regulatory requirements. |
| $CO_2$ emission compliance: high cost impact | • A federal cap-and-trade program or $CO_2$ tax is implemented with an effective production cost of $70/ton or greater. | • Acquire at least an additional 2,500 MW of wind and at least 70 MW of geothermal capacity or other base-load renewable resources, with the timing and annual amounts tied to the start of $CO_2$ regulations and trajectory of $CO_2$ costs. These minimum targets are suggested by the portfolio generated from case 17B, optimized using a $70/ton $CO_2$ cost.<br>• Consider emission offset possibilities to ameliorate resource acquisition and cost risks. | • Ratepayer affordability and company financial impacts associated with necessary resource acquisitions (including those needed to potentially replace less efficient fossil fuel plants).<br>• Compliance safety value or emergency off-ramp provisions kick in due to high compliance costs. |

| Trigger Event | Planning Scenario(s) | Resource Acquisition Strategy | Risks and Constraints |
|---|---|---|---|
| | | • Step up acquisition of higher-cost demand-side management programs and high-efficiency distributed generation to further minimize the carbon footprint.<br>• Consider advanced high-efficiency gas generation technologies, evaluating the trade-off between greater efficiency and higher capital costs and project risks.<br>• Aggressively pursue efficiency improvements for PacifiCorp's existing fossil fuel and hydropower plants.<br>• For long-term resource needs and to potentially replace existing fossil fuel plants, continue to reevaluate clean coal technologies, advanced nuclear, and emerging renewable and energy storage technologies.<br>• Modify the bid evaluation process to reflect updated $CO_2$ regulatory expectations. | |

**Figure 9.29 – Resource Acquisition Paths Tied to Load Growth and Natural Gas Prices**



**Procurement Delays**

The main procurement risk is an inability to procure resources in the required time frame to meet the need. There are various reasons why a designated resource cannot be procured in the time-frame identified in the IRP and 10-year business plans. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or a sudden change in environmental or other electric utility regulations may change the company's entire resource procurement strategy.

Possible paths PacifiCorp could take if there was either a delay in the on-line date of a resource or, if it was no longer feasible or desirable to acquire a given resource, include the following:

- Use alternative bids if they haven't been released under a current RFP
- Issue an emergency RFP for a specific resource
- Move up the delivery date of the next resource by negotiating with the supplier/developer
- Rely on near-term purchases until a longer-term alternative is identified, acquired through PacifiCorp's mini-RFPs or sole source procurement
- Install temporary generators to address some or all of the capacity needs
- Temporarily drop below the 12 percent planning reserve margin
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts

## MANAGING CARBON RISK FOR EXISTING PLANTS

Carbon dioxide reduction regulations at the federal and state levels would prompt the company to continue to look for measures to lower $CO_2$ emissions of existing thermal plants through cost-effective means. The cost, timing, and compliance flexibility afforded by $CO_2$ reduction rules will impact what types of measures would be cost-effective and practical from operational and regulatory perspectives. For a cap-and-trade system, examples of factors include the allocation of free allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. To lower the emission levels for existing thermal plants, options include changing the fuel type, repowering with more efficient generation equipment, lowering the plant heat rate so it is more efficient, and. adoption of new technologies such as $CO_2$ capture with sequestration when commercially proven. Indirectly, plant carbon risk can be addressed by acquiring offsets in the form of renewable generation and energy efficiency programs. Under an aggressive $CO_2$ regulatory environment, early coal plant retirement becomes a tenable option. Such coal plant retirement decisions would also depend on market conditions and technological advancements that would enable cost-effective base-load power replacement or retrofit opportunities.

High $CO_2$ costs would shift technology preferences both for new resources and existing resources to those with more efficient heat rates and also away from coal, unless carbon is sequestered. There may be opportunities to repower some of the existing coal fleet with a different less carbon-intensive fuel such as natural gas, but as a general rule, coal units will continue to use the existing coal technology until it is more cost-effective to replace the unit in total. A major issue is whether new technologies will be available that can be exchanged for existing coal economically.

Fuel switching and dual-fueling provide some limited opportunities to address emissions, but will require both capital investment and an understanding of the trade-offs in operating costs and risks. While these options would provide the company a means to lower its emission profile, such options would be extremely expensive to implement without a high carbon emission penalty.

## USE OF PHYSICAL AND FINANCIAL HEDGING FOR ELECTRICITY PRICE RISK

The company proposes to continue to hedge the price risk inherently carried due to volume mismatches between sales obligations and economic resources by purchasing or selling fixed-price energy in the forward market. These transactions mitigate the company's financial exposure to the short-term markets, which historically have much greater price volatility than the longer-term markets. Specifically, purchasing to cover a short position in the forward market reduces the company's financial exposure to increasing prices, albeit these transactions also reduce the company's financial opportunity if prices decrease. Selling to cover a long position has a similar effect.

The company also proposes to continue to hedge the physical delivery risk inherently carried due to the volume mismatch between physical resources and physical obligations by purchasing or selling physical products in the forward through real-time markets. The purpose of purchases is to ensure adequate resources to maintain reliable delivery to the company's obligations such as retail load. The purpose of sales is to ensure the company's ability to economically generate and deliver electricity to wholesale purchasers.

## MANAGING GAS SUPPLY RISK

Adding natural gas generating resources to PacifiCorp's system requires an understanding of the fuel supply risks associated with such resources, and the application of prudent risk management practices to ensure the availability of sufficient physical supplies and limit price volatility exposure. The risks discussed below include price, availability, and deliverability.

### Price Risk

PacifiCorp manages price risk through a documented hedging strategy. This strategy involves fully hedging price risk in the nearest 12-month period and hedging less of the exposure each year beyond that through year four. Near-term prices are fully hedged to add price certainty to near term planning horizons, budgets, and rate case filings. Further out, where plans and budgets are less certain, PacifiCorp considers its most recent ten-year business plan in making hedging decisions. PacifiCorp balances the benefit of hedging that plan's price assumptions with prudent risk management for its ratepayers and shareholders. PacifiCorp hedges price risk through the use of financial swap transactions and/or physical transactions. These transactions are executed with various counterparties that meet PacifiCorp's credit and contractual requirements.

**Availability Risk**

Availability risk refers to the risk associated with having natural gas supply in the vicinity of contemplated generating assets. PacifiCorp purchases physical supply on a forward basis achieving contractual commitments for supply. The company also relies on its ability to purchase physical supplies in the future to meet requirements. This second approach subjects PacifiCorp to price risk resulting from swings in supply-demand balances, as well as the risk that natural gas production in a producing region ceases regardless of price. It is reasonable to believe that a region-wide cease in production, given reserve estimates, could only be brought about by extreme and unforeseen events such as natural disaster or regulatory moratoriums on the production or consumption of natural gas—events that long-term supply commitments would not counteract. Index prices are designed to reflect the prevailing cost of supply at various delivery locations. As described above, PacifiCorp hedges its exposure to changes in those index prices, thereby allowing for procurement of supply at floating index prices or waiting to acquire supply when requirements estimates are more accurate and the premiums for longer-term commitments are no longer demanded by suppliers.

**Deliverability Risk**

Deliverability risk refers to the risk associated with transporting natural gas supply from supply locations to generating facilities. The IRP accounts for the cost of natural gas transportation service required to fuel gas plants, and uses existing tariff pipeline-defined transportation capacity and transportation costs in evaluating the need, timing, and location of new natural gas-fired generating plants. More specifically, the IRP uses existing maximum tariff rates for demand charges, volumetric costs, and reimbursement of fuel and lost/unaccounted natural gas. These tariff rates are developed through cost of service filings with appropriate regulators—the FERC for interstate pipelines and relevant state regulators for intrastate pipelines. By definition, rates are developed based on cost of service of existing operations, without consideration for maintenance and operations of future expansions. The result of this is that the IRP assumes that the economics of a new natural gas fired generator reflect the current cost of service for existing natural gas transportation facilities; whereas, the cost of any new natural gas transportation capacity is dependent on the volumetric size of the new capacity, and prevailing costs of construction, maintenance, and operations (e.g. steel, labor, financing).

Also, the IRP accounts for the availability of natural gas transportation service required to fuel new electricity generating facilities. In selecting a gas-fired resource, the implicit assumption is made that natural gas transportation infrastructure exists or will be built. This is a reasonable assumption if one further assumes that the construction of new pipeline facilities is a function of cost, which is addressed above.

PacifiCorp manages this transportation cost through two transaction types: transportation service agreements and delivered natural gas purchases:

- PacifiCorp enters into transportation service agreements that offer PacifiCorp the right to ship natural gas from prolific production basins or liquidly traded "hubs" to generating assets. Natural gas hubs exist where a large volume of production is gathered and delivered into a large interstate pipeline or where large pipelines intersect. These hubs lead to liquidly traded markets as the movement of gas from one transporting pipeline to another lead to a large number of willing buyers and sellers.

- PacifiCorp purchases natural gas delivered to generating plants and/or hubs. This approach pushes the deliverability risk to the supplier by contractually committing it to making necessary supply and/or transportation arrangements.

PacifiCorp is confident that the risks associated with fueling current and prospective natural gas fueled generation can be effectively managed. Risk management involves ongoing monitoring of the factors that affect price, availability, and deliverability. While prudence warrants the monitoring of many factors, some issues that PacifiCorp needs to pay particular attention to, given today's market, include the following:

- Potential counterparties need to be continually monitored for their long-term viability, especially given the current economic downturn.
- Environmental concerns could impact natural gas prices, particularly given the prospects of a $CO_2$ cap-and-trade or tax program. PacifiCorp continues to monitor the regulatory environment and its potential impact on natural gas pricing.
- As production grows in the Rocky Mountains, so does the transportation infrastructure. PacifiCorp continues to monitor this activity for risks and opportunities that new pipeline infrastructure may yield.

## TREATMENT OF CUSTOMER AND INVESTOR RISKS

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

### Stochastic Risks

One of the principle sources of risk that is addressed in this IRP is stochastic risk. Stochastic risks are quantifiable uncertainties for particular variables. The variables addressed in this IRP include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

### Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in this plan. Capital expenditures continue to increase, driven by the need for infrastructure investment to support load growth and maintain reliable electricity supplies, and the effects of cost inflation. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

## Scenario Risks

Scenario risks pertain to abrupt or fundamental changes to model inputs that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risk facing PacifiCorp continues to be government actions related to $CO_2$ emissions. This scenario risk relates to the uncertainty in predicting the scope, timing, and cost impact of $CO_2$ emission compliance rules. Chapter 3 framed this issue in terms of the impacts of $CO_2$ policy and cost uncertainty on wholesale electricity prices.

To address this risk, the company decided in 2007 that acquiring a coal plant was not a viable resource option until regulatory clarity concerning $CO_2$ costs and technology/fuel policies is obtained. While coal plants are allowed as eligible resources for competitive procurements that solicit base-load resources, PacifiCorp evaluates all bid resources using a range of $CO_2$ prices consistent with the scenario analysis methodology adopted for the company's IRP portfolio evaluation process. Further, coal resources must comply with applicable existing state $CO_2$ compliance regulations. The risk of potential future $CO_2$ costs is therefore fully accounted for in resource planning and procurement decision-making. The company's efforts to acquire wind and DSM resources also serve as effective $CO_2$ risk mitigation measures.

# 10. TRANSMISSION EXPANSION ACTION PLAN

## INTRODUCTION

Since the original announcement of Energy Gateway in May 2007 and as discussed further in Chapter 4, PacifiCorp has emphasized that significant infrastructure of new transmission capacity is needed to adequately serve PacifiCorp's existing and future loads. The company's position has not changed in this regard and still requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South) of new transmission capacity to adequately serve its customers load and growth needs for the long-term.

PacifiCorp also recognized in its original announcement the need and benefits of potentially "upsizing" the Energy Gateway Program to increase transmission capacity by two-fold (6,000 MW). This upsizing would potentially provide a number of local and regional benefits such as: maximizing the use of new proposed corridors, potential to reduce environmental impacts, provide economies of scale needed for large infrastructure, lower cost per megawatt of transport capacity made available, and improved opportunity for third parties to obtain new long-term firm transmission capacity.

PacifiCorp still believes there are short-term and long-term benefits for upsizing Energy Gateway and has vigorously pursued other participants the past year and a half. To this point, significant barriers still exist preventing PacifiCorp and other third parties from making a business decision to upsize the Energy Gateway Program without taking significant financial and delivery risk. PacifiCorp is proceeding with efforts regarding planning, rating, and permitting requirements for the Energy Gateway Program which facilitates a planned ultimate transmission capacity of 3,000 MW for Gateway West and 3,000 MW for Gateway South (6,000 MW total). In order to achieve the ratings while meeting customer requirements, PacifiCorp plans to achieve the ratings in stages or phases based on need and construction timing.

PacifiCorp is moving forward with the expansion plan that will construct transmission lines and substations required to provide 1,500 MW on Gateway West and 1,500 MW on Gateway South (3,000 MW total) transmission capacity required to meet PacifiCorp's long-term regulatory requirement to serve loads.

In addition, several main grid reinforcement projects that are complementary to the Energy Gateway program are scheduled for completion over the next several years. They are described after the Energy Gateway segments.

High-level descriptions of the Energy Gateway segments and company planning activities are outlined below. In-service dates are based on optimal timing of transmission needs and best efforts to complete construction. The dates reflect the most recent Gateway planning assessment, which occurred after the completion of IRP modeling described in the preceding chapters. Gateway plan modifications will be incorporated in PacifiCorp's 2010 business plan and the 2008 IRP update. In-service dates are subject to timing shifts based on permitting, environmental approvals, and construction schedules.

## GATEWAY SEGMENT ACTION PLANS

### Walla Walla to McNary – Segment A

Originally planned as a single circuit 230 kV transmission line approximately 56 miles in length between Wall Walla, Washington and Umatilla, Oregon that connects existing substations at Walla Walla, Wallula, and McNary. The initial target completion date was 2010; however, additional information became available in early 2009 that prompted the decision to defer moving forward with the current project scope in 2009.

PacifiCorp acquired the Chehalis generation plant in late 2008 and on February 13, 2009 redirected 470 MW of transmission rights to the Mid Columbia area. Existing transmission rights between Yakima and Walla Walla allow a portion of the Chehalis resources to cover any Walla Walla short resource position. This minimizes any net power costs benefits from the prior economics that showed Hermiston generation located in Oregon displacing Mid-Columbia purchases and serving Yakima and Walla Walla loads during short supply periods.

Over the next six to twelve months, PacifiCorp is actively participating in transmission plans and system rating processes impacting the Northwest, and these plans are expected to mature and possibly influence PacifiCorp's Westside Plan. At that time, the company will determine any additional transmission needed in the Walla Walla / McNary area. PacifiCorp will continue to evaluate the project and incorporate the analysis with regional transmission needs.

### Populus to Terminal – Segment B

A double circuit 345 kV line that will run approximately 135 miles from a new substation (Populus) near Downey, Idaho to the existing Terminal Substation near Salt Lake International Airport west of Salt Lake City, Utah. When completed in 2010, this segment will improve reliability along a critical transmission corridor (Path C) and provide additional transfer capability of energy resources both south bound and north bound. It will also provide a vital link for Energy Gateway path ratings.

### Mona to Limber to Oquirrh – Segment C

A single circuit 500 kV line that will run approximately 65 miles between the existing Mona Substation in central Utah to a future substation called Limber in the Tooele Valley, west of Salt Lake City, Utah. It will also include a double circuit 345 kV line that will run approximately 21 miles between the future Limber Substation to an existing substation called Oquirrh in the Salt Lake valley. When completed in 2012, it provides a critical northbound path for additional resource whether internally generated or purchased through market transactions. It will also provide a vital link for reliability and Energy Gateway path ratings.

### Oquirrh to Terminal

A double circuit 345 kV line that will run approximately 14 miles between the Oquirrh Substation to an existing Terminal Substation near Salt Lake International Airport west of Salt Lake City, Utah. When completed in 2012, it will add operational flexibility to the bulk electrical system, improved reliability and will provide a vital link for Energy Gateway path ratings.

**Windstar to Aeolus to Bridger to Populus – Segment D**

Part of Energy Gateway West, it is comprised of two single circuit 230 kV lines that will run approximately 82 and 72 miles respectively between the recently constructed Windstar Substation in eastern Wyoming to a new substation called Aeolus near Medicine Bow, Wyoming. It will continue as a 500 kV single circuit line that will run approximately 141 miles from Aeolus Substation to a new annex substation near the existing Bridger Substation near Jim Bridger Power Plant in western Wyoming.

The last section will connect the new annex substation located near Bridger Substation to the Populus Substation that is being constructed as part of the Populus to Terminal segment. When completed in 2014, the entire segment will move wind or other resources from eastern Wyoming to a critical hub (Populus) located near Downey, Idaho. The Populus Substation is the intersection substation for Gateway West and Gateway Central.

**Populus to Hemingway – Segment E**

Two single circuit 500 kV lines that will run approximately 135 and 149 miles respectively between the Populus Substation and the existing Midpoint Substation. One of the lines will also connect the existing Borah Substation between Populus and Midpoint. The segment will continue as a single circuit 500 kV line for approximately 126 miles from Midpoint Substation to a new Hemingway Substation located south of Boise on the south side of the Snake River between the towns of Melba and Murphy. When completed in 2016 the segment will connect resources located in eastern Wyoming and Gateway Central to load centers further west. It will also allow the company to maintain reliable electric service in the Western Interconnection.

**Aeolus to Mona – Segment F**

A single-circuit 500 kV line that runs approximately 395 miles between the Aeolus Substation (constructed as part of Gateway West) and the Mona Substation (expanded as part of Gateway Central). When completed in 2017 the segment will connect Gateway West and Gateway Central providing operational flexibility for the bulk electric network, reliability and supports path ratings for each segment.

**Sigurd to Red Butte – Segment G**

A single circuit 345 kV line that runs approximately 160 miles connecting the existing Sigurd Substation located in central Utah to another existing substation called Red Butte Substation located in southwest Utah. When completed in 2014, it provides a critical path to meet load obligations, increase export capability and to maintain transmission capacity on TOT2C for contracted point to point service. Specific routing alternatives are currently being considered in the permitting and ratings processes.

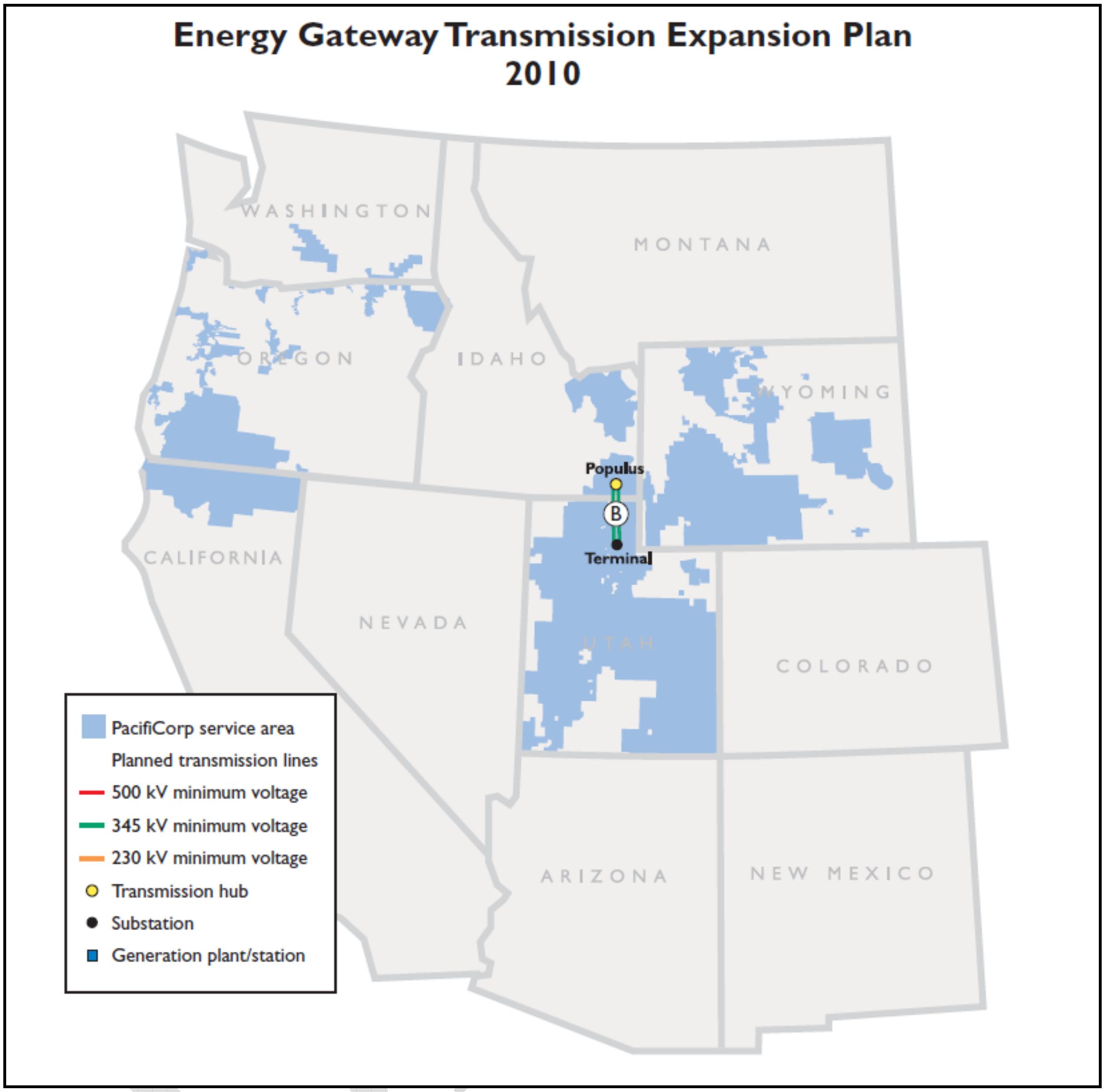
Segment G originally included a single circuit 500 kV line from Red Butte Substation in Utah to Crystal Substation in Nevada. The transmission line is being deferred for further review due to the fact that existing customer forecasted needs are anticipated to be met without its construction. Studies show bi-directional flows to markets are met by installing upgrades at Harry Allen Substation in Nevada and other system reinforcements in 2014. Although the segment is not needed at this time for the 1,500 MW Gateway South expansion plan, the line segment and related substation upgrades will be required for Energy Gateway South to obtain the next incremental rating of 3,000 MW total.

Construction of the planned transmission segments by estimated in-service dates and additional megawatt capacity are shown in the following sequence of maps. Delivery of the segments by the calendar years shown are particularly critical for Gateway West from Windstar to Populus, Gateway Central from Mona to Terminal, and Gateway South from Sigurd to Red Butte, due to the IRP preferred portfolio reliance on available transmission.

Maintaining sufficient transmission capacity for southwest Utah loads and maintaining contracted point-to-point transmission service prior to the Sigurd to Red Butte - Segment G addition in 2014 will require several substation upgrades. The Sigurd to Red Butte project is being considered with other alternatives to meet the requirements in SW Utah. In 2010, PacifiCorp is planning to install additional station equipment at Harry Allen Substation, Pinto Substation and Three Peaks Substation and in 2011 additional station equipment is being installed at Red Butte Substation.

Additional main grid reinforcement projects also includes upgrades to TOT2C path at Harry Allen Substation in Nevada, which will increase bi-directional flows to markets in the Desert Southwest needed in 2014.

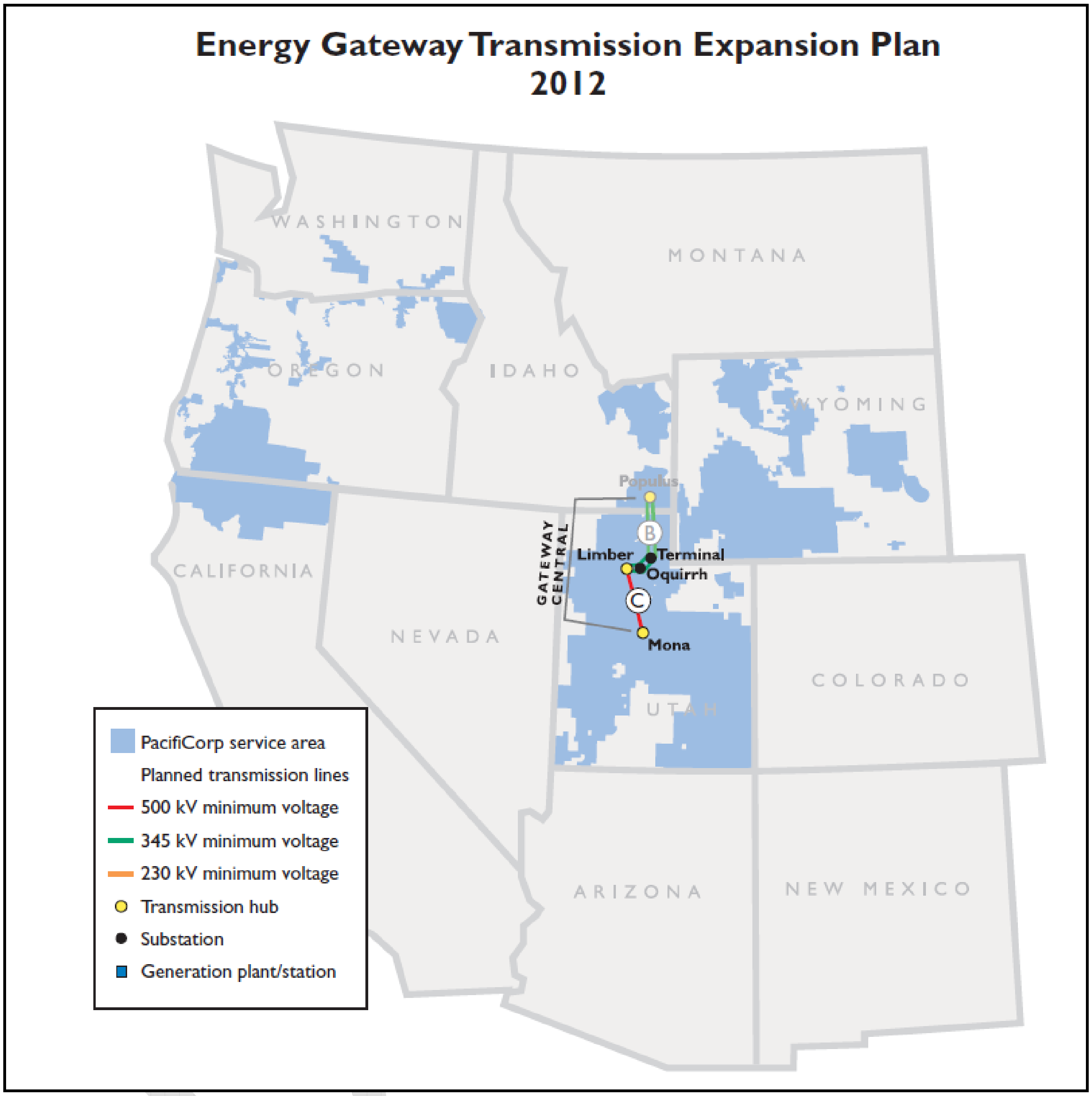
## Figure 10.1 – Energy Gateway 2010 Additions




**Note:** This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

| Segment | Segment Description | Line | Planned Rating (Initial completion) | Planned Rating (Core completion) |
|---|---|---|---|---|
| B | Populus - Terminal | 345 kV double circuit | 700 MW | 1400 MW |

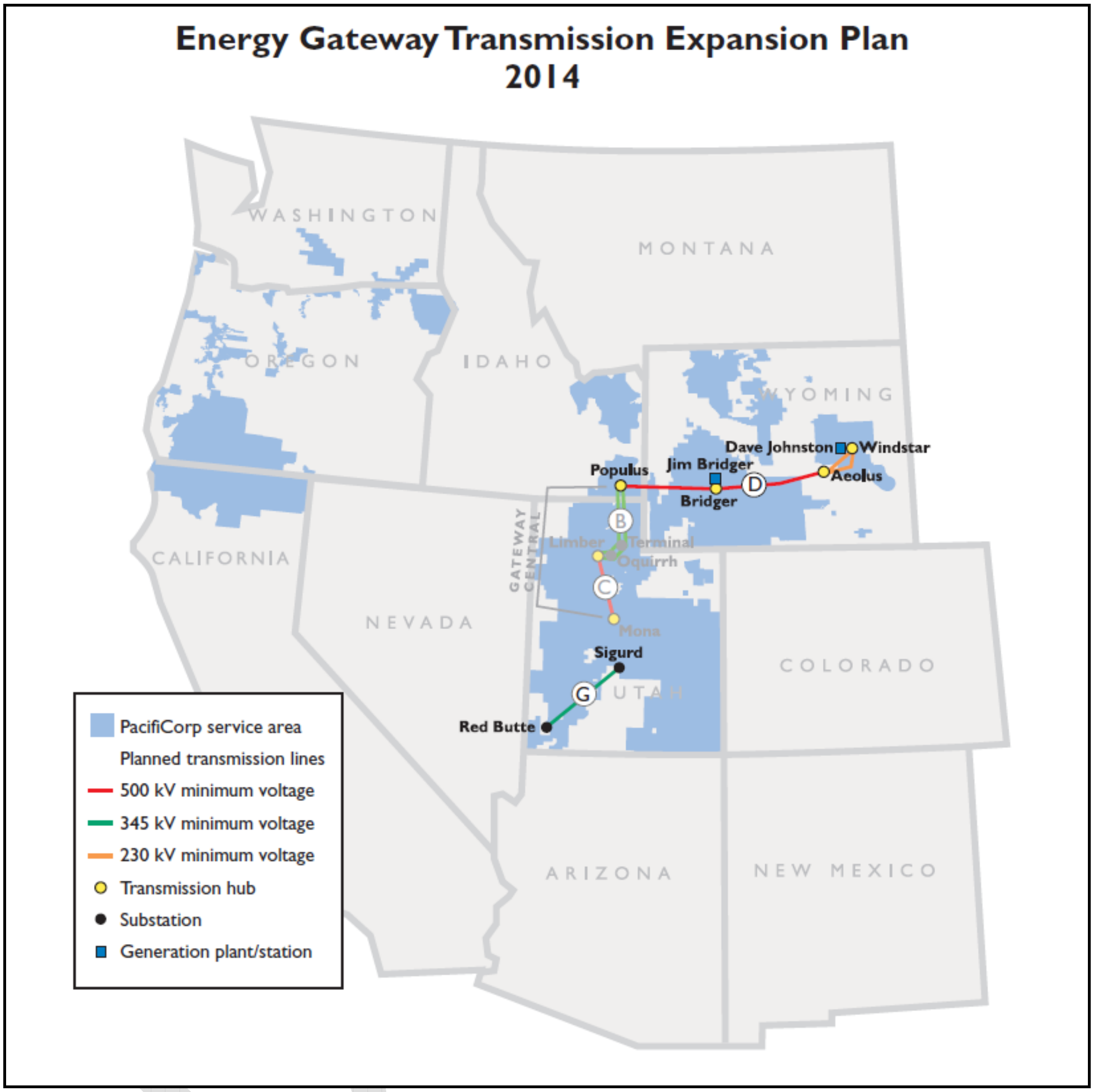
## Figure 10.2 – Energy Gateway 2012 Additions




**Note:** This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

| Segment | Segment Description | Line | Planned Rating (Initial completion) | Planned Rating (Core completion) |
|---|---|---|---|---|
| C | Mona – Limber<br>Limber – Oquirrh | 500 kV single circuit/<br>345 kV double circuit | 700 MW | 1500 MW |
| Other | Oquirrh – Terminal | 345 kV double circuit | 700 MW | 1500 MW |

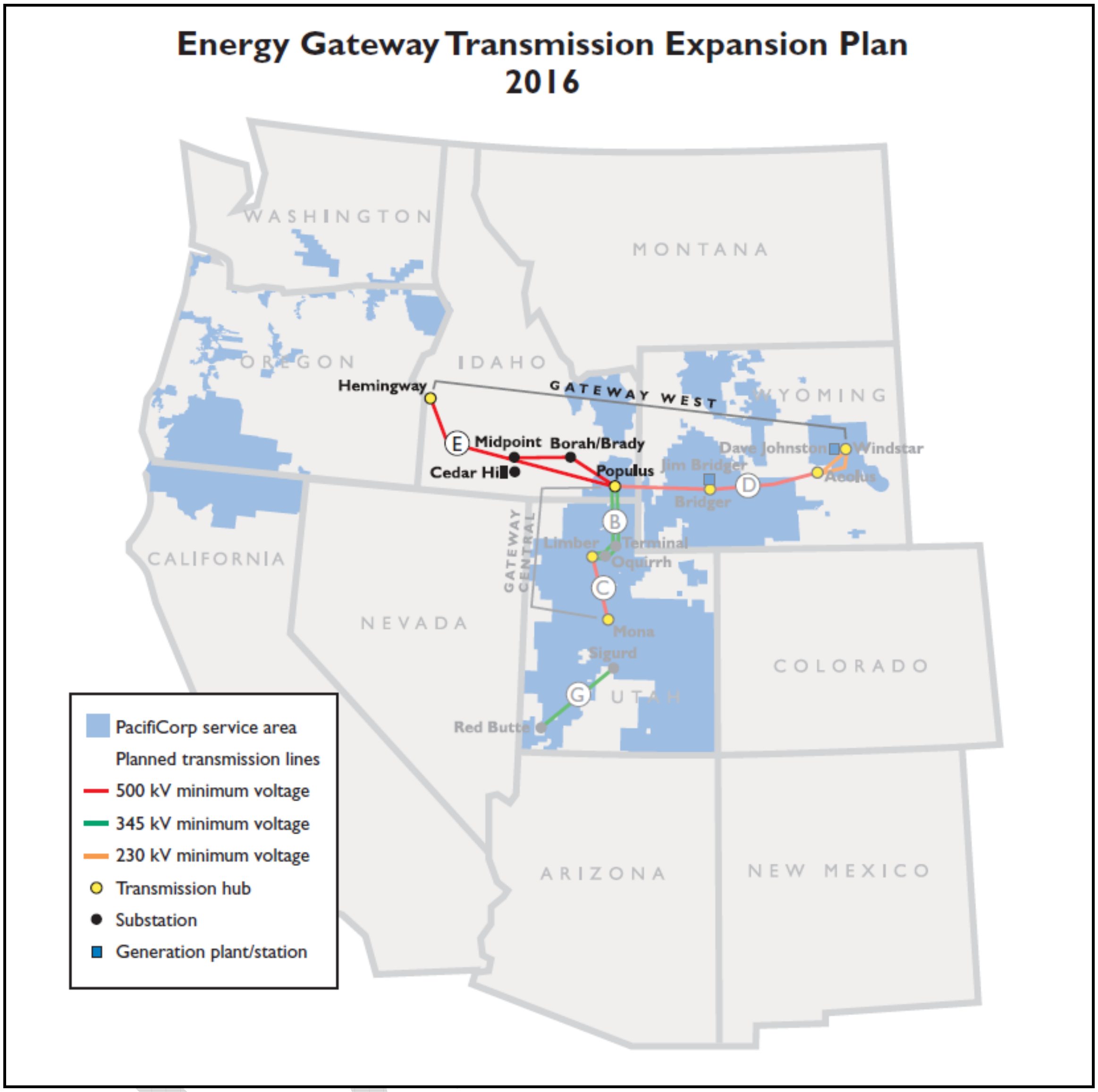
### Figure 10.3 – Energy Gateway 2014 Additions




**Note:** This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

| Segment | Segment Description | Line | Planned Rating (Initial completion) | Planned Rating (Core completion) |
|---|---|---|---|---|
| D | Windstar – Aeolus<br>Aeolus –Bridger<br>Bridger - Populus | 2-230 kV single circuits<br>500 kV single circuit<br>500 kV single circuit | 700 MW<br>700 MW<br>700 MW | 700 MW<br>1500 MW<br>1500 MW |
| G | Sigurd – Red Butte | 345 kV single circuit | 600 MW | 600 MW |
| Various | Various upgrades at Harry Allen to increase capacity to the Desert Southwest | TOT2C Path | 600 MW | 600 MW |

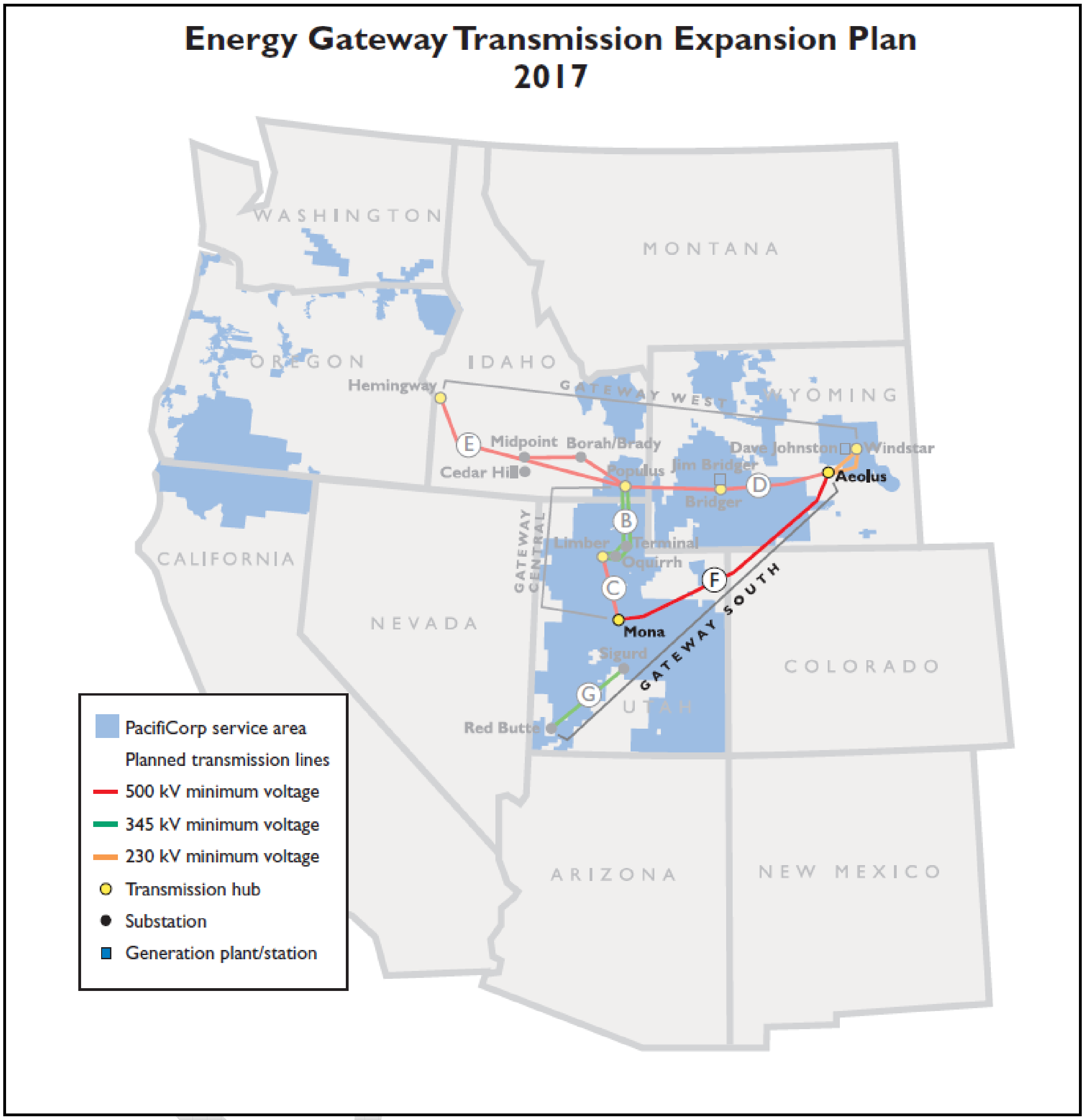
## Figure 10.4 – Energy Gateway 2016 Additions




**Note:** This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

| Segment | Segment Description | Line | Planned Rating (Initial completion) | Planned Rating (Core completion) |
|---|---|---|---|---|
| E | Populus – Borah – Midpoint | 500 kV single circuit | 700 MW | 1500 MW |
| E | Populus – Midpoint – Hemingway | 500 kV single circuit | 700 MW | 1500 MW |

## Figure 10.5 – Energy Gateway 2017 Additions




**Note:** This series of maps generally reflect the expansion necessary to adequately serve PacifiCorp's existing and future loads, which requires 3,000 MW (1,500 MW on Gateway West and 1,500 MW on Gateway South). PacifiCorp is proceeding with efforts regarding planning, rating, and permitting for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

| Segment | Segment Description | Line | Planned Rating (Initial completion) | Planned Rating (Core completion) |
|---|---|---|---|---|
| F | Aeolus – Mona | 500 kV single circuit | 1500 MW | 1500 MW |

**Westside Plan / Red Butte – Crystal**

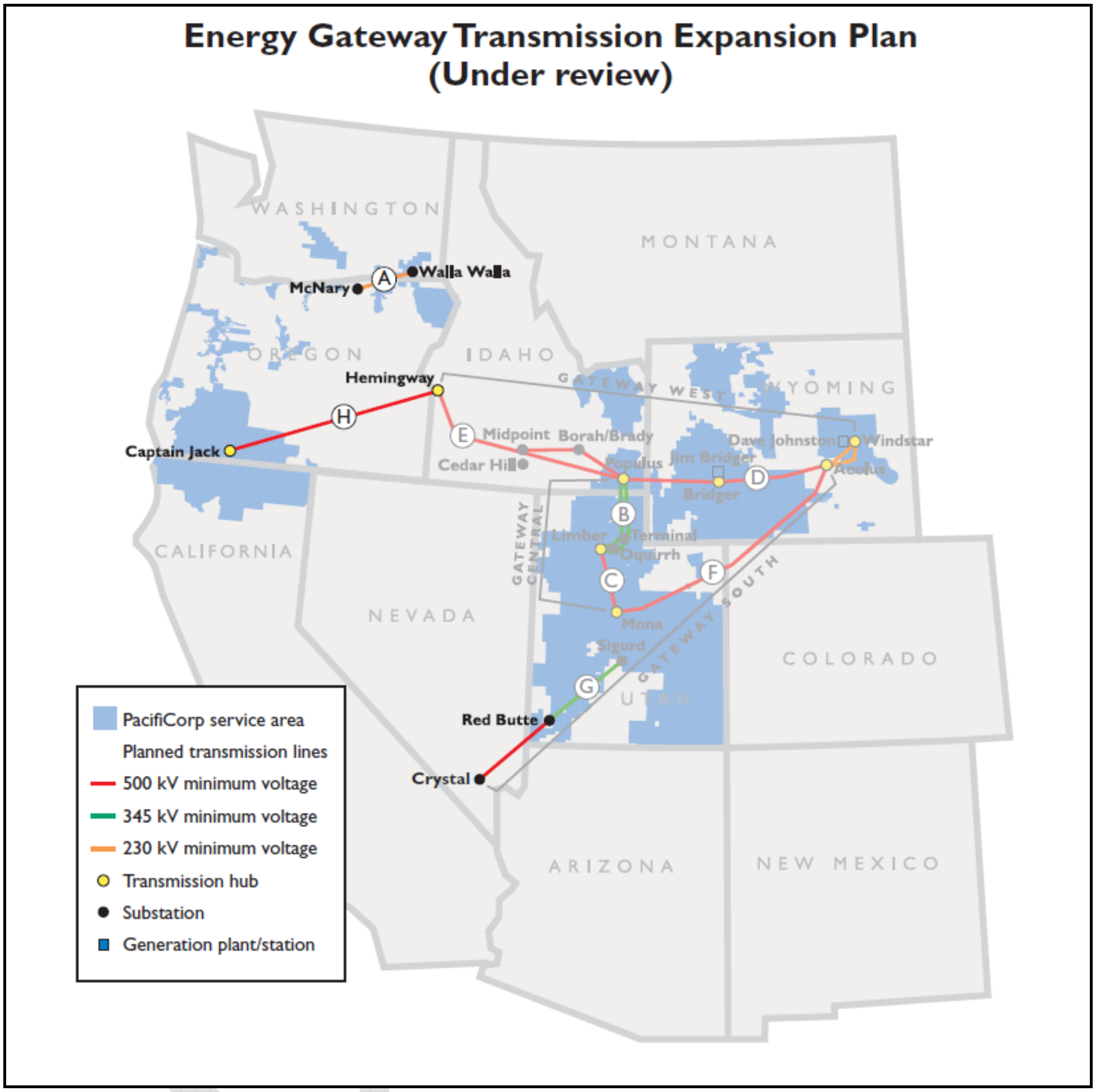
The west side of PacifiCorp's system (Washington, Oregon and California) is well integrated with Avista Energy, Bonneville Power Administration, Portland General Electric, and, to a lesser degree, interconnections to the California Independent System Operator. Additionally, several regional projects have been proposed to interconnect in the northwest (California to Canada Transmission, Boardman to Hemingway, Southern Crossing, West of McNary, I-5 reinforcement, Devils Gap, Northern Lights and others).

PacifiCorp's Walla Walla to McNary single circuit 230 kV line and Hemingway to Captain Jack single circuit 500 kV line will be planned and coordinated with other regional projects to provide the best solution for customers and the region. Ultimate configuration and timing of PacifiCorp's Walla Walla to McNary and Hemingway to Captain Jack projects is an action item resulting from this IRP.

The Red Butte to Crystal single circuit 500 kV line was originally planned for 2012 but was deferred due to other Energy Gateway/system reinforcement projects providing sufficient transmission capacity to meet customer requirements. The line will be reevaluated as future needs are identified.

The map shown below shows the geographic context of the segments described above.

## Figure 10.6 – Westside Plan / Red Butte – Crystal




**Note:** This map generally reflects key expansion segments under review. It does not reflect all the segments that are necessary to for an ultimate Energy Gateway capacity of 6,000 MW (3,000 MW on Gateway West and 3,000 MW on Gateway South).

| Segment | Segment Description | Line | Planned Rating (Initial completion) | Planned Rating (Core completion) |
|---|---|---|---|---|
| A | Walla Wall – McNary | 230 kV single circuit | 400 MW | 400 MW |
| G | Red Butte - Crystal | 500 kV single circuit | TBD | 1500 MW |
| H | Hemingway – Captain Jack | 500 kV single circuit | TBD | 1500 MW |