Assuring a **bright future** for our customers

# 2007

# Integrated Resource Plan

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

**Pacific Power | Rocky Mountain Power | PacifiCorp Energy**

This 2007 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

For more information, contact:

PacifiCorp
IRP Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
IRP@PacifiCorp.com
http://www.PacifiCorp.com

*This report is printed on recycled paper*

***Cover Photos (Left to Right):***
*Wind: Foot Creek 1*
*Hydroelectric Generation: Yale Reservoir (Washington)*
*Demand side management: Agricultural Irrigation*
*Thermal-Gas: Currant Creek Power Plant*
*Transmission: South Central Wyoming line*

## TABLE OF CONTENTS

## INDEX OF TABLES

## INDEX OF FIGURES

# 1. EXECUTIVE SUMMARY

## INTRODUCTION

PacifiCorp's 2007 Integrated Resource Plan (IRP) presents a framework of future actions to ensure PacifiCorp continues to provide reliable, least-cost service with manageable and reasonable risk to its customers. Active public involvement from customer interest groups, regulatory staff, regulators and other stakeholders provided considerable guidance in the development of this IRP. The analytical approach used conforms to all State Standards and Guidelines, and resulted in a preferred portfolio that represents a balance of resource additions that meet future customer needs while minimizing cost, balancing diverse stakeholder interests and addressing environmental concerns. This IRP builds on PacifiCorp's prior resource planning efforts and reflects significant advancements in portfolio modeling and risk analysis.

## PLANNING PRINCIPLES AND OBJECTIVES

The mandate for an IRP is to assure, on a long-term basis, an adequate and reliable electricity supply at the lowest reasonable cost and in a manner "consistent with the long-run public interest." 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, and MidAmerican Energy Holdings Company (MEHC) transaction commitments that related to IRP activities.

As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs. 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.

The emphasis of the IRP is to determine the most robust resource plan under a reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future. The modeling is intended to support rather than overshadow the expert judgment of PacifiCorp's decision-makers. The preferred portfolio is not meant to be a static planning product, but rather is expected to evolve as part of the ongoing planning process. As a multi-objective planning effort, the IRP must reach a balanced position upon considering several priorities and accounting for diverse and sometimes conflicting stakeholder views. In short, the IRP cannot be all things to all people. As the owner of the IRP, PacifiCorp is uniquely positioned to determine the resource plan that best accomplishes IRP objectives on a system-wide basis, thereby meeting customer, community, and investor obligations collectively.

## THE PLANNING ENVIRONMENT

There are many significant 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 in the power industry marketplace, along with government policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

One major issue within the power industry marketplace is capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). The pace of new generation additions has begun to slow again in the west, raising the question of future resource adequacy in certain areas. The Western Electricity Coordinating Council 2006 Power Supply Assessment indicates that the Rocky Mountain sub-region will show a resource deficit by 2010.

Another significant issue is the prospect for long-term natural gas commodity price escalation and continued high volatility. Following an unprecedented increase in natural gas commodity escalation and volatility, forecasters expect a medium-term, temporary drop in natural gas commodity prices due to liquefied natural gas (LNG) facility expansion. Price uncertainty will continue because greater LNG imports will strengthen the linkage to volatile global gas and energy markets.

One of the largest issues emerging from governmental policy and regulatory initiatives is how to plan given an eventual, but highly uncertain, climate change regulatory regime. Not only have there been significant policy developments for currently-regulated pollutants, but there have also been important state-level climate change regulatory initiatives. Other regulatory issues include state renewable portfolio standards, hydropower relicensing, and major relevant provisions of the Energy Policy Act of 2005.

In conjunction with resource planning efforts, PacifiCorp has a greenhouse gas mitigation strategy that includes a public working group to consider emission reduction best practices, carbon dioxide scenario analysis for the IRP and procurement programs, renewable generation and demand-side management resource acquisition plans, and emissions accounting.

Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak load obligations are met on a reliable basis. Various regional transmission planning processes in the Western Interconnection have developed over the last several years to serve as the primary forums where major transmission projects are developed and coordinated. PacifiCorp is engaged in a number of these planning initiatives.

The Energy Policy Act of 2005, the first major energy law enacted in more than a decade, includes numerous provisions impacting electric utilities. Key provisions include (1) the promotion of clean coal technology, renewable energy, and nuclear power, (2) the encouragement of more hydroelectric production through streamlined relicensing procedures and increased efficiency, (3) the use of time-based metering options, and (4) the provision of mandatory reliability standards.

PacifiCorp's recent resource procurement activities include requests for proposal for east-side base load resources and renewable resources. In addition, requests for proposals have been issued for demand-side resource programs.

PacifiCorp's planning process is further impacted by the rapid evolution of state-specific resource policies that place, or are expected to place, constraints on PacifiCorp's resource selection decisions, and disparate state interests that complicate the company's ability to address state IRP requirements to the satisfaction of all stakeholders.

## RESOURCE NEEDS ASSESSMENT

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.4 percent annually from 2007 to 2016, which is slightly faster than the average annual historical growth rate (See Table 1.1). The eastern portion of the PacifiCorp system continues to grow faster than the western system, with an average annual energy growth rate of 3.2 percent and 0.8 percent, respectively, over the forecast horizon.

**Table 1.1 – Historical and Forecasted Average Energy Growth Rates for Load**

| Average Annual Growth Rate | Total | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|---|
| 1995-2005 | **1.6%** | 0.1% | 1.4% | 1.4% | 1.3% | 3.0% | 1.3% |
| 2007-2016 | **2.4%** | 0.6% | 1.3% | 5.6% | 1.1% | 2.7% | 1.0% |

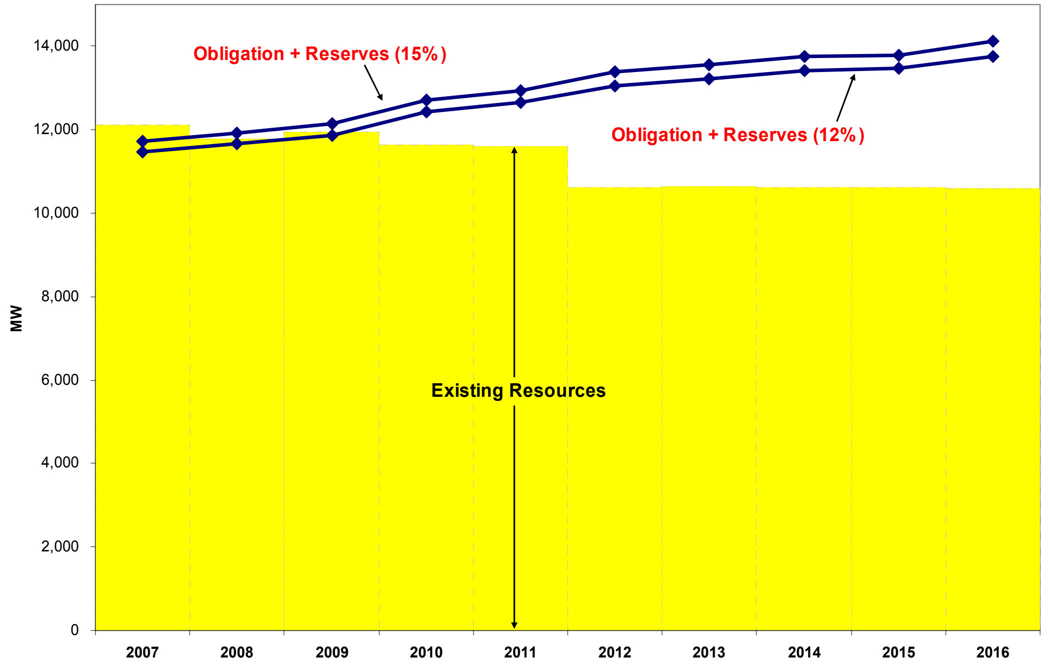
On both a capacity and energy basis, load and resource balances are calculated using existing resource levels, obligations and reserve requirements. Based on load and resource balance calculations, the company projects a summer peak resource deficit for the PacifiCorp system beginning in 2008 to 2010, depending on the capacity planning reserve margin assumed. Table 1.2 shows the annual capacity position (megawatt resource surplus or deficit) for the system using a 12 percent and 15 percent planning reserve margin, while Figure 1.1 shows the corresponding annual resource and obligation levels.

**Table 1.2 – Capacity System Position for 12% and 15% Planning Reserve Margin**

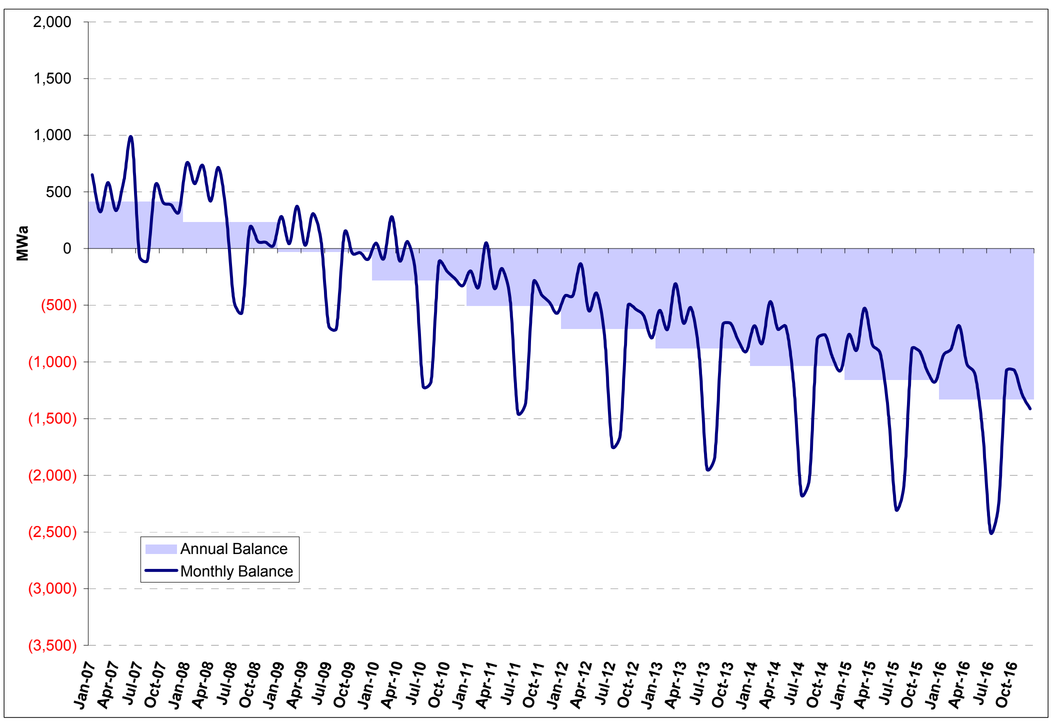
| System Position (MW) | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| 12% PRM | 665 | 113 | 73 | (791) | (1,038) | (2,446) | (2,563) | (2,794) | (2,842) | (3,171) |
| 15% PRM | 415 | (147) | (188) | (1,073) | (1,327) | (2,768) | (2,890) | (3,126) | (3,176) | (3,513) |

The PacifiCorp deficits prior to 2011 to 2012 will be met by additional renewables, demand-side programs, and market purchases. The company will consider other options during this time frame if they are cost-effective and provide other system benefits. This could include acceleration of a natural gas plant to complement the accelerated and expanded acquisition of renewable wind facilities. On an average annual energy basis, the system becomes deficient beginning in 2009 (Figure 1.2), based on a 12 percent planning reserve margin. To address these widening deficits in a cost-effective and risk-informed manner, a mix of resource types is anticipated.

## Figure 1.1 – System Capacity Chart




## Figure 1.2 – Monthly and Annual Average Energy Balance



## RESOURCE OPTIONS

The company developed cost and performance profiles for supply-side resources, demand-side management programs, transmission expansion projects, and firm market purchases (front office transactions) for use in portfolio modeling. Each supply-side option also included the estimation and use of capital cost ranges for each supply-side option. These cost ranges reflect cost uncertainty, and their use in this plan acknowledges the significant construction cost increases that are occurring.

PacifiCorp used the Electric Power Research Institute's Technical Assessment Guide (TAG®), along with recent project experience and consultant studies, to develop its supply-side resource options. The purpose of using TAG data is to rely on consistently-derived cost estimates from a well-respected independent outside source. The TAG database is considered the default source for developing the supply-side resource alternatives used in the 2007 IRP. Values are adjusted as necessary using information from PacifiCorp or other sources that reflects corporate or location-specific considerations. TAG capital costs for certain technologies were adjusted to be more in line with PacifiCorp's recent cost studies and project experience. In addition, TAG emission estimates were adjusted based on permitting expectations in PacifiCorp's service territory. The use of TAG information is new to PacifiCorp's integrated resource planning process.

The company also developed transmission resources to support meeting loads with new generation options, to integrate wind, to enhance transfer capability and maintain reliability across PacifiCorp's system, and to boost import/export capability with respect to external markets. These transmission resources were entered as options in PacifiCorp's capacity expansion optimization tool, and were thus allowed to compete directly with other resources for inclusion in portfolios.

## MODELING AND RISK ANALYSIS APPROACH

The IRP modeling effort seeks to determine the comparative cost, risk, supply reliability, and emissions attributes of resource portfolios.

PacifiCorp used two modeling tools for portfolio analysis: the Capacity Expansion Module (CEM) and the Planning and Risk (PaR) Module. The CEM performs a deterministic least-cost optimization with resource options over the twenty-year study period. The CEM operates by minimizing for each year the operating costs for existing resources subject to system load balance, reliability and other constraints. Over the study period, it also optimizes resource additions subject to resource investment and capacity constraints (monthly peak loads plus a planning reserve margin for a 24-zone model topology). The PaR module is a chronological commitment/dispatch production cost model that was operated in probabilistic (stochastic) mode to develop risk-adjusted portfolio performance measures.

The 2007 IRP modeling effort consisted of resource screening, risk analysis portfolio development, and detailed production cost and stochastic risk analysis. For resource screening, the company used the CEM to evaluate generation, load control, price-responsive demand-side management, market purchases, and transmission resources on a comparable basis with the use of "alternative future" scenarios. The main purpose of these scenarios is to identify general resource patterns attributable to changes in assumptions, and to help identify robust resources—those that frequently appear in the model's optimized portfolios under a range of futures. PacifiCorp sought assistance from public stakeholders to construct the alternative future scenarios, which capture variations in potential $CO_2$ regulatory costs, natural gas prices, wholesale electricity prices, retail load growth, and the scope of renewable portfolio standards.

Using the results from the alternative future scenario studies, PacifiCorp defined risk analysis portfolios for stochastic simulation. The CEM was used to help build fixed resource investment schedules for wind and distributed resources, and to optimize the selection of other resource options according to specific resource strategies. Other key portfolio development criteria included diversity among the major new resource types and the impact of evolving state resource policies. The resulting portfolios were then simulated using the PaR model. The PaR simulations incorporate stochastic risk in its production cost estimates by using Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability.

PacifiCorp devoted considerable effort to model the effect of $CO_2$ emission compliance strategies. Stochastic simulations were conducted with various $CO_2$ emission cost adders to capture the risks associated with potential $CO_2$ emission compliance regulations. Since the probability of realizing a specific $CO_2$ emissions cost cannot be determined with a reasonable degree of accuracy, potential $CO_2$ emission costs were treated as a scenario risk in this IRP. PacifiCorp defines a scenario risk as an externally-driven fundamental and persistent change to the expected value of some parameter that is expected to significantly impact portfolio costs. This risk category is intended to embrace abrupt changes to risk factors that are not amenable to stochastic analysis. The practice of combining stochastic simulation with $CO_2$ cost adder scenario analysis represents advancement with respect to the modeling approach used for PacifiCorp's 2004 IRP.

All risk analysis portfolios were simulated with five $CO_2$ adder levels—\$0/ton, \$8/ton, \$15/ton, \$38/ton, and \$61/ton (in 2008 dollars)—and associated forward gas/electricity price forecasts. The company modeled both a cap-and-trade and emissions tax compliance strategy, and expanded its reporting of $CO_2$ emissions impacts.

Portfolio performance was assessed with the following measures: (1) stochastic mean cost (Present Value of Revenue Requirements), (2) customer rate impact, measured as the levelized net present value of the change in the system average customer price due to new resources for 2007 through 2026, (3) emissions externality cost, (4) capital cost, (5) risk exposure, (6) $CO_2$ and other emissions, (7) and supply reliability statistics.

The preferred portfolio is selected from among the risk analysis portfolios primarily on the basis of relative cost-effectiveness, customer rate impact, and cost/risk balance across the $CO_2$ adder levels. The preferred portfolio represents the most robust resource plan under a reasonably wide range of potential futures.

## MODELING AND PORTFOLIO SELECTION RESULTS

PacifiCorp assessed "alternative future" scenarios to determine resources and capacity quantities suitable for inclusion in risk analysis portfolios. Based on the Capacity Expansion Module's optimized investment plans, the company selected wind (as a proxy for all renewable resources), combined heat and power, supercritical pulverized coal, combined cycle combustion turbine, single-cycle combustion turbine, integrated gasification combined cycle (IGCC), load control programs, transmission additions and short-term market purchases in subsequent portfolio studies.

The company studied portfolios using its stochastic production cost simulation model. These portfolios were distinguished by a variety of resource strategies intended to address major portfolio risks, such as carbon regulations and natural gas/electricity price volatility. These resource strategies were distinguished by the planning reserve margin level and the quantity and timing of wind, pulverized coal, front office transactions, and IGCC resources included.

The portfolio analysis yielded the following general conclusions:

- Diversification of resources helps to balance costs and risks. A combination of supercritical pulverized coal, additional renewable generation, and gas-fired resources is desired to achieve a low-cost portfolio that effectively addresses all major sources of risk; conversely, portfolios dominated by a single resource type were found to be more expensive and risky for customers. Studies also demonstrated that increasing wind capacity and reducing reliance on market purchases promotes a better balance of portfolio cost and risk.
- Eliminating front office transactions after 2011 decreased risk exposure and increased portfolio cost. To maintain planning flexibility and resource diversity, PacifiCorp will continue to rely on them as needed to support energy requirements in the west control area, and use them as needed to address peak load requirements in the east control area.
- While the portfolio analysis indicated that lowering the planning reserve margin increased portfolio stochastic risk and reduced reliability, the decision on what margin to adopt is a subjective one that depends on balancing portfolio risk against affordability. The portfolio modeling also showed that reducing the planning reserve margin from 15% to 12% increased $CO_2$ and other emissions due to greater reliance on the company's existing coal fleet.

Based on superior performance with respect to stochastic cost, customer rate impact, cost-versus-risk balance, and supply reliability, a portfolio with the following characteristics was chosen as the preferred portfolio:

- A total of 2,000 megawatts of renewable resources by 2013
- An additional 100 megawatts of load control (Class 1 demand-side management) beginning in 2010
- A west-side combined cycle combustion turbine in 2011
- High-capacity-factor resources in the east in 2012 and 2014
- East-side combined cycle combustion turbines in 2012 and 2016
- Balance of system need fulfilled by front office transactions beginning in 2010
- Transmission additions between 2010 and 2014 to support integration of the resource portfolio with loads

The preferred portfolio's specific proxy resources and acquisition timing are shown in Table 1.3.

**Table 1.3 – PacifiCorp's 2007 IRP Preferred Portfolio**

| Supply and Demand-side Proxy Resources | | | Nameplate Capacity, MW | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Resource | Type | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
| East | Utah pulverized coal | Supercritical | | | | | | 340 | | | | |
| | Wyoming pulverized coal | Supercritical | | | | | | | | 527 | | |
| | Combined cycle CT | 2x1 F class with duct firing | | | | | | 548 | | | | |
| | Combined cycle CT | 1x1 G class with duct firing | | | | | | | | | | 357 |
| | Combined Heat and Power | Generic east-wide | | | | | | 25 | | | | |
| | Renewable | Wind, Wyoming | | 200 | | 200 | 200 | | 300 | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | | 26 | 25 | 18 | | | |
| | Front office transactions** | Heavy Load Hour, 3rd Qtr | - | - | - | 393 | 272 | 97 | 3 | 149 | 192 | 165 |
| West | CCCT | 2x1 F Type with duct firing | | | | | 602 | | | | | |
| | Combined Heat and Power | Generic west-wide | | | | | | 75 | | | | |
| | Renewable | Wind, SE Washington | 300 | 100 | | | | | | | | |
| | Renewable | Wind, NC Oregon | | | 100 | 100 | | 100 | | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | 12 | 11 | 12 | | | | |
| | Front office transactions** | Flat annual product | - | - | - | 219 | 64 | 555 | 657 | 247 | 246 | 249 |
| | Annual Additions, Long Term Resources | | 300 | 300 | 100 | 312 | 839 | 1,125 | 318 | 527 | - | 357 |
| | Annual Additions, Short Term Resources | | - | - | - | 612 | 336 | 652 | 660 | 396 | 438 | 414 |
| | Total Annual Additions | | 300 | 300 | 100 | 924 | 1,175 | 1,777 | 978 | 923 | 438 | 771 |

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

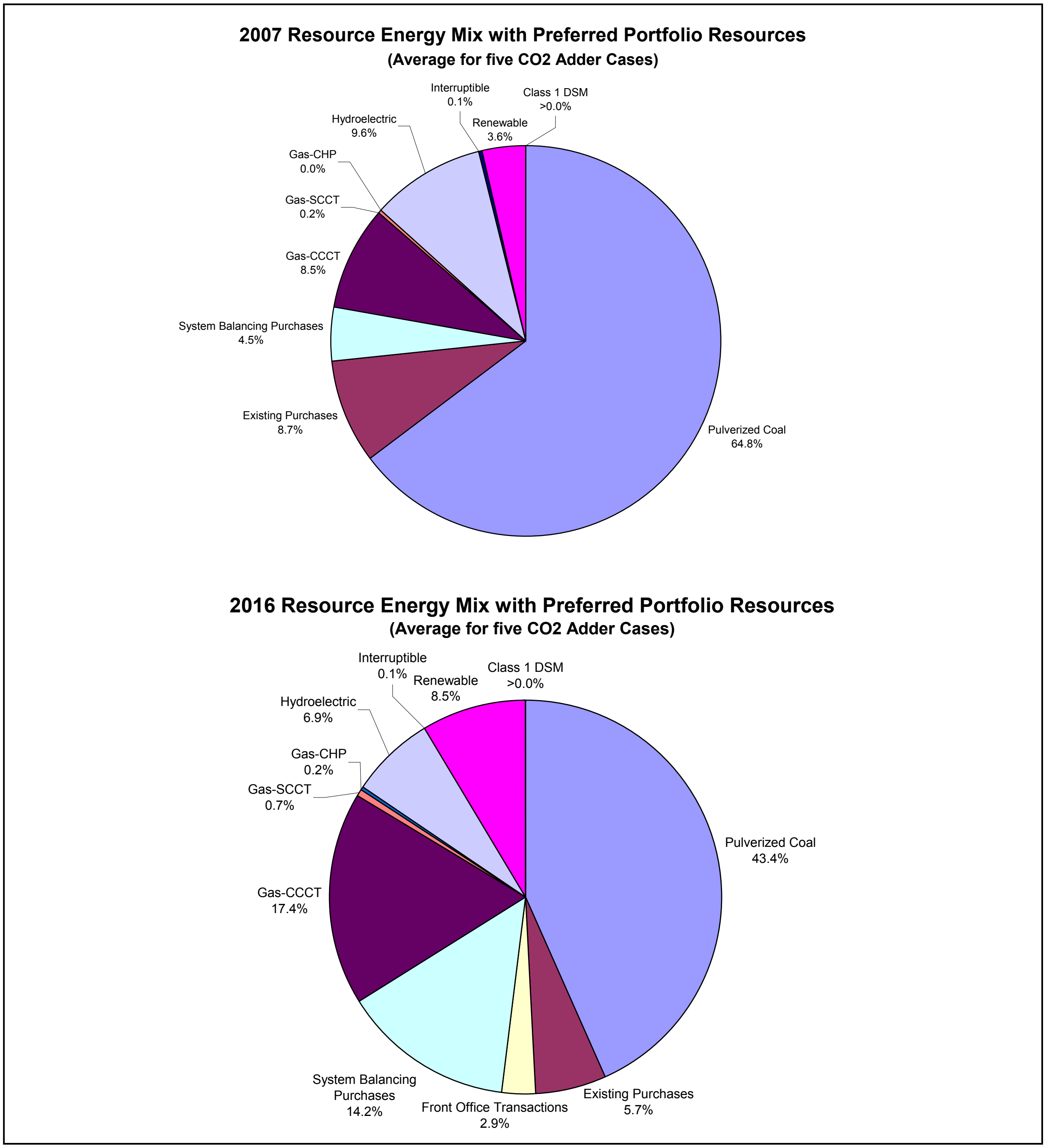
| Transmission Proxy Resources* | | Transfer Capability, Megawatts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Resource | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
| East | Path C Upgrade: Borah to Path-C South to Utah North | | | | 300 | | | | | | |
| | Utah - Desert Southwest (Includes Mona - Oquirrh) | | | | | | 600 | | | | |
| | Mona - Utah North | | | | | | 400 | | | | |
| | Craig-Hayden to Park City | | | | | | 176 | | | | |
| | Miners - Jim Bridger - Terminal | | | | | | 600 | | | | |
| | Jim Bridger - Terminal | | | | | | | | 500 | | |
| West | Walla Walla - Yakima | | | | 400 | | | | | | |
| | West Main - Walla Walla | | | | | 630 | | | | | |
| | Total Annual Additions | - | - | - | 700 | 630 | 1,776 | - | 500 | - | - |

* Transmission resource proxies represent a range of possible procurement strategies, including new wheeling contracts or construction of transmission facilities by PacifiCorp or as a joint project with other parties.

The preferred portfolio reflects a diverse resource mix, as evidenced by the increasing contribution of renewables, gas-fired, and front office transactions to system generation. Figure 1.3 compares the system energy mixes for 2007 and 2016, which include preferred portfolio resources and reflect the average generation across the five $CO_2$ cost adders modeled.

While the preferred portfolio is based on a target planning reserve margin of 12 percent, PacifiCorp is targeting a reserve margin range of 12 to 15 percent to increase planning flexibility given a time of rapid public policy evolution and wide uncertainty over the resulting down-stream cost impacts. The preferred portfolio also is consistent with the company's strategic view on the role of firm market purchases for meeting capacity needs: that limited use of such purchases is beneficial by increasing planning flexibility and portfolio diversity, but that the company seeks less reliance on them for the long term. Market availability to support the level of firm purchases in the preferred portfolio is adequate as evidenced by recent purchase offer activity. For example, requests in 2007 for third-quarter projects for 2007-2012 yielded over 5,000 megawatts in offers.

**Figure 1.3 – Projected PacifiCorp Resource Energy Mix**



## ACTION PLAN

The integrated resource plan is intended to provide guidance for the company's resource procurement activities over the next few years. To follow through on the findings of this resource plan, PacifiCorp's action plan includes:

- **Reaffirming commitments to renewable resources:**
  - Accelerate its previous commitment to acquire 1,400 megawatts of cost-effective renewable resources from 2015 to 2010,
  - Increase the amount of cost-effective renewable resources to 2,000 megawatts by 2013,
  - Actively seek to add transmission infrastructure to deliver wind power to key load areas. Investigate adding flexible generating resources, such as natural gas, to integrate new wind resources
  - Enhance its integrated resource planning modeling to address renewable portfolio standards and the impacts of adding large quantities of wind resources to its system
- **Increased focus on energy efficiency:**
  - Continue to run programs to acquire 250 average megawatts of cost-effective energy efficiency, and
  - Add an additional 200 average megawatts of cost-effective energy efficiency initiatives
- **Maintaining and expanding load control programs:**
  - Maintain and build upon the existing 150 megawatts of irrigation and air conditioning load control in Utah and Idaho,
  - Add 100 megawatts of additional load control split between East and West beginning in 2010,
  - Leverage voluntary demand-side measures, such as demand buyback, to improve system reliability during peak load hours, and
  - Incorporate the results of the demand-side management potentials study into the company's demand-side management programs and future integrated resource plans.
- **Studying and addressing environmental issues:**
  - Enhance its integrated resource planning modeling to address new carbon regulations, and
  - Take a leadership role in discussions on global climate change and continue to investigate carbon reduction technologies, including nuclear power.
- **Addressing transmission constraints:**
  - Expand its transmission system to allow the resources identified in the preferred portfolio to serve customer loads in a cost-effective and reliable manner
- **Adding a diverse mix of base load / intermediate load resources:**
  - Acquire up to 1,700 megawatts of base load / intermediate load resources on the east side of its system for the term 2012 through 2014, through a mix of thermal resources and purchases, consistent with the April 2007 filed request for proposal, and,
  - Acquire 200 to 1,350 megawatts of base load / intermediate load resources on the west side of its system from 2010 to 2014 through a mix of thermal resources and purchases.

# 2. IRP COMPONENTS, PLANNING PRINCIPLES, OBJECTIVES, AND APPROACH

**Chapter Highlights**

- 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."
- As a multi-objective planning effort, the IRP must reach a balanced position upon considering several priorities and accounting for diverse and sometimes conflicting stakeholder views.
- The IRP is a roadmap for PacifiCorp's long-term resource strategy, developed according to seven planning principles. One of the principles is that it strategically aligns with business priorities and meets MEHC transaction commitments.
- Key analytical and modeling objectives were to (1) evaluate all resources on a comparable basis using the company's new resource expansion optimization tool, and (2) enhance uncertainty and risk analysis.
- The outcome of PacifiCorp's portfolio analysis is a preferred portfolio that represents the lowest-cost diversified resource plan that accounts for cost/risk trade-offs, system reliability, ratepayer impacts, and $CO_2$ emissions. The preferred portfolio is also the most robust resource plan under a reasonably wide range of potential futures.
- PacifiCorp continuously seeks to improve the IRP public process; a number of recent initiatives to enhance stakeholder engagement for this IRP are profiled.
- PacifiCorp summarizes the progress towards meeting 18 MEHC transaction commitments that related to IRP activities.

## INTRODUCTION

This chapter outlines the components of this Integrated Resource Plan (IRP), and describes the groundwork for its development: the set of planning principles and analysis objectives that underpin the IRP development effort, and the overall approach for building it.

This IRP builds on PacifiCorp's prior resource planning efforts and reflects significant advancements in portfolio modeling and risk analysis. It was developed in a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties. PacifiCorp is filing this IRP with its state regulatory agencies, and requests that they acknowledge and support its conclusions, including the Action Plan.

## 2007 INTEGRATED RESOURCE PLAN COMPONENTS

The basic components of PacifiCorp's 2007 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 market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3)
- A resource needs assessment covering the company's load forecast, status of existing resources, resource expansion alternatives, and determination of the load and energy positions for the 10-year resource acquisition period (Chapter 4)
- Profiles and background information for the resource options considered for addressing future capacity deficits (Chapter 5)
- A description of the IRP modeling and risk analysis approach (Chapter 6)
- A summary of modeling results and PacifiCorp's preferred portfolio (Chapter 7)
- An action plan linking the company's preferred portfolio with specific implementation actions (Chapter 8)

The IRP appendices, included as a separate volume, comprise base modeling assumptions, supporting technical information, detailed Capacity Expansion Module (CEM) modeling results, supplementary portfolio information, studies intended to meet certain state commission IRP acknowledgement requirements, and status reports on IRP regulatory compliance and action plan progress. PacifiCorp's response to written comments on the draft IRP report is incorporated in Appendix F.

## 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."[1] 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

[1] 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.

tradeoffs. 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.

Given this role and the long-term planning focus, it is important to note the qualifications associated with the IRP so that the planning outcome can be placed in the proper context. First, resource portfolio analysis seeks to help clarify the unknown future as opposed to predicting it. Consequently, the emphasis of the IRP is to determine the most robust resource plan under a reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future. In tandem with the robustness concept is the view that selection of the preferred portfolio should not be overly influenced by any particular set of quantitative results given the complexity and inherent imprecision of the modeling effort. In other words, modeling is intended to support and not overshadow the expert judgment of PacifiCorp's decision-makers.

A second IRP qualification is that the preferred portfolio is not meant to be a static planning product, but rather is expected to evolve as part of the ongoing planning process. As resources are acquired and new planning information comes in, the company refreshes the preferred portfolio and action plan based on the set of planning principles enumerated below. Because the IRP is a road mapping effort, it is not intended as a referendum on specific resource decisions. The preferred portfolio represents a snapshot view of PacifiCorp's long-term resource planning strategy informed by current information. As emphasized in this IRP and prior ones, specific resource acquisition decisions stem from PacifiCorp's competitive procurement process.

A third qualification is that as a multi-objective planning effort, the IRP must reach a balanced position upon considering several priorities and accounting for diverse and sometimes conflicting stakeholder views. In short, the IRP cannot be all things to all people. As the owner of the IRP, PacifiCorp is uniquely positioned to determine the resource plan that best accomplishes IRP objectives on a system-wide basis, thereby meeting customer and investor obligations collectively.

## PLANNING PRINCIPLES

PacifiCorp subscribed to a number of planning principles that guided the overall IRP development effort and resource decision-making process.

- Development of the IRP is guided by the state commission rules and guidelines for integrated resource planning, as well as specific IRP process and analysis requirements arising from state commission acknowledgement proceedings. At the same time, the company conducted its IRP process with the understanding that commission IRP rules and acknowledgement proceedings are not intended to usurp its decision-making authority for resource acquisition.

- PacifiCorp continues to plan on a system-wide basis. However, newly enacted state energy and environment policy mandates (and those under consideration) present considerable challenges for planning on this basis. This IRP considers such state mandates as part of the portfolio development and analysis process, acknowledging that the definition of an "optimal" portfolio must be extended to accommodate sometimes disparate state policy goals.

- With portfolio costs increasing due to rapid construction price increases and the move towards more expensive alternative technologies to meet new state resource acquisition policies, PacifiCorp is more mindful of rate impact considerations for this IRP.

- The IRP and associated action plan was developed with PacifiCorp and MidAmerican Energy Holding Company (MEHC) business principles in mind, and meets MEHC transaction commitments. The business principles that relate to long-term resource planning include (1) improving electricity system reliability, (2) investing in physical assets that bolster corporate strength and competitiveness, and (3) protecting the environment in a cost-effective manner.

- The company subscribes to a portfolio management approach for acquiring resources to meet its future load obligations. It seeks a diversified, low-cost mix of resources that minimizes price and environmental risk for its customers while enhancing value for its investors.

- PacifiCorp continues to plan using the proxy resource approach, whereby resource options included in the IRP models are constituted with generic cost and performance attributes and assume PacifiCorp ownership for supply-side alternatives to simplify the analysis. (Some adjustments are made to resource attributes to reflect corporate experience or location-specific considerations, such as elevation for gas-fired resources.) With this proxy approach, modeled resources are only indicative of the resources that might be procured, the specific attributes of which may be modified to account for conditions at procurement time. Wind was selected as the proxy resource for all renewables based on wide availability in PacifiCorp's service territory, relative cost-effectiveness and cost certainty, and technological maturity. In the case of modeled transmission options, these are proxies representing a range of procurement strategies, including new wheeling contracts or construction of transmission facilities by PacifiCorp or as joint projects with other parties.

- PacifiCorp believes that $CO_2$ regulation will come into play during the 10-year resource acquisition period that is the focus of this IRP (2007 through 2016). Potential carbon dioxide emission costs serve as a major source of portfolio risk that is addressed through scenario analysis and balancing this risk against others. PacifiCorp also believes that given the state of knowledge concerning prospective $CO_2$ regulations, it is prudent to not assign probabilities to specific $CO_2$ cost outcomes as part of portfolio risk analysis.

- The company continues to seek improvements in the stakeholder engagement process and enhance the level of transparency of the overall process.

## KEY ANALYTICAL AND MODELING OBJECTIVES

The main analytical objective of the IRP is to determine the preferred resource portfolio for the next ten years (2007-2016) based on a finding of need and a comparative assessment of available resource opportunities. The preferred portfolio represents the resource plan that has the best balance of cost and risk.

A key analytical objective for this IRP was to treat all resource options on a comparable basis when developing alternative portfolios. To that end, PacifiCorp added a resource expansion optimization tool (the Capacity Expansion Module, or CEM) into its portfolio modeling framework. This model performs automated economic screening of resources and determines the optimal resource expansion plan based on planning scenarios. This tool enabled thermal generation, renewable generation, market purchases, demand-side management, and transmission to compete against each other on the basis of their impact on Present Value of Revenue Requirements (PVRR), the key measure of a portfolio's performance.

Important caveats associated with the CEM are that it does not capture stochastic risks in its optimization algorithm, and that it is designed as a high-level screening tool. In contrast to the Planning and Risk Module (PaR)—PacifiCorp's detailed production costing and market simulation model, the CEM cannot incorporate stochastic variables in its solution algorithm and is instead meant to address high-level system operational details. (For example, unlike the PaR, it does not capture hourly chronological commitment constraints). Consequently, a modeling objective for this IRP was to exploit the complementary but different capabilities of the CEM and PaR. Chapter 6 describes the roles that each of these models played throughout PacifiCorp's resource portfolio analysis.

An additional analytical and modeling objective for this IRP was to enhance uncertainty and risk analysis. PacifiCorp accomplished this objective by making the following data and modeling methodology changes, which are detailed later in this report.

- Incorporated stochastic simulation of candidate portfolios at various $CO_2$ adder levels, in contrast to running deterministic simulations with $CO_2$ adder levels independently as was done for the 2004 IRP.

- Introduced stochastic analysis of front office transactions (market purchases), which includes comparing stochastic risk measures of a portfolio with front office transaction resources against a portfolio in which these resources are replaced with an asset-based coal plant.

- Development of low and high capital cost estimates for supply-side resources in recognition of increased construction cost volatility trends.

- Extensive expansion of the number of input sensitivity studies relative to the 2004 IRP, including 36 studies using the CEM and 27 stochastic studies using PaR.

- Incorporated probability-weighted forward gas price curves into the IRP models; the curves are based on a weighted average of PIRA Energy's low, medium, and high gas price cases.

A final analytical objective for this IRP was to determine an appropriate level of reliance on market purchases given their flexibility benefits and risks. As opposed to the 2004 IRP, where market purchases were treated as a fixed resource, for this IRP they were handled as a competing resource option with associated prices modeled as stochastic variables to capture price risk.

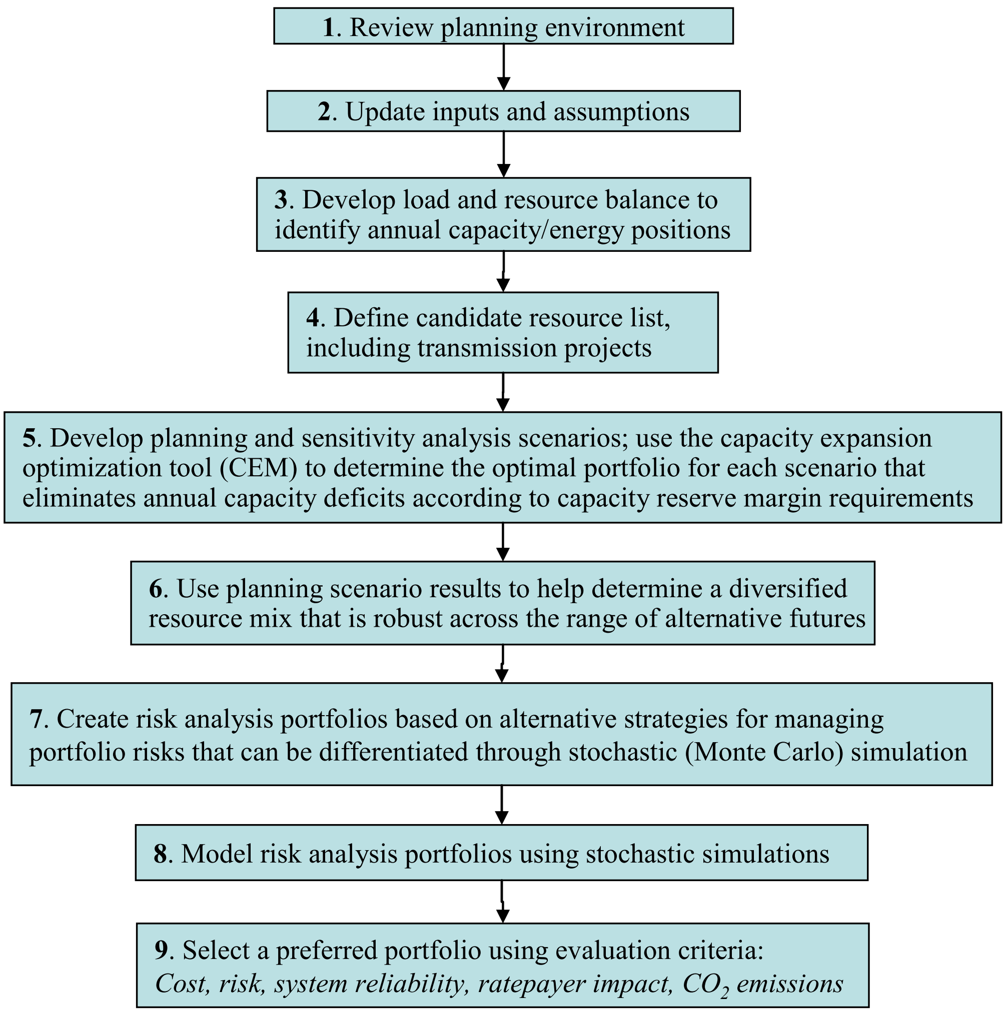
## INTEGRATED RESOURCE PLANNING APPROACH OVERVIEW

The 2007 IRP approach consisted of both analytical and public processes that occurred in tandem. These two processes are described below.

### Analytical Process

The analytical process is comprised of nine major steps that are summarized in Figure 2.1. Chapter 3 addresses Step 1, "review the planning environment". Step 2, "update inputs and assumptions", is covered largely in Appendices A and J. Chapter 4 covers Step 3, "develop load and resource balance". Step 4, "define candidate resource list" is treated in Chapter 5. Steps 5 through 8, which address the modeling and risk analysis process and results, are covered in Chapters 6 and 7.

**Figure 2.1 – Integrated Resource Planning Analytical Process Steps**




As shown in the diagram, the outcome of the analytical process is a preferred portfolio that represents the lowest-cost diversified resource plan that accounts for cost, risk, system reliability, ratepayer impacts, and $CO_2$ emissions.

## Public Process

The core of the 2007 IRP public process was a series of 13 public meetings 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.

PacifiCorp held three of the meetings in 2005—two load forecasting workshops (August 3 and October 5) and a 2007 IRP kick-off meeting on December 7. Table 2.1 shows the timeline of the public meetings in relation to the overall IRP timeline, commencing with the December 7 IRP kick-off meeting. Appendix F, in the separate appendix volume, provides more details concerning the public meeting process and individual meetings. Stakeholder engagement efforts are chronicled in the last section of this chapter.

### Table 2.1 – IRP and Public Process Timeline

| | IRP Timeline | Aug-05 | Sept-05 | Oct-05 | Nov-05 | Dec-05 | Jan-06 | Feb-06 | Mar-06 | Apr-06 | May-06 | Jun-06 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Prepare IRP Assumptions and Models | | | | | | | | | | |
| | | Public Meetings | | | | | | | | | | |
| 1 | **Technical Workshop - Load Forecasting, August 3, 2005** | X | | | | | | | | | | |
| 2 | **Technical Workshop - Load Forecasting, October 5, 2005** | | | X | | | | | | | | |
| 3 | **General Public Input Meeting, December 7, 2006** | | | | | X | | | | | | |
| 4 | **Technical Workshop - Renewables, Jan 13, 2006** | | | | | | X | | | | | |
| 5 | **Technical Workshop - Load Forecasting, Jan. 24, 2006** | | | | | | X | | | | | |
| 6 | **Technical Workshop - DSM, Feb 10, 2006** | | | | | | | X | | | | |
| 7 | **General Public Meeting, April 20, 2006** | | | | | | | | | X | | |
| 8 | **General Public Meeting, May 10, 2006** | | | | | | | | | | X | |
| 9 | **General Public Meeting, June 7, 2006** | | | | | | | | | | | X |
| 10 | **General Public Meeting, August 23, 2006** | | | | | | | | | | | |
| 11 | **General Public Meeting, October 31, 2006** | | | | | | | | | | | |
| 12 | **General Public Meeting, February 1, 2007** | | | | | | | | | | | |
| 13 | **General Public Meeting, April 18, 2007** | | | | | | | | | | | |

| | IRP Timeline | Jul-06 | Aug-06 | Sep-06 | Oct-06 | Nov-06 | Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Conduct Analysis / Prepare IRP Report | | | | | | | | | | File |
| 1 | **Technical Workshop - Load Forecasting, August 3, 2005** | | | | | | | | | | | |
| 2 | **Technical Workshop - Load Forecasting, October 5, 2005** | | | | | | | | | | | |
| 3 | **General Public Input Meeting, December 7, 2006** | | | | | | | | | | | |
| 4 | **Technical Workshop - Renewables, Jan 13, 2006** | | | | | | | | | | | |
| 5 | **Technical Workshop - Load Forecasting, Jan. 24, 2006** | | | | | | | | | | | |
| 6 | **Technical Workshop - DSM, Feb 10, 2006** | | | | | | | | | | | |
| 7 | **General Public Meeting, April 20, 2006** | | | | | | | | | | | |
| 8 | **General Public Meeting, May 10, 2006** | | | | | | | | | | | |
| 9 | **General Public Meeting, June 7, 2006** | | | | | | | | | | | |
| 10 | **General Public Meeting, August 23, 2006** | | X | | | | | | | | | |
| 11 | **General Public Meeting, October 31, 2006** | | | | X | | | | | | | |
| 12 | **General Public Meeting, February 1, 2007** | | | | | | | | X | | | |
| 13 | **General Public Meeting, April 18, 2007** | | | | | | | | | | X | X |

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), 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.

PacifiCorp and its parent company, MidAmerican Energy Holdings Company (MEHC), also participated in numerous organizations and working groups that address regional planning issues in the areas of supply, system coordination, energy management, and transmission resources. Table 2.2 lists a number of these organizations by focus area.

**Table 2.2 – Participation in Regional Planning Organizations and Working Groups**

| Organization | Focus Area |
|---|---|
| Western Electricity Coordinating Council/Seams Steering Group – Western Interconnection (SSG-WI) | System reliability and adequacy |
| Northwest Power Pool | System reliability and adequacy |
| Northwest Power and Conservation Council | Regional power system |
| Pacific Northwest Utilities Conference Committee (PNUCC) | Regional power system |
| Northwest Wind Integration Technical Workgroup | Wind |
| Big Sky Carbon Sequestration Partnership Energy Future Coalition | Climate change |
| Global Climate Change Working Group (MEHC commitment) | Climate change |
| Integrated Gasification Combined Cycle Working Group (MEHC commitment) | Clean coal technology |
| Northwest Energy Efficiency Alliance | Energy efficiency |
| Conservation Advisory Council (Energy Trust of Oregon) | Energy efficiency |
| Utah DSM Advisory Group | Energy efficiency |
| Washington DSM Advisory Group | Energy efficiency |
| Northwest Transmission Assessment Committee (NTAC) | Transmission |
| Rocky Mountain Area Transmission Study (RMATS) | Transmission |
| Northern Tier Transmission Group (NTTG) | Transmission |
| Western Regional Transmission Expansion Partnership | Transmission |
| Ely Energy Center / Robinson Summit – Harry Allen 500 kV Transmission Project Regional Planning Review Group | Transmission |
| Utah Resource Forum | Peak power demand issues |

Finally, PacifiCorp provided IRP participants the opportunity to critique the draft IRP document in April 2007.

## STAKEHOLDER ENGAGEMENT

PacifiCorp maintains a strong commitment to improve the value of the IRP public process to external stakeholders as well as the company. This is evidenced by a number of initiatives taken by PacifiCorp during 2005 and 2006. First, PacifiCorp instituted a stakeholder satisfaction survey in the spring of 2005. The purpose of this survey was to determine if the company was on the right track with respect to execution of the IRP public process, and to solicit recommendations on improvements to better support stakeholder needs.[2] PacifiCorp implemented several recommendations for the 2007 IRP, as detailed in Table 2.3.

[2] A presentation summarizing the survey results can be found on PacifiCorp's Web site. The link to the presentation is http://www.pacificorp.com/File/File52811.pdf.

**Table 2.3 – Public Process Recommendations Implemented for the 2007 IRP**

| Public Process Recommendation | Outcome |
|---|---|
| Distribute model run results during the course of the IRP modeling phase rather than waiting to distribute them at the public meetings. | PacifiCorp distributed via e-mail a document package to participants on October 4, 2006 with updated CEM modeling results and other documentation, including an updated paper that describes the planning scenarios and associated input assumptions. The company also distributed a paper on candidate portfolio development on October 12, 2006 and February 5, 2007. |
| Distribute appendices for review along with the main draft IRP document. | PacifiCorp distributed for review the draft appendices to support the review of the main document. |
| Work to ensure that the participant base is more evenly balanced as far as representation is concerned; issue personal invitations to stakeholders as necessary. | PacifiCorp expanded its meeting invitation and contact list from about 80 individuals for the 2004 IRP to 135 for the 2007 IRP. PacifiCorp also added a video-conference site in Cheyenne, Wyoming, to facilitate meeting attendance. This list expansion also encompasses IRP meeting invitations to MEHC transaction stakeholders per Commitment #48, described in the next section. |
| Send information out earlier to prepare for meetings. | PacifiCorp maintains a policy of distributing meeting handouts at least two days in advance of a meeting. Exceptions may occur due to the need for last-minute management reviews of meeting materials. Only one of the 13 public meetings was impacted in this way. |

Another PacifiCorp initiative was to front-load public meetings during the 2007 IRP schedule and to focus those meetings on the more contentious, technical, or complex issues. This meeting plan was prompted by the company's concern during the 2004 IRP process that critical stakeholder input was provided well after the point where recommendations and concerns could be easily addressed in the process. Based on the outcome of these meetings, the company found the front-loading approach beneficial as an early sounding board for its proposed modeling assumptions and approaches, and intends to build on this approach for the next IRP.

## MIDAMERICAN ENERGY HOLDINGS COMPANY IRP COMMITMENTS

MEHC and PacifiCorp committed to continue to produce IRPs according to the schedule and Commission rules and orders at the time the transaction was in process. Other commitments were made to (1) encourage stakeholders to participate in the integrated resource planning process and consider transmission upgrades, (2) develop a plan to achieve renewable resource commitments, (3) consider utilization of advanced coal-fuel technology such as IGCC technology when adding coal-fueled generation, (4) conduct a market potential study of additional demand-side management and energy efficiency opportunities, (5) evaluate expansion of the Blundell Geothermal resource, and (6) include utility "own/operate" resources as a benchmark in future request for proposals. A detailed description of these commitments and a description of how they are addressed in the 2007 Integrated Resource Plan are provided in Table 2.4 below.

**Table 2.4 – MidAmerican/PacifiCorp Transaction Commitments Addressed in the IRP**

| MEHC Commitment Number | MEHC Commitment Description | How the Commitment is Addressed in the 2007 IRP |
|---|---|---|
| 30 | PacifiCorp will continue to produce Integrated Resource Plans according to the then-current schedule and the then-current Commission rules and orders. | This plan complies with various Commission rules and orders. |
| 48 | IRP Stakeholder Process: PacifiCorp will provide public notice and an invitation to encourage stakeholders to participate in the Integrated Resource Plan (IRP) process. The IRP process will be used to consider Commitments 34, 39, 40, 41, 44, 52 and 53. PacifiCorp will hold IRP meetings at locations or by using communications technologies that encourage broad participation. | Public notice for each Integrated Resource Planning meeting was provided to stakeholders. For all Integrated Resource Planning meetings, video conference facilities were made available in Portland, Oregon and Salt Lake City, Utah in addition to a telephone link. Several of the meetings also included video conference facilities in Cheyenne, Wyoming. Consideration of commitments 34, 39, 40, 41, 44, 52 and 53 are described below. |
| 34 | Transmission Investment: MEHC and PacifiCorp have identified incremental transmission projects that enhance reliability, facilitate the receipt of renewable resources, or enable further system optimization. Subject to permitting and the availability of materials, equipment and rights-of-way, MEHC and PacifiCorp commit to use their best efforts to achieve the following transmission system infrastructure improvements:<br>• Path C Upgrade (~$78 million) – Increase Path C capacity by 300 MW (from S.E. Idaho to Northern Utah). The target completion date for this project is 2010.<br>• Mona - Oquirrh (~$196 million) – Increase the import capability from Mona into the Wasatch Front (from Wasatch Front South to Wasatch Front North). This project would enhance the ability to import power from new resources delivered at or to Mona, and to import from Southern California by "wheeling" over the Adelanto DC tie. The target completion date for this project is 2011.<br>• Walla Walla - Yakima or Mid-C (~$88 million) – Establish a link between the "Walla Walla bubble" and the "Yakima bubble" | Each of these three transmission upgrades has been included in the company's modeling. The Path C upgrade is included as a planned transmission upgrade while the other two projects are options that can be selected by the Capacity Expansion Module. |

| MEHC Commitment Number | MEHC Commitment Description | How the Commitment is Addressed in the 2007 IRP |
|---|---|---|
| | and/or reinforce the link between the "Walla Walla bubble" and the Mid-Columbia (at Vantage). Either of these projects presents opportunities to enhance PacifiCorp's ability to accept the output from wind generators and balance the system cost effectively in a regional environment. The target completion date for this project is 2010. (Footnote): It is possible that upon further review, a particular investment might not be cost-effective, optimal for customers or able to be completed by the target date. If that should occur, MEHC pledges to propose an alternative to the Commission with a comparable benefit. | |
| 39 | In Commitment 31, MEHC and PacifiCorp adopt a commitment to source future PacifiCorp generation resources consistent with the then-current rules and regulations of each state. In addition to that commitment, for the next ten years, MEHC and PacifiCorp commit that they will submit as part of any commission approved RFPs for resources with a dependable life greater than 10 years and greater than 100 MW—including renewable energy RFPs—a 100 MW or more utility "own/operate" alternative for the particular resource. It is not the intent or objective that such alternatives be favored over other options. Rather, the option for PacifiCorp to own and operate the resource which is the subject of the RFP will enable comparison and evaluation of that option against other viable alternatives. In addition to providing regulators and interested parties with an additional viable option for assessment, it can be expected that this commitment will enhance PacifiCorp's ability to increase the proportion of cost-effective renewable energy in its generation portfolio, based upon the actual experience of MEC and the "Renewable Energy" commitment offered below. | This commitment is being addressed in the company's request for proposals. |
| 40 | MEHC reaffirms PacifiCorp's commitment to acquire 1,400 MW of new cost-effective renewable resources, representing approximately 7% of PacifiCorp's load.<br>MEHC and PacifiCorp commit to work with developers and bidders to bring at least 100 MW of cost-effective wind resources in service within one year of the close of the transaction. | This Integrated Resource Plan reflects the commitment to acquire 1,400 megawatts of new cost-effective renewable resources. The 100 megawatt goal has been met, and the company is within 54 megawatts of reaching the 400 megawatt goal at the time of this |

| MEHC Commitment Number | MEHC Commitment Description | How the Commitment is Addressed in the 2007 IRP |
|---|---|---|
| | MEHC and PacifiCorp expect that the commitment to build the Walla-Walla and Path C transmission lines will facilitate up to 400 MW of renewable resource projects with an expected in-service date of 2010.<br>MEHC and PacifiCorp commit to actively work with developers to identify other transmission improvements that can facilitate the delivery of cost-effective wind energy in PacifiCorp's service area.<br>In addition, MEHC and PacifiCorp commit to work constructively with states to implement renewable energy action plans so as to enable PacifiCorp to achieve at least 1,400 MW of cost-effective renewable energy resources by 2015. Such renewable energy resources are not limited to wind energy resources. | report.<br><br>The company has included several transmission upgrades in 2007 Integrated Resource Planning analyses that can facilitate additional renewable resource development. A Renewables Action Plan to achieve at least 1,400 megawatts of cost-effective renewable energy resource by 2015 was filed concurrently with the 2007 IRP. |
| 41 | MEHC supports and affirms PacifiCorp's commitment to consider utilization of advanced coal-fuel technology such as super-critical or IGCC technology when adding coal-fueled generation. | IGCC technology is included as a resource option in the 2007 Integrated Resource Planning process. Chapter 5 details various clean coal project activities, including the joint Wyoming Infrastructure Authority/PacifiCorp IGCC project. |
| 44 | MEHC and PacifiCorp commit to conducting a company-defined third-party market potential study of additional DSM and energy efficiency opportunities within PacifiCorp's service areas. The objective of the study will be to identify opportunities not yet identified by the company and, if and where possible, to recommend programs or actions to pursue those opportunities found to be cost-effective. The study will focus on opportunities for deliverable DSM and energy efficiency resources rather than technical potentials that may not be attainable through DSM and energy efficiency efforts. On-site solar and combined heat and power programs may be considered in the study. During the three-month period following the close of the transaction, MEHC and PacifiCorp will consult with DSM advisory groups and other interested parties to define the proper scope of the study. The findings of the study will be reported back to DSM advisory groups, commission staffs, and other interested stakeholders and will be used by the Company in helping to direct ongoing DSM | The demand side management potential study is underway and is expected to be completed on schedule. The results of the study will be used to inform future Integrated Resource Plans. |

| MEHC Commitment Number | MEHC Commitment Description | How the Commitment is Addressed in the 2007 IRP |
|---|---|---|
| | and energy efficiency efforts. The study will be completed within fifteen months after the closing on the transaction, and MEHC shareholders will absorb the first $1 million of the costs of the study.<br>PacifiCorp further commits to meeting its portion of the NWPPC's energy efficiency targets for Oregon, Washington and Idaho, as long as the targets can be achieved in a manner deemed cost-effective by the affected states.<br>In addition, MEHC and PacifiCorp commit that PacifiCorp and MEC will annually collaborate to identify any incremental programs that might be cost-effective for PacifiCorp customers. The Commission will be notified of any additional cost-effective programs that are identified. | |
| 52 | Upon closing, MEHC and PacifiCorp commit to immediately evaluate increasing the generation capacity of the Blundell geothermal facility by the amount determined to be cost-effective. Such evaluation shall be summarized in a report and filed with the Commission concurrent with the filing of PacifiCorp's next IRP. This incremental amount is expected to be at least 11 MW and may be as much as 100 MW. All cost effective increases in Blundell capacity, completed before January 1, 2015, should be counted toward satisfaction of PacifiCorp's 1,400 MW renewable energy goal, in an amount equal to the capacity of geothermal energy actually added at the plant. | A report describing the Blundell evaluation was filed in March 2007 with all six states. |
| 53 | MEHC or PacifiCorp commit to commence as soon as practical after close of the transaction a system impact study to examine the feasibility of constructing transmission facilities from the Jim Bridger generating facilities to Miners Substation in Wyoming. Upon receipt of the results of the system impact study, MEHC or PacifiCorp will review and discuss with stakeholders the desirability and economic feasibility of performing a subsequent facilities study for the Bridger to Miners transmission project. | This commitment was completed by the company on August 23, 2006. The Miners substation to Jim Bridger transmission upgrade is included as an option in the 2007 Integrated Resource Planning analysis. |

| MEHC Commitment Number | MEHC Commitment Description | How the Commitment is Addressed in the 2007 IRP |
|---|---|---|
| C22a, O26a, Wy21a | Concurrent with its next IRP filing, PacifiCorp commits to file a ten-year plan for achieving the 1,400 MW renewables target, including specific milestones over the ten years when resources will be added. The filing will include a ten-year plan for installing transmission that will facilitate the delivery of renewable energy and the achievement of its 2015 goal of at least 1,400 MW of cost-effective renewable energy. Within six (6) months after the close of the transaction, MEHC and PacifiCorp will file with the Commission a preliminary plan for achieving the 1,400 MW renewable target. | The preliminary plan was filed on September 21, 2006. The final plan was filed concurrently with the 2007 IRP filing. |
| C22b, O26b, Wy21b | PacifiCorp commits to address as part of its next IRP the appropriate role of incremental hydropower projects in meeting the 1400 MW renewables target. | A Renewables Action Plan to achieve at least 1,400 megawatts of cost-effective renewable energy resources by 2015 was concurrently with the 2007 IRP. It will address hydropower projects in the document. |
| I23, U17, Wy20 | PacifiCorp agrees to include the following items in the 2006 IRP [2007 IRP]:<br>a) a wind penetration study to reappraise wind integration costs and cost-effective renewable energy levels; and<br>b) an assessment of transmission options for PacifiCorp's system identified in the RMATS scenario 1 related to facilitating additional generation at Jim Bridger and, on equal footing, new cost-effective wind resources. | a) Wind supply curves were developed and used to select wind on a comparable basis with other resources in the Capacity Expansion Module. Appendix J addresses the company's wind resource methodology used in this plan.<br><br>b) The company included transmission options in southwest and southeast Wyoming as potential upgrades in its modeling in order to facilitate wind development in Wyoming. |

## 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[3]." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

[3] Since PacifiCorp is now a subsidiary of a privately-owned company, this section will refer to PacifiCorp's "investors" as opposed to "shareholders."

**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**

PacifiCorp uses proxy resources in its portfolio evaluation and determination of the preferred portfolio. These proxy resources are characterized with generic capital cost estimates that are adjusted to reflect recent project experience and company-specific financial parameters. The actual cost of a generating or transmission asset is expected to vary from the cost assumed in this plan. 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 are government actions to regulate $CO_2$ emissions. This scenario risk relates to the uncertainty in predicting the scope, timing, and cost impact of $CO_2$ emission compliance rules.

At the present time, the issue of how the risk associated with uncertain $CO_2$ regulatory costs should be allocated to customers and investors is an open one. Complicating factors include the following:

- The prospect that a supercritical coal plant that is part of the company's preferred portfolio could receive IRP acknowledgement in one state and not another.
- The need to weigh resource $CO_2$ cost risk against the opportunity costs of investing in alternative resources with their own attendant cost risks (In this IRP, PacifiCorp shows that coal plants provide important portfolio risk diversification benefits when paired with other low-$CO_2$ emitting resources.)
- Ratepayer/investor risk allocation may be treated differently among PacifiCorp's jurisdictions depending on state resource policies and the evolution of inter-jurisdictional cost allocation approaches designed to address them.

At the combined Climate Change and Integrated Gasification Combined Cycle Working Group meeting on November 28, 2006, PacifiCorp facilitated a public discussion on ratepayer/investor risk allocation in the event that the company acquires a coal unit that is not able to capture and store $CO_2$ emissions.[4] The outcome of the discussion was that no consensus could be reached on the risk allocation issue and how the company can effectively proceed with resource planning given the regulatory uncertainties; more questions were raised than answers provided.

[4] PacifiCorp arranged this discussion on $CO_2$ regulatory risk in fulfillment of an MEHC transaction commitment.

# 3. THE PLANNING ENVIRONMENT

**Chapter Highlights**

- The pace of new generation additions has begun to slow again in the west, raising the question of future resource adequacy in certain areas. The Western Electricity Coordinating Council 2006 Power Supply Assessment indicates that the Rockies sub-region will show a resource deficit by 2010.

- Following an unprecedented increase in natural gas commodity escalation and volatility, forecasters expect a medium-term, temporary drop in natural gas commodity prices due to liquefied natural gas (LNG) facility expansion. Price uncertainty will continue because greater LNG imports will strengthen the linkage to volatile global gas and energy markets.

- In conjunction with resource planning efforts, PacifiCorp has a greenhouse gas mitigation strategy that includes a public working group to consider emission reduction best practices, carbon dioxide scenario analysis for the IRP and procurement programs, renewables and demand-side management resource acquisition plans, and emissions accounting.

- Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak load obligations are met on a reliable basis. Various regional transmission planning processes in the Western Interconnection have developed over the last several years to serve as the primary forums where major transmission projects are developed and coordinated. PacifiCorp is engaged in a number of these planning initiatives.

- The Energy Policy Act of 2005, the first major energy law enacted in more than a decade, includes numerous provisions impacting electric utilities. Key provisions include the promotion of clean coal technology and renewable energy, the encouragement of more hydroelectric production through streamlined relicensing procedures and increased efficiency, the use of time-based metering options and the provision of mandatory reliability standards.

- PacifiCorp's recent resource procurement activities include requests for proposal for east-side baseload resources and renewable resources. In addition, requests for proposals have been issued for demand-side resource programs.

- PacifiCorp's planning process is impacted by (1) rapid evolution of state-specific resource policies that place, or are expected to place, constraints on PacifiCorp's resource selection decisions, and (2) disparate state interests that complicate the company's ability to address state IRP requirements to the satisfaction of all stakeholders.

## 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 in the power industry marketplace, along with government policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

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 emerging issue facing PacifiCorp is how to plan given an eventual, but highly uncertain, climate change regulatory regime. While this chapter reviews the significant policy developments for currently-regulated pollutants, it focuses on climate change regulatory initiatives, particularly at the state level. A high-level summary of the company's greenhouse gas emissions mitigation strategy follows. Other regulatory topics covered include state renewable portfolio standards, hydropower relicensing, and major relevant provisions of the Energy Policy Act of 2005; namely, those pertaining to clean coal technologies, renewable energy, demand response programs and advanced metering, fossil fuel generation efficiency standards, and transmission reliability.

## MARKETPLACE AND FUNDAMENTALS

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 marketplace of the Western Interconnection. 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 has historically participated in the wholesale marketplace 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 terms and time scales ranging from hourly to years in advance. Without it, 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 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 experiences of the 2000-2001 market crisis and several more recent but briefer periods of price escalation in the west have underscored. Marketplace risks have been amplified in recent years by the growing role of natural gas fired generation in the Western Interconnection that have tied electricity market prices increasingly to natural gas commodity prices.

## Electricity Markets

Two overriding issues will tend to influence western electricity markets over the term of this plan's decision horizon. One of those is the evolution of natural gas prices, which is discussed in the next section. The other is the overall balance of generating resources in the Western Interconnection in relation to demand.

A slow pace of generating resource additions during the 1990s and robust growth in demand across the West were the main ingredients that set up the market crises of 2000-2001, although there were many other well documented contributing factors. Since that crisis, a wave of new capacity additions and demand side actions have righted the resource imbalance and restored aggregate planning and operating reserve margins. However, the pace of new generation additions has begun to slow again, raising the question of future resource adequacy and associated marketplace turmoil.

The WECC currently reports adequate reserve margins for the Western Interconnection in aggregate, based on existing resources. Currently, the Western Interconnection maintains an adequate margin of generation over projected demand through 2011 with the existing resource base and new generation projects currently under construction or in advanced development. However, Southern California, the desert southwest and the Rocky Mountain sub-regions show narrower projected margins and are more vulnerable to resource shortfalls or unexpected demand growth spurts, with the potential to propagate market upsets. Indeed, widespread and extremely hot temperatures in summer 2006 tested resource adequacy and caused a period of elevated market prices and a few instances of supply inadequacy near misses.

The pace and location of future resource additions have the potential to balance supply and demand adequately, but could also significantly undershoot or overshoot demand growth. Major transmission additions could also contribute to overall supply adequacy, but these have generally lagged generation additions and demand growth in the Western Interconnection.

Underlying these issues is the unresolved question of resource adequacy and responsibility throughout the Western Interconnection. The WECC does not have a regional planning reserve requirement. Without a system-wide binding standard for resource adequacy and responsibility with a multi-year horizon consistent with the multi-year time frame for most resource additions, there is elevated risk that the WECC or some of its sub-regions will experience demand growth in excess of supplies.

Uncertainty in magnitude of demand and uncertainty in availability of resources compound the resource adequacy issue. Resource uncertainty is especially important in the Northwest, where hydro accounts for more than half of installed capacity and the average energy availability from hydro can vary substantially from year to year.

The current WECC 2006 Power Supply Assessment analyzes resource adequacy for a number of possible future conditions for sub-regions of the Western Interconnection. Under base summer conditions, this assessment indicates that three of the WECC's sub-regions (Southern California, the desert southwest and Rockies) show resource deficits by 2010. More adverse conditions accelerate the deficits for these sub-regions to 2008. These results suggest that, even for utilities or sub-regions that maintain adequate reserve margins, there is an elevated risk of periods of exposure to high and volatile market prices, and that these risks must be carefully examined in resource plans.

**Natural Gas Supply and Demand Issues**

Over the last four years North American natural gas markets have demonstrated unprecedented price escalation and volatility. Spot gas prices averaged $3.34/MMBtu at the Henry Hub benchmark in 2002 but more than doubled by 2005, averaging $8.80/MMBtu.

Several factors have contributed to these market conditions and their interaction will play a major role in setting natural gas prices over the medium-term future. In particular, domestic United States production has reached a plateau, with growth from the Rocky Mountain region and from unconventional resources largely offset by declining volumes from conventional mature producing regions. The higher finding and development costs of unconventional resources have also raised the price level necessary to stimulate such marginal supply growth. On the demand side, substantial growth of gas-fired generating resources has more than offset declines in industrial demand for natural gas. This shift has reduced the amount of industrial demand that is most price-elastic and increased inelastic generation demand. Substantial oil price escalation over this same time period has 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 created a pronounced supply/demand imbalance in North American markets, raising prices sufficiently high to discourage marginal demand and to attract imports from an equally tight global market. This imbalance also made North American markets more susceptible to upset from weather and other event shocks and tied them more directly to global gas and energy markets.

Most forecasters expect a gradual restoration of better supply/demand balance to North American markets over the next five years, and this profile is reflected in New York Mercantile Exchange (NYMEX) futures prices. The primary factor contributing to the forecasted price decline is a substantial growth in liquefied natural gas imports over this period. For example, the U.S. Energy Information Administration's Annual Energy Outlook projects 2010 liquefied natural gas (LNG) imports to grow by 300% over 2005 levels.

This growth in LNG imports will be supported by rapid expansion of LNG regasification capacity that is well underway in North America, but will still take several years to reach fruition. It also requires parallel growth in capital-intensive liquefaction capacity in major producing regions, which is also underway, and sufficient LNG shipping capacity, which is currently overbuilt. North American regasification capacity is now forecasted to be more than adequate within five years, and has the potential to substantially overshoot demand for these facilities early in the next decade. On the other hand, recent delays and cost escalation in major liquefaction facilities has added some uncertainty to the forecasted downward price pressure.

The momentum behind LNG growth explains the medium-term trend of declining natural gas prices seen in both forward prices, such as natural gas futures prices on the New York Mercantile Exchange, and in forecasts of prices such as the Department of Energy's Annual Energy Outlook and other proprietary forecasts. Besides the downward price trend, the growth in reliance on LNG has other implications for North American natural gas markets. With a larger fraction of North American supply coming from LNG, a stronger linkage to global gas and energy markets is solidified. How this translates to U.S. gas price volatility is by no means clear, as the contracting structure and terms and role of LNG spot cargos in global LNG markets is evolving. Recently, delays in commercial arrangements for Alaska North Slope natural gas pipeline development have escalated the potential for LNG market share gains to indefinitely delay Alaska North Slope and Mackenzie Delta arctic frontier sources, although these are not now expected to contribute to supplies before 2015 and 2011, respectively, in any case.

Several factors besides potential LNG supply delays contribute to a wide range of price uncertainty over the next five years, including constraints on U.S. production infrastructure, linkages to oil prices, and supply and demand elasticities. PacifiCorp relies on PIRA Energy's Scenario Service, which describes and quantifies a range of forecasts, as a measure of future natural gas price uncertainty. Over time PIRA's natural gas scenarios have depicted a widening range of price uncertainty.

Given the range of uncertainty over future natural gas prices, it is prudent to recognize possible high and low gas prices as well as the most likely prices. PacifiCorp lays out such cases in Chapter 5, describing low, medium, and high scenarios for both gas and wholesale electricity prices. In addition, the IRP has adopted a probability-weighted or expected value forecast case, shown in Appendix A, which is higher than the reference or most likely forecast case, implying risk asymmetry towards the up-side.

Western regional natural gas markets are likely to remain well-connected to overall North American natural gas prices for the medium term outlook. Although Rocky Mountain region production is forecasted to be among the fastest growing in North America, major pipeline expansions to the mid-west and east are slated for the next five years and these should maintain market price correlations between Cheyenne/Opal and Henry Hub. A number of west coast LNG regasification facilities have been proposed, and one in Ensenada, Mexico, is under construction and expected to begin operation in 2008. Of the other facilities proposed for the west coast, there is relatively low probability that more than one will reach completion over the next five years. In any case, the presence of west coast LNG regasification facilities is not likely to cause large or abrupt disruptions in the relationship between western regional prices and overall North American natural gas prices.

## FUTURE EMISSION COMPLIANCE ISSUES

Over the next decade, PacifiCorp faces a changing environment with regard to electricity plant emission regulations. Although the exact nature of these changes remains uncertain, they are expected to impact the cost of future resource alternatives and the cost of existing resources in PacifiCorp's generation portfolio. No greater uncertainty exists in this area than the potential for global climate change and policy actions to control carbon dioxide, the principal emission associated with climate change. The section below briefly summarizes issues surrounding currently regulated air emissions. The potential for future regulation of $CO_2$ emissions due to climate change concerns and PacifiCorp's climate change strategy are then discussed in detail.

## 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 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.

Within the current federal political environment there exists a contentious debate over establishing a new energy policy and revising the CAA in order to reduce overall emissions from the combustion of fossil fuels. Currently, the debate focuses on emission standards and compliance measures for sulfur dioxide ($SO_2$), nitrogen oxides ($NO_X$), mercury (Hg), particulate matter (PM), and regulation of carbon dioxide emissions. Several proposals to amend the Clean Air Act to limit air pollution emissions from the electric industry are being discussed at the national level. Specifically, a number of alternative proposals for federal multi-pollutant legislation would require significant reductions in emissions of $SO_2$, and $NO_X$, and establish new definitive standards for mercury. Some proposals also contain measures to limit $CO_2$ and to revise certain other regulatory requirements such as NSR.

Within existing law, EPA's Regional Haze Rule and the related efforts of the Western Regional Air Partnership will require emissions reductions to improve visibility in scenic areas. Additionally, newly proposed administrative rulemakings by EPA, including the Clean Air Interstate Rule and the Clean Air Mercury Rule will require significant reductions in emissions from electrical generating units. The outcome of the current debate, manifested in new legislation or rulemakings, will shape PacifiCorp's emission requirements over the coming decade. 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.

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 the next ten years to install necessary equipment under future emissions control scenarios to the extent that it's cost-effective. The company has started its clean air projects, such as the installation of a baghouse, flue gas desulfurization and low nitrogen-oxide burners at the Huntington 2 plant.

## 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, landfill gas, combined heat and power (CHP) and 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 2006* reference case, the shares of these fuels change slightly from 2004 to 2030, with more coal and less petroleum and natural gas. The combined share of carbon-neutral renewable and nuclear energy is stable from 2004 to 2030 at 14 percent. As a result, $CO_2$ emissions increase by a moderate average of 1.2 percent per year over the period – 5,900 million metric tons in 2004 to 8,114 million metric tons by 2030, slightly higher than the average annual increase in total energy use. At the same time, the economy becomes less carbon intensive: the percentage increase in $CO_2$ emissions is one-third the increase in GDP, and emissions per capita increase by only 11 percent over the 26-year period.

According to the Administration's *Annual Energy Outlook 2006* report, 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; 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, more rapid improvements in technology, or more rapid adoption of voluntary programs could result in lower $CO_2$ emissions levels than projected here.

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 7% 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. The Bush Administration has proposed an 18% voluntary carbon intensity reduction target, i.e., emissions per unit of economic output. Such an approach could translate into a tons/MWh approach in the electricity sector.

Democratic victories on November 7, 2006 in the House and Senate appear likely to boost efforts to strengthen U.S. global warming policy, but it is far from certain whether the 110$^{th}$ Congress and President Bush will work together over the coming two years to enact a first-ever federal law to cap greenhouse gas emissions.

With Democrats taking over the House and the Senate in January, experts and lawmakers alike expect an emboldened legislative branch to advance an entirely new of set environment and energy proposals unlike anything seen during President Bush's previous six years in the White House. The Senate Environment and Public Works Committee, chaired by Senator Barbara Boxer (D-CA), has committed to having a set of intensive hearings on the issue of global warming during 2007.

On January 5, 2007, Senator Bingaman (D-NM) circulated a discussion draft which identifies his current proposal for mandatory greenhouse gas reduction legislation. On January 12, 2007, Senators Lieberman (I-CT) and McCain (R-AZ) reintroduced their proposed federal carbon legislation.[5] Senate legislation has also been released by Senators Sanders (I-VT) and Boxer (D-CA)[6] and Senators Feinstein (D-CA) and Carper (R-DE).[7]

On January 18, 2007, House Speaker Pelosi (D-CA) announced the formation of a new Select Committee on Energy Independence and Global Warming. The panel will draw on members from as many as nine existing panels that already have authority over the issue. Rep. Ed Markey (D-Mass.) is expected to lead the new committee, which will only be commissioned for the 110th Congress. The speaker also expressed her intent to have legislation through the committees by July 4, 2007.

**Regional Initiatives**

Western regional state initiatives were significant in 2006. The most notable developments have been the Western Public Utility Commissions' Joint Action Framework on Climate Change and the Western Regional Climate Action Initiative.

On December 1, 2006, California utility regulators and their counterparts in New Mexico, Oregon and Washington pledged to coordinate efforts to limit greenhouse gas emissions. The regulators in those four states will work together to address climate change, from promoting energy efficiency to encouraging the use of clean energy. The respective heads of the California Public Utilities Commission, the Washington Utilities and Transportation Commission, the Oregon Public Utility Commission, and the New Mexico Regulation Commission signed the agreement. The Joint Action Framework on Climate Change outlines a commitment to regional cooperation to address climate change.

On February 26, 2007, during the annual winter meeting of the National Governors Association, Governors Arnold Schwarzenegger (California), Janet Napolitano (Arizona), Bill Richardson (New Mexico), Ted Kulongoski (Oregon) and Christine Gregoire (Washington) signed the Western Regional Climate Action Initiative[8] that directs their respective states to develop a regional target for reducing greenhouse gases by August 2007. By August 2008, they are expected to de-

---

[5] S.280, the "Climate Stewardship and Innovation Act of 2007"
[6] S.309, the "Global Warming Pollution Reduction Act"
[7] S.319, the "Electric Utility Cap and Trade Act of 2007"
[8] See, http://gov.ca.gov/mp3/press/022607_WesternClimateAgreementFinal.pdf

vise a market-based program, such as a load-based cap-and-trade program to reach the target. The five states also have agreed to participate in a multi-state registry to track and manage greenhouse gas emissions in their region. The Initiative builds on existing greenhouse gas reduction efforts in the individual states as well as two existing regional efforts. In 2003, California, Oregon and Washington created the West Coast Global Warming Initiative, and in 2006, Arizona and New Mexico launched the Southwest Climate Change Initiative.

In response to limited federal activity, state policy has grown in prominence. While some states have adopted policies that address power plant emissions directly by either capping emissions or setting an emissions rate limit (such as the Northeastern Regional Greenhouse Gas Initiative), other states have sought to reduce carbon emissions through resource selection either by adopting renewable portfolio standards or requiring utilities to consider potential carbon costs within their integrated resource planning. Within PacifiCorp's service territory, only California has adopted specific legislation directly regulating utility greenhouse gas emissions. Washington and Oregon are expected to consider and possibly adopt climate legislation modeled after the California legislation during the 2007 legislative session. Wyoming has its Carbon Committee and Utah's Governor recently convened a climate council to discuss the state climate policies. California's greenhouse gas emissions policies are profiled below.

**State Initiatives**

***California Emissions Performance Standard (SB1368)***

California Senate Bill 1368 (SB 1368), signed into law on September 29, 2006, is an emissions performance standard law designed to effectuate a rulemaking at the California Public Utilities Commission, Docket No. R.06-04-009[9], and grants authority to the California Energy Commission to promulgate a similar emissions performance standard for publicly-owned utilities. PacifiCorp has been an active participant within the Commission docket. SB 1368 establishes a greenhouse gas emissions performance standard that prohibits any load serving entity, including electrical corporations, community choice aggregators, electric service providers, and local publicly owned electric utilities, from entering into a long-term financial commitment unless base load generation complies with a greenhouse gases emission performance standard not exceed the rate of emissions of a combined-cycle natural gas facility.

A long-term financial commitment is defined as a new ownership investment in base load generation or a new or renewed contract with a term of five or more years, which includes procurement of base load generation. Base load generation includes electricity generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent.

SB 1368 precludes the California Public Utilities Commission and the California Energy Commission from approving the construction of or contract for base load generation that does not meet the greenhouse gas emissions performance standard. Costs incurred for electricity purchase agreements that are approved by the Public Utilities Commission that comply with the greenhouse gas emission performance standard are recognized as procurement costs incurred pursuant

[9] The California PUC final Emissions Performance Standard Staff Workshop Report, which includes the latest staff straw proposal, is posted on the PUC website at: www.cpuc.ca.gov/static/energy/electric/climate+change. The direct link to the Report is www.cpuc.ca.gov/published/REPORT/60350.htm.

to an approved procurement plan and the Public Utilities Commission is required to ensure timely cost recovery of those costs. Long-term financial commitments entered into through a contract approved by the Public Utilities Commission for electricity generated by a zero- or low-carbon generating resource[10] that is contracted for on behalf of consumers in California on a cost-of-service basis is recoverable in rates, and the Public Utilities Commission may, after hearing, approve an increase from one-half to one percent in the return on investment by the third party entering into the contract with an electrical corporation relating to its investment in zero- or low-carbon generation resources.

On January 25, 2007, the California Public Utilities Commission approved the decision of President Peevey and Administrative Law Judge Gottstein in Rulemaking 06-06-009[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". The decision adopts an emissions performance standard of 1,100 pounds per megawatt-hour for new long-term base load (60%) financial commitments. The term "long-term financial commitments", will also include new financial investments by utilities in their own existing base load generation that extends the life of a plant by five years or more.

The Commission also adopted an interpretation of §§ 8341(d)(2) and (5) and clarified that it will determine compliance with the standard based on the reasonably projected net emissions over the life of a facility, but in calculating the net emissions rate, the Commission will not count carbon dioxide that is sequestered through injection in geological formations. This allows for a sequestration project to become operational after the power plant comes on line or the load serving entity enters into the contract. PacifiCorp had argued for such an interpretation as a means of allowing advanced coal projects to demonstrate compliance with the greenhouse gas emissions performance standard even though their carbon sequestering equipment may not be operational during the first few years of a project.

Regarding § 8341(d)(9)'s multi-jurisdictional utility qualification requirements for alternative compliance, the Commission adopted the tests proposed by PacifiCorp. In fact, the Commission went further and concluded that the information provided by PacifiCorp during the rulemaking process and the Oregon Public Utilities Commission's January 8, 2007 Order #07-002[12], which establishes a proceeding to examine carbon dioxide risk associated with resource decisions, were sufficient for the Commission to conclude that PacifiCorp meets the alternative compliance requirements. As a result, PacifiCorp is not obligated to submit an alternative compliance application and is only required to file an annual attestation advice letter affirming that it still satisfies the alternative compliance requirements by February 1 of each year, beginning in 2008.

The California Energy Commission must adopt regulations for municipal utilities consistent with the Public Utilities Commission rules by June 30, 2007.[13] Enforcement of the emission perform-

---

[10] Zero- or low-carbon generating resource is defined as an electrical generating resource that will generate electricity while producing emissions of greenhouse gases at a rate substantially below the greenhouse gas emission performance standards, as determined by the PUC.
[11] See, http://www.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/63931.htm
[12] See, http://apps.puc.state.or.us/edockets/orders.asp?ordernumber=07-002
[13] SB1368, *supra* note 42.

ance standard begins immediately upon the establishment of the standard. Existing combined-cycle power plants that are in operation, or have a California Energy Commission final permit decision to operate as of June 30, 2007, are grandfathered under the bill and deemed to be in compliance with the greenhouse gas emission performance standard.

***California Global Warming Solutions Act of 2006 (AB32)***

On September 27, 2006, California Governor Arnold Schwarzenegger signed into law Assembly Bill 32 (AB 32), known as the California Global Warming Solutions Act of 2006. California has since become the focus of climate change policy due to its massive economy, the fact that it is the 12th largest emitter of greenhouse gases in the world, and has had a history of catalyzing the formation of national environmental policy and regulation.

The bill itself is fairly performance-oriented and could result in a comprehensive, and thus effective, greenhouse gas mitigation strategy beyond the traditional focus solely on utilities. Under the legislation, greenhouse gas emissions would be reduced to 1990 levels by 2020 (a 25% reduction) and further reduced to 80% below 1990 levels by 2050. In determining and measuring these levels, the protocols of the California Climate Action Registry are to be incorporated to the maximum extent feasible. AB 32 also sets forth the following milestones for the California Air Resources Board:

- **By July 1, 2007**, the Air Resources Board forms Environmental Justice and Economic & Technology Advancement advisory committees.
- **By July 1, 2007**, the Air Resources Board adopts list of discrete early action measures that can be adopted and implemented before January 1, 2010.
- **By January 1, 2008**, the Air Resources Board adopts regulations for mandatory greenhouse gas emissions reporting. The Air Resources Board defines a 1990 emissions baseline for California (including emissions from imported power) and adopts that as the 2020 statewide cap.
- **By January 1, 2009**, the Air Resources Board adopts plan indicating how emission reductions will be achieved from significant sources of greenhouse gas emissions via regulations, market mechanisms and other actions.
- **During 2009**, the Air Resources Board staff drafts rule language to implement its plan and holds a series of public workshop on each measure (including market mechanisms).
- **By January 1, 2010**, early action measures take effect.
- **During 2010**, the Air Resources Board conducts series of rulemakings, after workshops and public hearings, to adopt greenhouse gas regulations including rules governing market mechanisms.
- **By January 1, 2011,** the Air Resources Board completes major rulemakings for reducing GHGs including market mechanisms. The Air Resources Board may revise the rules and adopt new ones after January 1, 2011 in furtherance of the 2020 cap.
- **By January 1, 2012,** greenhouse gas rules and market mechanisms adopted by the Air Resources Board take effect and are legally enforceable. (Note: This deadline dovetails well with the post-2012 Kyoto Protocol negotiations.)
- **December 31, 2020,** is the deadline for achieving the 2020 greenhouse gas emissions cap enforced by the Air Resources Board.

Furthermore, prior to creating enforceable mandates or market mechanisms (i.e. cap-and-trade programs), AB 32 specifies that the Air Resources Board must evaluate at least the following factors:

- Impacts on California's economy, the environment, and public health,
- Equity between regulated entities,
- Electricity reliability,
- Conformance with other environmental laws, and
- To ensure that the rules do not disproportionately impact low-income communities.

Although AB 32 does not specify a specific market-based policy tool to address greenhouse gas emissions, Governor Schwarzenegger has steered the state regulatory agencies in the direction of an international cap-and-trade type program by issuing a new executive order related to AB 32 in October 2006. The executive order[14] specifies that:

- The California Secretary for Environmental Protection shall create a Market Advisory Committee of national and international experts to make recommendations to the State Air Resources Board on or before June 30, 2007, on the design of a market-based compliance program.
- The Air Resources Board shall collaborate with the California Secretary for Environmental Protection and the Climate Action Team to develop a comprehensive market-based compliance program with the goal of creating a program that permits trading with the European Union, the Regional Greenhouse Gas Initiative and other jurisdictions.

The executive order appears to be well in line with the text of AB 32 and cites "numerous studies" by institutions such as U.C. Berkeley, Stanford, and the Pew Center on Global Climate Change that indicate that market-based policy mechanisms, such as emissions trading, are the most efficient and effective policy tools to address climate change.

California Governor Schwarzenegger has already met with New York Governor Pataki to discuss ways that the California market mechanism for climate change can potentially tie in with the Regional Greenhouse Gas Initiative's market-based cap and trade system. Nonetheless, the extent to which these two systems can be integrated remains to be seen.

In light of the passage of AB 32, on November 1, 2006 the California Public Utilities Commission indicated via an administrative law judge's ruling that they will develop a model rule to effectuate a state-wide load-based greenhouse gas cap-and-trade program for the electricity sector. The rulemaking will be undertaken as part of the Commission's existing Docket No. R.06-04-009.[15] PacifiCorp has been an active participant within this docket.

---

[14] http://gov.ca.gov/index.php?/press-release/4447/

[15] The California PUC final Emissions Performance Standard Staff Workshop Report, which includes the latest staff straw proposal, is posted on the PUC website at: www.cpuc.ca.gov/static/energy/electric/climate+change. The direct link to the Report is www.cpuc.ca.gov/published/REPORT/60350.htm.

***Washington's Act Mitigating the Impacts of Climate Change 2007 (SB6001)***
Washington Governor Christine Gregoire on May 3, 2007 signed Senate Bill 6001, which contains provisions aimed at reducing the state's greenhouse gas (GHG) emissions. First, the Act established the following goals for statewide GHG emissions:

- by 2020, reduce emissions to 1990 levels;
- by 2035, reduce emissions to 25 percent below 1990 levels; and
- by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below the state's expected emissions that year.

It then established en employment goal that by 2020, increase the number of clean energy sector jobs to 25,000 from the 8,400 jobs the state had in 2004.

The bill also requires by December 31, 2007, Department of Energy (DOE) and Department of Community, Trade & Economic Development (CTED) must report to the appropriate committees of the Legislature the total GHG emissions for 1990, and totals in each major sector for 1990. By December 31 of each even-numbered year beginning in 2010, DOE and CTED must report to the Governor and the Legislature the total GHG emissions for the preceding two years, and totals in each major source sector.

The Governor is also directed to develop policy recommendations on how the state can achieve the specified GHG emissions reduction goals. The recommendations must include such issues as how market mechanisms would assist in achieving the goals. The recommendations must be submitted to the Legislature during the 2008 Legislative Session.

The bill also establishes a GHG Emissions Performance Standard (EPS). Beginning July 1, 2008, the GHG emissions performance standard for all baseload electric generation for which electric utilities enter into long-term financial commitments on or after such date is the lower of:

- 1,100 pounds of GHG per megawatt-hour; or
- the average available GHG emissions output as updated by CTED.

In general, all baseload electric generation that begins operation after June 30, 2008, and is located in Washington, must comply with the performance standard. The following facilities are deemed to be in compliance with the performance standard:

- all baseload electric generation facilities in operation as of June 30, 2008, until they are the subject of long-term financial commitments;
- all electric generation facilities or power plants powered exclusively by renewable resources; and
- all cogeneration facilities in the state that are fueled by natural gas or waste gas in operation as of June 30, 2008, until they are the subject of a new ownership interest or are upgraded.

The following emissions produced by baseload electric generation do not count against the performance standard:

- emissions that are injected permanently in geological formations;

- emissions that are permanently sequestered by other means approved by DOE; and
- emissions sequestered or mitigated under a plan approved by the EFSEC, as specified in the act.

Unlike California's EPS, the Washington proposal offers some potential emissions mitigation options to allow energy from new coal plants to be used in the state. These provisions allow coal power as long as operators reduce emissions from other sources to meet the EPS. For example, a new base-load coal plant has up to five years after commencing operation to initiate a $CO_2$ capture-and-sequestration process to meet the law. If the technology is not available at that time, the plant owner has options to mitigate the $CO_2$ emissions to meet the EPS and stay in the Washington energy market. For example, a plant owner can purchase "verifiable GHG emission reductions" from another power plant located within the Western Interconnection that would not have occurred otherwise. Coal plant operators could also purchase $CO_2$-emitting power generators with the intent to shut them down, and use the avoided $CO_2$ emissions as offsets to meet the EPS for a new power plant project.

By June 30, 2008, DOE and Washington State Energy Facility Site Evaluation Council (EFSEC) must coordinate and adopt rules to implement and enforce the GHG emissions performance standard, including the evaluation of sequestration and mitigation plans. In addition, CTED must consult with specified groups, such as the Bonneville Power Administration, and consider the effects of the standard on system reliability and the overall costs to electricity customers.

In order to update the standard, CTED must conduct a survey every five years of new combined-cycle natural gas thermal electric generation turbines commercially available and offered for sale by manufacturers and purchased in the United States. CTED must use the survey results to adopt by rule the average available GHG emissions output. The survey results must be reported to the Legislature every five years, beginning June 30, 2013.

Electric utilities may not enter into long-term financial commitments for baseload electric generation unless the generation complies with the performance standard. For an investor-owned utility (IOU), the Washington Utilities and Transportation Commission (WUTC) must review a long-term financial commitment in a general rate case. The WUTC must also review an IOU's proposed decision to acquire electric generation or enter into a power purchase agreement for electricity, upon application of the utility. The process for reviewing proposed decisions must be specified in rule and conducted under the Administrative Procedures Act. The WUTC must consult with DOE when verifying compliance with the performance standard. The WUTC must adopt all implementing rules by December 31, 2008. The WUTC may exempt a utility from the performance standard for unanticipated electric system reliability needs, catastrophic events, or threat of significant financial harm arising from unforeseen circumstances.

DOE, in consultation with CTED, EFSEC, the WUTC, and the governing boards of consumer-owned utilities, must review the GHG emissions performance standard no less than every five years or upon the implementation of a federal or state law or rule regulating $CO_2$ emissions of electric utilities, and report to the Legislature.

By December 31, 2007, the Governor must report to the Legislature the potential benefits of creating tax incentives to encourage base load electric facilities to upgrade their equipment to reduce $CO_2$ emissions, the nature and level of tax incentives likely to produce the greatest benefits, and the cost of providing such incentives.

***Oregon Examination of Treatment of $CO_2$ Policy Risk within IRP Planning***

On January 8, 2007, the Oregon Public Utilities Commission issued an order within the Integrated Resource Planning docket UM 1056.[16] As part of the Order, the Commission announced it was opening an investigation to review the treatment of carbon dioxide risk in Integrated Resource Plans (per footnote 11, this will apply to future Requests for Proposals), which will ultimately replace the analysis required in Order 93-695. Next, the Commission noted in footnote five that it had committed to explore a carbon dioxide emissions performance standard for long-term power supplies in adopting the Joint Action Framework on Climate Change, and that this investigation would follow the proceeding on carbon dioxide risk in Integrated Resource Plans.

On February 8, 2007, the Oregon Public Utilities Commission announced it would begin work under docket UM-1302[17] investigating the treatment of carbon dioxide risk in Integrated Resource Plans.

**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 established a Global Climate Change Working Group, meant to examine best utility practices for addressing carbon risk. The company has also 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 2007 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.

- **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,

[16] See, http://apps.puc.state.or.us/edockets/orders.asp?ordernumber=07-002
[17] See, http://apps.puc.state.or.us/edockets/docket.asp?DocketID=13896

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. As part of PacifiCorp's Global Climate Change Working Group effort, a Preliminary Global Climate Change Action Plan will be completed by the company in 2007 and filed with the six state utility commissions. Within the Plan, PacifiCorp expects to propose significant changes to its corporate greenhouse gas mitigation strategy.

## 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[18], 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.[19] As of late 2006, 23 states and the District of Columbia had adopted RPS regulations. The most recent adoption occurred in Washington, which passed a ballot measure in November 2006. Two states in PacifiCorp's service territory—California and Washington—now have an RPS in place. Recent RPS legislative and regulatory activities in California, Washington, and Oregon are summarized below.

### <u>California</u>

In 2006, the California legislature approved, and Governor Schwarzenegger signed into law, a bill that codifies an earlier deadline for reaching the state's renewable energy goals. Existing law had established the RPS program and a goal of 20% of retail electric sales from renewable resources by 2017. The new legislation, Senate Bill 107[20], accelerates the target date to December

[18] Interest in a federal RPS policy is expanding. For example, a bipartisan group of Senators and Representatives have re-introduced the 25x'25 House and Senate Concurrent Resolutions in January 2007 calling for a new national renewable energy supply goal of 25% by 2025.
[19] See, http://www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm
[20] SB 107 as enacted and chaptered is posted on the legislature's web site at:

31, 2010. The law now comports with earlier decisions by the California Public Utilities Commission that established the "20% by 2010" target. Senate Bill 107 requires compliance with the standard by investor-owned utilities, community choice aggregators, and electric service providers. Municipal utilities are exempt, but must meet expanded reporting requirements on their plans and accomplishments in supporting the development and use of renewable resources. Other provisions of the bill authorize the use of renewable energy credits, "flexible compliance" approaches, and program eligibility for renewable power produced outside the state if it is delivered to California locations.

Existing law requires the California Energy Commission to certify eligible renewable resources, to develop a regional accounting system to verify compliance, and to allocate and award supplemental energy payments (SEPs) to cover above-market costs of renewables. The bill requires the Energy Commission to recover all costs of the regional accounting system from user fees. The bill also requires the Energy Commission to develop tracking, accounting, verification, and enforcement mechanisms for renewable energy credits (RECs). Certain renewable resource facilities located outside the state can be eligible for SEPs, but awards to those facilities are limited to 10% of total funds available.

PacifiCorp filed a proposed compliance plan for meeting the California RPS requirements in 2006. In its filing, PacifiCorp cited its 2001 eligible[21] renewable resource generation as approximately 4% of its retail sales in California. PacifiCorp is currently required to deliver 20% of its California load from eligible renewable resources by 2010. It is also worth noting that the California legislature is currently considering legislation that would establish a 33% requirement by 2020.

**Oregon**

At the request of Governor Kulongoski, a number of state agencies were asked to develop a Renewable Energy Action Plan (REAP) with input from stakeholders. These agencies—Agriculture, PUC, Economic Development, Energy, Environmental Quality, Forestry and Water Resources—prepared several drafts, which were sent to interested individuals, businesses and organizations and posted on the Oregon Department of Energy Web site. Public comment and stakeholder input was taken and a series of public meetings were held before finalizing the document. The final Renewable Energy Action Plan was released in April of 2005.

The REAP contains numerous renewable energy policy goals for the state and also a mandate to "support a Renewable Energy Working Group to be coordinated through the Governor's Office and the Oregon Department of Energy to guide the implementation of this Plan." A long list of actions for state agencies is included in the Plan, as well as numerous tasks for the Renewable Energy Working Group.

A Renewable Energy Working Group was formed through a collaborative process involving the Oregon Department of Energy and the Governor's Office. The primary mission of the Renewable Energy Working Group (REWG) was to guide implementation of the Renewable Energy Action

---

http://www.leginfo.ca.gov/pub/bill/sen/sb_0101-0150/sb_107_bill_20060926_chaptered.pdf

[21] The California RPS stipulated resources eligible for inclusion in meeting the RPS requirement. It should be noted that the only eligible hydro resources are those with capacity less than 30 megawatts.

Plan. Group members were tasked by the Governor to develop a legislative proposal for a RPS that would be 25 percent of retail sales by 2025. The Renewable Energy Working Group's legislative proposal was introduced during the 2007 legislative session and is currently under consideration. The proposal would establish an RPS with the schedule of at least 5% of load by January 1, 2011, at least 15% by January 1, 2015, at least 20 percent by January 1, 2020, and at least 25 percent by January 1, 2025.

In addition to its renewable energy focus, Oregon's proposed RPS also provides the framework for the further expansion of cost-effective conservation activity in the state by electric utilities. It allows the Commission to authorize an electric company to include in its rates the costs of funding or implementing cost-effective energy conservation measures beyond those currently funded through the state's public purpose charge—established under the state's restructuring legislation in 2002—and delivered by the Energy Trust of Oregon. If approved, Oregon's portfolio standard may allow conservation investments up to the potential conservation opportunity within the state, further adding to the demand-side resources available to address PacifiCorp's demand growth in the state.

### Washington

In November 2006, Washington voters approved ballot initiative I-937[22], which would establish an RPS with the schedule of at least 3% of load by January 1, 2012, at least 9% by January 1, 2016, and at least 15% by January 1, 2020. The annual targets are based on the average of the utility's load for the previous two years. The Washington Utilities and Transportation Commission undertook rulemaking UE-061895 to effectuate the referendum.

### Federal Renewable Portfolio Standard

Congress is expected to take up federal energy policy legislation, including the possibility of a federal RPS, as early as summer 2007. On the House side, Rep. Tom Udall (D-N.M.) has introduced legislation creating a 20% standard by 2020. Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-N.M.) has indicated he is planning legislation with a level of 15 percent by 2020.

The Senate has approved an RPS several times, most recently as part of the 2005 energy bill, but it died in conference with the House. Even so, environmentalists see the Democratic Congress as an opportunity for a host of initiatives that have failed in recent years. But the fate and timing of an RPS in the Energy and Commerce Committee, which has jurisdiction over the issue, is far from clear because a key committee leader and others have been skeptical of the need for an RPS.

## TRANSMISSION PLANNING

### Integrated Resource Planning Perspective

Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak load obligations are met on a reliable basis. With

[22] See, http://www.secstate.wa.gov/elections/initiatives/text/i937.pdf

this in mind, PacifiCorp's IRP team has increased its coordination with transmission planning personnel to more closely align long-term generation and transmission planning activities. The result for this IRP is a set of transmission resources for portfolio modeling 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 next section, PacifiCorp is engaged in a number of regional transmission planning initiatives intended to address transmission issues and project opportunities. Future IRP analysis efforts will be informed by these transmission planning initiatives.

## Interconnection-Wide Regional Planning

Various regional planning processes have developed over the last several years in the Western Interconnection. It is expected that, in the future, these processes will be the primary forums where major transmission projects are developed and coordinated. In the Western Interconnection, regional planning has evolved into a two tiered approach where an interconnection-wide entity, Western Electricity Coordinating Council (WECC) conducts regional planning at a very high level and several sub-regional planning groups focus with greater depth on their specific areas.

Last year, WECC took on the responsibility for interconnection-wide transmission expansion planning. 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, 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 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;
- steering report writing and other communications that include communications between the TEPPC and the sub-regional planning groups;
- advising the WECC Board on policy issues affecting economic transmission expansion planning;

- recommending budgets for WECC's economic transmission expansion planning process;
- organizing and coordinate activities with sub-regional planning processes; and
- approving recommendations to improve the economic transmission expansion planning process.

TEPPC analyses and studies will focus on plans with west-wide implications and will include a high level assessment of congestion and congestion costs. The analyses and studies will 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 may draw from state energy plans, integrated resource plans, large regional expansion proposals, sub-regional plans and studies, and other sources such as individual control areas if relevant in a regional context.

TEPPC's role does not include:

1. conducting sub-regional or detailed project-specific studies,
2. prioritizing and advocating specific economic expansion projects,
3. identifying potential "winners" and "losers,"
4. developing or advocating cost allocations,
5. developing or advocating cost allocation criteria,
6. providing mechanisms to obtain funding,
7. assigning transmission rights,
8. providing backstop permitting or approval authority, or
9. performing reliability analysis outside of what is being done today.

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.

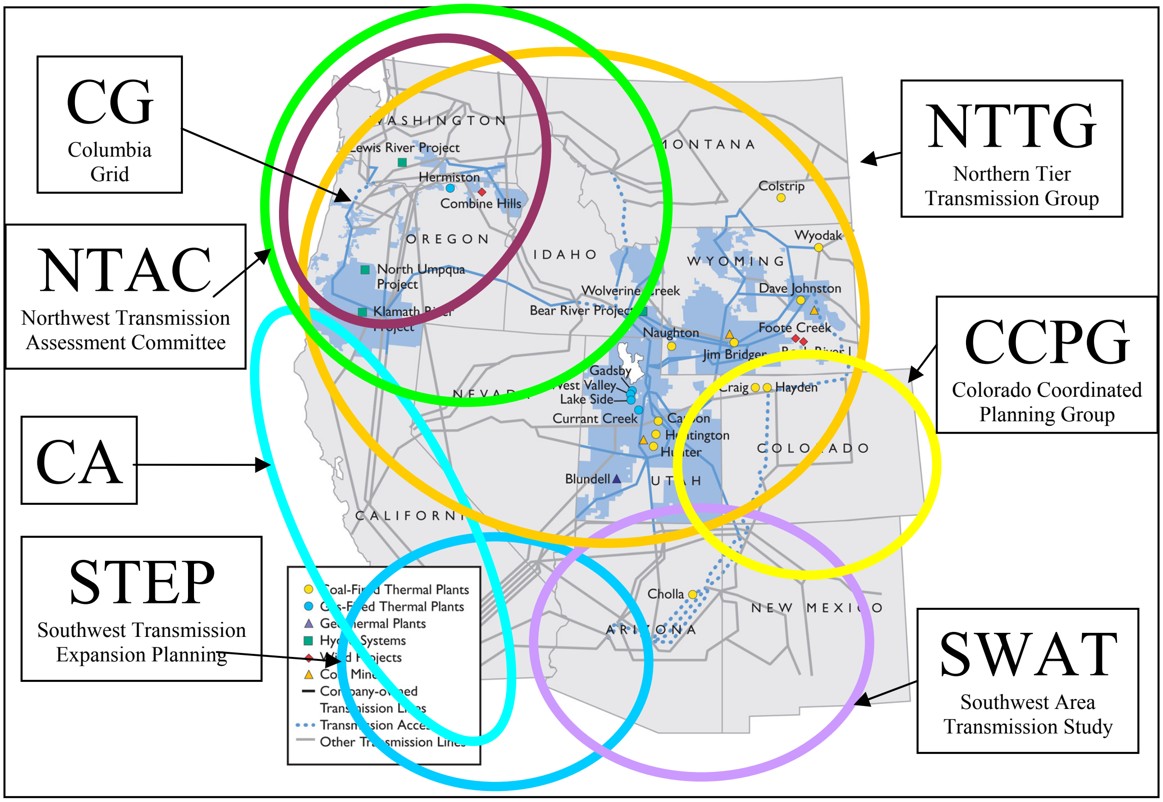
**Sub-regional Planning Groups**

Recognizing that planning the entire interconnection in one forum is impractical due to the overwhelming scope of the task, a number of smaller sub-regional groups have been formed to address specific problems 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 areas. It is these sub-regional forums where the majority of transmission projects are expected to be developed. These forums will be informally coordinated with each other directly through liaisons and through TEPPC. A current list of sub-regional groups is provided below.

- CCPG – Colorado Coordinated Planning Group
- CG – Columbia Grid
- NTAC - Northwest Transmission Assessment Committee
- NTTG – Northern Tier Transmission Group
- STEP - Southwest Transmission Expansion Planning
- SWAT – Southwest Area Transmission Study

The geographical areas covered by these sub-regional planning groups are approximately as shown in Figure 3.1 below. In addition to the above groups, California is attempting to coordinate the overall planning for their state.

**Figure 3.1 – Sub-regional Transmission Planning Groups in the WECC**




## 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. Relicensing or decommissioning of many of PacifiCorp's projects are nearing completion as Federal Energy Regulatory Commission (FERC) licenses or Orders are expected to be issued for the majority of the portfolio over the next 1 to 3 years.

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.

**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, 2006, PacifiCorp had incurred $79.0 million in costs for ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As relicensing efforts continue, 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 $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. About 90 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**

As noted, PacifiCorp continues to manage this process by pursuing negotiated settlements as part of the 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.

## ENERGY POLICY ACT OF 2005

The Energy Policy Act of 2005 (EPAct), the first major energy law enacted in more than a decade, documents the tone of the current political/social environment. More than 1,700 pages long, the Act has hundreds of provisions. With respect to electric utilities the major provisions of the act include the following.

- Promote clean coal technology and provides incentives for renewable energy such as biomass, wind, solar and hydroelectricity and by requiring net metering options
- Encourage more hydropower production by improving current procedures for hydroelectric project licensing and calling for plans to improve the efficiency of existing projects.
- Requires state commissions to consider adopting five new standards dealing with net metering, interconnection, fossil fuel generation efficiency, time-based metering and telecommunication, and fuel sources.
- Provide for enforceable mandatory reliability standards, incentives for transmission grid improvements and reform of transmission siting rules. These improvements will attract new investment into the industry and ensure the reliability of our nation's electricity grid in order to stop future blackouts.
- Provides research and development support and a production tax credit for advanced nuclear power facilities

This section covers the major EPAct provisions that impact PacifiCorp and how the company is addressing them.

**Clean Coal Provisions**

The EPAct contains a number of provisions to encourage development of clean coal technologies. These provisions cover not only power generation technologies, but other coal-based technologies to encourage national energy security, reduced dependency on premium fossil fuels such as oil and natural gas, increased efficiency, and reductions in emissions. The primary focus of the clean coal provisions of the EPAct is on gasification, but other advanced technologies such as ultra-supercritical boiler technologies are also considered.

Under Title IV of the EPAct, financial assistance is made available to qualifying projects. The primary focus for the financial assistance is for advanced combustion systems and processes that reduce air pollution. Financial assistance can consist of cost sharing or loans.

Under Title XIII of the EPAct, a number of tax incentives are established. These incentives are primarily focused on development of gasification technologies both for electric power generation and coal-based gasification processes that produce liquid and gaseous fuels as well as primary chemical feedstocks. Available credits will be allocated on a first-come, first-served basis taking into account Department of Energy (DOE) balancing of the EPAct policy goals (fuel diversity, location, technology, $CO_2$ capture, project economics), i.e. integrated gasification combined cycle (IGCC) projects that include greenhouse gas capture, increase by-product utilization, and other benefits will be given high priority in the allocation of credits for IGCC projects.

Under the guidelines there are three separate application periods (2006, 2007, and 2008); the application date for each application period is June 30 of each year. Based on the overwhelming response the DOE received in 2006, the availability of investment tax credits (ITCs) is expected to diminish with time.

PacifiCorp submitted confidential applications on June 29, 2006 to the DOE for ITCs under this section of the Act for IGCC facilities at both the Hunter and Jim Bridger plant sites. PacifiCorp also indicated an interest in Energy Northwest's planned development of the Pacific Mountain Energy Center IGCC project. The proposed location for this project is in Port Kalama, Washington. Energy Northwest submitted a confidential application to the DOE for ITCs under this portion of the Act for that portion of the plant which would not be owned by public power entities.

Section 413 of EPAct also authorizes, subject to appropriations, funding support for a demonstration project to be built in the Western U.S. The Wyoming Infrastructure Authority (WIA) issued an RFP for a Wyoming Coal Gasification Demonstration Project on July 17, 2006. The WIA's intent for this RFP process was to identify one or more Wyoming based projects for the purpose of seeking Section 413 funding. PacifiCorp provided an expression of interest in response to this RFP on August 17, 2006, followed by a confidential proposal to the WIA in October 2006. As described in Chapter 5, the WIA recently selected PacifiCorp to participate in the joint IGCC project.

In addition to the ITC programs available for qualifying IGCC or advanced clean coal technologies, the EPAct makes available $350 million for ITCs for qualifying industrial gasification projects (not necessarily for power generation).

Title XVII of the EPAct provides for loan guarantees for innovative technologies, such as (IGCC) or technologies that reduce or sequester pollutants or greenhouse gases. PacifiCorp has reviewed the potential application of loan guarantees for potential IGCC projects under consideration and has determined that loan guarantees provide little value to the company and would entail significant regulatory complications.

## Renewable Energy Provisions

The renewable energy production tax credit (PTC), which was set to expire at the end of 2005, was extended through the end of 2007. (The U.S. Congress extended it again through the end of 2008 as part of the Tax Relief and Health Care Act of 2006.) Additionally, the eligibility period for power production from open-loop biomass, geothermal, small irrigation, landfill gas and municipal solid waste projects is increased from 5 to 10 years. Finally, incremental hydropower production resulting from efficiency improvements or capacity expansion at existing dams was added to the list of production technologies eligible for the PTC.

PacifiCorp expects that extension of the PTC should aid the procurement of new wind and other renewable resources with a relatively short development lead-time. Nevertheless, dependence on year-to-year extensions represents a significant challenge for developing renewable resources with longer design/procure/construction periods, such as geothermal projects. Given the uncertain future of the PTC, PacifiCorp, along with other utilities, is attempting to acquire as much economic renewables as possible prior to the expiration date.

### Hydropower

The bill includes a major reform of the federal licensing procedure for hydroelectric dams. The modifications allow an applicant to propose an alternative to mandatory conditions placed on hydropower licenses by federal resource agencies (Departments of Interior, Commerce and Agriculture). If a proposed alternative met the statutory environmental and resource protection standards, the alternative would be accepted. Hydro licensing reform has been a goal of the industry for years, but has been highly controversial with the environmental community.

The bill also includes incentives for improving the efficiency of existing hydroelectric dams and for modifying existing dams to produce electricity. (See Renewable Energy Provisions, above.)

### Public Utility Regulatory Policies Act Provisions

The bill establishes market conditions necessary to eliminate the Public Utility Regulatory Policies Act's (PURPA) mandatory purchase obligation. The EPAct also includes amendments that establish market conditions that eliminate the requirement for utilities to buy power from independent renewable energy and cogeneration plants where FERC determines that competitive market conditions exist, and revises the criteria for new qualifying facilities seeking to sell power under the mandatory purchase obligation. Unfortunately, competitive markets may not support the long-term contracts that many renewable generators need to secure financing at affordable rates.

Title XII of EPAct also amends a section of PURPA by adding five new ratemaking standards for electric utilities. State regulatory commissioners are to determine whether the new standards are appropriate for their states. The five standards include net metering, fuel source diversity, fossil fuel generation efficiency and interconnection service to customers with their own on-site generating facilities.

### Metering Provisions

Section 1252, "Smart Metering", of the EPAct requires that all utilities provide a time-based rate to all customer classes within 18 months of the enactment. In all states, PacifiCorp has met the basic requirements of the EPAct in regards to time-based rate schedule offerings.

Furthermore, the EPAct requires state commissions to conduct an investigation as to whether a time-based rate schedule and accompanying meter equipment is appropriate to implement and install within 18 months after date of enactment. The following time-based rates must be considered:

- "Time-of-use pricing" – Prices for specific periods and typically changed twice a year
- "Critical peak pricing" – Prices for peak days, discounts for reducing peak period consumption
- "Real-time pricing" – Prices may change hourly
- "Credits" – Large load customers who reduce a utility's planned capacity obligations

PacifiCorp has actively participated in all requested state commission investigations and/or technical conferences. These meetings must be completed by February 2007 with the commission recommendations provided by August 2007.

Section 110, "Daylight Savings", amends the Uniform Time Act of 1966 by extending Daylight Savings Time (DST) by four weeks beginning in 2007. DST will begin the second Sunday of March and end the first Sunday of November. This section also requires the Department of Energy to file a report to Congress nine months after enactment on the impact of this section on energy consumption in the U.S. Congress retains the right to revert DST back to the 2005 time once the report is complete.

To meet the requirements of Section 110, all of PacifiCorp's time-of-use and interval meters would be required to be replaced and/or reprogrammed to align the internal calendars with the new dates. With the possibility of Congress reverting to 2005 time, the exposure for cost to re-program the meters is significant.

To mitigate the costs of meter replacement and programming until such time as a formal decision is made, PacifiCorp has filed, or will be filing, interim tariff modifications in all states. If accepted, the modifications will keep the existing 2005 DST dates within the applicable tariffs until such time that a formal decision is made. PacifiCorp will comply with the requirements of the decision at that time.

**Fuel Source Diversity**

Section 111(d)(12), "Fuel Sources", requires electric utilities to develop "a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies." Within three years of enactment, state regulatory authorities must decide whether to enact this standard or determine that a comparable standard meets this objective.

During 2006, PacifiCorp reviewed this amendment with states and other interested parties through technical conferences sponsored by the state commissions. PacifiCorp believes that the state IRP standards and guidelines reflect a comparable standard that fulfills the requirement for a fuel source diversity plan. The Public Service Commission of Utah concurred with this view, issuing a determination that the current Utah IRP guidelines constitute a comparable standard.[23] During the October 17, 2006 technical conference, the company agreed to include a section in the IRP that discusses how fuel diversity is addressed in the planning process. This section is included in Chapter 8, "Action Plan."

---

[23] Public Service Commission of Utah, "Determination Concerning the PURPA Fuel Sources Standard" (Docket No. 06-999-03), issued March 13, 2007.

**Fossil Fuel Generation Efficiency Standard**
The PURPA amendments include a requirement that each electric utility develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation plants. States must determine whether to adopt this standard by August 8, 2008. States do not have to comply if the state has already adopted or considered a comparable provision.[24] PacifiCorp has been reviewing this amendment with states and other interested parties through technical conferences sponsored by the state commissions. PacifiCorp believes that the IRP currently serves as a comparable provision with respect to fleet efficiency improvements arising from new generation and retirement of old, less efficient fossil units.

In discussions with Utah Public Service Commission staff, PacifiCorp agreed to report in this IRP the 20-year forecasted average heat rate trend for the company's fossil fuel generator fleet. This forecasted average heat rate represents the individual generator heat rates weighted by their annual generation, accounting for new IRP resources and current planned retirements of existing fossil fuel generators. For existing fossil fuel resources, four-year average historical heat rate curves are used, whereas new resources use expected heat rates accounting for degradation over time. This fleet-wide heat rate trend information is provided in Figure 7.34 in Chapter 7, "Results."

In PacifiCorp's subsequent integrated resource plans, the company will summarize its efficiency improvement plans, as well as report heat rate trends using forward-looking heat rates that account for these plans.

**Transmission and Electric Reliability Provisions**

This portion of the EPAct is intended to:

- Help ensure that consumers receive electricity over a dependable, modern infrastructure;
- Remove outdated obstacles to investment in electricity transmission lines;
- Make electric reliability standards mandatory instead of optional; and
- Give Federal officials the authority to site new power lines in DOE-designated national corridors in certain limited circumstances.

Two sections of this legislation pertain specifically to the development of major new transmission lines: Section 368a, which defines "energy corridors", and Section 1221, which attempts to identify and address transmission congestion.

**Section 368a, Energy Corridors**
Section 368a directs the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior (the Agencies) to designate under their respective authorities corridors on Federal land in the 11 Western States for oil, gas and hydrogen pipelines and electricity transmission and distribution facilities (energy corridors). The legislation sets the timetable for corridor designation in the eleven Western States at no later than two (2) years after enactment, or August 2007.

---

[24]Edison Electric Institute, *Energy Policy Act of 2005, Summary of Title XII – Electricity, Title XVIII – Studies, and Related Provisions* (August 3, 2005), page 10.

The Agencies determined that designating corridors as required by Section 368a of the Act constitutes a major Federal action which may have a significant impact upon the environment within the meaning of the National Environmental Policy Act (NEPA). For this reason, the Agencies are preparing a draft Programmatic Environmental Impact Statement (PEIS) to identify the impacts associated with designating energy corridors. Based upon the information and analyses developed in the PEIS, the Agencies will designate energy corridors by amending their respective land use plans.

Public scoping meetings were held in October and November 2005. Potential energy corridor locations were depicted on draft maps and circulated for comment (See the following DOE web site for these maps: http://corridoreis.anl.gov/eis/pdmap/index.cfm). The draft PEIS was released for comments last fall. Final energy corridors will be identified in the final EIS which is scheduled to be released in August 2007. The majority of the preliminary energy corridors utilize existing corridors and/or rights-of-way; however, there are a small number of potential new corridor locations.

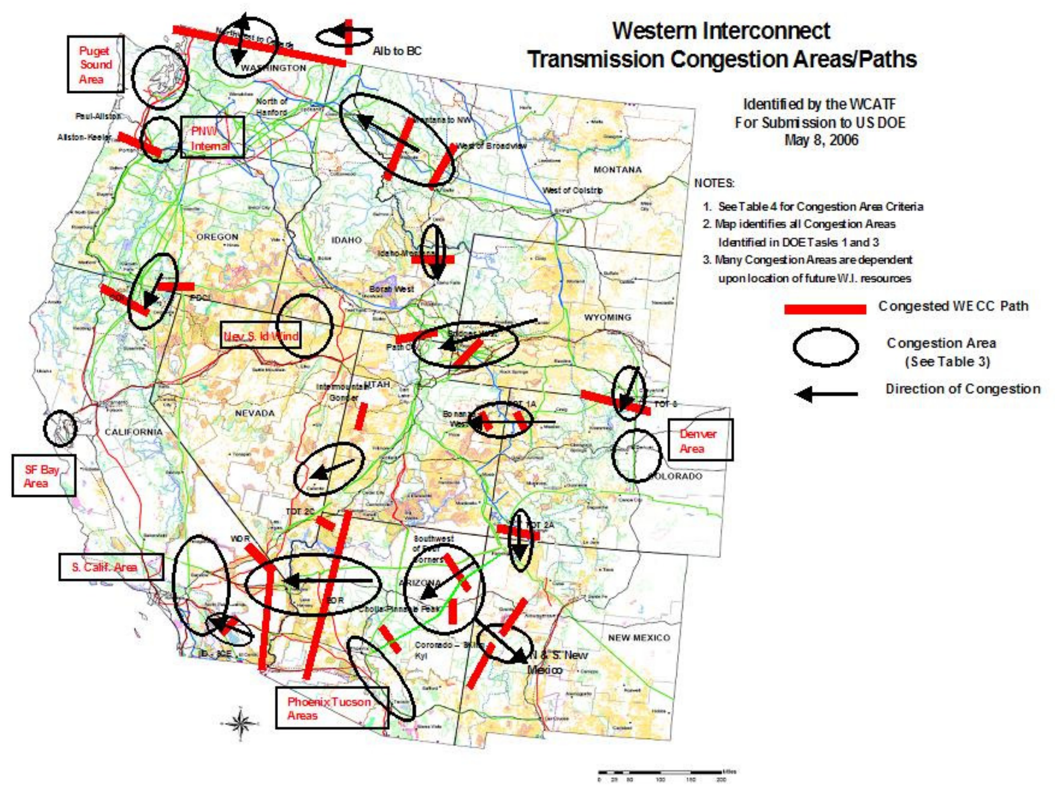
**Section 1221, National Transmission Congestion Study**

Section 1221 of the EPAct of 2005 required DOE to issue a national transmission congestion study for comment by August 2006 and every three years thereafter. Based on the study and public comments, DOE may designate selected geographic areas as "National Interest Electric Transmission Corridors." Applicants for projects proposed within designated corridors that are not acted upon by state siting authorities within one year may request FERC to exercise federal "backstop" siting authority. For the Western Interconnection, DOE relied on the Western Congestion Assessment Task Force (WCATF), which is an ad-hoc group formed primarily by WECC members, to complete the congestion study. The WCATF produced several work products for DOE including a summary of major studies, a report describing historical congestion, and the results of SSG-WI production cost studies conducted for the years 2008 and 2015. Figure 3.2 is a map provided to DOE showing the major areas of congestion in the Western Interconnection.

Based on the WCATF report and other information, the DOE produced a national transmission congestion report that shows congested areas across the Western Interconnection. The only critical congestion area highlighted in the Western Interconnection was in southern California. In addition to the congestion in southern California, it was noted that there are conditional constraints in the PacifiCorp area in association with exporting potential new coal and wind resources from the states of Montana and Wyoming (See Figure 3.3)

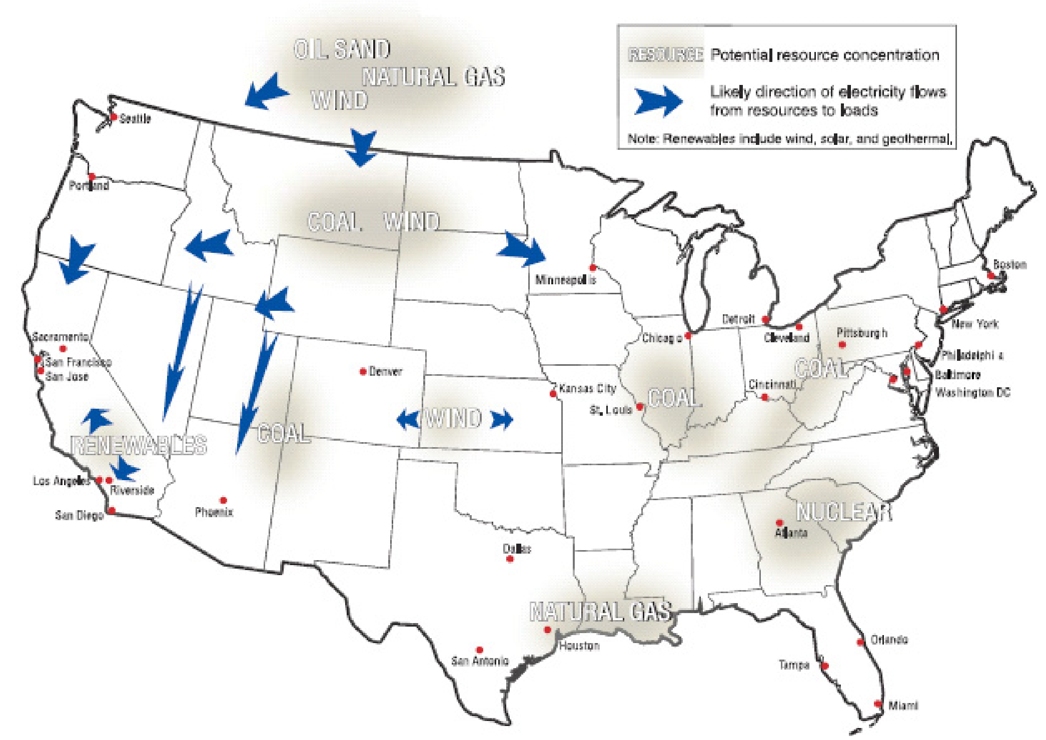
The effect of Section 1221 on PacifiCorp is unclear at this point, but it is expected to be beneficial as it should speed up the permitting process for new transmission facilities.

**Figure 3.2 – Western Interconnection Transmission Congestion Areas/Paths**




Source: Western Congestion Analysis Task Force, *Western Interconnection Congestion Areas: Summary Tables 1, 2 and 3 with Congestion Area Map*, prepared for the U.S. Department of Energy, May 8, 2006.

**Figure 3.3 – Conditional Constraint Areas**




Source: U.S. Department of Energy, *National Electric Transmission Congestion Study*, August, 2006.

## Climate Change

The EPAct established a Climate Change Technology Advisory Committee to identify statutory, regulatory, economic and other barriers to the commercialization and deployment of technologies and practices that would reduce the intensity of greenhouse gas production. Additionally, the new law directs the State Department to act as lead agency for integrating into U.S. foreign policy the goal of reducing greenhouse gas intensity in developing countries, and directs DOE to conduct an inventory of greenhouse gas intensity reducing technologies for transfer to developing countries.

## RECENT RESOURCE PROCUREMENT ACTIVITIES

### Supply-Side Resources

**2012 Request for Proposals for Base Load Resources**
As a consequence of the update to the 2004 Integrated Resource Plan (filed in November 2005), PacifiCorp suspended the 2009 Request for Proposal and is preparing a new RFP for acquisition of east-side base load resources for 2012, 2013, and 2014.

The base load RFP seeks to acquire up to 1,700 megawatts of cost-effective resources for the term of 2012 through 2014, consisting of a combination of generation assets, generation assets on the company's sites and market purchases (i.e., front office transactions).[25] The company has included two benchmark resources in the RFP. The benchmark resource for 2012 is 340 megawatts, representing the Intermountain Power Plant Unit 3 and the benchmark resource for 2014 is 575 megawatts, representing Bridger 5. The company issued its base load RFP on April 5, 2007.

**Renewables Request for Proposal 2003B**
PacifiCorp amended the renewables Request for Proposal 2003B in March 2006 to assist in meeting renewable procurement targets, including those related to the MidAmerican transaction commitment to acquire economic renewable resources. As a result of the bids received, PacifiCorp considered nearly twenty competing offers.

### Demand-side Resources

The 2005 DSM RFP to procure Class 1, 2 and 3 resources was issued according to the action plan in the 2004 IRP (See 2004 IRP, Table 9.3). The RFP was structured to solicit proposals for both specific resources types—for example, comprehensive residential equipment and service program—as well as an "all comers" request for each resource type. The most notable program addition originating from the 2005 DSM RFP is the Home Energy Savers program, filed and approved in 2006 in Idaho, Washington and Utah, and, pending commission approval, to be offered in California and Wyoming in 2007. The company also accepted a proposal to enhance business program penetration of the new construction market. In addition, there remain a select few program proposals from the 2005 DSM RFP that may be pursued provided the Company receives supporting information through their system-wide demand-side management potential study indicating that sufficient opportunity, customer interest, and delivery price points exist to support the proposals. The system-wide demand-side management potential study, a MidAmerican Energy Holdings Company commitment made during its acquisition of PacifiCorp in March 2006, is scheduled to be completed in June 2007. The Company intends to use the information from this study to assist in the refinement of their current demand-side programs (expand and improve their performance) as well as identify additional cost-effective and system relevant program opportunities across all program types, e.g., energy efficiency, demand control or management, and demand response.

[25] The RFP covers power purchase agreements, tolling service agreements, asset purchases, load curtailment contracts, and Qualifying Facility contracts. See Chapter 4, Action Plan, for more details concerning the Base Load RFP.

## THE IMPACT OF STATE RESOURCE POLICIES ON SYSTEM-WIDE PLANNING

A new planning issue that PacifiCorp is dealing with for this IRP cycle is the rapid evolution of state-specific resource policies that place, or are expected to place, constraints on PacifiCorp's resource selection decisions. As discussed earlier in this chapter, these policies cover $CO_2$ emissions, renewable energy, energy efficiency, load control, distributed generation, and the promotion of advanced clean coal and carbon sequestration technologies. Table 3.1 represents an inventory of state policy actions and events that occurred in 2006, and so far in 2007, that impact PacifiCorp's integrated resource planning process now and in the future.

Considerable complexity is added to system-wide resource planning and the supporting modeling process as a result of these policies. In addition, disparate state interests, as expressed in prior IRP acknowledgement proceedings and throughout the 2007 IRP development cycle, complicates the company's ability to address state IRP requirements to the satisfaction of all stakeholders.

**Table 3.1 – State Resource Policy Developments for 2006 and 2007**

| 2006 | 2007 |
|---|---|
| **January:** Oregon PUC, in its 2004 IRP acknowledgement order, does not acknowledge a near-term "high-capacity-factor" resource, and requires that PacifiCorp explore coal deferral options until IGCC is commercialized | **January:** The California PUC adopts a greenhouse gas emission performance standard for generators |
| **January:** Oregon PUC rejects the 2004 IRP Update Action Plan | **January:** The Oregon PUC rejects PacifiCorp's 2012 RFP |
| February: Oregon Renewable Energy Working Group is formed | **January:** The Oregon Carbon Allocation Task Force recommends a $CO_2$ load-based cap-and-trade model rule |
| **March:** Oregon, California, and Washington join other petitioners in asking the U.S. Supreme Court whether the U.S. Environmental Protection Agency has the authority to regulate carbon dioxide and other air pollutants associated with climate change | **February:** The Washington Governor signs Executive Order 07-02 setting climate change-related rules, including greenhouse gas emissions caps |
| **April:** Idaho moratorium on coal-fired plants is issued. | **February:** Washington introduces legislation setting carbon caps and a GHG emissions performance standard |
| **August:** Utah Blue Ribbon Advisory Council on Climate Change formed | **February:** the Western Regional Climate Change Action Initiative announced by California, Oregon, Washington, New Mexico, and Arizona |
| **September:** California adopts a carbon cap (AB 32) | **February:** Utah, Wyoming, Nevada, and North Dakota announce the NextGen Energy Alliance, which is to promote ad- |

| 2006 | 2007 |
|---|---|
| | vanced coal technologies and economic utilization of carbon dioxide |
| **November:** the Oregon governor announces a renewable portfolio standard plan | **March:** Oregon RPS and carbon-related legislation introduced (a cap and greenhouse gas emissions performance standard) |
| **November:** Washington adopts a renewable portfolio standard | **April:** The U.S. Supreme ruled that the EPA has the authority to regulate $CO_2$ emissions |
| **December:** Western Public Utility Commission Joint Action Framework on Climate Change (California, Oregon, Washington, New Mexico) launched | |
| **December:** The Utah PSC issues suggested modifications to PacifiCorp's 2012 base load RFP | |

# 4. RESOURCE NEEDS ASSESSMENT

**Chapter Highlights**

- On an energy basis, PacifiCorp expects a system-wide average load growth of 2.5 percent per year from 2007 through 2016. Wyoming shows the largest load growth over the 2007 to 2016 at 5.6 percent average annual rate. Utah load is projected to grow at an average annual rate of about 3 percent, while the other states where the company operates—Oregon, Washington, Idaho, and California—have load growth projected at about 1 percent.

- System peak load is expected to grow at a faster rate than overall load due to the changing mix of appliances over time. PacifiCorp's eastern system peak is expected to continue growing faster than its western system peak, with average annual growth rates of 3.2 percent and 0.8 percent, respectively, over the forecast horizon.

- PacifiCorp anticipates a system peak resource capacity of 12,131 megawatts for the summer of 2007.

- Near-term resource changes include the following:
  - Conversion of the Currant Creek facility from a single cycle combustion turbine to a combined cycle combustion turbine (June 2006)
  - The addition of the Lake Side combined cycle combustion turbine (expected commercial operation in June 2007)
  - The addition of the Leaning Juniper 1 and Marengo wind projects
  - Expiration of the 400-megawatt power purchase agreement with TransAlta Energy Marketing expires in June 2007
  - Expiration of the 575 megawatt BPA peaking contract in August 2011
  - Expiration of the West Valley plant lease in May 2008

- On both a capacity and energy basis, load and resource balances are calculated using existing resource levels, obligations, and reserve requirements. Contract expirations also impact these calculations.

- The company projects a summer peak resource deficit for the PacifiCorp system beginning in 2008 to 2010, depending on the capacity planning reserve margin assumed. Beginning in 2009, the company becomes energy deficient on an annual basis.

- The PacifiCorp deficits prior to 2011 to 2012 will be met by additional renewables, demand side programs, and market purchases. Then beginning in 2011 to 2012, base load, intermediate load, or both types of resource additions will be necessary to cover the widening capacity and energy deficits.

## INTRODUCTION

This chapter presents PacifiCorp's assessment of resource need, focusing on the first 10 years of the IRP's 20-year study period, 2007 through 2016. 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. PacifiCorp uses different approaches in forecasting sales for different customer classes. PacifiCorp also employs different methods to forecast the growth over different forecast horizons. Near-term forecasts rely on statistical time series and regression methodologies while longer term forecasts are dependent on end-use 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.[26] Appendix A provides additional details on methodologies and state level forecasts.

### Integrated Resource Planning Load Forecasts

Through the course of the 2007 integrated resource planning cycle, PacifiCorp relied on two load forecasts for the development of the load and resource balance and portfolio evaluations. The first official load forecast used in this IRP cycle, released in May 2006, was used to support portfolio analysis from May 2006 to February 2007. Between May 2006 and March 2007, events transpired that resulted in the need to revise the load forecast. Because of the magnitude of the forecast changes and the extended IRP filing schedule granted by the state commissions, the company decided that it was prudent to incorporate load forecast updates in the IRP. Consequently, PacifiCorp's IRP analysis from February 2007 onward reflects the new March 2007 load forecast.

The primary changes to the original May 2006 load forecast result from recent trends and conditions on the east side of PacifiCorp's service territory. Growth in Utah was slowing from what was previously planned; therefore, its growth rates were reduced. This was mainly associated with the growth in the commercial class and a slowing of the service activity in the state. Offsetting this were requests for service in the oil and gas industries of Wyoming. Higher prices, fuel supply uncertainty both nationally and worldwide resulted in plans to increase the development of the fields in Wyoming. Additionally, portions of Wyoming are experiencing air quality problems with existing extraction practices that require electrification of the existing services in the

[26] 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.

fields. The load requests from customers in these areas total over 1,000 megawatts in 2012. While these state trends largely offset each other on a total projected load basis, the revised Wyoming load growth affects the timing of the resource need. That is why the company decided to incorporate the new load forecast in the IRP.

The following sections describe the March 2007 energy and coincident peak load forecasts, as well as summarize the differences with respect to the original May 2006 forecast.

## Energy Forecast

Table 4.1 shows average annual energy load growth rates for the PacifiCorp system and individual states. Growth rates are shown for the historical period 1995 through 2005, and the forecast period 2007 through 2016.

**Table 4.1 – Historical and Forecasted Average Energy Growth Rates for Load**

| Average Annual Growth Rate | Total | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|---|
| 1995-2005 | **1.6%** | 0.1% | 1.4% | 1.4% | 1.3% | 3.0% | 1.3% |
| 2007-2016 | **2.4%** | 0.6% | 1.3% | 5.6% | 1.1% | 2.7% | 1.0% |

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.4 percent annually from fiscal year 2007 to 2016. This is slightly faster than the average annual historical growth rate experienced from 1995 to 2005. During this historical period the total load for these states increased at an average annual rate of 1.6 percent. Table 4.2 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 4.2 – Annual Load Growth in Megawatt-hours for 2006 and forecasted 2007 through 2016**

| Year | Total | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|---|
| **2006** | **58,466,744** | 15,388,512 | 4,637,218 | 8,818,396 | 991,346 | 22,958,123 | 5,673,149 |
| **2007** | **58,244,203** | 14,745,256 | 4,556,816 | 9,043,776 | 944,252 | 23,407,514 | 5,546,589 |
| **2008** | **60,003,127** | 14,774,141 | 4,577,294 | 10,035,331 | 948,959 | 24,070,475 | 5,596,927 |
| **2009** | **61,824,270** | 14,813,056 | 4,608,889 | 11,157,044 | 953,801 | 24,653,183 | 5,638,297 |
| **2010** | **63,939,431** | 14,927,068 | 4,821,004 | 12,019,398 | 979,509 | 25,494,009 | 5,698,443 |
| **2011** | **65,638,416** | 15,041,955 | 4,900,526 | 12,842,214 | 988,843 | 26,114,702 | 5,750,176 |
| **2012** | **67,027,436** | 15,157,677 | 4,944,106 | 13,347,838 | 998,372 | 26,767,715 | 5,811,728 |
| **2013** | **68,304,861** | 15,274,258 | 4,988,967 | 13,718,417 | 1,008,170 | 27,453,851 | 5,861,198 |
| **2014** | **69,525,861** | 15,391,817 | 5,033,291 | 13,991,101 | 1,018,178 | 28,175,184 | 5,916,290 |
| **2015** | **70,776,423** | 15,510,250 | 5,077,689 | 14,245,983 | 1,028,365 | 28,938,113 | 5,976,023 |
| **2016** | **72,305,522** | 15,629,572 | 5,125,690 | 14,712,173 | 1,038,612 | 29,745,665 | 6,053,810 |
| | | | | | | | |
| **AAG 2007-2016** | **2.4%** | 0.6% | 1.3% | 5.6% | 1.1% | 2.7% | 1.0% |
| **AAG 2016-2026** | **2.0%** | 1.3% | 1.3% | 2.0% | 1.6% | 2.7% | 1.1% |

As can be seen from the average annual growth rates at the bottom of the Table 4.2, the eastern system continues to grow faster than the western system, with an average annual growth rate of 3.2 percent and 0.8 percent, respectively, over the forecast horizon.

## System-Wide Coincident Peak Load Forecast

The system peaks are 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 in Appendix A. From these hourly forecasted values, forecast peaks for the maximum usage on the entire system during each month (the coincidental system peak) and the maximum usage within each state during each month are extracted.

The system peak load is expected to grow from the 2005 peak of 8,937 megawatts at a faster rate than overall load due to the changing mix of appliances over time. Table 4.3 shows that for the same time period the total peak is expected to grow by 2.6 percent. The system peak, which previously occurred in the winter, has switched to the summer as a result of these changes in appliance mix. The change in seasonal peak is due to an increasing demand for summer space conditioning in the residential and commercial classes and a decreasing demand for electric related space conditioning in the winter. This trend in space conditioning is expected to continue. Therefore, the disparity in summer and winter load growth will result in system peak demand growing faster than overall load. However, once the demand in space conditioning equipment stabilizes, the total load and system peak growth rates should equalize.

**Table 4.3 – Historical and Forecasted Coincidental Peak Load Growth Rates**

| Average Annual Growth Rate | Total | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|---|
| **1995-2005** | **1.9%** | (1.1)% | (1.0)% | (0.9)% | 1.9% | 7.3% | 5.8% |
| **2007-2016** | **2.6%** | 1.2% | 1.2% | 5.8% | 1.2% | 2.9% | 1.2% |

Again, PacifiCorp's eastern system peak is expected to continue growing faster than its western system peak, with average annual growth rates of 3.2 percent and 1.2 percent, respectively, over the forecast horizon. This is similar to historical growth patterns as Table 4.3 reflects. East system peak growth during this time has been faster than west system peak growth. Of course, peak growth is somewhat masked in Table 4.3 if you consider that the peak has shifted from winter months to summer months.

Table 4.4 shows the average annual coincidental peak growth occurring in the summer months for 1995 through 2005. This shows that some of what appears to be a decrease in peak load in many states is due to the shift from winter to summer, and that growth in peak is truly occurring. It also shows that faster growth is continuing to occur in the eastern portion of the system where average historical growth has been 2.8 percent, while the western portion of the system grew at 1.1 percent on average. This pattern is expected to continue as discussed previously.

**Table 4.4 – Historical Coincidental Peak Load - Summer**

| Average Annual Growth Rate | Total | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|---|
| **1995-2005** | 2.2% | 0.8% | 1.7% | 0.0% | 2.2% | 5.2% | 1.5% |

The system peak load is expected to grow at a slightly faster rate than the overall load due to the changing mix of appliances over time. Table 4.5 below shows that for the same time period the total peak is expected to grow by 2.6 percent. Until recently, the system peak occurred in the winter months. Due to a changing appliance mix from an increasing demand for summer space conditioning in the residential and commercial classes, and a reduction in electric related space conditioning in winter months, the system peak has started occurring in summer months. PacifiCorp expects this condition to continue. Therefore, the increasing summer load and decreasing winter loads are expected to result in a faster growing system peak than total load until changes in space conditioning equipment mix ends.

**Table 4.5 – Forecasted Coincidental Peak Load in Megawatts**

| Year | Total | OR | WA | WY | CA | UT | ID | SE-ID |
|---|---|---|---|---|---|---|---|---|
| **2006** | **9,577** | 2,684 | 816 | 1,094 | 156 | 4,011 | 561 | 256 |
| **2007** | **9,243** | 2,076 | 699 | 1,044 | 147 | 4,298 | 632 | 347 |
| **2008** | **9,440** | 2,075 | 702 | 1,145 | 147 | 4,409 | 631 | 331 |
| **2009** | **9,752** | 2,235 | 702 | 1,282 | 159 | 4,420 | 678 | 276 |
| **2010** | **10,261** | 2,254 | 729 | 1,416 | 141 | 4,720 | 696 | 305 |
| **2011** | **10,488** | 2,314 | 757 | 1,473 | 128 | 4,932 | 573 | 311 |
| **2012** | **10,836** | 2,320 | 766 | 1,569 | 155 | 4,973 | 686 | 367 |
| **2013** | **10,989** | 2,328 | 767 | 1,613 | 156 | 5,061 | 693 | 371 |
| **2014** | **11,157** | 2,331 | 773 | 1,648 | 158 | 5,184 | 708 | 355 |
| **2015** | **11,296** | 2,326 | 774 | 1,669 | 171 | 5,337 | 719 | 300 |
| **2016** | **11,619** | 2,314 | 775 | 1,733 | 163 | 5,547 | 745 | 342 |
| | | | | | | | | |
| **AAG 2007-2016** | **2.6%** | 1.2% | 1.2% | 5.8% | 1.2% | 2.9% | 1.8% | -0.2% |
| **AAG 2016-2026** | **2.2%** | 1.5% | 1.6% | 1.9% | 0.4% | 2.9% | 1.4% | 1.0% |

One noticeable aspect of the states contribution to the system coincidental peak forecast is that they do not continuously increase from year to year, even though the total system peak and each state's individual peak loads generally increase 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 150 megawatts of load difference between the maximum load and the loads during the last weeks of July. This anomaly can be seen when comparing the Idaho contribution to the system coincident peak in 2010 and 2011.

Another noticeable aspect is the decline in the loads from the actual period to the first forecast year. This is noticeable in Oregon when the 2007 is compared to the 2006 value. There may be several things that can impact this. In the Oregon case, a large industrial customer is expected to cease operations during 2007. This large customer and the associated multiplier effect of this customer will cause a decline in load for Oregon. Other factors contributing to the decline include the changing time of the system peak demand in 2007, variability in jurisdictional contribution to the peak demand over time, and weather effects to the Oregon contribution in 2006.

**<u>Jurisdictional Peak Load Forecast</u>**

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 4.6 reports the historical growth rates for each of the jurisdictional peak demands, while Table 4.7 reports the jurisdictional peak demand growth over the forecast horizon.

**Table 4.6 – Historical Jurisdictional Peak Load**

| Average Annual Growth Rate | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|
| **1995-2005** | 0.6% | 0.7% | -0.4% | 0.6% | 4.4% | 1.9% |

**Table 4.7 – Jurisdictional Peak Load in Megawatts for 2006 and forecast 2007 through 2016**

| Year | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|
| **2006** | 2,730 | 818 | 1,208 | 179 | 4,357 | 723 |
| **2007** | 2,393 | 751 | 1,185 | 191 | 4,347 | 678 |
| **2008** | 2,405 | 744 | 1,372 | 190 | 4,409 | 680 |
| **2009** | 2,457 | 750 | 1,572 | 194 | 4,483 | 736 |
| **2010** | 2,455 | 782 | 1,627 | 199 | 4,791 | 755 |
| **2011** | 2,472 | 795 | 1,681 | 201 | 4,932 | 770 |
| **2012** | 2,536 | 807 | 1,757 | 200 | 5,044 | 747 |
| **2013** | 2,533 | 807 | 1,778 | 205 | 5,172 | 757 |
| **2014** | 2,541 | 805 | 1,817 | 207 | 5,267 | 770 |
| **2015** | 2,552 | 808 | 1,844 | 209 | 5,416 | 780 |
| **2016** | 2,536 | 803 | 1,908 | 208 | 5,658 | 811 |
| | | | | | | |

| Year | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|
| AAG 2007-2016 | 0.6% | 0.7% | 5.4% | 1.0% | 3.0% | 2.0% |
| AAG 2016-2026 | 1.4% | 1.5% | 1.9% | 1.8% | 3.0% | 0.9% |

Additional detailed information about the load forecast can be found in Appendix A, Base Assumptions.

**May 2006 Load Forecast Comparison**

Tables 4.8 and 4.9 show the respective state annual peak load and energy differences between the March 2007 forecast and those for the May 2006 forecast. The impacts of slowing service activity in Utah and greater forecasted demand in Wyoming mentioned above are evident for both capacity and energy trends. For example, Utah continues to have one of the strongest economies in the nation and will likely continue to do so; however, there have been subtle signs of some slowing of very robust growth. As published in the Salt Lake City Tribune[27], the Utah Department of Workforce Services reported job growth of 4.5 percent for the year that ended in March 2007, which is down significantly from a peak of 5.4 percent in June 2006. An additional indicator of slightly slowing growth is in residential building permits in Utah, which declined by 6.9 percent in 2006 from the 2005 level. Statistics from the Bureau of Economic and Business Research at the University of Utah continue to show slowing when compared to 2006 through February 2007. This trend is also evident in PacifiCorp sales growth in Utah from 2006 into 2007. Taken together, these trends helped drive the slight slowing of the peak growth from a 3.0 percent average annual growth rate from 2007 to 2016 in the May 2006 forecast to a 2.9 percent average annual growth in the March 2007 forecast. From an energy perspective, the average annual load growth rate from 3.0 percent in the May 2006 forecast decreased to a 2.7 percent average annual growth rate for 2007 to 2016 in the March 2007 forecast.

Regarding the energy forecast difference for Oregon, the March 2007 forecast is based on an expected lower growth rate for residential electric heating usage. This lower usage is causing an impact on energy while the coincident peak demand remains relatively unchanged. In addition, long-term industrial retail sales are expected to be lower due to a further deterioration in the paper products and lumber industries in the west. This deterioration has less of an impact on peak, weather responsive demand than on total energy.

**Table 4.8 – Changes from May 2006 to March 2007: Forecasted Coincidental Peak Load (Megawatts)**

| Year | Total | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|---|
| 2007 | (182) | 1 | (41) | (76) | (2) | (43) | (21) |
| 2008 | (338) | (36) | (36) | (23) | (4) | (216) | (23) |
| 2009 | (273) | 24 | 6 | (107) | 13 | (254) | 45 |

[27] Mitchell, Lesley. "Utah's job growth rate stays ahead of nation." Salt Lake City Tribune. April 17, 2007. http://www.sltrib.com/search/ci_5691499

| Year | Total | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|---|
| **2010** | **17** | 72 | 48 | (17) | 13 | (53) | (46) |
| **2011** | **7** | 19 | 50 | 1 | (21) | (13) | (29) |
| **2012** | **213** | 78 | 75 | 88 | 14 | 22 | (64) |
| **2013** | **170** | 57 | 69 | 115 | 14 | (20) | (65) |
| **2014** | **140** | 36 | 67 | 140 | 14 | (56) | (61) |
| **2015** | **82** | (33) | 49 | 165 | 16 | (167) | 52 |
| **2016** | **105** | (104) | 40 | 204 | 6 | (140) | 99 |
| | | | | | | | |
| **AAG 2007-2016** | **0.3%** | (0.5)% | 1.2% | 2.3% | 0.6% | (0.2)% | 2.0% |
| **AAG 2016-2026** | **(0.3)%** | 0.5% | 0.1% | 0.8% | (1.6)% | (0.9)% | (0.1)% |

**Table 4.9 – Changes from May 2006 to March 2007: Forecasted Load Growth (Average Megawatts)**

| Year | Total | OR | WA | WY | CA | UT | ID |
|---|---|---|---|---|---|---|---|
| **2007** | **(49)** | 1 | 4 | (21) | (1) | (25) | (8) |
| **2008** | **(101)** | (34) | 7 | 1 | (1) | (67) | (7) |
| **2009** | **(70)** | (12) | (9) | 26 | (1) | (62) | (13) |
| **2010** | **(4)** | (20) | 12 | 80 | 1 | (65) | (12) |
| **2011** | **60** | (26) | 18 | 152 | 1 | (75) | (10) |
| **2012** | **74** | (33) | 18 | 192 | 1 | (93) | (11) |
| **2013** | **84** | (40) | 19 | 222 | 0 | (107) | (11) |
| **2014** | **85** | (47) | 19 | 242 | 0 | (117) | (12) |
| **2015** | **109** | (55) | 19 | 277 | 0 | (121) | (11) |
| **2016** | **128** | (67) | 17 | 315 | (0) | (126) | (12) |
| | | | | | | | |
| **AAG 2007-2016** | **0.3%** | (0.4)% | 0.3% | 2.6% | 0.0% | (0.3)% | (0.1)% |
| **AAG 2016-2026** | **0.1%** | 0.0% | (0.1)% | 1.0% | (0.2)% | 0.0% | (0.2)% |

## EXISTING RESOURCES

In 2007 PacifiCorp owns, or has interest in, resources with a system peak capacity of 12,131 megawatts. Table 4.10 provides anticipated system peak capacity ratings by resource category as of July 2007.

**Table 4.10 – Capacity Ratings of Existing Resources**

| Resource Type | MW* | Percent |
|---|---|---|
| Pulverized Coal | 6,097 | 50.3% |
| Purchases** | 1,836 | 15.1% |
| Gas-CCCT | 1,698 | 14.0% |

| Resource Type | MW* | Percent |
|---|---|---|
| Gas-SCCT | 385 | 3.2% |
| Hydroelectric | 1,556 | 12.8% |
| Interruptible | 233 | 1.9% |
| Renewable*** | 173 | 1.4% |
| Class 1 DSM | 153 | 1.3% |
| **Total** | **12,131** | **100%** |

* Represents the capacity available at the time of system peak.
** Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.
*** Renewables capacity reflects the capacity contribution at the time of peak load.

## Thermal Plants

In June 2006, the company converted the Currant Creek facility from a single cycle combustion turbine to a combined cycle combustion turbine, which increased the capability of the plant by 231 megawatts. The Lake Side combined cycle combustion turbine is expected to begin commercial operation in June 2007, adding 535 megawatts of additional capacity to the system. The lease for the West Valley plant expires in May 2008, reducing the company's total thermal plant capacity by 202 megawatts. Appendix A, Table A.12, provides operational characteristics of thermal plants and other generation resources for which PacifiCorp has an ownership interest.

## Renewables

PacifiCorp is committed to renewable energy resources as a viable, economic and environmentally prudent means of generating electricity. PacifiCorp's renewable resources, presented by resource type, are described below.

### Wind

PacifiCorp acquires wind power from PacifiCorp-owned wind plants and various purchase agreements. For the year ended December 31, 2006, PacifiCorp received 118,610 megawatt-hours from an owned wind project. In the same period, 394,973 megawatt-hours were purchased from other wind projects.

Since the 2004 Integrated Resource Plan, PacifiCorp has acquired large wind resources at Leaning Juniper 1 in Oregon (100.5 megawatts) and Marengo (140.4 megawatts) in Washington. Leaning Juniper was acquired in November 2006, while Marengo is expected to come on line in 2007. The company also entered into a 20-year power purchase agreement for the total output at the Wolverine Creek plant in Idaho (64.5 megawatts).

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. For the year ended December 31, 2006, electricity under these agreements totaled 552,835 megawatt-hours in addition to the wind energy generated or purchased for PacifiCorp's own use.

**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 23 megawatts. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which will increase the output by 11 megawatts, is currently under construction and is expected to be in service by the end of 2007.

**Biomass**
Since the 2004 IRP, PacifiCorp has acquired power through power purchase agreements, as well as from several small biomass facilities under Qualifying Facility Agreements. Examples include the 20 megawatt Roseburg Lumber power purchase agreement and the 10 megawatt Freres Lumber power purchase agreement.

**Solar**
PacifiCorp has invested in Solar II, the world's largest solar energy plant, located in the Mojave Desert, and continues to assess the economic viability of such solar resources. At present, absent state-specific incentives, central-station solar resources continue to appear uneconomic when compared to other renewable resource alternatives. However, advances in solar technology can reasonably be expected to continue, and state-specific incentives may result in economic projects for consideration.

Regarding distributed photovoltaic (PV) applications, 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 1,556 megawatts of hydroelectric generation. These resources account for approximately 13 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 10 megawatts of additional capacity to its hydroelectric portfolio since the release of the 2004 IRP. This additional capacity is the result of turbine upgrades at its J.C. Boyle hydroelectric plant.

## Demand-side Management

Demand-side management programs 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. These programs are divided into four general classes.

- **Class 1 DSM: Fully dispatchable or scheduled firm** – 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 programs, 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 (scheduled firm).

- **Class 2 DSM: Non-dispatchable, firm energy efficiency programs** – Class 2 programs are those for which energy and capacity savings are achieved through facilitation of technological advancements in equipment, appliances, lighting and structures. These types of programs provide an incentive to customers to replace 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: Price responsive 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 penalty. Savings are measured at a customer-by-customer level (via metering), 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 to construct a diversity factor suitable for modeling purposes. Savings endure only 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: Energy efficiency education and non-incentive based voluntary curtailment programs** – These programs represent energy and capacity reductions achieved through behavioral actions by customers in response to their desire to reduce their energy demands and costs, or voluntary compliance with a company request to conserve or shift their usage to off peak hours. Program savings are difficult to measure and aren't actively tracked in most cases. As a result, they can't be relied upon for planning purposes. The value of Class 4 DSM is longer-term in nature. Class 4 programs help foster an understanding and appreciation as to why utilities seek customer participation in Class 1-3 programs. 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."

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 1-4) and resource planning considerations. Company investments have increased four times (from $50 million to $200 million) over the last five years (2002-2006) compared to the preceding five years (1997-2001) as the company has expanded DSM activity in the states of Utah, Washington and Idaho and transitioned existing DSM activities in Oregon over to the Energy Trust of Oregon.

The company is currently working with the state of Wyoming on a DSM application which seeks to expand company investments in Wyoming and which was filed in December 2006 and, is pending Commission approval by May 2007. Additionally, the company is working to expand DSM programs in California and is preparing a DSM application with expanded program offerings for filing with the California Public Utilities Commission in May 2007. In addition, the company has recently introduced new programs such as the Home Energy Savers program in Idaho, Washington, Utah and soon Wyoming and California, as well as expanding the Idaho irrigation load management program into Utah for the 2007 summer season. The following represents a brief summary of the existing resources by class. Appendix A provides a detailed list of existing DSM programs available and resource targets for Classes 1 through 3.

**Class 1 Demand-side Management**

There are currently three types of Class 1 programs in operation. Utah's "Cool Keeper" residential and small commercial air conditioner load control program provided nearly 80 megawatts of dispatchable load control (at the generator) during the summer of 2006 and is expected to deliver the anticipated 90 megawatts by summer 2007. Idaho's irrigation load management program achieved 55 megawatts of "scheduled" relief during the summer of 2006 and has recently added a "dispatchable" event option to compliment the "scheduled" options in an effort to increase that amount in 2007. As noted above, the company has expanded the "schedule" option to Utah beginning in 2007. First-year participation is expected to be modest; however, the company hopes to grow the program overtime to 15 megawatts. In addition to these two programs, the company has 233 megawatts of firm curtailable resources under contract with a select set of large industrial customers. Contracted curtailable loads are expected to increase to 308 megawatts by 2009.

**Class 2 Demand-side Management**
The cumulative historical energy and capacity savings (1992-2006) associated with Class 2 DSM resource acquisitions are over 300 average megawatts of energy and 390 megawatts respectively (at the generator). The company projects that through the 2016 planning period, existing Class 2 programs will yield, on average, an additional 23 MWa and 30 megawatts each year in energy and capacity reductions, respectively. The company is actively seeking new Class 2 programs and improvements to existing programs in an effort to nearly double this amount, provided those resources can be acquired cost-effectively.

**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), a seasonal inverted rate program (Utah), year-around inverted rate programs (Oregon, Washington and California) and Energy Exchange programs (Oregon, Utah and Washington). Savings associated with these programs are captured within the company's load forecast, with the exception of the Energy Exchange program. The impacts of these programs are thus captured in the integrated resource planning framework. Future savings associated with new programs, or added savings of existing programs, are relied upon as reliability resources as opposed to base resources. Current system-wide participation in metered time-of-day and time-of-use programs exceeds 23,000 customers, up from 15,000 in 2004. Approximately 1.25 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 subsequent chapters, a variety of these programs were included as resource options in scenario modeling.

**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 education will show up in other Class 4 DSM program results and changes in the load forecast over time.

Table 4.11 summarizes the existing DSM programs, and describes how they are accounted for as a planned resource.

**Table 4.11 – Existing DSM Summary, 2007-2016**

| Program Class | Description | Energy Savings or Capacity at Generator | Included as Base Resources for 2007-2016 Period |
|---|---|---|---|
| 1 | Residential/small commercial air conditioner load control | 100 MW summer peak | Yes |
| | Irrigation load management | 55 MW summer peak | Yes |
| | Interruptible contracts | 233 MW building to 308 MW | Yes |

| Program Class | Description | Energy Savings or Capacity at Generator | Included as Base Resources for 2007-2016 Period |
|---|---|---|---|
| | | peak availability | |
| 2 | Company and Energy Trust of Oregon programs | 227 MWa and 295 MW | No, captured as decrement to future load forecast |
| | Historic acquisitions towards 450 MWa (2004-2006 only) | 95 MWa and 123 MW | No, accounted for in load forecasting |
| 3 | Energy Exchange | 0-65 MW | No, leveraged as economic and reliability resource dependent on market prices/system loads |
| | Time-based pricing | MWa/MW unavailable 23,000 customers | No, historical behavior captured in load forecast |
| | Inverted rate pricing | MWa/MW unavailable 1.25 million residential | No, historical behavior captured in load forecast |
| 4 | PowerForward | 0-78 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.

Listed below are the major contract expirations occurring within the next 10 years.

- The 202 megawatt West Valley lease expires in May 2008
- The 400 megawatt power purchase agreement with TransAlta Energy Marketing expires in June 2007
- The 575 megawatt BPA peaking contract expires in August 2011

Figure 4.1 presents the contract capacity in place for 2007 through 2016 as of April 2006. 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 4.1 – Contract Capacity in the 2007 Load and Resource Balance**

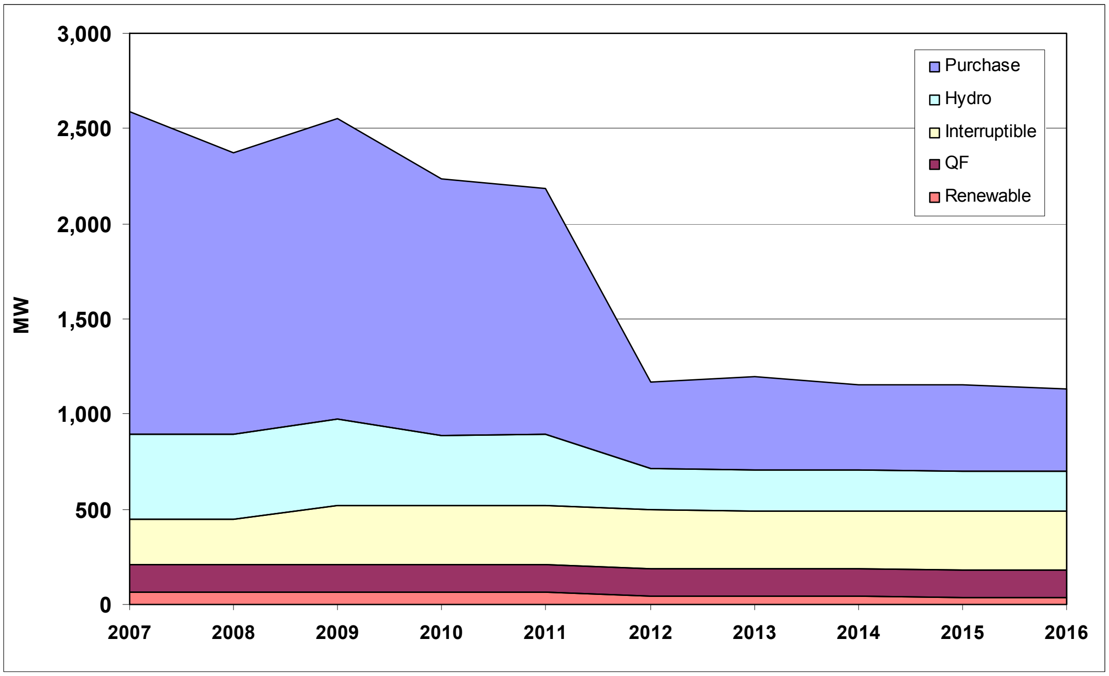
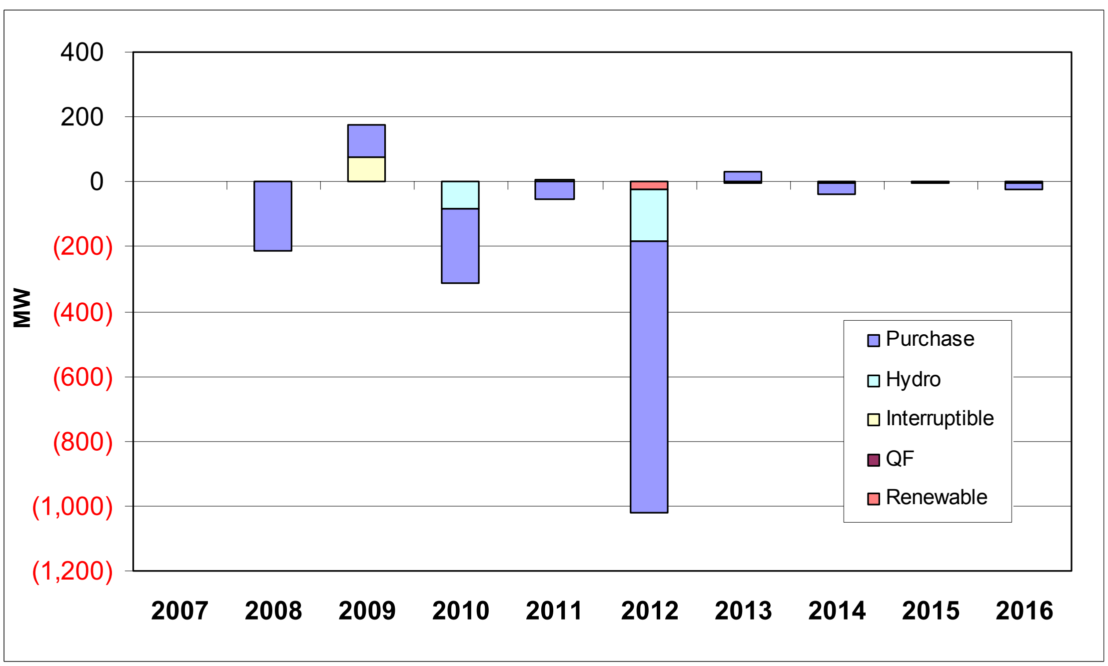



Figure 4.2 shows the year-to-year changes in contract capacity. Early year fluctuations are due to changes in short-term balancing contracts of one year or less, and expiration of the contracts cited above.

**Figure 4.2 – 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 (2007-2016) 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 (2007-2016). 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 are addressed with the studies and results of those studies described in Chapters 6 and 7 respectively.

### 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 by resource category are 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, four 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 counts these resources by the maximum capability that is sustainable for one hour at time of system peak. 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)** – There are about 160 megawatts of Class 1 demand-side management programs included as existing resources. 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 two geothermal plants (the existing Blundell plant with the bottoming-cycle upgrade, and the Cove Fort project), eight existing wind projects and three planned wind projects from the MEHC commitments. The capacity balance counts the geothermal plants 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 determined in a wind capacity planning contribution study (Appendix J). 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 about 300 megawatts 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 loads of the load forecast. Described in the beginning of this chapter the load forecast is an hourly description of electric loads in the PacifiCorp system for the 20-year IRP study period (2007-2026). The capacity balance counts the 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).

- **Sales** – This component 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 for the capacity balance. Note that for the 2007 IRP there was a reporting change for the delivery portion of exchange contracts. Exchange contract deliveries are no longer reported in the Purchase and Renewable components as was done for the 2004 IRP and 2004 IRP Update. These delivery amounts now appear in the Sales component.

**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.[28] 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 71 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-

[28] PacifiCorp models operating reserve requirements, which are based on minimum WECC Operating Reserves that cover Contingency Reserves and Regulating Reserves. PacifiCorp also includes incremental reserves for supporting wind, which is documented in Appendix J.

cates that existing resources do not meet obligation. If existing resources equals the obligation, then the reserve margin is zero percent. 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 must then be calculated. This is done 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 then computed by adding the computed reserves to the obligation and then subtracting the existing resources as 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 2004 IRP Update with a few exceptions. The following is a summary of these assumption changes.

- **Front Office Transactions** – For the 2007 IRP, front office transactions were taken out of the existing load and resource balance in order to treat them as potential resources that the Capacity Expansion Module can pick from. This was done in order to treat the front office transactions on a comparable basis to other supply-side resources.

- **Wind Commitment** – In the 2004 IRP Update, 1,400 megawatts of wind were included as planned resources in the initial load and resource balance. For the 2007 IRP, 400 megawatts of the overall 1,400-megawatt commitment are included in the initial load and resource balance. The remaining 1,000 megawatts are treated as part of the overall wind resource potential evaluated in portfolio modeling.

- **Clark County Load Service Contract** – In the 2004 IRP Update, the Clark County load service contract including the River Road combined-cycle gas resource was modeled. This contract ends in 2007 and affects little of the 20-year planning horizon. Also, the energy from the component resources and load obligation balances out. Thus, this contract is not part of this load and resource balance.

- **Planning Reserve Calculation for Firm Transactions and Load Curtailment Contracts** – In the 2007 IRP, the company represents front office transactions as firm purchases. Consistent with current market practices, the seller, rather than the company as the purchaser, carries the operating reserve obligation.[29] Load curtailment contracts and DSM programs directly reduce firm load. Thus, the planning reserve margin is not applied to firm purchases, DSM programs and interruptible resources. This was not done in the 2004 IRP Update.

- **Non-owned Reserves** – The 2007 IRP includes the modeling of capacity obligation resulting from the holding of reserves for counterparties within the PacifiCorp control areas. This was not done in the 2004 IRP Update.

- **Planning Reserve Margin** – The planning reserve margin is the generating capability that exceeds the expected peak load for each year. The 2004 IRP and 2004 IRP Update assumed a 15 percent planning reserve margin. However, the 2007 IRP considers resource portfolios at 12 and 15 percent levels. PacifiCorp views this percentage range as a prudent and reasonable range for planning purposes when considering both supply reliability and economic impact to customers.[30]

**Capacity Balance Results**

Table 4.12 shows the annual capacity balances and component line items using a 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 4.13 shows the system-level capacity balance assuming a 15 percent planning reserve margin.

Figures 4.3 through 4.5 display the annual capacity positions (resource surplus or deficits) for the system, west control area, and east control area, respectively. The associated obligation with both 12 and 15 percent planning reserve margins are shown. The decrease in resources in 2008 is caused by the expected expiration of the West Valley lease agreement. The slight increase in

[29] Recently, there have been proposals made to the Western Electricity Coordinating Council board of directors to change the current market practice that would require the operating reserve obligation to be calculated based on the load serving entity's load, and the obligation would be independent of purchases or sales. If this change is adopted, the company will need to modify its assumptions in future integrated resource plans to calculate the operating reserve obligation based on its load.

[30] To provide context, note that the IRP Benchmarking Study in Appendix C of the 2004 IRP Update identified numerous planning reserve margins used by utilities that range from 11 to 20 percent. Also, the Pacific Northwest Resource Adequacy Forum recently developed a regional pilot capacity adequacy standard that included a 19 percent planning reserve margin for summer peak planning for the Pacific Northwest.

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 4.4 highlights a decrease in obligation in the west starting in 2014. This is due to the expiration of the Sacramento Municipal Utility District and City of Redding power sales contracts.

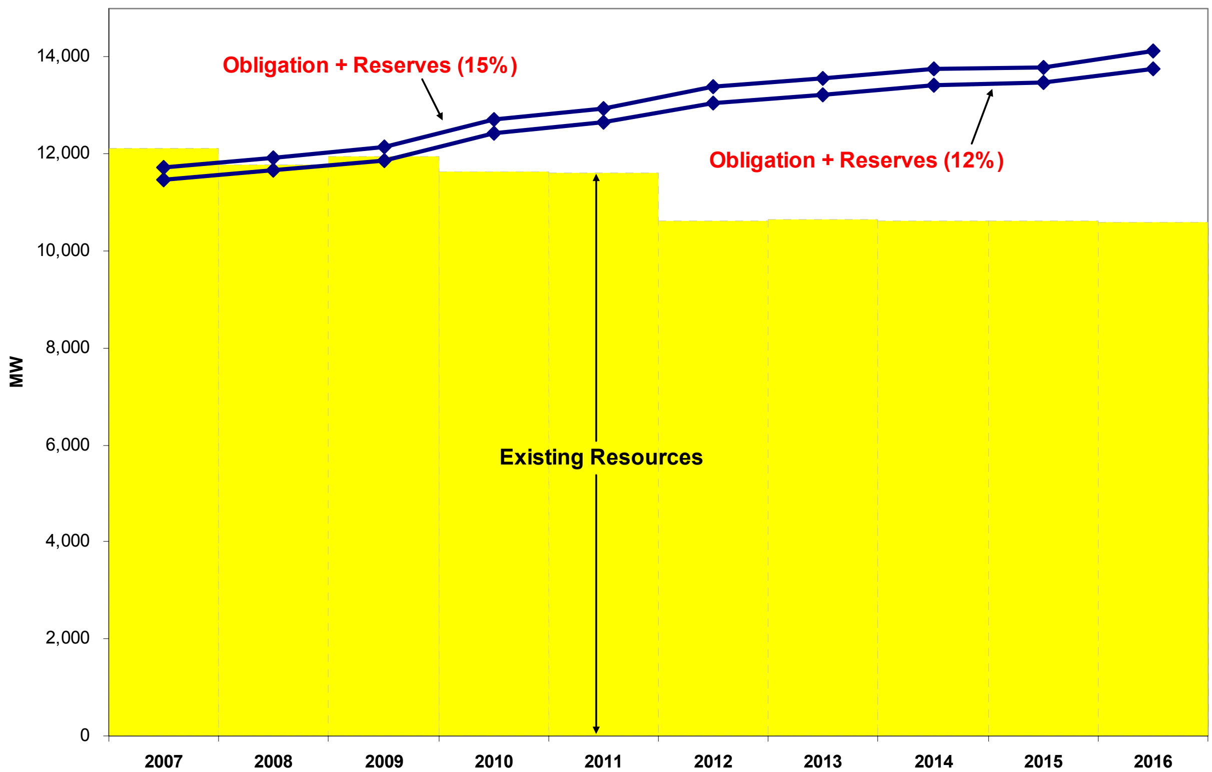
**Table 4.12 – Capacity Load and Resource Balance (12% Planning Reserve Margin)**

| Calendar Year | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| **East** | | | | | | | | | | |
| Thermal | 6,134 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 |
| Hydro | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 |
| DSM | 153 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 |
| Renewable | 65 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 105 | 105 |
| Purchase | 904 | 679 | 778 | 548 | 543 | 343 | 343 | 343 | 343 | 322 |
| QF | 106 | 106 | 106 | 106 | 106 | 106 | 106 | 106 | 106 | 106 |
| Interruptible | 233 | 233 | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 |
| **East Existing Resources** | 7,730 | 7,366 | 7,540 | 7,310 | 7,305 | 7,105 | 7,105 | 7,105 | 7,101 | 7,080 |
| | | | | | | | | | | |
| Load | 6,321 | 6,515 | 6,657 | 7,137 | 7,289 | 7,595 | 7,738 | 7,895 | 8,026 | 8,366 |
| Sale | 849 | 811 | 702 | 666 | 631 | 595 | 595 | 595 | 595 | 595 |
| **East Obligation** | 7,170 | 7,326 | 7,359 | 7,803 | 7,920 | 8,190 | 8,333 | 8,490 | 8,621 | 8,961 |
| | | | | | | | | | | |
| Planning reserves | 706 | 750 | 733 | 814 | 829 | 885 | 902 | 921 | 937 | 980 |
| Non-owned reserves | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 |
| **East Reserves** | 776 | 821 | 804 | 885 | 899 | 956 | 973 | 992 | 1,007 | 1,051 |
| | | | | | | | | | | |
| **East Obligation + Reserves** | 7,946 | 8,147 | 8,163 | 8,688 | 8,819 | 9,146 | 9,306 | 9,482 | 9,628 | 10,012 |
| **East Position** | (217) | (781) | (623) | (1,378) | (1,514) | (2,041) | (2,201) | (2,377) | (2,528) | (2,932) |
| **East Reserve Margin** | 9% | 1% | 4% | -6% | -7% | -13% | -14% | -16% | -17% | -21% |
| | | | | | | | | | | |
| **West** | | | | | | | | | | |
| Thermal | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 |
| Hydro | 1,421 | 1,421 | 1,414 | 1,328 | 1,357 | 1,225 | 1,249 | 1,243 | 1,244 | 1,242 |
| DSM | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 108 | 108 | 108 | 108 | 108 | 84 | 84 | 84 | 84 | 84 |
| Purchase | 786 | 800 | 800 | 799 | 749 | 112 | 141 | 107 | 107 | 107 |
| QF | 40 | 40 | 40 | 40 | 40 | 40 | 38 | 38 | 38 | 38 |
| **West Existing Resources** | 4,401 | 4,415 | 4,408 | 4,321 | 4,300 | 3,506 | 3,558 | 3,519 | 3,519 | 3,518 |
| | | | | | | | | | | |
| Load | 2,922 | 2,924 | 3,095 | 3,124 | 3,199 | 3,240 | 3,251 | 3,262 | 3,271 | 3,252 |
| Sale | 299 | 299 | 299 | 290 | 290 | 258 | 258 | 258 | 158 | 108 |
| **West Obligation** | 3,221 | 3,223 | 3,394 | 3,414 | 3,489 | 3,498 | 3,509 | 3,520 | 3,429 | 3,360 |
| | | | | | | | | | | |
| Planning reserves | 292 | 291 | 311 | 314 | 329 | 406 | 404 | 409 | 399 | 390 |
| Non-owned reserves | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| **West Reserves** | 299 | 297 | 318 | 320 | 335 | 413 | 411 | 416 | 405 | 397 |
| | | | | | | | | | | |
| **West Obligation + Reserves** | 3,520 | 3,520 | 3,712 | 3,734 | 3,824 | 3,911 | 3,920 | 3,936 | 3,834 | 3,757 |
| **West Position** | 881 | 895 | 696 | 587 | 476 | (405) | (362) | (417) | (314) | (239) |
| **West Reserve Margin** | 39% | 40% | 33% | 29% | 26% | 0% | 2% | 0% | 3% | 5% |
| | | | | | | | | | | |
| **System** | | | | | | | | | | |
| **Total Resources** | 12,131 | 11,780 | 11,948 | 11,631 | 11,605 | 10,611 | 10,663 | 10,624 | 10,620 | 10,598 |
| **Obligation** | 10,391 | 10,549 | 10,753 | 11,217 | 11,409 | 11,688 | 11,842 | 12,010 | 12,050 | 12,321 |
| **Reserves** | 1,075 | 1,118 | 1,122 | 1,205 | 1,234 | 1,369 | 1,384 | 1,408 | 1,412 | 1,447 |
| **Obligation + Reserves** | 11,466 | 11,667 | 11,874 | 12,421 | 12,643 | 13,057 | 13,226 | 13,417 | 13,462 | 13,768 |
| **System Position** | 665 | 113 | 73 | (791) | (1,038) | (2,446) | (2,563) | (2,794) | (2,842) | (3,171) |
| **Reserve Margin** | 18% | 13% | 13% | 5% | 3% | -9% | -10% | -11% | -12% | -14% |

**Table 4.13 – System Capacity Load and Resource (15% Planning Reserve Margin)**

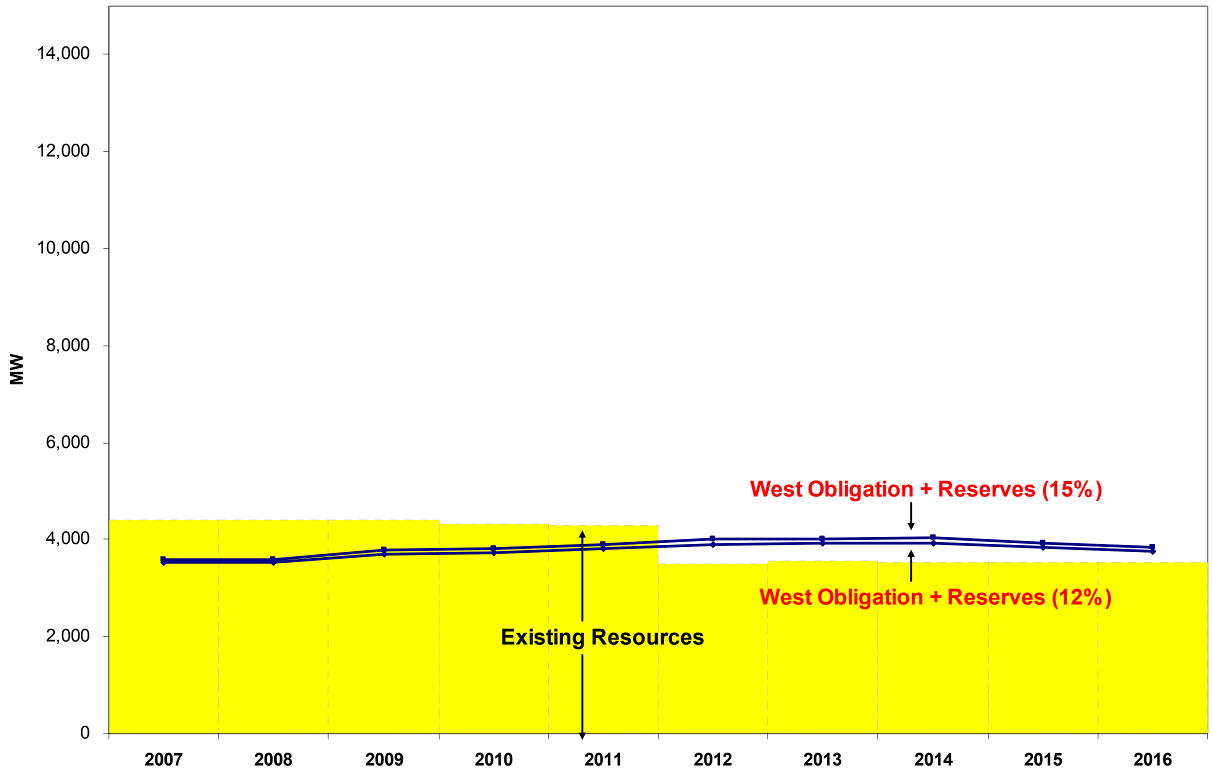
| Calendar Year | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| **System** | | | | | | | | | | |
| **Total Resources** | 12,131 | 11,780 | 11,948 | 11,631 | 11,605 | 10,611 | 10,663 | 10,624 | 10,620 | 10,598 |
| **Obligation** | 10,391 | 10,549 | 10,753 | 11,217 | 11,409 | 11,688 | 11,842 | 12,010 | 12,050 | 12,321 |
| **Reserves** | 1,324 | 1,378 | 1,383 | 1,487 | 1,524 | 1,691 | 1,710 | 1,740 | 1,746 | 1,790 |
| **Obligation + Reserves** | 11,715 | 11,927 | 12,136 | 12,703 | 12,932 | 13,380 | 13,552 | 13,750 | 13,796 | 14,111 |
| **System Position** | 415 | (147) | (188) | (1,073) | (1,327) | (2,768) | (2,890) | (3,126) | (3,176) | (3,513) |
| **Reserve Margin** | 19% | 14% | 13% | 5% | 3% | -9% | -9% | -11% | -11% | -14% |

**Figure 4.3 – System Coincident Peak Capacity Chart**



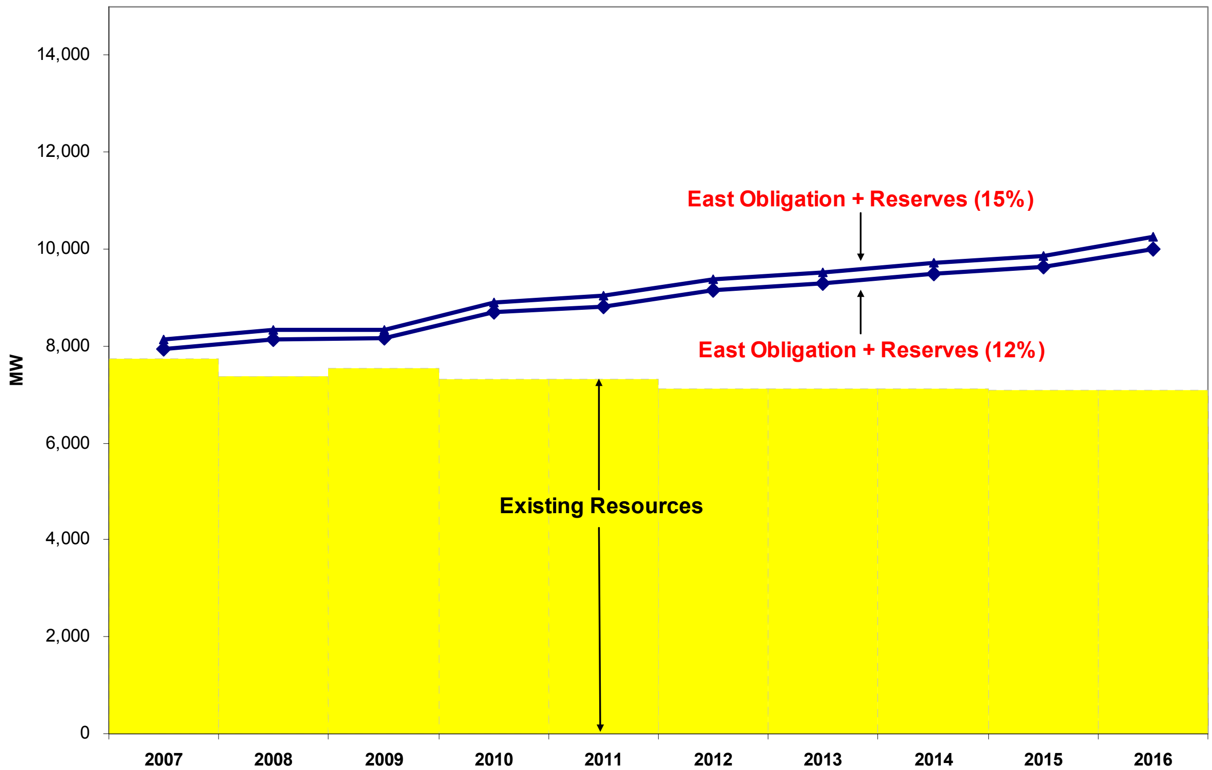

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Resources | 12,131 | 11,780 | 11,948 | 11,631 | 11,605 | 10,611 | 10,663 | 10,624 | 10,620 | 10,598 |
| Obligation +Reserves 12% PRM | 11,466 | 11,667 | 11,874 | 12,421 | 12,643 | 13,057 | 13,226 | 13,417 | 13,462 | 13,768 |
| Obligation +Reserves 15% PRM | 11,715 | 11,927 | 12,136 | 12,703 | 12,932 | 13,380 | 13,552 | 13,750 | 13,796 | 14,111 |
| 12% System Position | 665 | 113 | 73 | (791) | (1,038) | (2,446) | (2,563) | (2,794) | (2,842) | (3,171) |
| 15% System Position | 415 | (147) | (188) | (1,073) | (1,327) | (2,768) | (2,890) | (3,126) | (3,176) | (3,513) |

**Figure 4.4 – West Coincident Peak Capacity Chart**




| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Resources | 4,401 | 4,415 | 4,408 | 4,321 | 4,300 | 3,506 | 3,558 | 3,519 | 3,519 | 3,518 |
| Obligation + Reserves 12% PRM | 3,520 | 3,520 | 3,712 | 3,734 | 3,824 | 3,911 | 3,920 | 3,936 | 3,834 | 3,757 |
| Obligation +Reserves 15% PRM | 3,593 | 3,593 | 3,789 | 3,812 | 3,906 | 4,013 | 4,021 | 4,038 | 3,933 | 3,854 |
| 12% PRM Position | 881 | 895 | 696 | 587 | 476 | (405) | (362) | (417) | (314) | (239) |
| 15% PRM Position | 808 | 822 | 618 | 509 | 394 | (506) | (463) | (519) | (414) | (336) |

**Figure 4.5 – East Coincident Peak Capacity Chart**




| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Resources | 7,730 | 7,366 | 7,540 | 7,310 | 7,305 | 7,105 | 7,105 | 7,105 | 7,101 | 7,080 |
| Obligation + Reserves 12% PRM | 7,946 | 8,147 | 8,163 | 8,688 | 8,819 | 9,146 | 9,306 | 9,482 | 9,628 | 10,012 |
| Obligation + Reserves 15% PRM | 8,123 | 8,334 | 8,346 | 8,891 | 9,027 | 9,367 | 9,531 | 9,712 | 9,863 | 10,257 |
| 12% PRM Position | (217) | (781) | (623) | (1,378) | (1,514) | (2,041) | (2,201) | (2,377) | (2,528) | (2,932) |
| 15% PRM Position | (393) | (969) | (806) | (1,581) | (1,722) | (2,262) | (2,427) | (2,607) | (2,762) | (3,177) |

## 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 4.6 through 4.8 show the energy balances for the system, west control area, and east control area, respectively. They show 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 becomes energy deficient on an average annual basis, is 2009, absent any economic considerations.

**Figure 4.6 – Average Monthly and Annual System Energy Balances**

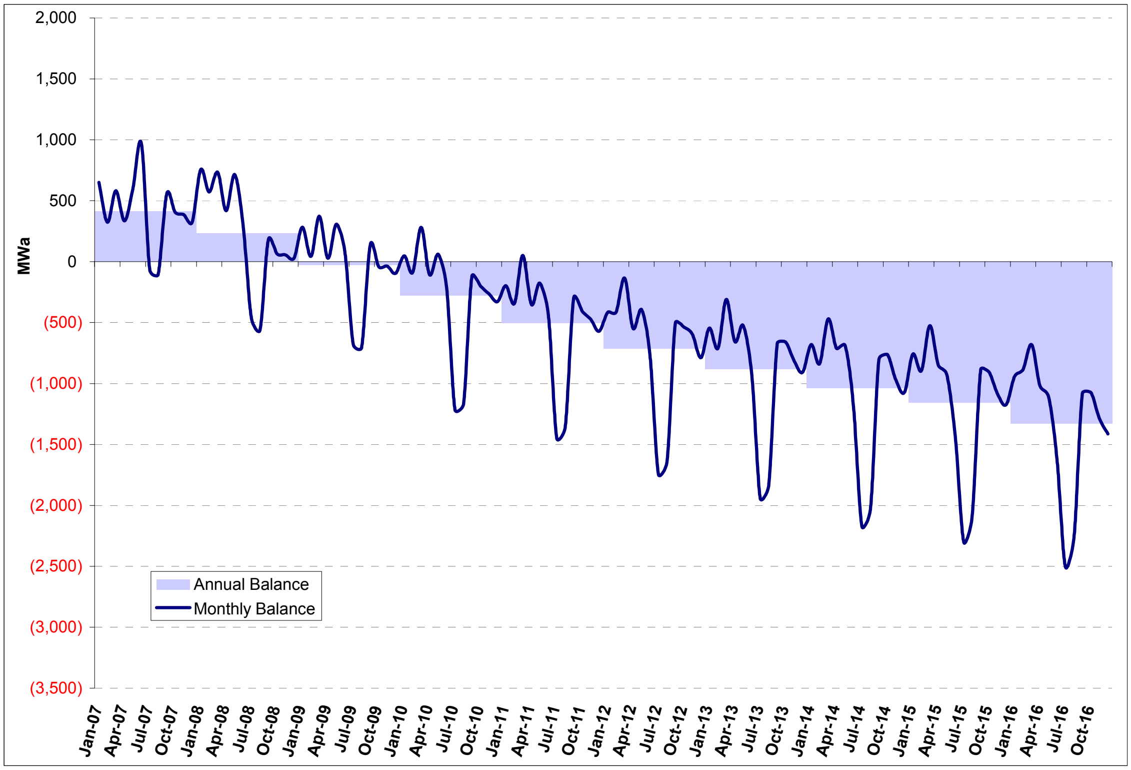



**Figure 4.7 – Average Monthly and Annual West Energy Balances**

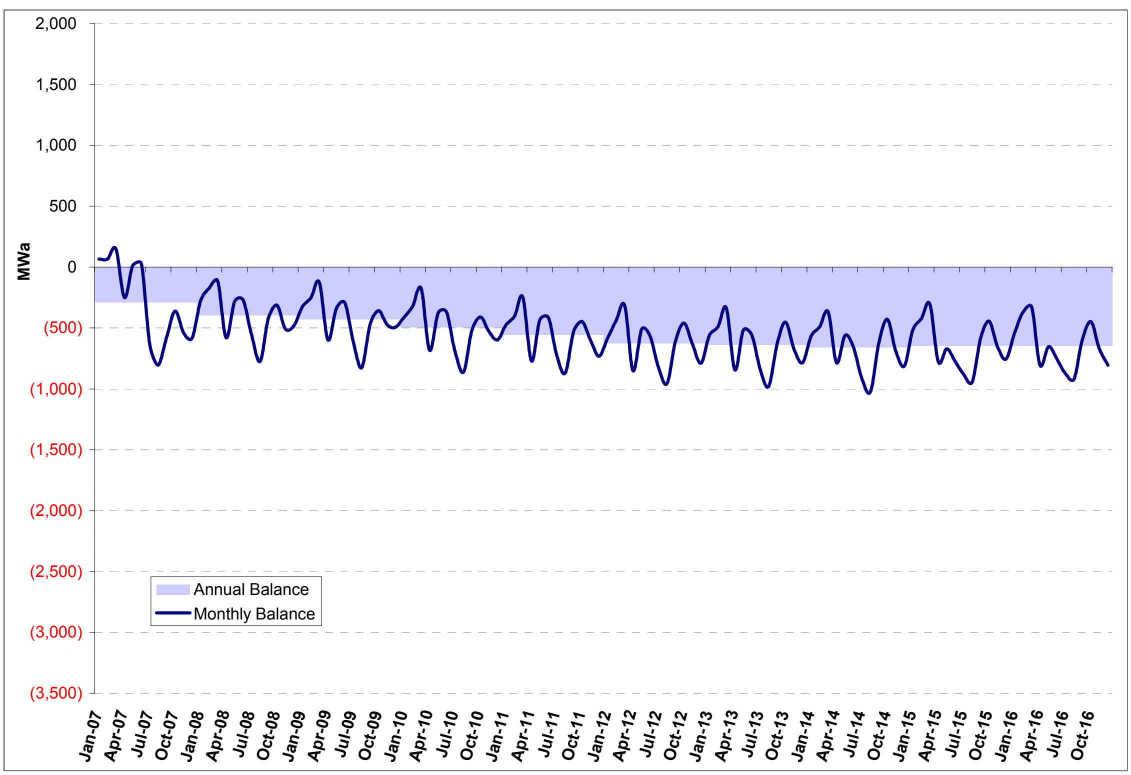
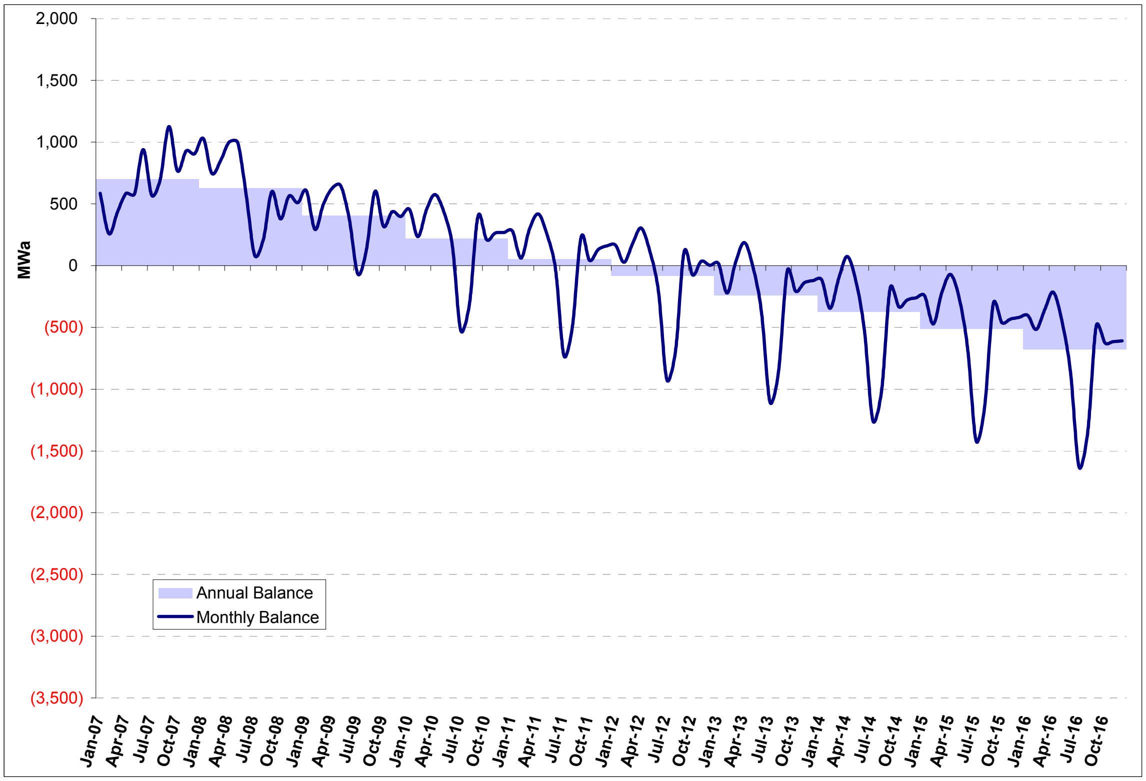


**Figure 4.8 – Average Monthly and Annual East Energy Balances**




## Load and Resource Balance Conclusions

The company projects a summer peak resource deficit for the PacifiCorp system beginning in 2008 to 2010, depending on the planning reserve margin assumed. The PacifiCorp deficits prior to 2011 to 2012 will be met by additional renewables, demand side programs, and market purchases. The company will consider other options during this time frame if they are cost-effective and provide other system benefits. This could include acceleration of a natural gas plant to complement the accelerated and expanded acquisition of renewable wind facilities. Then beginning in 2011 to 2012, base load, intermediate load, or both types of resource additions will be necessary to cover the widening capacity and annual energy deficits. The capacity balance at a 12 percent planning reserve margin indicates the start of a deficit beginning in 2010—the system is short by 791 megawatts. This capacity deficit increases to 2,400 megawatts in 2012 and then to almost 3,200 megawatts in 2016. On an annual basis, and disregarding economic considerations, the company becomes deficit with respect to energy by 2009.

# 5. RESOURCE OPTIONS

**Chapter Highlights**

- For use in portfolio modeling, PacifiCorp developed cost and performance profiles for supply-side resources, demand-side management programs, transmission expansion projects, and market purchases (front office transactions).
- PacifiCorp used the Electric Power Research Institute's Technical Assessment Guide (TAG®), along with recent project experience and consultant studies, to develop its supply-side resource options. The use of TAG information is new to PacifiCorp's integrated resource planning process.
- Also new to the company's integrated planning process is the estimation and use of capital cost ranges for each supply-side option. These cost ranges reflect cost uncertainty, and their use in this plan acknowledges the significant construction cost increases taking place.
- The company commissioned Quantec LLC to construct proxy supply curves for Class 1 (fully dispatchable or scheduled firm) and Class 3 (price-responsive) demand-side management programs.
- The company developed transmission resources to support new generation options, to enhance transfer capability and reliability across PacifiCorp's system, and to boost import/export capability with respect to external markets. These transmission resources were entered as options in PacifiCorp's capacity expansion optimization tool, and were thus allowed to compete directly with other resources for inclusion in portfolios.

## 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, 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. The chapter concludes with a discussion on the use and impact of physical and financial hedging strategies.

## SUPPLY-SIDE RESOURCES

### Resource Selection Criteria

The list of supply-side resource options has been reduced in relation to previous IRP resource lists to reflect the realities evidenced through previous studies and to help efficiently manage the computer processing time involved in developing detailed portfolios. For instance, subcritical pulverized coal resources are not included since it is felt than any new, large (greater than 500 megawatts) pulverized coal plant will utilize a supercritical boiler based on the increased efficiency and superior environmental performance of the supercritical designs. Similarly, natural gas based options based on smaller, less efficient combustion turbines have not been included since previous IRP exercises have demonstrated that the superior heat rate and cost performance of larger combustion turbines will cause the larger machines to be selected over the smaller options.

### Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major electrical generating resources from the 2004 IRP Update. This resource list was reviewed and, in some cases, simplified. Once the basic list of resources was determined the cost and performance attributes for each resource was estimated. A number of information sources were used to identify parameters needed to model these resources. PacifiCorp has conducted a number of engineering studies to understand the cost of coal and gas resources in recent years. Recent 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 has provided PacifiCorp with insight into the current cost of new power generating facilities. For newer technologies (integrated gasification combined cycle (IGCC) plants and supercritical pulverized coal plants) a study performed by WorleyParsons was used along with internal studies to review the cost estimates of these resources.

In order to refresh the modeling data used in the 2004 IRP Update, PacifiCorp purchased a license to utilize the Electric Power Research Institute (EPRI) new resource data base called the Technical Assessment Guide® (TAG). The TAG contains information on capital cost, heat rate, availability, and fixed and variable operating and maintenance cost estimates. The data in the TAG must be customized for each application by adjusting basic financial parameters as well as physical parameters for each potential site, such as coal quality, water availability, and elevation.

The 2006 TAG data were used to develop a cost and performance profile for each potential resource. The results of the TAG runs were compared to the actual cost data from recent projects as well as internal PacifiCorp studies of site specific generation options. The TAG results were customized to give results approximately in agreement to these recent studies. The customization was primarily done for capital costs, and reflects market conditions as of late spring of 2006. Of particular concern with the capital costs contained in the TAG database was the apparent lag in the TAG results in recognizing the recent trend of increases in capital costs for power generating equipment. It was apparent from numerous discussions with engineering and construction companies in the power industry that construction costs have increased substantially in the last two to three years. These increases, on the order of 25 to 35 percent with respect to the costs reported in the 2004 IRP Update, are due to increased construction activity stemming from shortages of equipment, material, and skilled construction labor. The TAG numbers, in general, did not address this recent capital cost trend. The TAG methodology does allow for customization to account for this increase. Therefore, costs were adjusted in the TAG to be consistent with other studies. Heat rate, availability, and operating and maintenance costs were, in general, calculated by the TAG.

TAG runs were created for all technologies in the supply-side resource table except as noted below for combined heat and power plants.

## Handling of Technology Improvement Trends and Cost Uncertainty

As mentioned above, the capital cost uncertainty for many of the proposed projects is increasing. Additionally, some technologies, such as IGCC, have a greater uncertainty because only a few demonstration units have been built and operated. A range of estimated capital costs is displayed in the supply-side resource options table. This range of capital cost was adjusted by factors reflecting the potential cost of various technologies as compared to a combined cycle natural gas plant. The combined cycle natural gas plant is the easiest technology to predict capital costs for since there is less field labor and PacifiCorp has recent (Currant Creek) and on-going (Lake Side) experience with this kind of project.

The cost factors used to reflect technology risk in the uncertainty range for various resource options were taken from a U.S Energy Information Administration paper "Assumptions to the Annual Energy Outlook 2006, DOE/EIA-0554(2006), March 2006". In addition to the technology factors the TAG capital cost estimates were adjusted by 5 percent on the low end and 10 percent on the high end to give an overall range.

There is a potential for future relative cost decreases for certain technologies such as IGCC. As the technology matures and more plants are built and operated the costs of such new technologies may decrease relative to more mature options such as pulverized coal. The supply-side options table does 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.

## Resource Options and Associated Attributes

Tables 5.1 and 5.2 present cost and performance attributes for supply-side resource options designated for PacifiCorp's east and west control areas, respectively. Tables 5.3 and 5.4 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 2006 dollars. Options included in PacifiCorp's IRP models are highlighted. As mentioned above, the attributes were mainly derived from the EPRI TAG database with certain technologies adjusted to be more in line with PacifiCorp's recent cost studies and project experience. Cost and performance values reflect analysis concluded by July 2006. Additional explanatory notes for the tables are as follows:

- The second 600-megawatt Utah supercritical pulverized coal resource is modeled as a 340-megawatt share to emulate the Intermountain Power Project acquisition opportunity.

- 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 5.1 and 5.2 reflect mid-2006 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. These levels are reported for each wind site in the Wind Capacity Planning Contribution section of Appendix J.
- For customer-owned standby generators, the 40 megawatts of capacity is the assumed aggregate availability of dispatchable megawatts rather than an average capacity per plant. The capital cost listed includes interconnection and emission control upgrade costs. The variable operations and maintenance (O&M) cost reflects the cost of #2 fuel oil, which is based on an average forecasted monthly fuel price of $13.9/MMBtu for the 2007 to 2026 period.
- 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)
- For the CHP resources, a steam credit is applied against the variable O&M cost, or, in the case of the west-side topping cycle combustion turbine, against the heat rate.
- The costs presented do not include any investment tax credits.
- The heat rate for the solar trough resource with CCCT backup (11,750 Btu/kWh) reflects gas operation only, and comes directly from the EPRI TAG database. Gas backup for solar is less efficient than for a standalone CCCT.
- For the nuclear option, costs do not include fuel disposal.
- The capital cost columns in Tables 5.3 and 5.4 reports averages of the low and high capital cost estimates presented in Tables 5.1 and 5.2.

## Table 5.1 – East Side Supply-Side Resource Options
(2006 Dollars)

| Description | Location/Timing: Installation Location | Location/Timing: Earliest In-Service Date (Mid-Year) | Plant Details: Average Capacity (MW) | Plant Details: Design Plant Life in Years | Plant Details: Ave. Annual Heat Rate (Btu/kWh) | Outage Information: Maint. Outage Rate | Outage Information: Equivalent Forced Outage Rate (EFOR) | Costs: Low Estimate Capital Cost ($/kW) | Costs: High Estimate Capital Cost ($/kW) | Costs: Var. O&M ($/MWh) | Costs: Fixed O&M ($/kW-yr) | Emissions: SO2 lbs/MMBTU | Emissions: NOx lbs/MMBTU | Emissions: Hg lbs/Tbtu | Emissions: $CO_2$ lbs/MMBTU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **East Side Options (4500')** | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | |
| Utah PC Supercritical 1 (600 MW) | Utah | 2012 | 600 | 40 | 9,169 | 5% | 4% | $ 1,940 | $ 2,266 | $ 2.41 | $ 35.65 | 0.062 | 0.070 | 0.600 | 205.35 |
| Utah PC Supercritical 2 (600 MW) | Utah | 2012 | 600 | 40 | 9,169 | 5% | 4% | $ 1,940 | $ 2,266 | $ 2.41 | $ 35.65 | 0.062 | 0.070 | 0.600 | 205.35 |
| Utah IGCC (Min. Carbon Prep/Level II Controls) | Utah | 2014 | 508 | 40 | 8,732 | 5% | 6% | $ 2,269 | $ 2,690 | $ 1.10 | $ 81.31 | 0.014 | 0.014 | 0.300 | 205.35 |
| Utah IGCC (Min. Carbon Prep/Level II - no spare gas.) | Utah | 2014 | 508 | 40 | 8,732 | 10% | 11% | $ 2,141 | $ 2,538 | $ 1.10 | $ 76.71 | 0.014 | 0.014 | 0.300 | 205.35 |
| Utah IGCC with Carbon Capture & Sequestration | Utah | 2014 | 470 | 40 | 9,917 | 5% | 6% | $ 2,901 | $ 3,439 | $ 6.28 | $ 114.50 | 0.014 | 0.014 | 0.300 | 20.54 |
| Wyoming PC Supercritical (750 MW) | Wyoming | 2014 | 750 | 40 | 9,427 | 5% | 4% | $ 1,930 | $ 2,256 | $ 2.08 | $ 41.06 | 0.062 | 0.070 | 0.600 | 205.35 |
| Wyoming IGCC (Min. Carbon Prep/Level II Controls) | Wyoming | 2014 | 497 | 40 | 8,915 | 5% | 6% | $ 2,471 | $ 2,929 | $ 1.08 | $ 81.32 | 0.013 | 0.013 | 0.300 | 205.35 |
| **Natural Gas** | | | | | | | | | | | | | | | |
| Microturbine | Utah | 2007 | 0.03 | 15 | 12,885 | 1% | 1% | $ 929 | $ 1,076 | $ 2.00 | $ 200.00 | 0.001 | 0.101 | 0.255 | 118.00 |
| Small Non-CT CHP | Utah | 2009 | 25 | 25 | 5,156 | 5% | 10% | $ 824 | $ 945 | $ 0.20 | $ 29.49 | 0.001 | 0.080 | 0.255 | 118.00 |
| Small Industrial CHP | Utah | 2008 | 4 | 25 | 12,590 | 7% | 2% | $ 1,454 | $ 1,669 | $ (0.32) | $ 8.22 | 0.001 | 0.138 | 0.255 | 118.00 |
| Small Commercial CHP | Utah | 2008 | 1 | 25 | 10,035 | 3% | 1% | $ 1,167 | $ 1,339 | $ (0.03) | $ 1.35 | 0.001 | 0.220 | 0.255 | 118.00 |
| Fuel Cell - Small (Solid Oxide) | Utah | 2008 | 0.3 | 25 | 7,820 | 1% | 2% | $ 1,577 | $ 1,913 | $ 0.03 | $ 9.70 | 0.001 | 0.003 | 0.255 | 118.00 |
| Fuel Cell - Large (Solid Oxide) | Utah | 2012 | 25 | 25 | 6,250 | 2% | 3% | $ 1,117 | $ 1,355 | $ 0.03 | $ 8.40 | 0.001 | 0.003 | 0.255 | 118.00 |
| SCCT Aero | Utah | 2009 | 79 | 25 | 10,744 | 7% | 10% | $ 701 | $ 804 | $ 7.08 | $ 20.91 | 0.001 | 0.011 | 0.255 | 118.00 |
| Intercooled Aero SCCT | Utah | 2009 | 78 | 25 | 9,436 | 3% | 2% | $ 698 | $ 801 | $ 2.58 | $ 29.02 | 0.001 | 0.011 | 0.255 | 118.00 |
| Internal Combustion Engines | Utah | 2009 | 153 | 25 | 8,390 | 5% | 1% | $ 824 | $ 946 | $ 5.20 | $ 12.80 | 0.001 | 0.017 | 0.255 | 118.00 |
| SCCT Frame (2 Frame "F") | Utah | 2009 | 302 | 35 | 11,509 | 7% | 10% | $ 465 | $ 534 | $ 10.86 | $ 5.78 | 0.001 | 0.050 | 0.255 | 118.00 |
| CCCT (Wet "F" 1x1) | Utah | 2010 | 222 | 35 | 7,223 | 7% | 5% | $ 834 | $ 957 | $ 2.60 | $ 16.42 | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT Duct Firing (Wet "F" 1x1) | Utah | 2010 | 50 | 35 | 8,868 | 7% | 5% | $ 277 | $ 318 | $ 0.11 | $ - | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT (Wet "F" 2x1) | Utah | 2010 | 448 | 35 | 7,164 | 7% | 5% | $ 759 | $ 870 | $ 2.60 | $ 9.98 | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT Duct Firing (Wet "F" 2x1) | Utah | 2010 | 100 | 35 | 8,868 | 7% | 5% | $ 255 | $ 292 | $ 0.11 | $ - | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT (Wet "G" 1x1) | Utah | 2010 | 297 | 35 | 7,075 | 7% | 5% | $ 789 | $ 905 | $ 2.55 | $ 12.42 | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT Duct Firing (Wet "G" 1x1) | Utah | 2010 | 60 | 35 | 8,868 | 7% | 5% | $ 292 | $ 335 | $ 0.11 | $ - | 0.001 | 0.011 | 0.255 | 118.00 |
| **Other - Renewables** | | | | | | | | | | | | | | | |
| SW Wyoming Wind | Wyoming | 2008 | 50 | 20 | n/a | n/a | n/a | $ 1,556 | $ 1,919 | $ - | $ 29.78 | - | - | - | - |
| Idaho Wind | Utah | 2008 | 50 | 20 | n/a | n/a | n/a | $ 1,556 | $ 1,919 | $ - | $ 29.78 | - | - | - | - |
| Geothermal, Dual Flash | Utah | 2009 | 35 | 35 | n/a | 3% | 1% | $ 3,101 | $ 3,591 | $ 5.50 | $ 22.60 | - | - | - | - |
| Battery Storage | Utah | 2009 | 20 | 30 | 12,000 | 2% | 5% | $ 1,298 | $ 1,503 | $ 10.00 | $ 1.00 | 0.100 | 0.400 | 3.000 | 205.35 |
| Pumped Storage | Nevada | 2017 | 350 | 50 | 13,000 | 5% | 5% | $ 1,104 | $ 1,278 | $ 4.30 | $ 4.30 | 0.100 | 0.400 | 3.000 | 205.35 |
| Compressed Air Energy Storage (CAES) | Wyoming | 2010 | 350 | 25 | 11,670 | 7% | 10% | $ 698 | $ 808 | $ 5.50 | $ 3.80 | 0.001 | 0.011 | 0.255 | 118.00 |
| Nuclear, Passive Safety | Utah | 2022 | 600 | 40 | 10,710 | 7% | 8% | $ 2,382 | $ 2,889 | $ 0.38 | $ 109.72 | - | - | - | - |
| Solar Thermal Trough with Natural Gas Backup | Utah | 2010 | 200 | 30 | 11,750 | n/a | n/a | $ 3,541 | $ 4,337 | $ 3.10 | $ 26.10 | - | - | - | - |

## Table 5.2 – West Side Supply-Side Resource Options
(2006 Dollars)

| | 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 | Ave. 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 | $CO_2$ lbs/MMBTU |
| **West Side Options (1500')** | | | | | | | | | | | | | | | |
| **Natural Gas** | | | | | | | | | | | | | | | |
| Microturbine | Northwest | 2007 | 0.03 | 15 | 12,885 | 1% | 1% | $ 845 | $ 978 | $ 1.82 | $ 181.82 | 0.001 | 0.101 | 0.255 | 118.00 |
| Fuel Cell - Small (Solid Oxide) | Northwest | 2008 | 0.225 | 25 | 7,820 | 1% | 2% | $ 1,433 | $ 1,739 | $ 0.03 | $ 8.82 | 0.001 | 0.003 | 0.255 | 118.00 |
| SCCT Aero | Northwest | 2009 | 87 | 25 | 10,744 | 7% | 10% | $ 637 | $ 731 | $ 6.44 | $ 19.01 | 0.001 | 0.011 | 0.255 | 118.00 |
| Intercooled Aero SCCT | Northwest | 2009 | 86 | 25 | 9,436 | 3% | 2% | $ 635 | $ 728 | $ 2.35 | $ 26.38 | 0.001 | 0.011 | 0.255 | 118.00 |
| Internal Combustion Engines | Northwest | 2009 | 168 | 25 | 8,390 | 5% | 1% | $ 749 | $ 860 | $ 5.20 | $ 12.80 | 0.001 | 0.017 | 0.255 | 118.00 |
| SCCT Frame (2 Frame "F") | Northwest | 2009 | 332 | 35 | 11,509 | 7% | 10% | $ 423 | $ 485 | $ 9.87 | $ 5.25 | 0.001 | 0.050 | 0.255 | 118.00 |
| CCCT (Wet "F" 1x1) | Northwest | 2010 | 244 | 35 | 7,223 | 7% | 5% | $ 758 | $ 870 | $ 2.36 | $ 14.93 | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT Duct Firing (Wet "F" 1x1) | Northwest | 2010 | 55 | 35 | 8,868 | 7% | 5% | $ 252 | $ 289 | $ 0.10 | $ - | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT (Wet "F" 2x1) | Northwest | 2010 | 492 | 35 | 7,164 | 7% | 5% | $ 690 | $ 791 | $ 2.36 | $ 9.07 | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT Duct Firing (Wet "F" 2x1) | Northwest | 2010 | 110 | 35 | 8,868 | 7% | 5% | $ 232 | $ 266 | $ 0.10 | $ - | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT (Wet "G" 1x1) | Northwest | 2010 | 326 | 35 | 7,075 | 7% | 5% | $ 717 | $ 822 | $ 2.32 | $ 11.29 | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT Duct Firing (Wet "G" 1x1) | Northwest | 2010 | 66 | 35 | 8,868 | 7% | 5% | $ 266 | $ 305 | $ 0.10 | $ - | 0.001 | 0.011 | 0.255 | 118.00 |
| **Other - Renewables** | | | | | | | | | | | | | | | |
| Oregon Wind | Northwest | 2008 | 50 | 20 | n/a | n/a | 5% | $ 1,556 | $ 1,919 | $ - | $ 29.78 | - | - | - | - |
| Geothermal, Dual Flash | Northwest | 2009 | 35 | 35 | n/a | 3% | 1% | $ 3,101 | $ 3,591 | $ 5.50 | $ 22.60 | - | - | - | - |
| Compressed Air Energy Storage (CAES) | Northwest | 2010 | 385 | 25 | 11,670 | 7% | 10% | $ 635 | $ 735 | $ 5.00 | $ 3.45 | 0.001 | 0.011 | 0.255 | 118.00 |
| **West Side Options (Sea Level)** | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | |
| Washington IGCC (Min. Carbon Prep/Level II Controls) | Northwest | 2014 | 600 | 40 | 8,732 | 5% | 6% | $ 2,269 | $ 2,690 | $ 1.10 | $ 81.31 | 0.014 | 0.014 | 0.300 | 205.35 |
| **Natural Gas** | | | | | | | | | | | | | | | |
| Microturbine | Northwest | 2007 | 0.03 | 15 | 12,885 | 1% | 1% | $ 803 | $ 929 | $ 1.73 | $ 172.73 | 0.001 | 0.101 | 0.255 | 118.00 |
| Large CHP | Northwest | 2009 | 120 | 25 | 11,655 | 7% | 5% | $ 756 | $ 824 | $ (17.75) | $ 14.22 | 0.001 | 0.050 | 0.255 | 118.00 |
| Small Non-CT CHP | Northwest | 2009 | 25 | 25 | 5,156 | 5% | 10% | $ 782 | $ 898 | $ 0.17 | $ 29.49 | 0.001 | 0.080 | 0.255 | 118.00 |
| Small Industrial CHP | Northwest | 2008 | 5 | 25 | 12,590 | 7% | 2% | $ 1,265 | $ 1,451 | $ (0.28) | $ 7.15 | 0.001 | 0.138 | 0.255 | 118.00 |
| Small Commercial CHP | Northwest | 2008 | 1 | 25 | 10,035 | 3% | 1% | $ 1,167 | $ 1,339 | $ (0.02) | $ 1.17 | 0.001 | 0.220 | 0.255 | 118.00 |
| Fuel Cell - Small (Solid Oxide) | Northwest | 2008 | 0.2 | 25 | 7,820 | 1% | 2% | $ 1,362 | $ 1,652 | $ 0.03 | $ 8.82 | 0.001 | 0.003 | 0.255 | 118.00 |
| SCCT Aero | Northwest | 2009 | 91 | 25 | 10,744 | 2% | 10% | $ 605 | $ 694 | $ 6.13 | $ 18.06 | 0.001 | 0.011 | 0.255 | 118.00 |
| Intercooled Aero SCCT | Northwest | 2009 | 90 | 25 | 9,436 | 7% | 2% | $ 603 | $ 692 | $ 2.23 | $ 25.06 | 0.001 | 0.011 | 0.255 | 118.00 |
| Internal Combustion Engines | Northwest | 2009 | 177 | 25 | 8,390 | 3% | 1% | $ 712 | $ 817 | $ 5.20 | $ 12.80 | 0.001 | 0.017 | 0.255 | 118.00 |
| SCCT Frame (2 Frame "F") | Northwest | 2009 | 350 | 35 | 11,509 | 5% | 10% | $ 402 | $ 461 | $ 9.40 | $ 5.00 | 0.001 | 0.050 | 0.255 | 118.00 |
| CCCT (Wet "F" 1x1) | Northwest | 2010 | 257 | 35 | 7,223 | 7% | 5% | $ 720 | $ 826 | $ 2.25 | $ 14.22 | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT Duct Firing (Wet "F" 1x1) | Northwest | 2010 | 58 | 35 | 8,868 | 7% | 5% | $ 240 | $ 275 | $ 0.10 | $ - | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT (Wet "F" 2x1) | Northwest | 2010 | 518 | 35 | 7,164 | 7% | 5% | $ 655 | $ 752 | $ 2.25 | $ 8.64 | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT Duct Firing (Wet "F" 2x1) | Northwest | 2010 | 116 | 35 | 8,868 | 7% | 5% | $ 220 | $ 252 | $ 0.10 | $ - | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT (Wet "G" 1x1) | Northwest | 2010 | 343 | 35 | 7,075 | 7% | 5% | $ 681 | $ 781 | $ 2.21 | $ 10.75 | 0.001 | 0.011 | 0.255 | 118.00 |
| CCCT Duct Firing (Wet "G" 1x1) | Northwest | 2010 | 69 | 35 | 8,868 | 7% | 5% | $ 252 | $ 290 | $ 0.10 | $ - | 0.001 | 0.011 | 0.255 | 118.00 |
| **Other- Renewables** | | | | | | | | | | | | | | | |
| Oregon Wind | Northwest | 2008 | 50 | 20 | n/a | n/a | 5% | $ 1,556 | $ 1,919 | $ - | $ 29.78 | - | - | - | - |
| Biomass (closed loop) | Northwest | 2010 | 100 | 35 | 10,979 | 5% | 4% | $ 2,213 | $ 2,563 | $ 1.91 | $ 4.12 | 0.062 | 0.350 | 0.600 | 205.39 |
| Nuclear, Passive Safety | Northwest | 2022 | 600 | 40 | 10,710 | 7% | 8% | $ 2,382 | $ 2,889 | $ 0.38 | $ 109.72 | - | - | - | - |
| Compressed Air Energy Storage (CAES) | Northwest | 2010 | 405 | 25 | 11,670 | 7% | 10% | $ 603 | $ 698 | $ 4.76 | $ 3.28 | 0.001 | 0.011 | 0.255 | 118.00 |
| Customer Owned Standby Generation | Northwest | 2008 | 40 | 20 | 10,500 | n/a | n/a | $ 170 | $ 170 | $ 146.00 | $ 3.50 | 0.058 | 0.231 | n/a | 190.00 |

# Table 5.3 – Total Resource Cost for East Side Supply-Side Resource Options
(2006 Dollars)

| Description | Capital Cost $/kW | | | Fixed Cost | | | | Convert to Mills | | | | Variable Costs mills/kWh | | | | Total Resource Cost (Mills/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Fixed O&M ($/kW-Yr) | | | | | | Levelized Fuel | | | | | | |
| | Total Capital Cost | Payment Factor | Annual Payment ($/kW-Yr) | O&M | Other | Total | Total Fixed ($/kW-Yr) | Capacity Factor | Total Fixed (Mills/kWh) | ¢/mmBtu | Mills/kWh | O&M | Total | Tax Credits | Environmental | |
| **East Side Options (4500')** | | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | | |
| Utah PC Supercritical 1 (600 MW) | $ 2,103 | 8.10% | $ 170.43 | $ 35.65 | $ 6.00 | $ 41.65 | $ 212.08 | 91% | 26.49 | 187.20 | 17.16 | $ 2.41 | - | - | 5.39 | $ 51.46 |
| Utah PC Supercritical 2 (600 MW) | $ 2,103 | 8.10% | $ 170.43 | $ 35.65 | $ 6.00 | $ 41.65 | $ 212.08 | 91% | 26.49 | 187.20 | 17.16 | $ 2.41 | - | - | 5.39 | $ 51.46 |
| Utah IGCC (Min. Carbon Prep/Level II Controls) | $ 2,479 | 7.82% | $ 193.86 | $ 81.31 | $ 6.00 | $ 87.31 | $ 281.17 | 89% | 36.06 | 187.20 | 16.35 | $ 1.10 | - | - | 4.83 | $ 58.35 |
| Utah IGCC (Min. Carbon Prep/Level II - no spare gas.) | $ 2,339 | 7.82% | $ 182.90 | $ 76.71 | $ 6.00 | $ 82.71 | $ 265.62 | 79% | 38.38 | 187.20 | 16.35 | $ 1.10 | - | - | 4.83 | $ 60.66 |
| Utah IGCC with Carbon Capture & Sequestration | $ 3,170 | 7.82% | $ 247.87 | $ 114.50 | $ 6.00 | $ 120.50 | $ 368.37 | 89% | 47.25 | 187.20 | 18.56 | $ 6.28 | - | - | 0.64 | $ 72.74 |
| Wyoming PC Supercritical (750 MW) | $ 2,093 | 8.10% | $ 169.61 | $ 41.06 | $ 6.00 | $ 47.06 | $ 216.67 | 91% | 27.06 | 103.67 | 9.77 | $ 2.08 | - | - | 5.54 | $ 44.46 |
| Wyoming IGCC (Min. Carbon Prep/Level II Controls) | $ 2,700 | 7.82% | $ 211.11 | $ 81.32 | $ 6.00 | $ 87.32 | $ 298.43 | 89% | 38.28 | 103.67 | 9.24 | $ 1.08 | - | - | 4.93 | $ 53.53 |
| **Natural Gas** | | | | | | | | | | | | | | | | |
| Microturbine | $ 1,003 | 11.21% | $ 112.38 | $ 200.00 | $ 0.50 | $ 200.50 | $ 312.88 | 98% | 36.45 | 693.70 | 89.39 | $ 2.00 | - | - | 4.45 | $ 139.37 |
| Small Non-CT CHP | $ 884 | 9.84% | $ 87.01 | $ 29.49 | $ 0.50 | $ 29.99 | $ 117.01 | 85% | 15.71 | 693.70 | 35.77 | $ 0.20 | - | - | 1.75 | $ 56.26 |
| Small Industrial CHP | $ 1,561 | 9.84% | $ 153.64 | $ 8.22 | $ 0.50 | $ 8.72 | $ 162.36 | 90% | 20.59 | 693.70 | 87.34 | $ (0.32) | - | - | 4.49 | $ 119.03 |
| Small Commercial CHP | $ 1,253 | 9.84% | $ 123.29 | $ 1.35 | $ 0.50 | $ 1.85 | $ 125.14 | 90% | 15.87 | 693.70 | 69.61 | $ (0.03) | - | - | 3.84 | $ 94.82 |
| Fuel Cell - Small (Solid Oxide) | $ 1,745 | 8.50% | $ 148.23 | $ 9.70 | $ 0.50 | $ 10.20 | $ 158.43 | 97% | 18.65 | 693.70 | 54.25 | $ 0.03 | - | - | 2.46 | $ 79.69 |
| Fuel Cell - Large (Solid Oxide) | $ 1,236 | 8.50% | $ 105.01 | $ 8.40 | $ 0.50 | $ 8.90 | $ 113.91 | 95% | 13.69 | 693.70 | 43.36 | $ 0.03 | - | - | 1.97 | $ 62.48 |
| SCCT Aero | $ 752 | 9.51% | $ 71.53 | $ 20.91 | $ 0.50 | $ 21.41 | $ 92.94 | 21% | 50.52 | 693.70 | 74.53 | $ 7.08 | 0.15 | - | 3.41 | $ 139.40 |
| Intercooled Aero SCCT | $ 750 | 9.51% | $ 71.27 | $ 29.02 | $ 0.50 | $ 29.52 | $ 100.79 | 21% | 54.79 | 693.70 | 65.46 | $ 2.58 | - | - | 2.99 | $ 129.21 |
| Internal Combustion Engines | $ 885 | 9.51% | $ 84.14 | $ 12.80 | $ 0.50 | $ 13.30 | $ 97.44 | 94% | 11.83 | 693.70 | 58.20 | $ 5.20 | - | - | 2.68 | $ 82.53 |
| SCCT Frame (2 Frame "F") | $ 499 | 8.33% | $ 41.61 | $ 5.78 | $ 0.50 | $ 6.28 | $ 47.89 | 21% | 26.03 | 693.70 | 79.84 | $ 10.86 | - | - | 3.79 | $ 124.53 |
| CCCT (Wet "F" 1x1) | $ 895 | 8.62% | $ 77.16 | $ 16.42 | $ 0.50 | $ 16.92 | $ 94.08 | 56% | 19.18 | 693.70 | 50.11 | $ 2.60 | - | - | 2.29 | $ 77.90 |
| CCCT Duct Firing (Wet "F" 1x1) | $ 298 | 8.62% | $ 25.67 | - | $ 0.50 | $ 0.50 | $ 26.17 | 16% | 18.67 | 693.70 | 61.52 | $ 0.11 | - | - | 2.81 | $ 86.70 |
| CCCT (Wet "F" 2x1) | $ 815 | 8.62% | $ 70.20 | $ 9.98 | $ 0.50 | $ 10.48 | $ 80.68 | 56% | 16.45 | 693.70 | 49.69 | $ 2.60 | 3.50 | - | 2.27 | $ 74.71 |
| CCCT Duct Firing (Wet "F" 2x1) | $ 273 | 8.62% | $ 23.56 | - | $ 0.50 | $ 0.50 | $ 24.06 | 16% | 17.17 | 693.70 | 61.52 | $ 0.11 | - | - | 2.81 | $ 85.19 |
| CCCT (Wet "G" 1x1) | $ 847 | 8.62% | $ 72.96 | $ 12.42 | $ 0.50 | $ 12.92 | $ 85.88 | 56% | 17.51 | 693.70 | 49.08 | $ 2.55 | - | - | 2.25 | $ 75.03 |
| CCCT Duct Firing (Wet "G" 1x1) | $ 314 | 8.62% | $ 27.05 | - | $ 0.50 | $ 0.50 | $ 27.55 | 16% | 19.66 | 693.70 | 61.52 | $ 0.11 | - | - | 2.81 | $ 87.68 |
| **Other - Renewables** | | | | | | | | | | | | | | | | |
| SW Wyoming Wind | $ 2,011 | 9.48% | $ 190.70 | $ 29.78 | $ 0.50 | $ 30.28 | $ 220.98 | 35% | 72.49 | - | - | - | - | (20.65) | - | $ 55.13 |
| Idaho Wind | $ 1,729 | 9.48% | $ 163.96 | $ 29.78 | $ 0.50 | $ 30.28 | $ 194.24 | 33% | 68.23 | - | - | - | - | (20.65) | - | $ 50.87 |
| Geothermal, Dual Flash | $ 3,346 | 7.46% | $ 249.55 | $ 22.60 | $ 0.50 | $ 23.10 | $ 272.65 | 96% | 32.32 | - | 21.13 | $ 5.50 | - | (20.65) | - | $ 38.30 |
| Battery Storage | $ 1,400 | 8.51% | $ 119.15 | $ 1.00 | $ 0.50 | $ 1.50 | $ 120.65 | 21% | 65.59 | 693.70 | 83.24 | $ 10.00 | - | - | 8.62 | $ 167.45 |
| Pumped Storage | $ 1,191 | 7.86% | $ 93.62 | $ 4.30 | $ 1.35 | $ 5.65 | $ 99.27 | 20% | 56.66 | 693.70 | 90.18 | $ 4.30 | - | - | 9.340 | $ 160.48 |
| Compressed Air Energy Storage (CAES) | $ 753 | 8.69% | $ 65.45 | $ 3.80 | $ 1.35 | $ 5.15 | $ 70.60 | 25% | 32.24 | 693.70 | 80.96 | $ 5.50 | - | - | 3.704 | $ 122.40 |
| Nuclear, Passive Safety | $ 2,635 | 8.01% | $ 210.97 | $ 109.72 | $ 6.00 | $ 115.72 | $ 326.69 | 85% | 43.87 | - | 6.63 | $ 0.38 | - | - | - | $ 50.88 |
| Solar Thermal Trough with Natural Gas Backup | $ 3,939 | 7.87% | $ 310.11 | $ 26.10 | $ 6.00 | $ 32.10 | $ 342.21 | 21% | 186.03 | - | - | $ 3.10 | - | - | - | $ 189.13 |

## Table 5.4 – Total Resource Cost for West Side Supply-Side Resource Options
(2006 Dollars)

| Description | Capital Cost $/kW | | | Fixed Cost | | | | | Convert to Mills | | | Variable Costs | | | | Total Resource Cost (Mills/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Fixed O&M ($/kW-Yr) | | | | | | Levelized Fuel | | mills/kWh | | | | |
| | Total Capital Cost | Payment Factor | Annual Payment ($/kW-Yr) | O&M | Other | Total | Total Fixed ($/kW-Yr) | Capacity Factor | Total Fixed (Mills/kWh) | ¢/mmBtu | Mills/kWh | O&M | Total | Tax Credits | Environmental | |
| **West Side Options (1500')** | | | | | | | | | | | | | | | | |
| **Natural Gas** | | | | | | | | | | | | | | | | |
| Microturbine | $ 912 | 11.21% | $ 102.16 | $ 181.82 | $ 0.50 | $ 182.32 | $ 284.48 | 98% | 33.14 | 699.25 | 90.10 | $ 1.82 | - | - | 4.45 | $ 136.72 |
| Fuel Cell - Small (Solid Oxide) | $ 1,586 | 8.50% | $ 134.76 | $ 8.82 | $ 0.50 | $ 9.32 | $ 144.08 | 97% | 16.96 | 699.25 | 54.68 | $ 0.03 | - | - | 2.46 | $ 78.51 |
| SCCT Aero | $ 684 | 9.51% | $ 65.02 | $ 19.01 | $ 0.50 | $ 19.51 | $ 84.53 | 21% | 45.95 | 699.25 | 75.13 | $ 6.44 | - | - | 3.41 | $ 134.53 |
| Intercooled Aero SCCT | $ 682 | 9.51% | $ 64.79 | $ 26.38 | $ 0.50 | $ 26.88 | $ 91.68 | 21% | 49.83 | 699.25 | 65.98 | $ 2.35 | - | - | 2.99 | $ 124.32 |
| Internal Combustion Engines | $ 805 | 9.51% | $ 76.49 | $ 12.80 | $ 0.50 | $ 13.30 | $ 89.79 | 94% | 10.90 | 699.25 | 58.67 | $ 5.20 | - | - | 2.68 | $ 82.15 |
| SCCT Frame (2 Frame "F") | $ 454 | 8.33% | $ 37.83 | $ 5.25 | $ 0.50 | $ 5.75 | $ 43.58 | 21% | 23.69 | 699.25 | 80.48 | $ 9.87 | - | - | 3.79 | $ 121.54 |
| CCCT (Wet "F" 1x1) | $ 814 | 8.62% | $ 70.15 | $ 14.93 | $ 0.50 | $ 15.43 | $ 85.57 | 56% | 17.44 | 699.25 | 50.51 | $ 2.36 | - | - | 2.29 | $ 76.36 |
| CCCT Duct Firing (Wet "F" 1x1) | $ 271 | 8.62% | $ 23.34 | - | $ 0.50 | $ 0.50 | $ 23.84 | 16% | 17.01 | 699.25 | 62.01 | $ 0.10 | - | - | 2.81 | $ 85.37 |
| CCCT (Wet "F" 2x1) | $ 741 | 8.62% | $ 63.82 | $ 9.07 | $ 0.50 | $ 9.57 | $ 73.39 | 56% | 14.96 | 699.25 | 50.09 | $ 2.36 | - | - | 2.27 | $ 73.42 |
| CCCT Duct Firing (Wet "F" 2x1) | $ 249 | 8.62% | $ 21.42 | - | $ 0.50 | $ 0.50 | $ 21.92 | 16% | 15.64 | 699.25 | 62.01 | $ 0.10 | - | - | 2.81 | $ 84.00 |
| CCCT (Wet "G" 1x1) | $ 770 | 8.62% | $ 66.33 | $ 11.29 | $ 0.50 | $ 11.79 | $ 78.12 | 56% | 15.92 | 699.25 | 49.47 | $ 2.32 | - | - | 2.25 | $ 73.64 |
| CCCT Duct Firing (Wet "G" 1x1) | $ 285 | 8.62% | $ 24.59 | - | $ 0.50 | $ 0.50 | $ 25.09 | 16% | 17.90 | 699.25 | 62.01 | $ 0.10 | - | - | 2.81 | $ 86.27 |
| **Other - Renewables** | | | | | | | | | | | | | | | | |
| Oregon Wind | $ 1,737 | 9.48% | $ 164.75 | $ 29.78 | $ 22.22 | $ 52.00 | $ 216.75 | 34% | 72.35 | - | - | - | - | (20.65) | - | $ 54.99 |
| Geothermal, Dual Flash | $ 3,346 | 7.46% | $ 249.55 | $ 22.60 | $ 0.50 | $ 23.10 | $ 272.65 | 96% | 32.32 | - | 21.13 | $ 5.50 | - | (20.65) | - | $ 38.30 |
| Compressed Air Energy Storage (CAES) | $ 685 | 8.69% | $ 59.50 | $ 3.45 | $ 1.35 | $ 4.80 | $ 64.31 | 25% | 29.36 | 699.25 | 81.60 | $ 5.00 | - | - | 3.70 | $ 119.67 |
| **West Side Options (Sea Level)** | | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | | |
| Washington IGCC (Min. Carbon Prep/Level II Controls) | $ 2,479 | 7.82% | $ 193.86 | $ 81.31 | $ 6.00 | $ 87.31 | $ 281.17 | 89% | 36.06 | 150.00 | 13.10 | $ 1.10 | - | - | 4.83 | $ 55.10 |
| **Natural Gas** | | | | | | | | | | | | | | | | |
| Microturbine | $ 866 | 11.21% | $ 97.06 | $ 172.73 | $ 0.50 | $ 173.23 | $ 270.28 | 98% | 31.48 | 699.25 | 90.10 | $ 1.73 | - | - | 4.45 | $ 134.98 |
| Large CHP | $ 790 | 9.84% | $ 77.75 | $ 14.22 | $ 0.50 | $ 14.72 | $ 92.46 | 89% | 11.93 | 699.25 | 81.50 | $ (17.75) | - | - | 3.84 | $ 86.23 |
| Small Non-CT CHP | $ 840 | 9.84% | $ 82.66 | $ 29.49 | $ 0.50 | $ 29.99 | $ 112.65 | 85% | 15.13 | 699.25 | 36.05 | $ 0.17 | - | - | 1.75 | $ 55.99 |
| Small Industrial CHP | $ 1,358 | 9.84% | $ 133.60 | $ 7.15 | $ 0.50 | $ 7.65 | $ 141.25 | 90% | 17.92 | 699.25 | 88.04 | $ (0.28) | - | - | 4.49 | $ 117.22 |
| Small Commercial CHP | $ 1,253 | 9.84% | $ 123.29 | $ 1.17 | $ 0.50 | $ 1.67 | $ 124.96 | 90% | 15.85 | 699.25 | 70.17 | $ (0.02) | - | - | 3.84 | $ 95.46 |
| Fuel Cell - Small (Solid Oxide) | $ 1,507 | 8.50% | $ 128.02 | $ 8.82 | $ 0.50 | $ 9.32 | $ 137.34 | 97% | 16.16 | 699.25 | 54.68 | $ 0.03 | - | - | 2.46 | $ 77.71 |
| SCCT Aero | $ 650 | 9.51% | $ 61.77 | $ 18.06 | $ 0.50 | $ 18.56 | $ 80.33 | 21% | 43.67 | 699.25 | 75.13 | $ 6.13 | - | - | 3.41 | $ 131.93 |
| Intercooled Aero SCCT | $ 647 | 9.51% | $ 61.55 | $ 25.06 | $ 0.50 | $ 25.56 | $ 87.12 | 21% | 47.36 | 699.25 | 65.98 | $ 2.23 | - | - | 2.99 | $ 121.73 |
| Internal Combustion Engines | $ 764 | 9.51% | $ 72.67 | $ 12.80 | $ 0.50 | $ 13.30 | $ 85.97 | 94% | 10.44 | 699.25 | 58.67 | $ 5.20 | - | - | 2.68 | $ 81.68 |
| SCCT Frame (2 Frame "F") | $ 431 | 8.33% | $ 35.94 | $ 5.00 | $ 0.50 | $ 5.50 | $ 41.44 | 21% | 22.53 | 699.25 | 80.48 | $ 9.40 | - | - | 3.79 | $ 119.90 |
| CCCT (Wet "F" 1x1) | $ 773 | 8.62% | $ 66.64 | $ 14.22 | $ 0.50 | $ 14.72 | $ 81.36 | 56% | 16.58 | 699.25 | 50.51 | $ 2.25 | - | - | 2.29 | $ 75.39 |
| CCCT Duct Firing (Wet "F" 1x1) | $ 257 | 8.62% | $ 22.17 | - | $ 0.50 | $ 0.50 | $ 22.67 | 16% | 16.18 | 699.25 | 62.01 | $ 0.10 | - | - | 2.81 | $ 84.53 |
| CCCT (Wet "F" 2x1) | $ 703 | 8.62% | $ 60.63 | $ 8.64 | $ 0.50 | $ 9.14 | $ 69.77 | 56% | 14.22 | 699.25 | 50.09 | $ 2.25 | - | - | 2.27 | $ 72.56 |
| CCCT Duct Firing (Wet "F" 2x1) | $ 236 | 8.62% | $ 20.35 | - | $ 0.50 | $ 0.50 | $ 20.85 | 16% | 14.88 | 699.25 | 62.01 | $ 0.10 | - | - | 2.81 | $ 83.24 |
| CCCT (Wet "G" 1x1) | $ 731 | 8.62% | $ 63.01 | $ 10.75 | $ 0.50 | $ 11.25 | $ 74.26 | 56% | 15.14 | 699.25 | 49.47 | $ 2.21 | - | - | 2.25 | $ 72.74 |
| CCCT Duct Firing (Wet "G" 1x1) | $ 271 | 8.62% | $ 23.36 | - | $ 0.50 | $ 0.50 | $ 23.86 | 16% | 17.02 | 699.25 | 62.01 | $ 0.10 | - | - | 2.81 | $ 85.38 |
| **Other- Renewables** | | | | | | | | | | | | | | | | |
| Oregon Wind | $ 1,729 | 9.48% | $ 163.96 | $ 29.78 | $ 22.22 | $ 52.00 | $ 215.96 | 34% | 72.51 | - | - | - | - | (20.65) | - | $ 55.15 |
| Biomass (closed loop) | $ 2,388 | 7.46% | $ 178.11 | $ 4.12 | $ 0.50 | $ 4.62 | $ 182.73 | 91% | 22.82 | 300.00 | 32.94 | $ 1.91 | - | (20.65) | 7.42 | $ 44.44 |
| Nuclear, Passive Safety | $ 2,635 | 8.01% | $ 210.97 | $ 109.72 | $ 6.00 | $ 115.72 | $ 326.69 | 85% | 43.87 | - | 6.35 | $ 0.38 | - | - | - | $ 50.60 |
| Compressed Air Energy Storage (CAES) | $ 651 | 8.69% | $ 56.53 | $ 3.28 | $ 1.35 | $ 4.63 | $ 61.16 | 25% | 27.93 | 699.25 | 81.60 | $ 4.76 | - | - | 3.70 | $ 117.99 |
| Customer Owned Standby Generation | $ 170 | 11.00% | $ 18.70 | $ 3.50 | $ 0.50 | $ 4.00 | $ 22.70 | 25% | 10.36 | - | - | $ 146.00 | - | - | 6.22 | $ 162.59 |

## Resource Descriptions

### Coal

Potential coal resources are shown in the supply-side resource options tables as supercritical pulverized coal boilers in Utah[31] and Wyoming, and IGCC facilities in Utah, Wyoming, and West Main. 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+ 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. One such concept involves the use of ammonia and chilling the flue gas. ALSTOM, a major supplier of utility boilers, gas-fired and steam turbine-generators, and air quality control equipment for power generation applications, has licensed a chilled ammonia process for the capture of $CO_2$ from the flue gas from pulverized coal and natural gas-fired combined-cycle plants. The process is expected to have application for both new generating units and retrofit applications. This technology holds the promise that the cost of energy from a pulverized coal plant with $CO_2$ capture will be competitive with the cost of energy from an integrated gasification combined cycle plant with $CO_2$ capture.[32]

ALSTOM is currently working on a 5 megawatt (thermal) demonstration scale facility along with the Electric Power Research Institute and We Energies that is to be constructed at We Energies' Pleasant Prairie Plant. PacifiCorp is participating through EPRI in this $CO_2$ Pilot Capture study; this participation will provide the company with access to summary analysis, performance, and cost projections of the technology. Startup of the project is expected in mid-2007 with extensive testing for at least one year. American Electric Power (AEP) recently announced plans

[31] Although the Supply-side Resource Options table shows the two Utah supercritical coal resources at 600 MW each, for modeling purposes, the company assumed that the second Utah resource would be acquired as a 57% share of 600 MW, or 340 MW.

[32] The chilled ammonia process entails the use of ammonia in place of amine-based processes. Most studies done to date on $CO_2$ capture from combustion gases have been based on the use of amine-based systems. Reagent costs are expected to be lower since ammonia is a reasonably low-cost commodity chemical. The use of ammonia instead of amine-based systems is expected to minimize the steam requirement associated with regenerating the solvent. This reduced steam requirement mitigates the impact on the net capability of the unit. Chilling the flue gas to low temperatures greatly reduces the volume of flue gas that has to be treated, thereby reducing equipment and process costs. The regeneration part of the process also operates at high pressure which reduces the electrical load associated with compression of the recovered $CO_2$.

to install a 30 megawatt (thermal) demonstration in 2009 and a 200 megawatt equivalent demonstration by 2011. Such large demonstrations will verify the commercial status of this process. It is expected that the chilled ammonia system will be able to remove approximately 90% of the $CO_2$ in the flue gas.

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 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. An extensive and costly front-end engineering design (FEED) study is required to obtain reasonably accurate estimates of the cost of building an IGCC plant. In 2005-2006, PacifiCorp contracted with Worley Parsons to study the cost of an IGCC located either in Utah or Wyoming. The costs presented in the supply-side resource options tables reflect the general results of that study effort.

An IGCC plant can be installed with a number of different configurations. Three different configurations are presented in the supply-side resource options table for an IGCC installed at a Utah location. One configuration involves installation of Level II emission controls with a spare gasifier and space provisions for future installation of carbon capture equipment. Level II emission controls would include a selective catalytic reduction (SCR) system for enhanced NOx control. A Level II emission control system would achieve emission levels close to those of a natural gas-fired combined cycle plant. Installation of a spare gasifier would enable availability and capacity factors close to a conventional pulverized-coal plant. Another IGCC configuration presented in the supply-side resource options table is for a plant without the spare gasifier. The third configuration presented is for an IGCC plant with carbon capture. The carbon capture case assumes a cost of $5/MWh for carbon dioxide sequestration; this cost includes the transportation, injection, storage, and monitoring of the carbon dioxide in a local geological formation.

PacifiCorp is involved in a number of potential IGCC projects that are in various stages of development. Major project development efforts are the Energy Northwest Pacific Mountain Energy Center (PMEC) and the Wyoming Infrastructure Authority (EPAct Section 413) project.

In March 2006, PacifiCorp responded with an expression of interest to Energy Northwest's invitation to participate in the PMEC project. Energy Northwest is currently in active negotiations with the two major technology consortia for the next stage of engineering and commercial efforts (Conoco-Phillips/Fluor/Siemens and General Electric/Bechtel), and the project is now going through the Energy Facility Site Evaluation Council (EFSEC) review process. The state of Washington recently passed Senate Bill 6001—climate change legislation that, among other provisions, implements a generation $CO_2$ emission standard of 1,100 lbs of $CO_2$ per MWh (or less) or permanent sequestration which meets the same level. Energy Northwest is currently evaluating options that would allow the PMEC clean coal project to satisfy these emissions levels.

PacifiCorp was recently selected by the Wyoming Infrastructure Authority (WIA) to participate in joint project development activities for an IGCC facility in Wyoming. The ultimate goal is to develop a Section 413 project under the EPact. PacifiCorp will commission and manage feasibility studies with one or more technology suppliers/consortia for an IGCC facility at its Jim Bridger plant with some level of carbon capture. Alternate Wyoming sites may be considered. During this feasibility study stage, WIA will seek federal funding to support the next stage of development, which would include a detailed Front End Engineering Design (FEED) study.

In addition to the PMEC and Wyoming IGCC projects, PacifiCorp has also been in discussions with a number of other proposed IGCC projects. These include Summit Power's IGCC project at Clatskanie, Oregon, Mission's IGCC project at Wallula, Washington, and Xcel's IGCC project in Colorado.

Finally, PacifiCorp actively participates in the Electric Power Research Institute's CoalFleet program. CoalFleet is a major utility and technology supplier-sponsored initiative to accelerate development, demonstration, and deployment of IGCC. 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.

**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 as well as distributed generation and CHP systems which are discussed below.

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 large 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 2012.

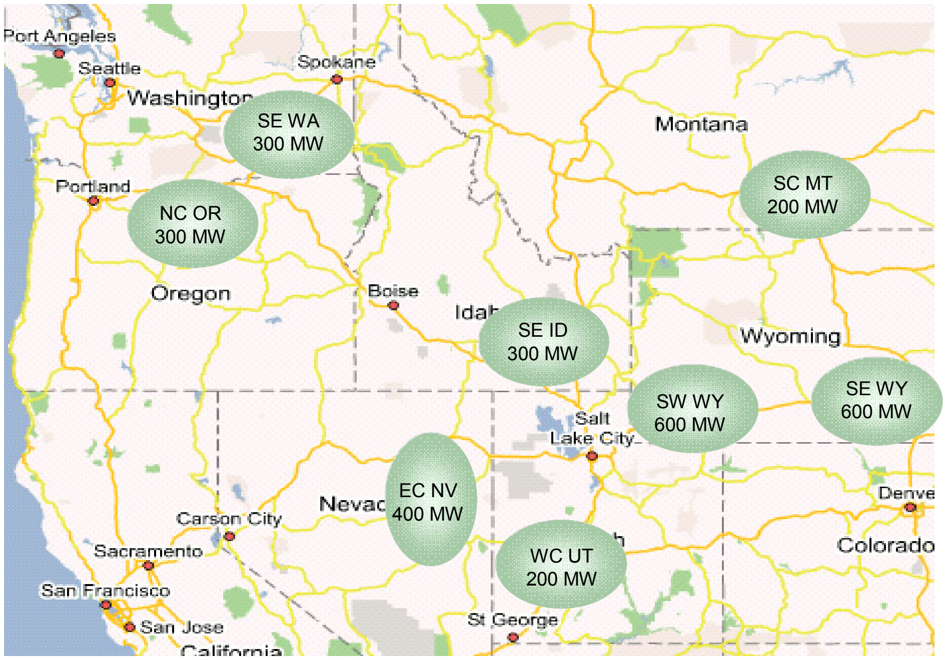
Combined cycle power plants options have been limited to 1x1 and 2x1 applications of "F" style combustion turbines and a "G" 1x1 facility. The "F" style machine options would allow an expansion of the Lake Side facility. Both the 1x1 and 2x1 configurations are included to give some flexibility to the 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. The increased cost of natural gas has slowed the building of natural gas power plants in recent years. Over the past year, natural-gas-based resources have not seen the same level of cost increases as coal-based generation resources. However, this is expected to change; the same market forces that are affecting the cost of large coal-based projects also impacts the demand for major equipment, commodities, specialty steels, shop space, and craft labor needed for the construction of natural gas based resources.

**Wind**

Wind power has experienced rapid development in the U.S., as well as the Northwest. The renewal of the investment tax credit with the Energy Policy Act of 2005 has made the availability of wind turbines an increasingly critical issue. The cost for wind turbines has increased significantly in recent months due to the demand for these machines.

The overall strategy for wind project representation was to develop a set of proxy wind sites composed of 100 nameplate megawatt blocks that could be selected as distinct resource options in the Capacity Expansion Module. (Note that the 100-megawatt size reflects a suitable average size for modeling purposes, and does not imply that acquisitions are of this size.) Figure 5.1 shows the general regions in which wind resources were assumed to be available and the quantity limits available to CEM for selection.

**Figure 5.1 – Proxy Wind Sites and Maximum Capacity Availabilities**




For other wind resource attributes, the company used multiple sources to derive attributes. PacifiCorp has been very active in purchasing wind projects in the last year. This has given the company considerable market knowledge of the current cost of wind development. Consequently, wind resources were developed primarily from PacifiCorp experiences with wind developers and from responses to the 2003 renewable resource request for proposals. 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.

For modeling purposes, it was deemed advantageous to represent wind projects as realistically as possible by capturing the fluctuation of wind generation on an hourly basis, capturing the system costs and effects of the variability, seasonality, and diurnal shape of wind generation. These attributes and the methodologies used to derive them are discussed in Appendix J.

**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.[33] Speculative risks associated with steam field development, as well as recent escalation in drilling costs, are not captured in the geothermal cost characterization. Note that at the time that PacifiCorp was deciding how to address renewable

[33] A single flash expansion study was performed for Blundell unit 3 and filed with the state commissions in March 2007. The report is available on the Utah Public Service Commissions web site at: http://www.psc.state.ut.us/elec/05docs/0503554/3-20-07Exhibit%20B.doc.

resources in the IRP models, the renewable production tax credit was in effect only through the end of 2007, and the company did not include the credit in its geothermal project economic analyses. This treatment reflects the view that year-to-year tax credit extensions do not benefit projects with long development periods typical of a new geothermal plant.

The biomass project would involve the combustion of whole trees that would be grown in a plantation setting, presumably in the Pacific Northwest. The TAG database used a western Washington site. The solar resource available in the TAG database is a solar thermal system using parabolic trough technology with natural gas backup. Such systems have been installed in the southern California desert for many years. Cost and performance of these trough systems are well known.

**Combined Heat and Power and Other Distributed Generation Alternatives**
A number of different CHP applications were developed. These options were not derived from the EPRI TAG since the license purchased from EPRI was for larger power generation applications. Costs for the CHP options listed come from a 2003 paper from the National Renewable Energy Laboratory (NREL) entitled "Gas-fired Distributed Energy Resource Technology Characterizations", and were adjusted for recent construction cost increases. CHP options include small (one megawatt or less) internal combustion engines with water jacket heat recovery, small (five megawatts or less) combustion turbines with exhaust gas heat recovery, non-combustion turbine based steam turbines (topping turbine cycle) systems to utilize process steam in industrial applications, and larger (40 to 120 megawatts) combustion turbines with significant steam based heat recovery from the flue gas. A large CHP concept has not been included in PacifiCorp's 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.

In order to derive an estimate of potential CHP capacity availability within PacifiCorp's service territory for modeling purposes, PacifiCorp surveyed its Customer Account Managers for project opportunities and reviewed existing customer account data. A list of strong CHP prospects was developed. Based on the generic CHP resource capacities used in the supply-side resource options tables, PacifiCorp determined the number of CHP resources to include as options for selection by the Capacity Expansion Module. Table 5.5 profiles these CHP options by east and west-side location.

**Table 5.5 – CHP Potential Prospects**

| Location | Strong Prospects (MW) | CHP 25 MW Unit | CHP 5 MW Unit | Total CHP Capacity Modeled (MW) |
|---|---|---|---|---|
| East | 103 | 3 units | 5 units | 100 |
| West | 66 | 2 units | 2 units | 60 |

**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. The concepts use TAG data and have been adjusted to account for current construction market conditions. Battery applications are typically smaller systems (less than 10 megawatts) which can have the most benefit in a smaller local area. 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. 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.

**Nuclear**
An emissions-free nuclear plant has been included in the supply-side resource options table. This option is based on the TAG database as well as information from a paper prepared by the Uranium Information Centre Ltd., "The Economics of Nuclear Power," April 2006. A 600 megawatt plant is characterized, utilizing advanced nuclear plant designs. Nuclear power is considered a viable option in the PacifiCorp service territory on or after 2018.

## DEMAND-SIDE RESOURCES

### <u>Resource Selection Criteria</u>

For the 2007 IRP, PacifiCorp evaluated and handled each class of DSM based on its characteristics and current availability. The company presented its proposed DSM resource representation and modeling methodology at a DSM technical workshop held on February 10, 2006, and considered public feedback in developing its final scheme. The following is a summary, by DSM class, of how the DSM options were selected for evaluation in the IRP.

**Class 1 Demand-side Management**
To address Class 1 programs (fully dispatchable or scheduled firm), the company commissioned Quantec LLC to construct proxy supply curves. (See Appendix B for the entire Quantec DSM supply curve report.) The supply curves targeted PacifiCorp's existing program expansion opportunities (e.g., air conditioning load control and irrigation load management) and new program opportunities identified as achievable. For modeling purposes, the Class 1 DSM opportunities were combined into the following five subcategories:

- **Subcategory 1** – Fully dispatchable winter programs, such as space heating
- **Subcategory 2** – Fully dispatchable summer programs, such as air conditioning, water heating, and pool pumps
- **Subcategory 3** – Fully dispatchable, large commercial and industrial, with a focus on adjustment of the heating, ventilation, and air conditioning (HVAC) equipment during the top summer hours
- **Subcategory 4** – Scheduled firm – irrigation

- **Subcategory 5** – Thermal energy storage, small commercial and industrial, with a focus on cooling systems for summer hours

**Class 2 Demand-side Management**
For Class 2 programs (non-dispatchable, firm energy efficiency programs), PacifiCorp updated and added new sample load shapes to reflect energy efficiency program opportunities in the market as identified by recent studies such as the Northwest Power Planning Council's 5th Power Plan. For example, based on its review, the company determined that residential lighting load shapes for the west and east control areas should be added. Table 5.6 lists the load shapes adopted for the 2007 IRP. Chapter 6 discusses how these sample load shapes were used to develop cost-effectiveness values of additional Class 2 resources.

Note that Class 2 DSM was not included as a resource option in portfolio modeling. The company is working to complete a more comprehensive system-wide demand-side management potential study scheduled to be completed by June 2007. This study will be used to develop modeled resource options for Classes 1, 2 and 3 for the next IRP.

**Table 5.6 – Sample Load Shapes Developed for 2007 IRP Decrement Analysis**

| East | West |
|---|---|
| commercial cooling | commercial cooling |
| commercial lighting | commercial lighting |
| residential cooling | residential cooling |
| system load | system load |
| residential lighting* | residential lighting* |
| residential – whole house (including AC)* | residential - heating* |

* New sample load shapes for the 2007 IRP

**Class 3 Demand-side Management**
For Class 3 DSM (price responsive programs), PacifiCorp commissioned Quantec to develop proxy supply curves for three Class 3 program concepts: curtailable rates, critical peak pricing, and demand buyback/bidding (DBB) products (See Appendix B). As with the Class 1 DSM resources, the company obtained and considered public feedback from its February 2006 DSM workshop in selecting these Class 3 DSM resources for the IRP.

**Class 4 Demand-side Management**
Class 4 resources are sought by the company. However, these resources are not currently taken into consideration within the 2007 IRP because they cannot be relied upon for planning purposes or cannot be easily quantified. Over time, most Class 4 DSM savings manifest themselves within the company's loads and load forecasts.

## Resource Options and Attributes

**Class 1 Demand-side Management**
Tables 5.7 and 5.8 summarize the key attributes for the five DSM Class 1 program subcategories listed above for the west and east control areas respectively. Appendix B provides more information on how the attributes were derived. Attributes are provided for three scenarios: low, base,

and high achievable potential. These scenarios reflect PacifiCorp assumed on-peak electricity market prices of $40/MWh, $60/MWh, and $100/MWh respectively, as well as incrementally higher PacifiCorp marketing efforts, program costs, and customer participation levels. As already noted, Quantec developed these attributes for creation of PacifiCorp DSM resources for portfolio modeling.[34] The sources for the DSM attributes are Figures B.20 and B.21 in Appendix B, reflecting the "no metering" cost assumptions (Also see the "Treatment of Metering Cost" section in Appendix B.)

.

**Table 5.7 – Class 1 DSM Program Attributes, West Control Area**

| Attributes | Fully Dispatchable-Winter | Fully Dispatchable - Summer | Fully Dispatchable - Large C&I | Scheduled Firm - Irrigation | Thermal Energy Storage |
|---|---|---|---|---|---|
| **Variable Costs ($/MWh)** | $ - | $ - | $ - | $ - | $ - |
| **Demand Reduction Period (Hours)** | 2 | 2 | 4 | 6 | 6 |
| **Start Year** | 2009 | 2009 | 2009 | 2009 | 2009 |
| **BASE** | | | | | |
| **Total Achievable Potential –Maximum (MW)** | 21 | 8 | 1 | 32 | 3 |
| **Resource Costs ($/kW/yr)** | $ 75 | $ 57 | $ 89 | $ 28 | $ 119 |
| **LOW** | | | | | |
| **Total Achievable Potential --Maximum (MW)** | 11 | 2 | 0 | 26 | 3 |
| **Resource Costs ($/kW/yr)** | $ 57 | $ 60 | $ 185 | $ 29 | $ 116 |
| **HIGH** | | | | | |
| **Total Achievable Potential --Maximum (MW)** | 32 | 10 | 3 | 38 | 4 |
| **Resource Costs ($/kW/yr)** | $ 83 | $ 69 | $ 104 | $ 37 | $ 121 |
| **Hours Available by Month** | | | | | |
| **January** | 3 | - | - | - | - |
| **February** | - | - | - | - | - |
| **March** | - | - | - | - | - |
| **April** | - | - | - | - | 240 |
| **May** | - | - | - | - | 186 |
| **June** | - | 8 | 8 | 96 | 180 |
| **July** | - | 46 | 46 | 96 | 186 |
| **August** | - | 33 | 33 | 96 | 186 |
| **September** | - | - | - | 48 | 180 |
| **October** | - | - | - | - | 279 |
| **November** | - | - | - | - | - |
| **December** | 84 | - | - | - | - |

[34] Quantec's DSM resource attributes were considered interim information needed to complete the 2007 IRP while the company works to complete a more comprehensive system-wide demand-side management potential study scheduled to be completed by June 2007.

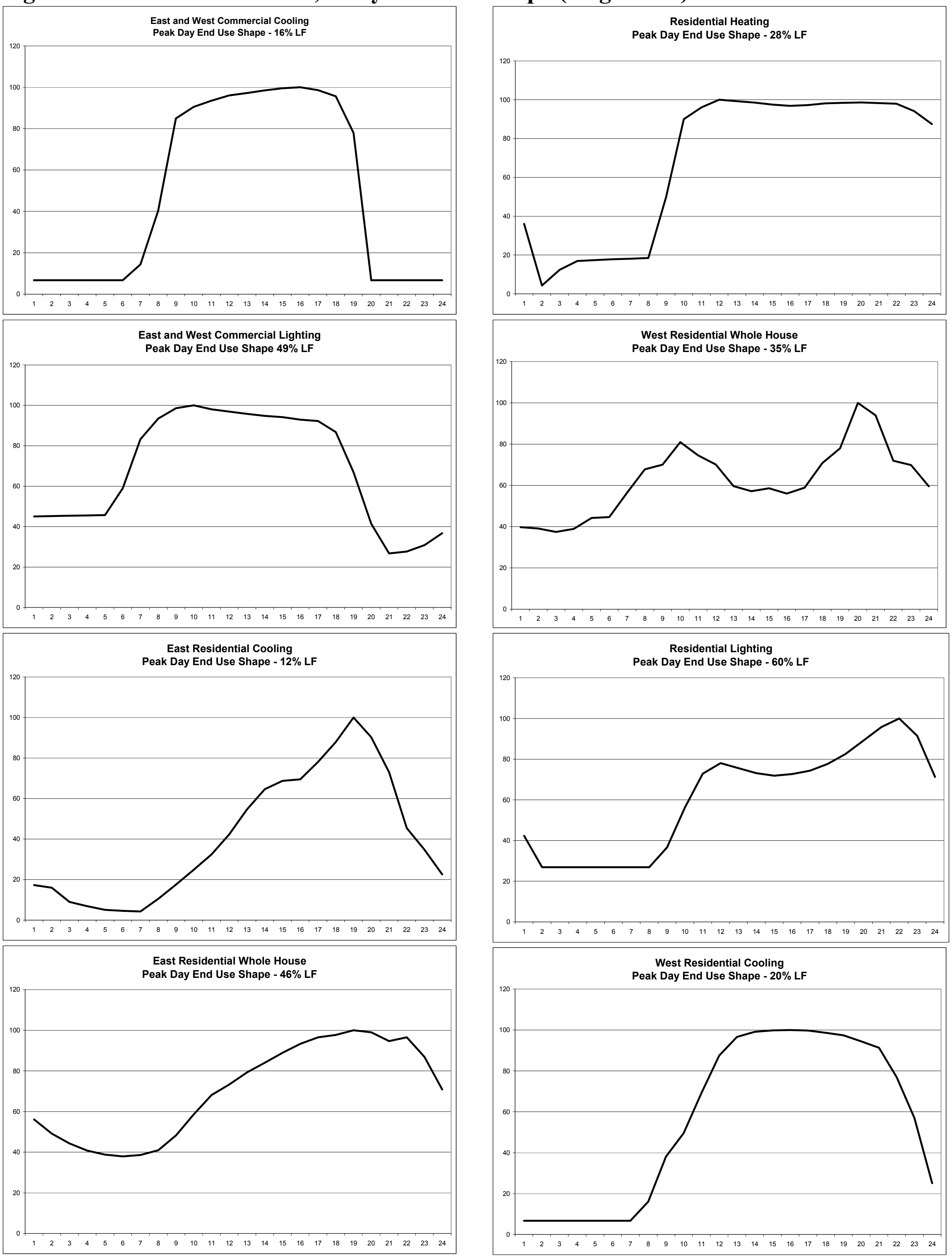
**Table 5.8 – Class 1 DSM Program Attributes, East Control Area**

| Attributes | Fully Dis-patchable-Winter | Fully Dis-patchable - Summer | Fully Dispatch-able - Large C&I | Scheduled Firm - Irri-gation | Thermal Energy Storage |
|---|---|---|---|---|---|
| Variable Costs ($/MWh) | $ - | $ - | $ - | $ - | $ - |
| Demand Reduction Period (Hours) | 2 | 2 | 4 | 6 | 6 |
| Start Year | 2009 | 2009 | 2009 | 2009 | 2009 |
| **BASE** | | | | | |
| Total Achievable Potential –Maximum (MW) | 16 | 48 | 2 | 15 | 6 |
| Resource Costs ($/kW/yr) | $ 75 | $ 58 | $ 82 | $ 27 | $ 117 |
| **LOW** | | | | | |
| Total Achievable Potential --Maximum (MW) | 8 | 13 | 0 | 3 | 4 |
| Resource Costs ($/kW/yr) | $ 57 | $ 52 | $ 159 | $ 28 | $ 115 |
| **HIGH** | | | | | |
| Total Achievable Potential --Maximum (MW) | 25 | 66 | 7 | 28 | 7 |
| Resource Costs ($/kW/yr) | $ 83 | $ 71 | $ 101 | $ 36 | $ 118 |
| **Hours Available by Month** | | | | | |
| January | 3 | - | - | - | - |
| February | - | - | - | - | - |
| March | - | - | - | - | - |
| April | - | - | - | - | 240 |
| May | - | - | - | - | 186 |
| June | - | 8 | 8 | 96 | 180 |
| July | - | 46 | 46 | 96 | 186 |
| August | - | 33 | 33 | 96 | 186 |
| September | - | - | - | 48 | 180 |
| October | - | - | - | - | 279 |
| November | - | - | - | - | - |
| December | 84 | - | - | - | - |

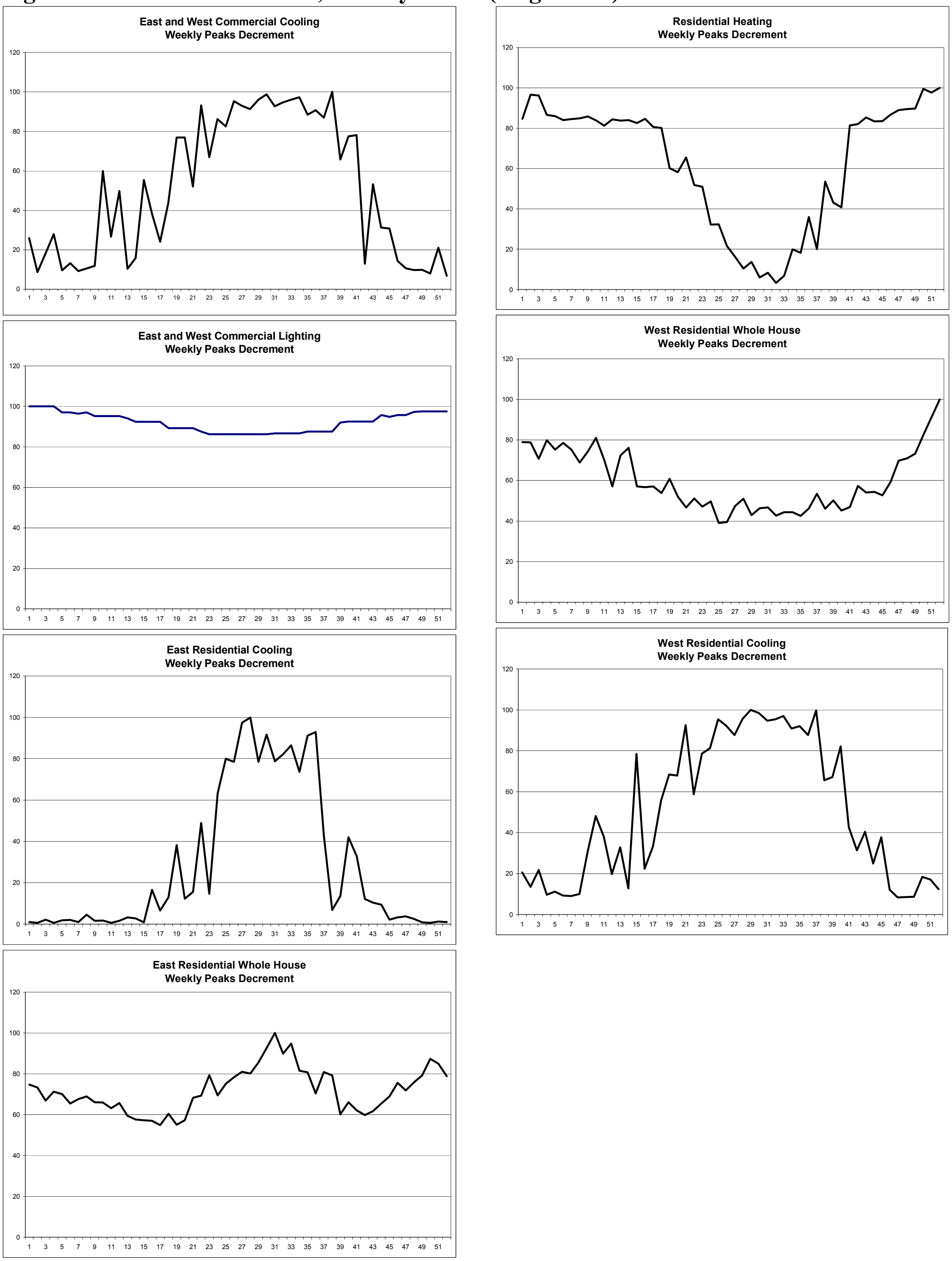
## Class 2 Demand-side Management

Figures 5.2 and 5.3 show the hourly end use shapes used for the Class 2 DSM decrement analysis. Figure 5.2 plots the hourly end use shapes for the peak day use for each of the 10 end uses. Figure 5.3 illustrates the seasonality of the end uses by plotting peak demand for each week. The east residential cooling shape was derived from an in-house metering study. All other shapes are composites of end use patterns from the Northwest Power Planning and Conservation Council. The megawatt scale on the y–axis of Figures 5.2 and 5.3 is for illustration purposes only and does not represent the market potential or planning estimates of any particular program for a given end use. For example, the commercial cooling shape was created from system specific weighting of hospital, school, office, lodging, and service cooling end use shapes.

## Figure 5.2 – DSM Decrement, Daily End Use Shape (megawatts)



## Figure 5.3 – DSM Decrement, Weekly Peaks (megawatts)[35]




[35] Weekly residential lighting peaks are constant throughout the year, though the daily timing of the peak can vary with the season.

### Class 3 Demand-side Management

Tables 5.9 and 5.10 summarize the key attributes for three DSM Class 3 program subcategories (curtailable rates, critical peak pricing and demand buyback) for the west and east control area respectively. Attributes are provided for three scenarios: low, base, and high achievable potential. These scenarios reflect PacifiCorp assumed on-peak electricity market prices of $40/MWh, $60/MWh, and $100/MWh respectively, as well as incrementally higher marketing efforts, program costs, and customer participation levels. Appendix B provides more information on how the Class 3 DSM attributes were derived.

**Table 5.9 – Class 3 DSM Program Attributes, West Control Area**

| Attributes | Curtailable Rates | Critical Peak Pricing | Demand Buyback |
|---|---|---|---|
| **Variable Costs ($/MWh)** | $ - | $ - | Market Prices |
| **Demand Reduction Period (Hours)** | 4 | 4 | 10 |
| **Start Year** | 2009 | 2009 | 2009 |
| **BASE** | | | |
| **Total Achievable Potential -- Maximum (MW)** | 21 | 3 | 8 |
| **Resource Costs ($/kW/yr)** | $ 50 | $ 56 | $ 14 |
| **LOW** | | | |
| **Total Achievable Potential -- Maximum (MW)** | 9 | 0 | 3 |
| **Resource Costs ($/kW/yr)** | $ 39 | $ 136 | $ 14 |
| **HIGH** | | | |
| **Total Achievable Potential -- Maximum (MW)** | 26 | 5 | 18 |
| **Resource Costs ($/kW/yr)** | $ 86 | $ 48 | $ 19 |
| **Hours Available by Month** | | | |
| **January** | - | - | - |
| **February** | - | - | - |
| **March** | - | - | - |
| **April** | - | - | - |
| **May** | - | - | - |
| **June** | - | - | - |
| **July** | 69 | 69 | 129 |
| **August** | 18 | 18 | 46 |
| **September** | - | - | - |
| **October** | - | - | - |
| **November** | - | - | - |
| **December** | - | - | - |

**Table 5.10 – Class 3 DSM Program Attributes, East Control Area**

| Attributes | Curtailable Rates | Critical Peak Pricing | Demand Buyback |
|---|---|---|---|
| Variable Costs ($/MWh) | $ - | $ - | Market Prices |
| Demand Reduction Period (Hours) | 4 | 4 | 10 |
| Start Year | 2009 | 2009 | 2009 |
| **BASE** | | | |
| Total Achievable Potential -- Maximum (MW) | 51 | 5 | 19 |
| Resource Costs ($/kW/yr) | $ 50 | $ 40 | $ 14 |
| **LOW** | | | |
| Total Achievable Potential -- Maximum (MW) | 22 | 1 | 6 |
| Resource Costs ($/kW/yr) | $ 38 | $ 89 | $ 13 |
| **HIGH** | | | |
| Total Achievable Potential -- Maximum (MW) | 63 | 9 | 46 |
| Resource Costs ($/kW/yr) | $ 86 | $ 36 | $ 18 |
| **Hours Available by Month** | | | |
| January | - | - | - |
| February | - | - | - |
| March | - | - | - |
| April | - | - | - |
| May | - | - | - |
| June | - | - | - |
| July | 69 | 69 | 129 |
| August | 18 | 18 | 46 |
| September | - | - | - |
| October | - | - | - |
| November | - | - | - |
| December | - | - | - |

## Resource Descriptions

### Class 1 Demand-side Management

Class 1 programs are divided into two types: fully-dispatchable and scheduled-firm. Often referred to as direct load control (DLC), fully-dispatchable programs are designed to reduce the demand during peak periods by turning off equipment or limiting the "cycle" time (i.e., frequency and duration of periods when the equipment is in operation) during system peak. The offerings for the residential sector are seasonally divided, while the potential with large commercial and industrial customers typically focus on summer cooling loads only. PacifiCorp's fully-dispatchable resource options are as follows:

- **Winter –** Direct load control of water and space heating during winter are the program options considered in this class. This program would be dispatched during the morning and evening peak hours. The largest potential for such a program will be in the west control area because of the higher saturation of electric space and water heating. Incentives are generally paid on a monthly basis. Although there are no large scale DLC programs in the Northwest, Portland General Electric (PGE) and Puget Sound Energy (PSE) have both studied implementation through pilot programs. Nationally, there are many utilities with space and/or water heating controls, including Duke Power, Wisconsin Power and Light, Great River Energy, and Alliant Energy.

- **Summer –** The main demand reduction (DR) product in this group is direct load control of air-conditioning units, which are typically dispatched during the hottest summer days, and are common place due to the relatively high summer loads in warm climates. PacifiCorp currently pays monthly incentives to residential and small commercial participants in Utah's Cool Keeper AC Load Control program. There is approximately 130 megawatts of connected load for this program, which is expected to increase to 180 megawatt by summer 2007. Using a 50% cycling dispatch strategy, approximately half can be expected during an event. In addition to those utilities listed above, Nevada Power, Florida Power and Light, Alliant Energy, MidAmerican Energy and the major utilities in California run air conditioner direct load control programs (e.g., Sacramento Municipal Utility District and San Diego Gas and Electric).

- **Large Commercial and Industrial –** Direct control of large commercial and industrial (C&I) customers requires coordination with the existing energy management systems (EMS). The focus of this program type is adjustment of the HVAC equipment during the top summer hours. Incentives are generally paid on a per-kW or per-ton (of cooling equipment) basis. Some utilities running comparable programs include Florida Light & Power, Hawaiian Electric, and Southern California Edison.

Scheduled-firm program strategies are those that provide consistent reductions during pre-specified hours, and target customers with usage patterns and technology that allow scheduled shifting of consumption from peak to off-peak periods. These program strategies include the following:

- **Irrigation Pumping –** Irrigation load control is a candidate for summer DR due to the relatively low load factor (approximately 30%) of pumping equipment and the coincidence of these loads with system summer peak. Through PacifiCorp's irrigation load control program, customers subscribe in advance for specific days and hours when their irrigation systems will be turned off. Load curtailment is executed automatically based on a pre-determined schedule through a timer device. Although a total of 100 megawatts is contracted with this program, only half is available due to the alternating schedules of program participants. In the Northwest, Bonneville Power Authority (BPA) has run a pilot irrigation program (on a dispatch, rather than scheduled, basis) and Idaho Power has a program similar to that of PacifiCorp.

- **Thermal Energy Storage –** For small commercial and industrial customers, it is possible to have thermal energy storage (TES) cooling systems that produce ice during off-peak periods, which is then used during the on-peak period to cool the building. The system is programmed to use ice-cooling during pre-specified times (typically six hours per day, from April to October) and participants are given incentives on a per-kW or per-ton-of-cooling basis.

**Class 2 Demand-side Management**
Class 2 DSM programs are not modeled in the 2007 IRP as resource options; rather, these are handled as a decrement to the load forecast. Appendix A provides descriptions of PacifiCorp's current Class 2 programs.

**Class 3 Demand-side Management**
Curtailable rate options have been offered by many utilities in the United States for many years. These programs are designed to ease system peak by requiring that customers shed load by a set amount or to a set level (such as by turning off equipment or relying more heavily on on-site generation) when requested by the utility. Participants are either provided with a fixed rate discount or variable incentives, depending on load reduction; penalties are often levied for participants who do not respond to curtailment events. Large commercial and industrial customers are the target market for those programs that address PacifiCorp's summer system peak. Many utilities provide a broad range of program options, including Duke Power, Georgia Power, Dominion Virginia Power, Pacific Gas and Electric, Consolidated Edison, Southern California Edison, MidAmerican Energy Company, and Wisconsin Power and Light.

Critical peak pricing (CPP) rates only take effect a limited number of times during the year. In times of emergency or high market prices, the utility can invoke a critical peak event, where customers are notified and rates become much higher than normal, encouraging customers to shed or shift load. Typically, the CPP rate is bundled with a time-of-use rate schedule, whereby customers are given a lower off-peak rate as an incentive to participate in the program. Customers in all customer classes (residential, commercial, and industrial) may choose to participate in a CPP program, although there are certain segments in the commercial sector that are less able to react to critical peak pricing signals. Currently, there are no CPP programs being offered by Northwest utilities. Peak pricing is, however, being offered through experimental pilots or full-scale programs by several organizations in the United States, notably Southern Company (Georgia Power), Gulf Power, Niagara Mohawk, California utilities (SCE, PG&E, SDG&E), PJM Interconnection, and New York ISO (NYISO). Adoption of CPP has not been as widespread in the Western states as they have in the East. In the Pacific Northwest, this may be partly explained by the generally milder climate and the fact that, due mainly to large hydroelectric resources, energy, rather than capacity, tends to be the constraining factor.

Demand buyback/bidding (DBB) products are designed to encourage customers to curtail loads during system emergencies or high price periods. Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for the energy reduced during each event, based primarily on the difference between market prices and the utility rates. Since 2001, all major investor-owned utilities in the Northwest and Bonneville Power Administration have offered variants of this option. PacifiCorp's current program, Energy Exchange, was used extensively during 2001 and resulted in maximum reduction of slightly over 40 megawatts in that period. Demand reductions from PacifiCorp's current program are approximately 1 megawatt. Demand buyback products are common in the United States and are being offered by many major utilities. The use of DBB offerings as a means of mitigating price volatility in power markets is especially common among independent system operators including CAISO, NYISO, PJM, and ISO-NE. However, DBB options are not currently being exercised regularly due to relatively low power prices.

## TRANSMISSION RESOURCES

### Resource Selection Criteria

PacifiCorp developed its transmission resource options to support new generation options included in the IRP models, to enhance transfer capacity and reliability across PacifiCorp's system, and to boost import/export capability with respect to external markets. These options included transmission projects targeted for investigation as part of the MEHC acquisition commitments. (See Chapter 2, "MidAmerican Energy Holdings Company IRP Commitments.")

### Resource Options and Attributes

Transmission options developed for portfolio analysis are shown in Table 5.11.[36] The column labeled "Point A" indicates one end of the transmission path, and "Point B" the other end. The maximum capacity associated with moving generation from one end to the other is shown in the subsequent columns. For resource optimization modeling, the CEM was allowed to phase in transmission purchases in 500 megawatts blocks as needed for four of the transmission paths: Bridger East-Ben Lomond (4); Mona-Utah North (5); Wyoming-Bridger East (8); and Utah North-West Main (9). Included in all portfolios is the MidAmerican Energy Holdings Company commitment (34a) for the 300 megawatt Path C upgrade assumed to be available in 2010. The transmission options as represented in the model topology are shown in Figure 5.4.

**Table 5.11 – Transmission Options**

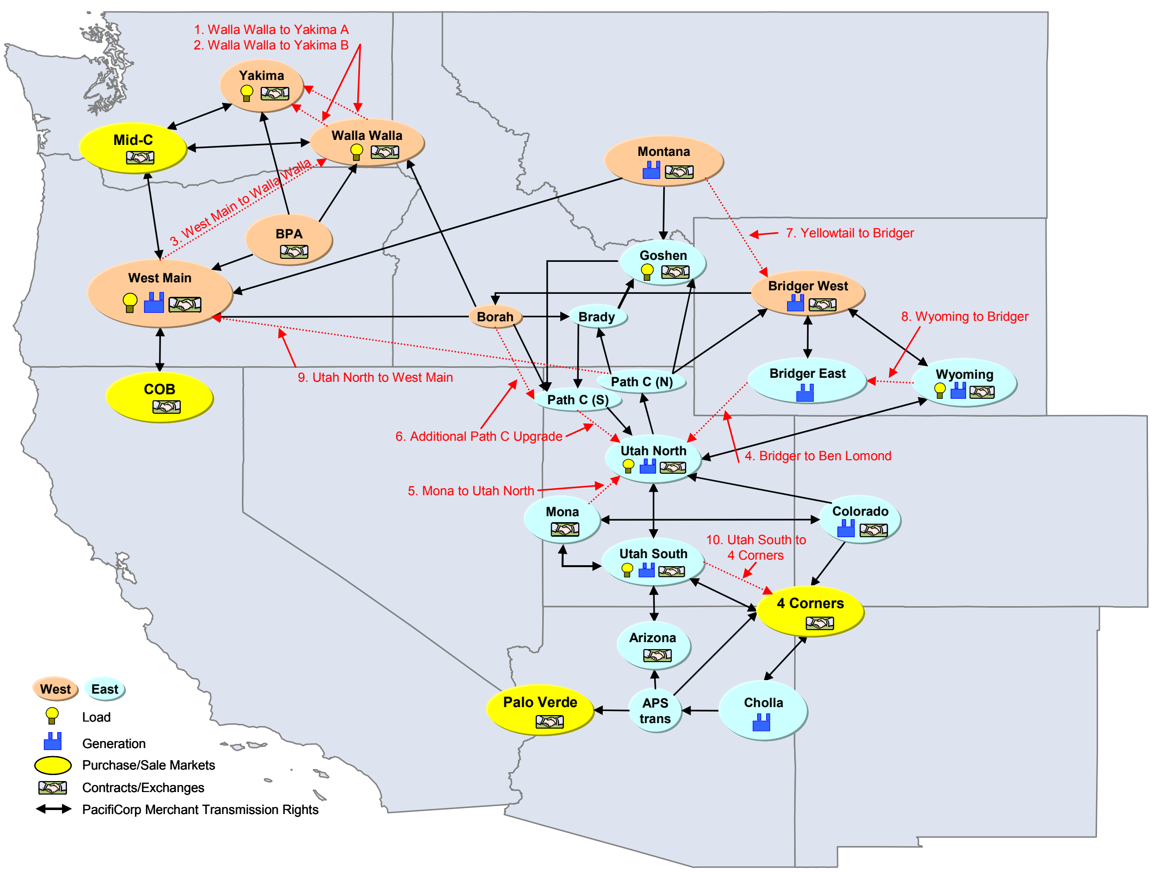
| No. | Point A | Point B | A to B Capacity (MW) | B to A Capacity (MW) | First Year Available | Number of Additions |
|---|---|---|---|---|---|---|
| 1 | Walla Walla | Yakima A | 630 | 0 | 2010 | 1 |
| 2 | Walla Walla | Yakima B | 400 | 400 | 2010 | 1 |
| 3 | West Main | Walla Walla | 630 | 0 | 2010 | 1 |
| 4 | Jim Bridger East | Ben Lomond | 500 | 0 | 2012 | 4 |
| 5 | Mona | Utah North | 500 | 0 | 2012 | 2 |
| 6 | Path C – South | Utah North | 600 | 0 | 2011 | 1 |
| 7 | Yellowtail | Jim Bridger | 400 | 0 | 2011 | 1 |
| 8 | Wyoming | Jim Bridger East | 500 | 500 | 2012 | 3 |
| 9 | Utah North | West Main | 500 | 500 | 2012 | 6 |
| 10 | Utah South | Desert Southwest (includes Mona-Oquirrh) | 600 | 600 | 2012 | 1 |
| **Base Transmission Assumptions – For All Portfolios** | | | | | | |
| 11 | Path C – South | Utah North | 300 | 0 | 2010 | 1 |
| 12 | Craig-Hayden | Park City | 176 | 0 | 2010 | 1 |

[36] The 2007 integrated resource plan used proxy transmission additions for portfolio planning purposes. The timing and cost of these proxy additions are based on high level planning estimates which are subject to change as more information becomes available. The company may address specific transmission needs by entering into new wheeling contracts, building additional facilities, or participating in joint transmission projects.

Transmission requirements associated specifically with wind resources located in southwest Wyoming, southeast Wyoming, and eastern Nevada were not modeled as transmission paths within the CEM. The transmission costs associated with those resources were included in the capital costs of the wind resources themselves, with the generation modeled as occurring (as delivered) in Utah North for the southwest Wyoming wind; Jim Bridger East for the southeastern Wyoming wind; and Utah South for the eastern Nevada wind.

In addition to these resource options, PacifiCorp also modeled a regional transmission project for sensitivity analysis using the Capacity Expansion Module. This resource serves as a proxy for projects like the proposed Frontier Project that links generation in Wyoming with load centers in Utah, Nevada and California. See Chapter 6, "Scenario and Sensitivity Study Development", for more details on how this regional transmission resource was modeled.

**Figure 5.4 – Transmission Options Topology**




## MARKET PURCHASES

### Resource 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 expected to be made on an annual forward basis to help the company cover short positions.

For this IRP, PacifiCorp tested portfolios that included a limit of 1,200 megawatts of front office transactions beyond 2011. Table 5.12 shows the maximum capacity available for the four market hubs in cases where front office transactions limits were applied.

**Table 5.12 – Maximum Available Front Office Transaction Quantities by Market Hub**

| Market Hub | Maximum Available Capacity (MW) |
|---|---|
| West Main | 250 |
| Mid Columbia | 250 |
| Four Corners | 500 |
| Mona | 200 |
| **TOTAL** | **1,200** |

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.

**Resource Options and Attributes**

Two front office transaction types were included for portfolio analysis: a west-side annual flat product, and an east-side heavy load hour (HLH) 3rd quarter product. The west-side transaction reflects purchases of flat annual energy—a constant delivery rate over all the hours of a year—delivered to the West Main bubble.[37] The east-side transactions are represented as heavy load hour (16 hours per day, 6 days per week) purchases from July through September available for delivery at both the Mona and Four Corners market hubs. 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 megawatt front office transaction is treated as a 112 megawatt contribution to meeting 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—Mid-Columbia (Mid-C), Mona, and Four Corners—and are set to the relevant forward market prices for the relevant time period and location.

[37] A bubble refers to a distinct area of a system model's network topology encompassing one or a combination of the following attributes: load, generation, markets (purchases and sales), and transmission facilities. A bubble is also referred to as a transmission area.

## Resource Description

As proxy resources, front office transactions represent a range of purchase transaction types. They are usually standard products, such as heavy load hour (HLH), light load hour (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.

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.

## Proposed Use and Impact of Physical and Financial Hedging

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. The purpose of these transactions is to 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 proposes to continue to hedge its electricity and natural gas fixed-price exposure using both physical products and financial products. Both products are effective in hedging this exposure.

# 6. MODELING AND RISK ANALYSIS APPROACH

**Chapter Highlights**

- The IRP modeling effort seeks to determine the comparative cost, risk, supply reliability, and emissions attributes of resource portfolios.

- The 2007 IRP modeling effort consisted of three phases: (1) resource screening using the company's capacity expansion optimization tool (the Capacity Expansion Module, or CEM), (2) risk analysis portfolio development, and (3) detailed probabilistic (stochastic) production cost simulation and resource risk analysis.

- For resource screening, PacifiCorp defined 16 alternative future scenarios and associated sensitivity studies with the assistance of public stakeholders. These alternative futures test wide variations in potential $CO_2$ regulatory costs, natural gas prices, wholesale electricity prices, retail load growth, and the scope of renewable portfolio standards.

- In addition, the company defined futures to evaluate the availability of renewable production tax credits and the level of achievable market potential for load control and demand-response programs.

- PacifiCorp next defined risk analysis portfolios for stochastic simulation. The CEM was used to help build fixed resource investment schedules for wind and distributed resources, and to optimize the selection of other resource options according to specific resource strategies.

- PacifiCorp devoted considerable effort to model the effect of $CO_2$ emission compliance strategies. All risk analysis portfolios were simulated with five $CO_2$ adder levels—$0/ton, $8/ton, $15/ton, $38/ton, and $61/ton (in 2008 dollars)—and associated forward gas/electricity price forecasts. The company modeled both a cap-and-trade and emissions tax compliance strategy, and expanded its reporting of $CO_2$ emissions impacts.

- Portfolio performance was assessed with the following measures: (1) stochastic mean cost (Present Value of Revenue Requirements), (2) customer rate impact, measured as the levelized net present value of the change in the system average customer price due to new resources for 2008 through 2026, (3) emissions externality cost, (4) capital cost, (5) risk exposure, (6) $CO_2$ and other emissions, (7) and supply reliability statistics.

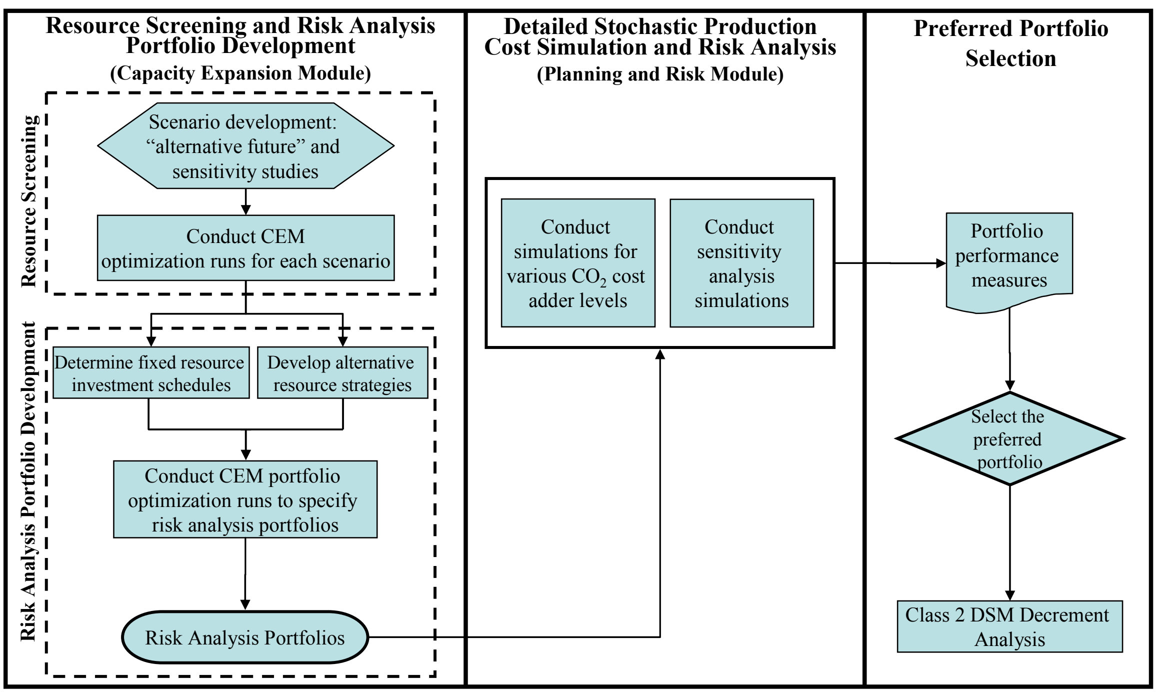
- The preferred portfolio is selected from among the risk analysis portfolios primarily on the basis of relative cost-effectiveness, customer rate impact, and cost/risk balance across the $CO_2$ adder levels.

## INTRODUCTION

The IRP modeling effort seeks to determine the comparative cost, risk, reliability, and pollutant emissions attributes of resource portfolios. These portfolio attributes form the basis of an overall 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 7, was used to help determine PacifiCorp's preferred portfolio.

The 2007 IRP modeling effort consists of three phases: (1) resource screening, (2) risk analysis portfolio development, and (3) detailed production cost and stochastic risk analysis. The Capacity Expansion Module (CEM) supports resource screening and development of risk analysis portfolios. Detailed production cost simulation and associated stochastic analysis, which attempts to quantify the most significant sources of portfolio risk, are supported by the Planning and Risk (PaR) Module. Figure 6.1 characterizes the three phases in flow chart form, showing the main steps involved and how these phases are linked with the preferred portfolio selection phase (far right on the chart). This chapter covers each of these steps.

**Figure 6.1 – Modeling and Risk Analysis Process**




## RESOURCE SCREENING

For resource screening, PacifiCorp evaluated generation, demand-side management, market purchase, and transmission resources on a comparable basis using the Capacity Expansion Module. The CEM performs a deterministic least-cost optimization with these resources over the twenty-year study horizon. To support resource screening, the company developed a set of "alternative future" scenarios to study. These scenarios consist of combinations of input variables representing the primary sources of portfolio cost uncertainty. Additional sensitivity analysis scenarios were also developed to investigate the individual effects of certain planning and resource-specific assumptions.

The main objectives of this screening effort include the following:

- Determine and study resource selection choices given different assumptions about the future
- Determine the range of resource quantities selected for alternative future scenarios designed to favor one or more resource types over others.
- Identify the frequency of resources selected across the alternative futures modeled.
- Determine acquisition patterns (quantities and timing) for smaller-scale resource types—front office transactions, wind, DSM programs, and Combined Heat and Power facilities—to be incorporated into the risk analysis portfolios based on an aggregate view of the alternative future modeling results.

**Alternative Future Scenarios**

The alternative future scenarios consist of cases to test the impact of variations in load growth as well as combinations of several variable values that simulate conditions variously favorable and unfavorable to the major resource types (coal, gas, renewables, and DSM). The input variables chosen to represent the alternative futures consist of the following:

- Incremental coal cost, consisting of new $CO_2$ regulatory costs (via a dollar-per-ton $CO_2$ adder) and alternative commodity price trends driven by assumptions on coal production and transportation costs.
- Natural gas and wholesale electricity prices, based on PacifiCorp's forward price curves
- Retail load growth
- The level of renewable electricity generation requirements stemming from renewable portfolio standard (RPS) regulations
- The availability of renewable energy Production Tax Credits (PTCs) after 2007
- The potential for demand-side management programs, defined as a program's achievable market potential adjusted to account for competition with existing programs

PacifiCorp developed low, medium, and high values for each of these input variables to ensure that a reasonably wide range in potential outcomes is captured. The one exception is for renewable PTC availability, which was structured as a yes-or-no outcome.

Table 6.1 profiles the 16 alternative future scenarios developed, indicating the assigned variable value levels for each of the six input variables. Note that alternative future scenarios are labeled with the acronym "CAF", which stands for CEM alternative future. The CAF studies include a business-as-usual case reflecting no new regulatory requirements (CAF00) and a medium case based on the company's official load forecast and forward price curves (CAF11, "medium load growth"). All CAF scenarios assume a 15-percent planning reserve margin.

**Table 6.1 – Alternative Future Scenarios**

| CAF # | Name | Coal Cost: $CO_2$ Adder/Coal Commodity Price | Gas/ Electric Price | Load Growth | Renewable Sales Percentage due to RPS | Renewable PTC Availability | DSM Potential |
|---|---|---|---|---|---|---|---|
| 0 | Business As Usual | None/Medium | Medium | Medium | Low | Yes | Medium |
| 1 | Low Cost Coal/High Cost Gas | None/Low | High | Medium | Medium | Yes | Medium |
| 2 | with Low Load Growth | None/Low | High | Low | Medium | Yes | Medium |
| 3 | with High Load Growth | None/Low | High | High | Medium | Yes | Medium |
| 4 | High Cost Coal/Low Cost Gas | High/High | Low | Medium | Medium | Yes | Medium |
| 5 | with Low Load Growth | High/High | Low | Low | Medium | Yes | Medium |
| 6 | with High Load Growth | High/High | Low | High | Medium | Yes | Medium |
| 7 | Favorable Wind Environment | High/Medium | High | Medium | High | Yes | Medium |
| 8 | Unfavorable Wind Environment | None/Medium | Low | Medium | Low | No | Medium |
| 9 | High DSM Potential | High/Medium | High | Medium | Medium | Yes | High |
| 10 | Low DSM Potential | None/Medium | Low | Medium | Medium | Yes | Low |
| 11 | Medium Load Growth | Medium/Medium | Medium | Medium | Medium | Yes | Medium |
| 12 | Low Load Growth | Medium/Medium | Medium | Low | Medium | Yes | Medium |
| 13 | High Load Growth | Medium/Medium | Medium | High | Medium | Yes | Medium |
| 14 | Low Cost Portfolio Bookend | None/Low | Low | Low | Medium | Yes | Medium |
| 15 | High Cost Portfolio Bookend | High/High | High | High | Medium | No | Medium |

| Variable Value Frequency Counts (Excluding "Business As Usual" Scenario) | | | | | | |
|---|---|---|---|---|---|---|
| "High" Count | 6/4 | 6 | 4 | 1 | N/A | 1 |
| "Medium" Count | 3/7 | 3 | 7 | 13 | N/A | 13 |
| "Low" and "None" Count | 6/4 | 6 | 4 | 1 | N/A | 1 |
| TOTALS | 15/15 | 15 | 15 | 15 | N/A | 15 |

In developing these scenarios as well as other CEM studies, PacifiCorp relied heavily on feedback from public stakeholders. An important design criterion was to ensure that the scenarios, in aggregate, were not biased towards certain resource outcomes. As indicated at the bottom of Table 6.1, the number of scenarios with low and high values for an input variable is the same. Another design criterion was to construct them so as to enable straightforward comparisons with respect to changes in variables, particularly load growth.

Table 6.2 summarizes the values and data sources for the input variables with low, medium, and high values. Additional details for each input variable follow.

**Table 6.2 – Scenario Input Variable Values and Sources**

| Input Variable | Low Value | Medium Value | High Value |
|---|---|---|---|
| **$CO_2$ Cost Adder** | None | $8/ton in 2008 dollars, beginning in 2010 with costs phased in at 50%, escalating to 75% in 2011 and 100% in 2012 | $37.9/ton in 2008 dollars ($25/ton in 1990 dollars), beginning in 2010 with costs phased in at 50%, escalating to 75% in 2011 and 100% in 2012 |
| **Coal Commodity Prices for New Resources** | 12% lower than the PacifiCorp Fuels Marketing & Supply Group price forecast by 2026 | PacifiCorp Fuels Marketing & Supply Dept. price forecast | 20% higher than the PacifiCorp Fuels Marketing & Supply Group price forecasts by 2026 |
| **Natural Gas Prices** | 32% lower than the PacifiCorp official forward prices (dated August 3, 2006), on an average annual basis for 2007 through 2016 | PacifiCorp official forward prices, dated August 31, 2006; Incorporates PIRA Energy's August 3, 2006 probabilistic-weighted long-term gas forecast | 86% higher than the PacifiCorp official forward prices (dated August 3, 2006), on an average annual basis for 2007 through 2016 |
| **Wholesale Electricity Prices** | 14% lower than the PacifiCorp official forward prices, dated August 31, 2006, on an average annual basis for 2007 through 2016; low values reflect a $0/ton $CO_2$ adder and the PIRA low Gas price forecast case | PacifiCorp official forward prices, dated August 31, 2006 | 25% higher than the PacifiCorp official forward prices, dated August 31, 2006, on an average annual basis for 2007 through 2016; high values reflect a $37.7/ton $CO_2$ adder and the PIRA high gas price forecast case |
| **Retail Load Growth** | Average annual system-wide load growth of 0.6% for 2007 through 2026 | Average annual system-wide load growth of 2.0% for 2007 through 2026 (PacifiCorp long term load forecast, May 1, 2006) | Average annual system-wide load growth of 3.6% for 2007 through 2026 |
| **Renewable Portfolio Standards** | 3% of system-wide retail load by 2020 | 6% of system-wide retail load by 2020 (Assumes California, Washington, and Oregon RPS targets in place) | 15% of system-wide retail load by 2020 (Assumes RPS targets in place in all states) |
| **Class 1 and Class 3 DSM Achievable Potential** | Starting in 2009:<br>● 69 MW of Class 1 programs<br>● 40 MW of Class 3 programs | Starting in 2009:<br>● 153 MW of Class 1 programs<br>● 106 MW of Class 3 programs | Starting in 2009:<br>● 219 MW of Class 1 programs<br>● 166 MW of Class 3 programs |

## Carbon Dioxide Regulation Cost

For the $CO_2$ regulation cost, PacifiCorp sought public comments and recommendations on a suitable cost adder for its high scenario value. At the IRP public meeting held on June 7, 2006, PacifiCorp proposed $25/ton and $40/ton adders (in 1990 dollars). Meeting participants accepted the $25/ton level ($38/ton in 2008 dollars) as appropriate for reflecting the threshold at which a significant shift in resource selection would occur based on regulatory costs.

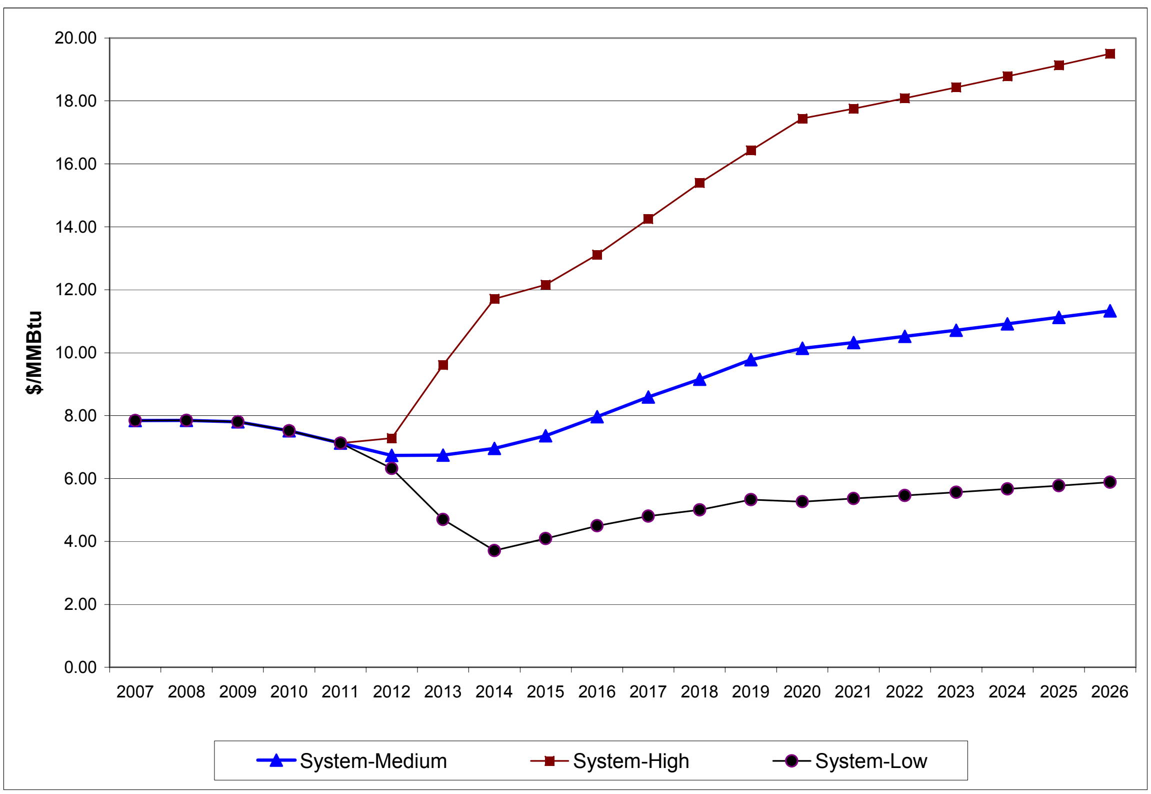
**Commodity Coal Cost**

Percentages for the low and high coal commodity cost values are based on the U.S. Energy Information Administration's low and high delivered coal price sensitivity forecast cases reported in the 2006 Annual Energy Outlook.[38] PacifiCorp assumed one-half of the difference between the sensitivity and reference cases to account for the fact that transportation costs, a main component of the cost forecast, are a relatively smaller portion of the delivered fuel cost in the Rocky Mountain region than for the U.S. as a whole.

**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 scenario. The low and high gas price forecasts were based on PIRA Energy's Henry Hub low and high prices cases, and come from PIRA Energy's long-term gas forecast update, dated June 15, 2006. Figure 6.2 shows the system average annual low, medium, and high natural gas prices. Figure 6.3 shows the system annual average low, medium, and high electricity prices by Heavy Load Hour and Light Load Hour periods.[39]

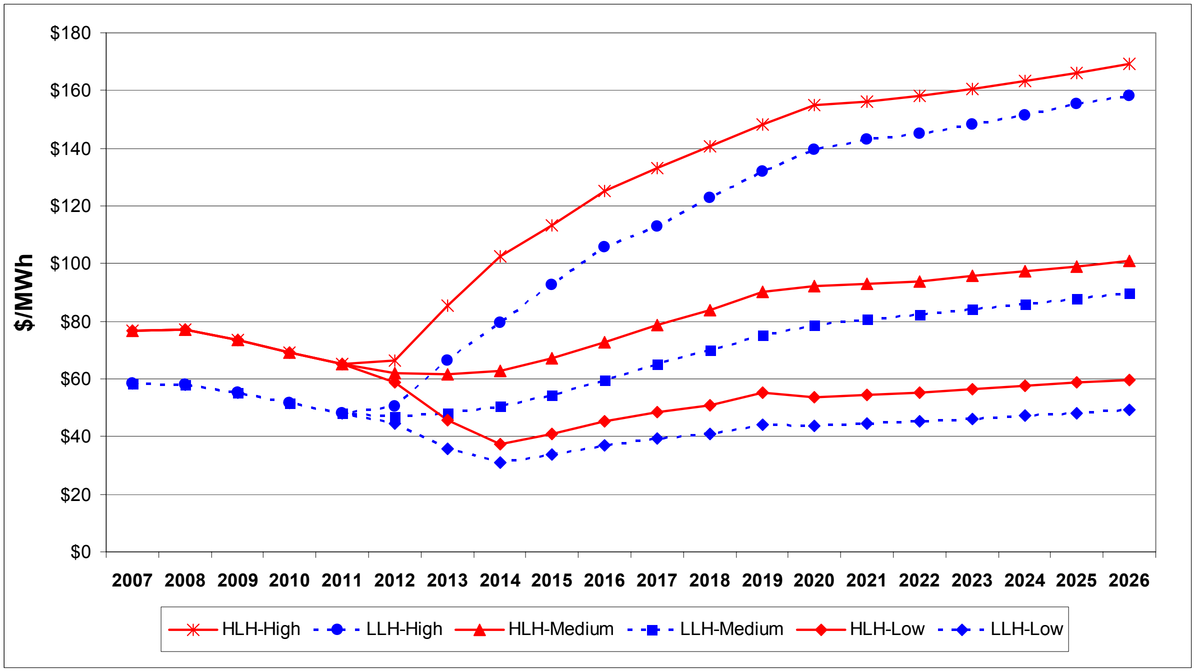
**Figure 6.2 – System Average Annual Natural Gas Prices: Low, Medium, and High Scenario Values**




[38] U.S. Energy Information Administration, *Annual Energy Outlook 2006 with Projections to 2030*, DOE/EIA-0383(2006), December 2005.

[39] Heavy Load Hours constitute the period from 6 a.m. to 10 p.m., Monday through Saturday. Light Load Hours are 10 p.m. to 6 a.m., Monday through Saturday, and all of Sunday and holidays.

**Figure 6.3 – System Average Annual Electricity Prices for Heavy and Light Load Hour Natural Gas Prices: Low, Medium, and High Scenario Values**




**Retail Load Growth**

The low and high load growth forecasts were determined by using the 5th and 95th percentile average load values from 100 stochastic iterations of the PaR model for 2026. Annual growth factors were applied to the medium load forecast. For the low forecast, the growth factor is the ratio of the average loads for the 5th percentile stochastic values to the load for the medium value in 2026. For the high forecast, the growth factor is the ratio of the average loads for the 95th percentile stochastic values to the load for the medium load value in 2026.

**Renewable Portfolio Standards**

For modeling the impact of renewable portfolio standards across the company's six-state service territory, PacifiCorp determined a system-wide annual generation requirement based on an assessment of state RPS requirements in California and Washington, and the contribution of each state to system retail sales. The system renewables generation requirement is translated into an incremental requirement by deducting renewables generation expected for 2007.

**Class 1 and Class 3 DSM Potential**

The development of low, medium, and high potentials for Class 1 and Class 3 demand-side management programs is described in detail in Chapter 5 and Appendix B. The Class 1 DSM programs included in the alternative future scenarios consist of dispatchable load control, scheduled irrigation, and thermal energy storage. The Class 3 programs consist of curtailable rates, critical peak pricing, and demand buyback. While the alternative future scenario studies included both Class 1 and Class 3 programs as resource options, only Class 1 resources were considered for risk analysis portfolio development. This decision was based on the need to conduct further research on the reliability of Class 3 DSM resources to address peak load demand issues, and to improve the modeling representation of the programs based on the DSM potentials study.

## Sensitivity Analysis Scenarios for the Capacity Expansion Module

The Capacity Expansion Module sensitivity analysis scenarios—designated with the acronym SAS and totaling 16 in number—are intended to supplement the alternative future analysis.[40] The focus of these scenarios is to determine optimal portfolios resulting from changes to secondary variables and other resource selection factors, with the results to be compared to those for a reference scenario. These sensitivity scenarios are defined with the primary variable values specified for the "Medium Load Growth" scenario (CAF11) except where noted below. The CEM sensitivity scenarios, which are listed in Table 6.3, test the following conditions:

- Alternative capacity Planning Reserve Margin levels – low (12%) and high (18%) values.
- Deferred carbon dioxide adder implementation – $CO_2$ costs start accruing in 2016 as opposed to 2012, which is the assumed year of a fully phased-in $CO_2$ adder.
- The impact of a regional transmission project – The regional transmission option consists of a new 1,500-megawatt line from Wyoming to the SP15 transmission zone in southern California, and a new 1,500-megawatt line from Utah to the NP15 transmission zone in northern California. (The CEM was not allowed to choose this resource; rather, it was fixed in order to determine the economic benefits assuming that it is built and PacifiCorp acquires an ownership share or transmission rights.)
- Determination of the carbon dioxide adder threshold value that affects resource selection; specifically, run the CEM with incrementally higher $CO_2$ adders to determine at what point major changes in resource selection are made.
- Low and high wind project capital costs (see Table 6.4)
- Low and high coal commodity prices
- Low and high IGCC plant capital costs (see Table 6.4)
- Integrated Gasification Combined Cycle technology configurations – constrain the Capacity Expansion Module to select an IGCC plant if not chosen as a resource given expected values for the primary variables (i.e., the "Medium Load Growth", CAF11). The IGCC plant is tested with three configurations: minimum carbon capture provisions, one gasifier, and carbon sequestration included. The scenarios are used to determine the incremental cost impact relative to an unconstrained resource choice.
- An alternative approach for determining the peak system obligation[41]
- Impact of renewable Production Tax Credit expiration combined with other regulatory developments favorable for wind projects, namely $CO_2$ regulation and widely-adopted renewable portfolio standards. This scenario uses variable values defined for the "favorable wind environment" alternative future scenario (CAF07).

[40] A sensitivity scenario for testing the impact of replacing Klamath Falls hydro units with alternative resources was excluded from the list, as it was determined that such analysis was not appropriate for the IRP setting given ongoing litigation and settlement discussions.

[41] In its 2004 IRP Acknowledgement Order, the Oregon Public Utility Commission directed PacifiCorp to "evaluate alternatives for determining the expected annual peak demand for determining the planning margin—for example, planning to the average of the eight-hour super-peak period." (Order No. 06-029, January 23, 2006.)

**Table 6.3 – Sensitivity Scenarios**

| SAS# | Name | Basis |
|---|---|---|
| 1 | Plan to 12% planning reserve margin | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 2 | Plan to 18% planning reserve margin | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 3 | $CO_2$ adder implementation in 2016 | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 4 | Regional transmission project | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 5-10<br>5-15<br>5-20 | $CO_2$ adder impact on resource selection: test \$15, \$20, \$25 per ton adders (approximately \$10, \$15, and \$20 in 1990 dollars) | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 6 | Low wind capital cost | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 7 | High wind capital cost | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 8 | Low coal price | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 9 | High coal price | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 10 | Low IGCC capital cost | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 11 | High IGCC capital cost | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 12 | Add a carbon-capture-ready IGCC to the portfolio (base case for SAS13 and SAS14) | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 13 | Replace the IGCC resource in the SAS12 portfolio with a single-gasifier version | SAS #12 |
| 14 | Replace the IGCC resource in the SAS12 portfolio with one that includes carbon sequestration | SAS #12 |
| 15 | Plan to "average of super-peak" load | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 16 | "Favorable Wind Environment" scenario assuming permanent expiration of the renewables PTC beginning in 2008 | Alternative Futures Scenario #07 ("Favorable Wind Environment") |

**Table 6.4 – CEM Sensitivity Scenario Capital Cost Values**

| Input Variable | Low Value | Medium Value | High Value |
|---|---|---|---|
| **IGCC Capital Cost** | 5% lower than the PacifiCorp Resource Development and Construction Dept. cost estimates | Based on a configuration with minimum carbon capture preparation and Level II emission controls. PacifiCorp Resource Development and Construction Dept. cost estimates | 12.5% higher than the PacifiCorp Resource Development and Construction Dept. cost estimates |
| **Wind Capital Cost** | 10% lower than the PacifiCorp Resource Development and Construction Dept. cost estimates | Based on PacifiCorp Resource Development and Construction Dept. cost estimates | 11% higher than the PacifiCorp Resource Development and Construction Dept. cost estimates |

## Sensitivity Analysis Scenarios for the Planning and Risk Module

A number of stochastic simulations were performed for sensitivity analysis purposes. Several of the scenarios were designed to address specific risk analysis requirements identified in the Oregon Public Utility Commission's Integrated Resource Planning guidelines and 2004 IRP acknowledgement order. The Planning and Risk Module sensitivity scenarios test the following conditions:

- Plan to a 12% planning reserve margin, and include a sufficient amount of Class 3 demand-side management program capacity to eliminate Energy Not Served (ENS).[42] This study addresses an Oregon Public Utility Commission acknowledgement order requirement.
- Plan to an 18% planning reserve margin – use the same portfolio resources selected by the Capacity Expansion Module for Sensitivity Analysis Scenario #2 ("Plan to 18% capacity reserve margin")
- Using one of the risk analysis portfolios as the basis, replace a new base load resource with an equivalent amount of front office transactions to determine the incremental cost and risk impacts.
- Using one of the risk analysis portfolios as the basis, replace a base load pulverized coal resource with an IGCC plant that has minimum carbon capture provisions. Also include sufficient shorter-term resources to maintain the planning reserve margin until an IGCC plant can be placed into service.
- Using one of the risk analysis portfolios as the basis, replace a new resource with Combined Heat & Power (CHP) and aggregated dispatchable customer-owned standby generators to determine the incremental cost and risk impacts.[43] This sensitivity addresses an analysis requirement in the Oregon Public Utility Commission's 2004 Integrated Resource Plan acknowledgement order.

## Capacity Expansion Module Optimization Runs

The Capacity Expansion Module is executed for each alternative future and sensitivity scenario, generating an optimized investment plan and associated real levelized present value of revenue requirements (PVRR) for 2007 through 2026. To avoid bunching of coal-fired resources at the end of the 10-year investment period when higher variable cost CCCT growth stations become available, a two-year investment extension period is added to enable the model to select all resource options through 2018.[44]

---

[42] Energy Not Served is a condition due to physical or market constraints where insufficient energy is available to meet load obligations.

[43] Large industrial sector CHP was included as a resource option in the CEM scenarios. For this sensitivity scenario, proxy resources representing small-to-medium sized industrial CHP plants (5 and 25 MW) were included along with a resource representing aggregate standby generators. For standby generators, PacifiCorp used Portland General Electric Company's standby generator program as the basis for determining resource characteristics. Due to air quality issues in Utah, standby generators were only modeled as a west-side resource.

[44] Growth stations are included as a generic resource choice beginning in 2019 to address load growth, plant retirements, and contract expirations during the out-years of the study period. Optimizing with a single resource for part of the study period is a necessary compromise for maintaining acceptable model run-times.

The CEM 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 the 24-zone model topology).

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, the CEM 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 CEM for PVRR reporting by both the CEM and Planning and Risk module.

**Modeling Front Office Transactions**

Front office transactions, described in Chapter 5, are assumed to be transacted on a one-year basis, and are represented as available in each year of the study. For capacity optimization modeling, the CEM engages in market purchase acquisition—both front office transactions and spot market purchases—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 scenario, 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. In addition, front office transactions are only available through 2018. After 2018, the purchases are set to zero, at which point the model can select "growth stations."

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

## RISK ANALYSIS PORTFOLIO DEVELOPMENT

Risk analysis portfolios refer to portfolio solutions, obtained from one or more CEM runs, which are subjected to stochastic production cost simulation using the Planning and Risk module. To develop the risk analysis portfolios, PacifiCorp relied on the CEM to build fixed resource investment schedules for wind and distributed resources, and to optimize the selection of other resource options according to specific resource strategies defined as constraints on the model solution. For example, a resource strategy may entail restricting the range of resource choices, placing constraints on when resources can be selected, or implementing upper limits on resource quantities. The impact of evolving state regulatory policies was considered in developing resource constraints.

## Determination of Fixed Resource Investment Schedules

PacifiCorp used the CEM to determine fixed resource investment schedules for certain smaller-scale resource types—wind, demand-side management programs and CHP facilities—in order to limit resource variability for subsequent CEM optimization studies and in the risk analysis portfolios themselves. (Restricting the number of resources is important for managing portfolio analysis complexity and model run-times.[45]) These investment schedules constitute set resource quantities, locations, and in-service dates that are included in all risk analysis portfolios. In the case of the proxy wind resources, PacifiCorp developed multiple fixed investment schedules for portfolio testing. For DSM and CHP a single investment schedule was developed and used in the risk analysis portfolios.

The company determined most of the fixed resource investment schedules by assessing the CEM's resource selection behavior across the range of alternative future scenarios described above. The next chapter describes the investment schedules derived from the alternative future scenario analysis.

## Alternative Resource Strategies

PacifiCorp's resource strategies fall into two categories: (1) those intended to evaluate the impacts of incremental resource changes, and (2) those intended to evaluate a specific resource investment policy. Strategies that fall into the first category typically involve specifying model constraints around a single resource, such as forcing selection for a certain year or removing it altogether as an option. The second category encompasses strategies that broadly tackle certain portfolio risks. Such risks include $CO_2$ regulatory costs, escalation and volatility of wholesale electricity and natural gas prices, and potential state restrictions and standards for resource acquisition (e.g., renewable portfolio standards). Examples of such resource strategies include eliminating or deferring an entire resource type such as coal, gas, or market purchases.

## Optimization Runs for Risk Analysis Portfolio Development

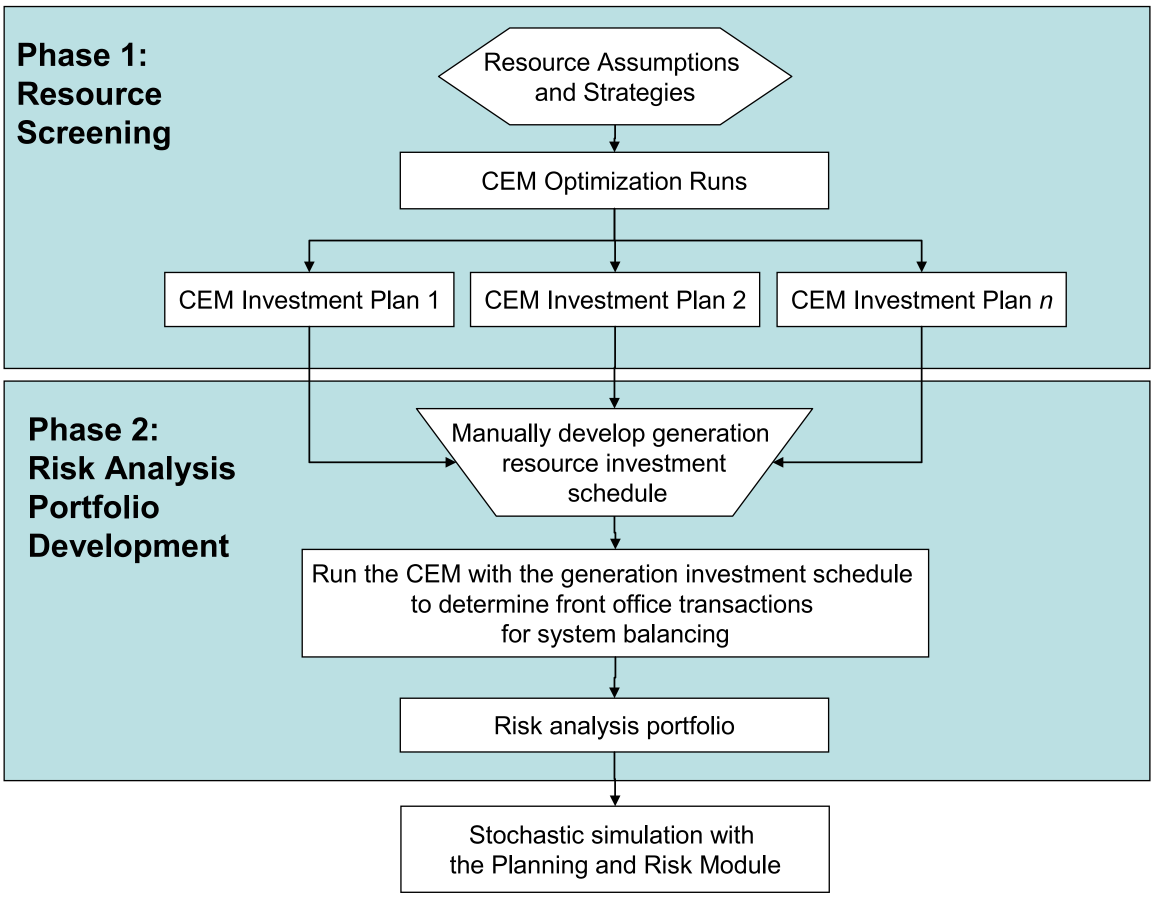
The CEM is ready for execution once the fixed resource investment schedules and resource strategies have been defined and input into the model. All CEM runs are configured as "Mixed Integer Programming" problems. This means that expansion choices can be represented as either build/not-build binary variables or continuous variables that enable the model to select fractional resource amounts. The mixed integer solution better characterizes investments where large fixed capital costs are involved.

In certain cases, a single CEM run completely defines the portfolio that is to be simulated using PaR. In other cases, a group of CEM runs are used to test multiple resource strategies or assumptions. For this later situation, PacifiCorp manually selects the resource investment schedule based on observations across the set of CEM runs. This approach is typically used to determine the model's selection behavior for a specific resource when other resources are constrained in differ-

[45] A limitation of this modeling strategy is that variable amounts of DSM and CHP resources were not subjected to risk analysis using the PaR model. PacifiCorp will continue to refine its approach to modeling distributed resources in concert with the scheduled June 2007 receipt of DSM and CHP supply curve data from the multi-state DSM potentials study.

ent ways. A resource that is routinely selected or chosen for a certain year indicates a robust resource under the set of simulated resource strategies. The CEM is then executed a second time with this fixed set of generation resources. The purpose of this additional run is to have the CEM optimize the selection of remaining available resource options, thereby ensuring that the final portfolio meets the model's planning reserve margin constraints. This two-step process is summarized in Figure 6.4.

**Figure 6.4 – Two-Stage Risk Analysis Portfolio Development Process**




## STOCHASTIC SIMULATION OF RISK ANALYSIS PORTFOLIOS

### Stochastic Risk Analysis

PacifiCorp next simulates each risk analysis portfolio, along with existing system resources, using the Planning and Risk model in stochastics mode. The PaR simulation produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The PaR simulation also incorporates stochastic risk in its production cost estimates by using Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability.[46]

[46] Although wind resource generation was not varied in the same way as the other stochastic variables, the hour-to-hour generation did vary throughout the year, but the pattern was repeated identically for all study years (2007-2026) and iterations (1-100).

A stochastic model in PaR guides the random sampling process. The stochastic model accounts for both short-term and long-term variable volatility as well as correlation effects among the variables. (Appendix E describes PacifiCorp's stochastic modeling methodology.) The output of the stochastic model consists of stochastic parameters—multipliers that represent the stochastic "shocks" applied to the expected value forecasts for each variable.

The PaR model is configured to conduct 100 Monte Carlo simulations 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 alternative futures. 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, or "risk exposure." The company uses scatter plots of portfolio cost versus risk exposure to help assess how each portfolio performs with respect to balancing cost and risk, as well as showing the cost-risk tradeoff for specific resource strategies.

**Scenario Risk Analysis**

In addition to modeling portfolio stochastic risks (the base stochastic simulation step in Figure 6.1), stochastic simulations were also conducted with various $CO_2$ emission cost adders to capture the risks associated with potential $CO_2$ emission compliance regulations. Since the probability of realizing a specific $CO_2$ emissions cost cannot be determined with a reasonable degree of accuracy, potential $CO_2$ emission costs were treated as a scenario risk in this IRP. PacifiCorp defines a scenario risk as an externally-driven fundamental and persistent change to the expected value of some parameter that is expected to significantly impact portfolio costs. This risk category is intended to embrace abrupt changes to risk factors that are not amenable to stochastic analysis.

The practice of combining stochastic simulation with $CO_2$ cost adder scenario analysis represents advancement with respect to the modeling approach used for PacifiCorp's 2004 IRP. Previously, the company simulated $CO_2$ scenario risks using several separate deterministic production cost runs.

Another scenario risk investigated in this IRP is potential widespread enactment of California's greenhouse gas emissions performance standard. (See Chapter 3, "California Greenhouse Gas Emissions Policies", for background information.) PacifiCorp used the CEM and PaR models to develop a portfolio that (1) excludes all new resources—generation and purchase contracts—that fail the emission performance threshold and (2) meets system-wide Renewable Portfolio Standard generation requirements stemming from assumed RPS enactment in all of PacifiCorp's west-side jurisdictions. Stochastic simulation of this portfolio yielded cost, risk, and $CO_2$ emission measures for comparison against other risk analysis portfolios. The results of this analysis are reported as the conclusion to Chapter 7.

## PORTFOLIO PERFORMANCE MEASURES

Stochastic simulation results for the risk analysis 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

- Stochastic mean cost (Present Value of Revenue Requirements, or PVRR)
- Customer rate impact
- Environmental (emissions) externality cost
- Capital cost

Risk

- Risk exposure
- Production cost variability

Emissions

- Carbon dioxide emissions

Reliability

- Average annual Energy Not Served (ENS)
- Loss of Load Probability (LOLP)

The following sections describe in detail each of the performance measures listed above.

### Stochastic Mean Cost

The stochastic mean cost for each risk analysis 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 capital cost additions of new resources determined by the CEM for that portfolio.

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. 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 included in the stochastic mean PVRR include the value of renewable energy credits (green tags), renewable production tax credits, emission allowance costs and credits, and the cost assigned to Energy Not Served.[47]. Emission allowance costs or credits are determined outside of the CEM and PaR models and added to the PVRR as one of the final calculation steps.

[47] The cost of Energy Not Served is set to $400/MWh, which is the FERC wholesale electricity price cap now in effect for the California Independent System Operator. Note that PacifiCorp added this cost to its stochastic PVRR calculations subsequent to the distribution of early risk analysis portfolio results to public stakeholders in October 2006.

The PVRR measure captures the total resource cost for each portfolio. 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. In addition, the PVRR accounts for emissions adders used for costing environmental externalities.

## Customer Rate Impact

In addition to PVRR measures, PacifiCorp calculates the per-megawatt-hour customer rate impact associated with each of the risk analysis portfolios.

The rate impact measure is the change in the customer dollar-per-megawatt-hour price for the period 2012 through 2026, expressed on a levelized net present value basis. This approach differs from the one used for the 2004 IRP in two respects. First, the rates represent stochastic mean values from the Monte Carlo simulations rather than deterministic values. Second, the rate is a single summary change measure. In contrast, the 2004 IRP reported just the year-to-year impacts.

The dollars in the rate numerator consist of the stochastic mean system operating cost (fuel cost, cap-and–trade 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.[48] The rate denominator is the retail load. The present value calculations use a 7.1% discount rate.

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.

## Environmental Externality Cost

For this IRP, PacifiCorp quantified environmental externalities by using externality cost adders for air emissions impacts—an approach that is consistent with prior company IRPs. The quantification of air emissions impacts through cost adders is generally recognized as the least ambiguous and least subjective approach to assessing externalities. A full range of other potential impacts, such as those on water supplies, traffic and land use patterns, and visual or aesthetic qualities, critically depend on the specifics of any particular project. The DSM potentials study to be completed in June 2007 addresses environmental externalities not currently included in this IRP.

[48] New IRP resource capital costs are represented in 2006 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.

The externality cost adder is treated as a variable cost in both the CEM and PaR models, and therefore is accounted for in each model's dispatch solution. Cost adders are included for $CO_2$, $SO_2$, $NO_X$, and mercury (Hg) emissions. See Chapter A of the Technical Appendix for information on pollutant allowance prices used in the IRP models.

**Modeling the Impact of $CO_2$ Externality Costs on Forward Electricity Prices**

PacifiCorp currently uses an inflation-adjusted $CO_2$ allowance price of $8/ton (2008$) in its calculation of official forward electricity price curves. These official price curves serve as the wholesale electricity price inputs to both the CEM and PaR models. For alternative $CO_2$ cost adders, new price curves are estimated using the Company's market price forecasting model, MIDAS.

The forward price curves need to account for the effect of a $CO_2$ allowance market on forecasted natural gas, $SO_2$ allowance, and $NO_X$ allowance prices. PacifiCorp contracted with ICF Consulting to estimate these interaction effects for use in developing the forward electricity prices needed for the $CO_2$ cost adder scenarios.

ICF used their national power market simulation tool, IPM®, to develop natural gas, $SO_2$ allowance, and $NO_X$ allowance prices taking into account the $CO_2$ allowance prices provided by PacifiCorp. The IPM® simulations used ICF's "expected case" model run as the starting point for forecast development.

Allowance trading markets for $NO_X$ and $SO_2$ currently exist, while a market for mercury is slated to start in 2010. Carbon emissions are currently not regulated except in California. To simulate the impacts of allowance trading, allowance costs and credits are estimated outside of the CEM and PaR models using a spreadsheet model. The allowance trading calculations use baseline annual emissions caps along with the PaR model's annual emission quantities for a portfolio simulation. (For a stochastic simulation, the calculations use the average emissions across the 100 iterations.) Annual emissions above a cap are multiplied by the per-ton annual allowance price (or in the case of mercury, a per-pound price), while emissions below the cap are assigned a cost credit equal to the difference between the cap and the actual emissions multiplied by the allowance price. Note that as a simplifying assumption, all allowances are traded in the year accrued. The resulting net present value of the 20-year stream of annual allowance balances is included in the PVRR.[49]

PacifiCorp modeled future carbon regulation scenarios assuming that $CO_2$ emissions are capped to 2000 levels, and that a $CO_2$ allowance trading market begins in 2010. In recognition of the timing uncertainty, 2010 $CO_2$ costs are probability-weighted by a factor of 0.50. Likewise, 2011 costs are weighted by a factor of 0.75. By 2012, the full inflation-adjusted $CO_2$ allowance cost is imposed, growing at inflation thereafter.

The $CO_2$ adder scenario simulations were performed with five adder levels: $0, $8, $15, $38, and $61 per ton (in 2008 dollars). For the $61/ton cost adder, the cap-and-trade program is assumed to start in 2010, but is not fully phased in until 2016.

As a key performance measure, PacifiCorp reports the emissions externality cost as the increase in stochastic mean PVRR relative to the $0 adder case at each successively higher $CO_2$ adder level. For the set of risk analysis portfolio finalists, the externality cost is calculated as a tax

[49] To avoid double counting, the emission adder cost is backed out of the PaR model's total production cost.

(emission quantity multiplied by the emissions cost adders) as well as a net allowance cost balance under a cap-and-trade regime for all pollutants.

## Risk Exposure

Risk exposure is the stochastic upper-tail mean PVRR minus the stochastic mean PVRR. The upper-tail mean PVRR is a measure of high-end stochastic risk, and is calculated as the average of the five stochastic simulation iterations with the highest net variable cost. Risk exposure is somewhat analogous to Value at Risk (VaR) measures. The fifth and ninety-fifth percentile PVRRs are also reported. These PVRR values correspond to the iteration out of the 100 that represents the fifth and ninety-fifth percentiles, respectively. These measures represent snapshot indicators of low-risk and high-risk stochastic outcomes.

## 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.

## Production Cost Variability

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 2007 through 2026.

## Carbon Dioxide Emissions

Carbon dioxide emissions are reported for two time periods: 2007–2016 and 2007–2026. The 10-year view excludes the emissions impact of growth stations—generic combined cycle units that serve primarily to meet load growth beyond the 10-year investment window.

For risk analysis portfolios considered as finalists for preferred portfolio selection, $CO_2$ emissions are reported for both generation sources (direct emissions) as well as combined with the net effect of wholesale market activity. The emission contribution assigned to market purchases (indirect emissions, net of emission credits from wholesale sales). The indirect $CO_2$ emissions related to purchases are calculated by multiplying net purchased power generation by an average emissions factor of 0.565 tons/MWh which is offset by emissions deemed to go with wholesale sales at the average system emission rate. This factor is based on actual 2005 purchases, and is applied through the 20-year forecast. The total system emissions footprint (generation only) for sulfur dioxide, nitrogen oxides, mercury is also reported for the period 2007–2026.

## Supply Reliability

### Energy Not Served

Energy Not Served is a condition where there is insufficient generation available to meet load because of physical constraints or market conditions. Certain iterations of a PaR stochastic simulation will have “Energy Not Served” or ENS. 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. For example, a large load shock in a transmission-constrained topology bubble would yield a relatively large amount of ENS. Running the PaR model in stochastic mode without including the stochastic variability of load yields virtually no ENS over the planning horizon. Similarly, deterministic PaR simulations do not experience ENS because there is no random behavior of model parameters; loads increase in a smooth fashion over time.

The stochastic ENS results, averaged across all 100 iterations, are used to compare the reliability among portfolios when stressed. Consequently, stochastic ENS results are indicative of relative differences in portfolio reliability given extreme modeled conditions with low probability of occurrence, and are not intended to represent indicators of expected system reliability under normal conditions. It is noteworthy that in actual practice PacifiCorp has not needed to shed retail load, other than the curtailment contract customers, due to a resource shortage.

For reporting of the ENS statistics, PacifiCorp calculates an average annual value for 2007 through 2016 in gigawatt-hours, as well as the upper-tail ENS (average of the five iterations with the highest ENS). Simulations using the \$8/ton $CO_2$ cost adder are reported, as the adder level does not have a material influence on ENS results.

**Loss of Load Probability**

The new IRP guidelines issued in January 2007 by OPUC (Order 07-002) state:

> "*Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios.*"

To meet the LOLP guideline, PacifiCorp developed a metric and applied it to the risk analysis portfolios simulated with the Planning and Risk model.

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 is a simple concept:

$$\mathbf{LOLP} = \Pr(\mathbf{S} \leq \mathbf{L})$$

*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. Loss of load probability is considered a limited measure of reliability, and does not account for numerous risk factors, utility agreements, and other considerations that govern the operation of the utility network.

For reporting LOLP, PacifiCorp calculates the probability of Energy Not Served 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 7, the proportion of iterations with ENS events in July exceeding selected threshold levels are reported for each risk analysis portfolio simulated with the PaR module. The LOLP is reported as a study average as well as year-by-year results for an example threshold level of 25,000 Megawatt-hours. This threshold methodology follows the lead of the Pacific Northwest Resource Adequacy Forum, which reports the probability of a "significant event" occurring during the winter season.

## PREFERRED PORTFOLIO SELECTION

The preferred portfolio is selected from among the risk analysis portfolios primarily on the basis of relative cost-effectiveness, customer rate impact, and the balance between cost and risk exposure. Also important is the robustness of the portfolios with respect to their cost and risk performance under successively higher $CO_2$ adder scenarios; the portfolios that consistently rank the highest regardless of the assumed $CO_2$ adder are strong contenders for selection as the preferred portfolio. Supply reliability risk and $CO_2$ emissions are also important, but play a lesser role in selecting the preferred portfolio because differences among portfolios with respect to these measures are relatively small.

These primary selection criteria are in line with state IRP guidelines that dictate that the preferred portfolio be least-cost after accounting for uncertainty, risk, and the long-run public interest.

## CLASS 2 DEMAND-SIDE MANAGEMENT PROGRAM ANALYSIS

### Decrement Analysis

For the Class 2 demand-side management decrement analysis, the preferred portfolio was used to calculate the reduced system operating costs (or decrement value) of various types of Class 2 programs. PacifiCorp will use these decrements values when evaluating the cost-effectiveness of current programs and potential new DSM programs between IRP cycles.

The process used for this IRP is to model Class 2 DSM program types as contracts that supply energy according to hourly load shapes provided by PacifiCorp's DSM department. These contracts serve as surrogates for direct load reductions attributable to energy efficiency programs. The Planning and Risk Module is then run in stochastics mode with and without the Class 2 DSM resources to establish the change in system cost (reduction in the stochastic mean PVRR for 100 simulations) from lower market purchases or resource re-optimization due to the addition of the Class 2 DSM. This approach differs from that used in the 2004 IRP. For the 2004 IRP, the load decrements were modeled as reductions in the load forecasts, with system cost differences determined by deterministic PaR runs. The new approach simplifies the data set-up process and accounts for stochastic risk in the cost estimates.

To determine the Class 2 DSM decrements, 12 shaped planning decrements, each at 100 megawatts at peak, were modeled starting in 2010 throughout the 20-year IRP study period. The decrements are shaped to each of the following loads for both the east and west control areas. Table 6.5 below provides an overview of the planning decrement design, showing the load size (load factor) and end-use hourly load shape.

**Table 6.5 – Planning Decrement Design**

| Decrement Size | East System Load Center | West System Load Center | End-Use Hourly Load Shape |
|---|---|---|---|
| 100 MW | 7% Load Factor | 20% Load Factor | Residential Cooling |
| 100 MW | 60% Load Factor | 60% Load Factor | Residential Lighting |
| 100 MW | 46% Load Factor | n/a | Residential Whole House |
| 100 MW | 16% Load Factor | 16% Load Factor | Commercial Cooling |
| 100 MW | 49% Load Factor | 49% Load Factor | Commercial Lighting |
| 100 MW | n/a | 28% Load Factor | Residential Heating |
| 100 MW | East load shape (approx. 65% Load Factor) | West load shape (approx. 67% Load Factor) | East/West System Load |

The company will evaluate additional DSM program opportunities by replacing the forward-market-price avoided cost used in the traditional DSM cost effectiveness tests with the shaped decrement values. For such evaluations, the decrement values will be pro-rated to match the load shape of new DSM proposals. Once new programs are implemented, their contributions to load reductions will be incorporated directly into the load forecast used for the next IRP.

## Public Utility Commission Guidelines for Conservation Program Analysis in the IRP

During the 2007 integrated resource planning process and development of the company's Class 2 energy efficiency resource assessment, there were questions raised as to whether PacifiCorp had sufficient information available, absent the completion of a system-wide demand-side resource assessment study, to arrive at a fair representation of the energy efficiency resource potential available over the planning period. While having additional data from such a study would likely have provided additional clarity around this assessment, the company had several other reliable sources of information from which to arrive at a forecast of achievable resource potential as represented within the 2007 IRP. These sources have been used for prior planning exercises and continue to be used to identify significant resource opportunities. Additionally, these sources have proven reliable in the past in helping the company achieve verifiable results.

Class 2 energy efficiency resources comprise a significant portion of the overall demand-side management investments and resource targets within the 2007 IRP. There are approximately 250 MWa of Class 2 energy efficiency resources accounted for within the 2007 preferred portfolio. These resources were identified through a composite of resource assessment exercises conducted over the last five years. These assessments, coupled with the performance of the company's existing demand-side resource portfolio and associated lessons-learned, aided PacifiCorp in the development of the 2007 Class 2 energy efficiency plan contributions. The studies and information sources relied upon included market-specific as well as measure-specific characterization studies/work, third-party program process and impact evaluations, regional assessments such as the Northwest Power Planning Council's 5th Power Plan, the Energy Trust of Oregon's forecast, demand-side management advisory groups, and others. These sources represent the most relevant information available from which to draw assumptions regarding resource potential. The company's confidence in this information is reflected in their use for adjusting the 2007 plan's load forecast, indicating they will be acquired within cost-effective parameters.

To avoid foreclosing opportunities to exceed the 250 MWa target already established for the IRP until a new target can be defined using the results of the multi-state DSM potentials study, the company intends to use the Class 2 DSM decrement analysis described above to establish values, at various load shapes, of 200 MWa of incremental resource acquisitions (beyond the 250 MWa in the 2007 IRP) that might present themselves between planning cycles. However, since the amounts and shapes, availability, timing and acquisition costs are less certain than the resources from existing programs and assessments, they were not placed within the company's 2007 load and resource balance. As these resources are identified and determined to be cost-effective based on the decrement values, they will be incorporated into the next integrated resource plan update.

Modeling of demand-side resources in the 2007 integrated resource planning process is robust and treats them as functionally equivalent to supply-side resources, even without the utilization of specific supply curves. Forecasted loads are reduced by the known and certain demand-side management resources in much the same manner that a supply-side resource would offset the load.

In regards to additional assessment work, PacifiCorp will complete a comprehensive system-wide demand-side resource market assessment by late June, 2007. At that time, the company will begin incorporating the results of that assessment, in addition to the sources identified above and used during this IRP planning cycle, into the planning assumptions and forecasts going forward. Once the system-wide demand-side resource assessment information is available, both the incremental 200 MWa amount as well as the Class 2 DSM modeling methodology will be revisited to assure that the planning process places the appropriate dependence on demand-side resources commensurate with their availability.

In summary, while the potential study and supply curves will refine the company's approach to assessing and modeling demand-side management resources, the current practices and approaches do not arbitrarily limit the amount, the value or potential acquisition of cost-effective energy efficiency resources within the current plan.

# 7. MODELING AND PORTFOLIO SELECTION RESULTS

**Chapter Highlights**

- PacifiCorp assessed 16 alternative future scenarios to determine resources and capacity quantities suitable for inclusion in risk analysis portfolios. Based on the Capacity Expansion Module's optimized investment plans, the company selected wind (a proxy for all renewables), combined heat and power, supercritical pulverized coal (SCPC), combined cycle combustion turbine (CCCT), single-cycle combustion turbine (SCCT), integrated gasification combined cycle (IGCC), load control programs, and short-term market purchases (front office transactions) in subsequent portfolio studies.

- The company initially studied 12 portfolios using its stochastic production cost simulation model. These portfolios tested a variety of resource strategies, distinguished by the planning reserve margin and the quantity of wind, pulverized coal, front office transactions, and IGCC resources included.

- The stochastic modeling results for the 12 portfolios indicate that the best strategy for achieving a low-cost, risk-informed portfolio is to include supercritical pulverized coal along with additional wind and natural gas resources to mitigate $CO_2$ cost risk.

- PacifiCorp evaluated a second set of five portfolios to account for (1) new and evolving state resource policies that place constraints on the company's resource choices, and (2) new Wyoming load growth information. All of these portfolios included 600 megawatts of additional wind (incremental to the original 1,400-megawatt renewables commitment), 100 megawatts of CHP, and 95 megawatts of new load control programs.

- The analysis of the original 12 portfolios informed the development of the second set of portfolios; these portfolios focused on the timing of SCPC plants, the mix of gas-fired plants and market purchases to address east-side load growth, the timing and type of resources needed to make up for the loss of the BPA peaking contract in 2011, and the planning reserve margin level.

- Based on superior performance with respect to stochastic cost, customer rate impact, cost vs. risk balance, and supply reliability, a portfolio with the following characteristics was chosen as the preferred portfolio:
  - A total of 2,000 megawatts of renewables by 2013
  - A west-side CCCT in 2011
  - High-capacity-factor baseload resources in the east in 2012 and 2014
  - East-side CCCTs in 2012 and 2016
  - Balance of system need fulfilled by front office transactions beginning in 2010

## INTRODUCTION

This chapter presents modeling results for the portfolio analysis, as well as chronicles the development of the portfolios, the associated decision process that guided their formulation, and the selection of a preferred portfolio.

Discussion of the portfolio analysis results falls into the following six sections.

- **Alternative Future and Sensitivity Scenario Results** – This section presents the Capacity Expansion Module's optimized resource investment plans and PVRRs for the alternative future and sensitivity scenarios. These results constitute the outcome of the resource screening phase of the IRP modeling effort.
- **Risk Analysis Portfolio Development and Stochastic Simulation Results** – This section describes the derivation and resource specifications for the risk analysis portfolios, and then provides a comparative assessment based on the performance measures described in Chapter 6. Creation of fixed investment schedules for wind, demand-side management programs, and combined heat and power resources, is covered first, followed by a description of the portfolio design goals and alternative resource strategies used to formulate them. The section also presents findings on a cost-versus-risk exposure tradeoff analysis of the resource strategies. (As discussed in Chapter 6, risk exposure is defined as the upper-tail mean PVRR minus the overall stochastic mean PVRR.)
- **Selection of the Preferred Portfolio** – This section provides a consolidated view of the portfolio evaluation results to indicate which portfolio is the most desirable after cost, risk, reliability, $CO_2$ emissions, and state resource policy evolution are considered.
- **Fuel Diversity Planning** – This section describes how fuel source diversity is addressed in the 2007 Integrated Resource Plan.
- **Forecasted Fossil Fuel Generator Heat Rate Trend** – This section reports the system-average fossil fuel generator heat rate trend for the preferred portfolio. This information addresses a new Utah Commission IRP reporting requirement to support the PURPA Fuel Sources Standard.
- **Class 2 Demand-side Management Decrement Analysis** – This section presents the decrement values for Class 2 program evaluations using the preferred portfolio to calculate the system benefit.

## ALTERNATIVE FUTURE AND SENSITIVITY SCENARIO RESULTS

### Alternative Future Scenario Results

This section presents the modeling results and findings for the CEM alternative future studies. As a refresher, Table 7.1 repeats the alternative future specifications outlined in Chapter 6.

**Table 7.1 – Alternative Future Scenarios**

| CAF # | Name | Coal Cost: $CO_2$ Adder/Coal Commodity Price | Gas/ Electric Price | Load Growth | Renewable Sales Percentage due to RPS | Renewable PTC Availability | DSM Potential |
|---|---|---|---|---|---|---|---|
| 00 | Business As Usual | None/Medium | Medium | Medium | Low | Yes | Medium |
| 01 | Low Cost Coal/High Cost Gas | None/Low | High | Medium | Medium | Yes | Medium |
| 02 | With Low Load Growth | None/Low | High | Low | Medium | Yes | Medium |
| 03 | With High Load Growth | None/Low | High | High | Medium | Yes | Medium |
| 04 | High Cost Coal/Low Cost Gas | High/High | Low | Medium | Medium | Yes | Medium |
| 05 | With Low Load Growth | High/High | Low | Low | Medium | Yes | Medium |
| 06 | With High Load Growth | High/High | Low | High | Medium | Yes | Medium |
| 07 | Favorable Wind Environment | High/Medium | High | Medium | High | Yes | Medium |
| 08 | Unfavorable Wind Environment | None/Medium | Low | Medium | Low | No | Medium |
| 09 | High DSM Potential | High/Medium | High | Medium | Medium | Yes | High |
| 10 | Low DSM Potential | None/Medium | Low | Medium | Medium | Yes | Low |
| 11 | Medium Load Growth | Medium/Medium | Medium | Medium | Medium | Yes | Medium |
| 12 | Low Load Growth | Medium/Medium | Medium | Low | Medium | Yes | Medium |
| 13 | High Load Growth | Medium/Medium | Medium | High | Medium | Yes | Medium |
| 14 | Low Cost Portfolio Bookend | None/Low | Low | Low | Medium | Yes | Medium |
| 15 | High Cost Portfolio Bookend | High/High | High | High | Medium | No | Medium |

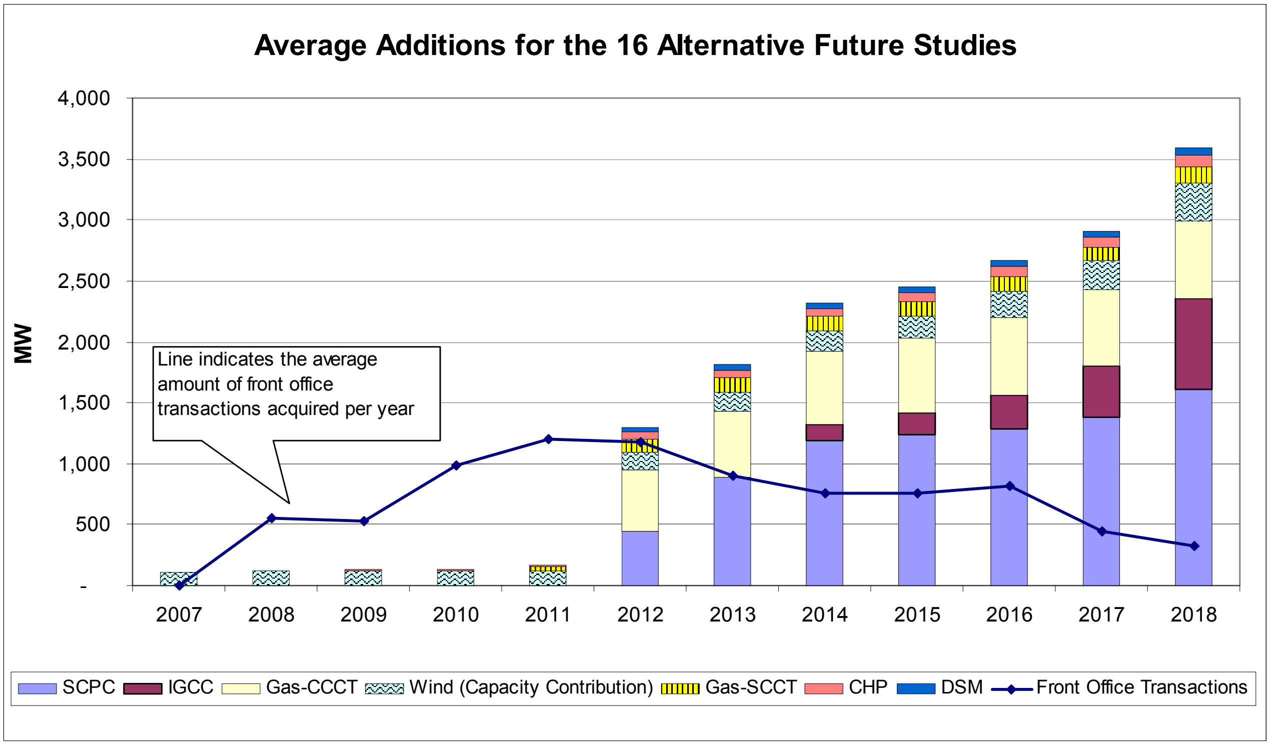
Table 7.2 reports the PVRR and total cumulative additions (2007–2018) by resource type for the 16 alternative future studies. The wind capacity contribution and average annual front office transactions acquired for 2007 through 2018 are also shown.

**Table 7.2 – Alternative Future Scenario PVRR and Cumulative Additions for 2007-2018**

| Study | PVRR | Planning Reserve Margin | DSM - Class 1 | DSM - Class 3 | DSM-Total | Gas-CCCT-1x1 | Gas-CCCT-2x1 | Gas-CCCT | Gas-CHP | Gas-Frame | Gas-Total | Coal - IGCC | Coal - SCPC | Nameplate Wind | Wind Capacity Contribution | Total Nameplate | FOT - Avg 2007-2018 | FOT - Avg 2007-2018 Plus PRM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CAF00 | $ 19,619 | 15% | 47 | 103 | 150 | | | | 125 | | 125 | 500 | 2,440 | 500 | 134 | 3,715 | 966 | 1,111 |
| CAF01 | $ 18,071 | 15% | 48 | 103 | 151 | | | | 25 | | 25 | 2,002 | 2,440 | 1,100 | 217 | 5,718 | 669 | 769 |
| CAF02 | $ 11,022 | 15% | 47 | 31 | 78 | | | | | | | 500 | 2,440 | 600 | 125 | 3,618 | 406 | 467 |
| CAF03 | $ 30,159 | 15% | 87 | 82 | 169 | | 602 | 602 | 125 | 634 | 1,361 | 2,510 | 2,440 | 3,100 | 514 | 9,580 | 748 | 860 |
| CAF04 | $ 30,504 | 15% | 47 | 31 | 78 | | 1,698 | 1,698 | 125 | | 1,823 | | | 2,200 | 354 | 4,101 | 961 | 1,105 |
| CAF05 | $ 23,920 | 15% | 47 | 52 | 99 | | | | 125 | | 125 | | | 2,100 | 317 | 2,324 | 796 | 916 |
| CAF06 | $ 40,002 | 15% | 87 | 82 | 169 | 1,498 | 2,300 | 3,798 | 125 | | 3,923 | | | 2,400 | 409 | 6,492 | 1,071 | 1,232 |
| CAF07 | $ 33,339 | 15% | 32 | 26 | 58 | | | | 100 | | 100 | 500 | 2,440 | 3,600 | 568 | 6,698 | 753 | 866 |
| CAF08 | $ 18,858 | 15% | 47 | 82 | 129 | | 1,150 | 1,150 | 125 | | 1,275 | | 750 | | | 2,154 | 958 | 1,102 |
| CAF09 | $ 33,213 | 15% | | 64 | 64 | | | | 100 | | 100 | 500 | 2,440 | 3,100 | 514 | 6,204 | 733 | 843 |
| CAF10 | $ 19,002 | 15% | 29 | 39 | 68 | | 1,150 | 1,150 | 75 | | 1,225 | | 750 | 700 | 148 | 2,743 | 929 | 1,068 |
| CAF11 | $ 24,606 | 15% | 105 | 106 | 211 | | | | 125 | 634 | 759 | 500 | 2,440 | 1,800 | 342 | 5,710 | 876 | 1,007 |
| CAF12 | $ 17,689 | 15% | 47 | 103 | 150 | | | | 100 | | 100 | 500 | 1,500 | 900 | 184 | 3,150 | 602 | 693 |
| CAF13 | $ 35,024 | 15% | 127 | 106 | 233 | 392 | 602 | 994 | 125 | 634 | 1,753 | 2,002 | 2,440 | 2,700 | 467 | 9,128 | 1,000 | 1,150 |
| CAF14 | $ 13,689 | 15% | 47 | 103 | 150 | | | | 25 | | 25 | | 750 | 500 | 122 | 1,425 | 622 | 716 |
| CAF15 | $ 49,234 | 15% | 95 | 103 | 198 | 784 | | 784 | 125 | 302 | 1,211 | 2,510 | 2,440 | 3,100 | 514 | 9,459 | 913 | 1,049 |
| **CAF Averages** | **$ 26,122** | | **63** | **76** | **135** | **891** | **1,250** | **1,454** | **103** | **551** | **929** | **1,202** | **1,978** | **1,893** | **329** | **5,139** | **813** | **935** |

Figure 7.1 provides a composite view of cumulative additions by resource type over time, averaged for all 16 alternative future investment plans. Annual front office transactions acquired are also shown.

**Figure 7.1 – Cumulative Resource Additions by Year for Alternative Future Studies**




**Demand-side Management Program Selection Patterns**

The CEM chose, on average, 135 megawatts of DSM resources across the alternative future studies—63 megawatts of Class 1 resources and 76 megawatts of Class 3 resources. The CEM selected Class 1 programs under all scenarios except one: the high DSM potential scenario. This result is covered under the DSM potential scenario discussion later in this section.

The highest individual amount selected for a scenario was 233 megawatts; this was for CAF13, the high load growth study. In contrast, the lowest amount was 58 megawatts under CAF07, the favorable wind environment scenario. It is apparent that conditions that support aggressive wind investment for the model have a dampening effect on the amount of DSM selected.

Table 7.3 shows the CEM's DSM additions for scenarios that included (1) low and high load growth assumptions, (2) low and high coal costs (based principally on the $CO_2$ adder level), and (3) low and high gas/electricity prices. The megawatt additions are reported as averages for the group of portfolios.[50]

[50] A complicating factor for interpreting the model's resource selection behavior is the impact of resource size. The model may find it advantageous to select a small resource to minimally meet the planning reserve margin constraint for a particular year, rather than invest in a larger yet less costly resource.

**Table 7.3 – DSM Resource Selection by Alternative Future Type**

| Alternative Future Type | Number of Scenarios | Megawatt Average | | |
|---|---|---|---|---|
| | | Class 1 DSM | Class 3 DSM | Total |
| Low Load Growth | 4 | 47 | 72 | 119 |
| High Load Growth | 4 | 89 | 84 | 178 |
| | | | | |
| Low Coal Cost | 6 | 81 | 84 | 165 |
| High Coal Cost | 6 | 51 | 60 | 111 |
| | | | | |
| Low Gas/Electricity Prices | 6 | 51 | 65 | 116 |
| High Gas/Electricity Prices | 6 | 52 | 68 | 120 |

### DSM Potential Scenarios

The two DSM potential scenarios, CAF09 and CAF10, are intended to determine how other resource costs affect the CEM's choice of DSM resources at higher and lower levels of program participation. The High DSM potential scenario tests whether high fuel and market prices compensate for the higher DSM resource cost that accompanies greater program participation. The "low DSM potential" scenario tests the opposite set of conditions. Note that as the market potential increases, the resource cost ($/kW/yr) for most of the DSM programs is higher as well.[51] The higher cost reflects a greater level of incentive and administrative expenditures needed to maintain program savings at an elevated level.

As mentioned above, the CEM did not choose any Class 1 DSM programs under the high potential scenario, even with a high $CO_2$ adder and high gas and electricity prices in place. (On the other hand, the CEM selected 3,100 megawatts of wind.) The only DSM resources selected were the east and west demand buyback programs.

For the low potential scenario, CAF10, both Class 1 and Class 2 programs are selected. However, the combined amounts are only 4 megawatts greater than the DSM total under the high potential scenario.

### Load Growth Scenarios

The alternative future scenarios CAF10, CAF11, and CAF12 test the CEM's resource preferences under a wide load growth range, holding other scenario variables constant. Table 7.4 profiles the resource additions for each of these load growth scenarios.

**Table 7.4 – Resource Additions for Load Growth Scenarios**

| Load Growth Assumption | Scenario | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|---|
| | | Cumulative Build Amounts (MW): 2007-2018 | | | | |
| **Low** | CAF12 | 150 | 1,500 | 500 | 100 | 900 |
| **Medium** | CAF11 | 211 | 2,440 | 500 | 759 | 1,800 |
| **High** | CAF13 | 233 | 2,440 | 2,002 | 1,753 | 2,700 |

[51] Critical Peak Pricing is the only program type for which unit resource costs decrease as the market potential increases.

The most interesting model behavior relates to the type of gas resource selected under each load growth scenario. For the low load growth scenario (CAF12), the model selects no central-station gas resources; instead, it relies mostly on coal builds. Under the medium load growth scenario (CAF11), the model then turns to SCCT frames and additional pulverized coal to address the higher loads, but no CCCT capacity was added to the investment plan at this point. (Wind nameplate capacity also doubled from 900 to 1,800 megawatts.) Under the high load growth scenario (CAF13), the next incremental resources selected were IGCC and CCCT, with the model having already selected all SCPC resources available to it under medium load growth conditions.

Tables 7.5, 7.6 and 7.7 show the CEM's resource additions for all scenarios that include the low, medium, and high load growth assumptions, respectively. The model tends to add pulverized coal first to meet incremental load growth, and then add significantly more gas and wind resources under the higher load growth scenarios. For all scenarios that include high load growth, the model chooses every SCPC resource available to it.

**Table 7.5 – Resource Additions for Scenarios with Low Load Growth**

| | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|
| **Scenario** | **Cumulative Build Amounts (MW): 2007-2018** | | | | |
| CAF02 | 78 | 2,440 | 500 | - | 600 |
| CAF05 | 99 | - | - | 125 | 2,100 |
| CAF12 | 150 | 1,500 | 500 | 100 | 900 |
| CAF14 | 150 | 750 | - | 25 | 500 |
| **Average** | **119** | **1,173** | **500** | **63** | **600** |

**Table 7.6 – Resource Additions for Scenarios with Medium Load Growth**

| | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|
| **Scenario** | **Cumulative Build Amounts (MW): 2007-2018** | | | | |
| CAF00 | 150 | 2,440 | 500 | 125 | 500 |
| CAF01 | 151 | 2,440 | 2,002 | 25 | 1,100 |
| CAF04 | 78 | - | - | 1,823 | 2,200 |
| CAF07 | 58 | 2,440 | 500 | 100 | 3,600 |
| CAF08 | 129 | 750 | - | 1,275 | - |
| CAF09 | 64 | 2,440 | 500 | 100 | 3,100 |
| CAF10 | 68 | 750 | - | 1,225 | 700 |
| CAF11 | 211 | 2,440 | 500 | 759 | 1,800 |
| **Average** | **114** | **1,957** | **800** | **679** | **1,625** |

**Table 7.7 – Resource Additions for Scenarios with High Load Growth**

| | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|
| **Scenario** | **Cumulative Build Amounts (MW): 2007-2018** | | | | |
| CAF03 | 169 | 2,440 | 2,510 | 1,361 | 3,100 |
| CAF06 | 169 | - | | 3,923 | 2,400 |
| CAF13 | 233 | 2,440 | 2,002 | 1,753 | 2,700 |

| | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|
| **Scenario** | **Cumulative Build Amounts (MW): 2007-2018** | | | | |
| CAF15 | 198 | 2,440 | 2,510 | 1,211 | 3,100 |
| **Average** | **136** | **2,440** | **1,207** | **1,030** | **1,925** |

## Gas/Electricity Price Scenarios

Tables 7.8 and 7.9 show the CEM resource additions for the six scenarios that include the low and high gas/electricity price assumptions, respectively.

With low prices, the model chose coal for only three of the six scenarios. Those three scenarios (CAF08, CAF10, CAF14), assumed no $CO_2$ adder, and only one coal plant was selected. The model selected wind for nearly all low-price scenarios, the exception being the "unfavorable wind environment" scenario, CAF08. Scenarios that also included the low coal cost assumption (CAF10, CAF14) had a relatively small amount of wind investment at 400 megawatts. For the scenario with a high coal cost and load growth (CAF06), the fossil fuel investment plant consisted of only CCCT resources at 3,798 megawatts.

**Table 7.8 – Resource Additions for Scenarios with Low Gas/Electricity Prices**

| | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|
| **Scenario** | **Cumulative Build Amounts (MW): 2007-2018** | | | | |
| CAF04 | 78 | - | - | 1,823 | 2,200 |
| CAF05 | 99 | - | - | 125 | 2,100 |
| CAF06 | 169 | - | - | 3,923 | 2,400 |
| CAF08 | 129 | 750 | - | 1,275 | - |
| CAF10 | 68 | 750 | - | 1,225 | 700 |
| CAF14 | 150 | 750 | - | 25 | 500 |
| **Average** | **116** | **375** | **-** | **1,399** | **1,317** |

With high gas and electricity prices, the model invested heavily in both supercritical pulverized coal and wind, except for the scenario with low load growth. For all scenarios, every SCPC option was chosen (2,440 megawatts). Gas resources (CCCT and SCCT frame) were selected only for the two scenarios that also had high load growth (CAF03, CAF15). The model selected west IGCC resources in all scenarios, and added all the IGCC units available to it under the high price/high load growth scenario (CAF03).

**Table 7.9 – Resource Additions for Scenarios with High Gas/Electricity Prices**

| | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|
| **Scenario** | **Cumulative Build Amounts (MW): 2007-2018** | | | | |
| CAF01 | 151 | 2,440 | 2,002 | 25 | 1,100 |
| CAF02 | 78 | 2,440 | 500 | - | 600 |
| CAF03 | 169 | 2,440 | 2,510 | 1,361 | 3,100 |
| CAF07 | 58 | 2,440 | 500 | 100 | 3,600 |
| CAF09 | 64 | 2,440 | 500 | 100 | 3,100 |
| CAF15 | 198 | 2,440 | 2,510 | 1,211 | 3,100 |

| | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|
| **Scenario** | **Cumulative Build Amounts (MW): 2007-2018** | | | | |
| **Average** | **120** | **2,440** | **1,420** | **466** | **2,433** |

**Carbon Dioxide Adder/Coal Cost Scenarios**
Tables 7.10 and 7.11 show the CEM's resource additions for scenarios that have the low and high coal cost assumptions, respectively.

The CEM added 1,716 megawatts of supercritical pulverized coal capacity, on average, for the scenarios with low coal cost assumptions. As expected, the CEM built the most coal capacity when high gas/electricity prices and high load growth are included as assumptions (CAF1 and CAF3).

**Table 7.10 – Resource Additions for Scenarios with Low $CO_2$ Adder/Coal Costs**

| | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|
| **Scenario** | **Cumulative Build Amounts (MW): 2007-2018** | | | | |
| CAF00 | 150 | 2,440 | 500 | 125 | 500 |
| CAF01 | 151 | 2,440 | 2,002 | 25 | 1,100 |
| CAF02 | 78 | 2,440 | 500 | - | 600 |
| CAF03 | 169 | 2,440 | 2,510 | 1,361 | 3,100 |
| CAF08 | 129 | 750 | - | 1,275 | 0 |
| CAF10 | 68 | 750 | - | 1,225 | 700 |
| CAF14 | 150 | 750 | - | 25 | 500 |
| **Average** | **124** | **1,716** | **787** | **577** | **929** |

With high coal costs (Table 7.11), the model did not add any coal resources unless the scenario was accompanied by high gas/electricity prices. Base load gas was added in only three of the six portfolios. Substantial wind capacity was added in all scenarios, with an average of 2,750 megawatts (a 446-megawatt capacity contribution).

**Table 7.11 – Resource Additions for Scenarios with High $CO_2$ Adder/Coal Costs**

| | DSM | Coal-SCPC | Coal-IGCC | Gas | Wind Nameplate |
|---|---|---|---|---|---|
| **Scenario** | **Cumulative Build Amounts (MW): 2007-2018** | | | | |
| CAF04 | 78 | - | - | 1,823 | 2,200 |
| CAF05 | 99 | - | - | 125 | 2,100 |
| CAF06 | 169 | - | - | 3,923 | 2,400 |
| CAF07 | 58 | 2,440 | 500 | 100 | 3,600 |
| CAF09 | 64 | 2,440 | 500 | 100 | 3,100 |
| CAF15 | 198 | 2,440 | 2,510 | 1,211 | 3,100 |
| **Average** | **111** | **1,220** | **585** | **1,214** | **2,750** |

## Sensitivity Analysis Results

This section presents the modeling results for the CEM sensitivity analysis studies. As a refresher, Table 7.12 repeats the sensitivity scenario specifications outlined in Chapter 6.

**Table 7.12 – Sensitivity Analysis Scenarios**

| SAS# | Name | Basis |
|---|---|---|
| 01 | Plan to 12% capacity reserve margin | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 02 | Plan to 18% capacity reserve margin | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 03 | $CO_2$ adder implementation in 2016 | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 04 | Regional transmission project | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 5-10<br>5-15<br>5-20 | $CO_2$ adder impact on resource selection: test \$15, \$20, \$25 per ton adders (approximately \$10, \$15, and \$20 in 1990 dollars) | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 06 | Low wind capital cost | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 07 | High wind capital cost | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 08 | Low coal price | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 09 | High coal price | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 10 | Low IGCC capital cost | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 11 | High IGCC capital cost | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 12 | Add a carbon-capture-ready IGCC to the portfolio (base case for SAS13 and SAS14) | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 13 | Replace the IGCC resource in the SAS12 portfolio with a single-gasifier version | SAS #12 |
| 14 | Replace the IGCC resource in the SAS12 portfolio with one that includes carbon sequestration | SAS #12 |
| 15 | Plan to "average of super-peak" load | Alternative Futures Scenario #11 ("Medium Load Growth") |
| 16 | "Favorable Wind Environment" scenario assuming permanent expiration of the renewables PTC beginning in 2008 | Alternative Futures Scenario #07 ("Favorable Wind Environment") |

Table 7.13 reports the PVRR and total cumulative additions (2007–2018) by resource type for the 16 sensitivity studies. The wind capacity contribution and average annual front office transactions acquired for 2007 through 2018 are also shown. The study results are summarized below.

**Table 7.13 – Sensitivity Analysis Scenario PVRR and Cumulative Additions, 2007-2018**

| Study | PVRR | Planning Reserve Margin | DSM - Class 1 | DSM - Class 3 | DSM-Total | Gas-CCCT-1x1 | Gas-CCCT-2x1 | Gas-CCCT | Gas-CHP | Gas-Frame | Gas-Total | Coal - IGCC | Coal - SCPC | Nameplate Wind | Wind Capacity Contribution | Total Nameplate | | FOT - Avg 2007-2018 | FOT - Avg 2007-2018 Plus PRM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SAS01 | $ 24,400 | 12% | 55 | 106 | 161 | | | | 125 | | 125 | 500 | 2,440 | 1,100 | 223 | 4,326 | | 865 | 969 |
| SAS02 | $ 24,983 | 18% | 55 | 106 | 161 | | | | 100 | 634 | 734 | 500 | 2,440 | 1,700 | 326 | 5,535 | | 936 | 1,104 |
| SAS03 | $ 22,673 | 15% | 47 | 106 | 153 | | | | 125 | 302 | 427 | 500 | 2,440 | 1,500 | 291 | 5,020 | | 942 | 1,083 |
| SAS04 | $ 24,182 | 15% | 113 | 106 | 219 | | | | 125 | | 125 | 997 | 2,440 | 2,400 | 409 | 6,181 | | 896 | 1,031 |
| SAS05-10 | $ 28,551 | 15% | 103 | 106 | 209 | | 602 | 602 | 125 | 634 | 1,361 | 500 | 1,840 | 2,500 | 406 | 6,410 | | 872 | 1,003 |
| SAS05-15 | $ 32,390 | 15% | 127 | 106 | 233 | | 602 | 602 | 125 | 634 | 1,361 | 500 | 1,090 | 3,100 | 514 | 6,284 | | 935 | 1,075 |
| SAS05-20 | $ 36,073 | 15% | 143 | 106 | 249 | | 1,150 | 1,150 | 125 | 720 | 1,995 | | 750 | 3,100 | 514 | 6,094 | | 906 | 1,042 |
| SAS06 | $ 24,282 | 15% | 55 | 106 | 161 | | | | 125 | 634 | 759 | 500 | 2,440 | 2,600 | 422 | 6,460 | | 806 | 927 |
| SAS07 | $ 24,836 | 15% | 47 | 82 | 129 | | | | 100 | 634 | 734 | 997 | 2,440 | 700 | 163 | 5,000 | | 897 | 1,031 |
| SAS08 | $ 24,401 | 15% | 95 | 103 | 198 | | | | 125 | 302 | 427 | 500 | 2,440 | 1,300 | 253 | 4,865 | | 920 | 1,058 |
| SAS09 | $ 24,980 | 15% | 47 | 103 | 150 | | | | 125 | 302 | 427 | 500 | 2,440 | 1,500 | 300 | 5,017 | | 890 | 1,023 |
| SAS10 | $ 24,559 | 15% | 47 | 103 | 150 | | | | 125 | 332 | 457 | 997 | 2,440 | 1,100 | 223 | 5,144 | | 889 | 1,023 |
| SAS11 | $ 24,660 | 15% | 103 | 106 | 209 | | | | 125 | 634 | 759 | 500 | 2,440 | 1,800 | 334 | 5,708 | | 922 | 1,060 |
| SAS12 | $ 24,976 | 15% | 103 | 106 | 209 | | | | 100 | 332 | 432 | 1,250 | 2,440 | 1,000 | 196 | 5,331 | | 915 | 1,052 |
| SAS13 | $ 24,980 | 15% | 47 | 106 | 153 | | | | 100 | 302 | 402 | 1,250 | 2,440 | 800 | 165 | 5,045 | | 828 | 953 |
| SAS14 | $ 25,521 | 15% | 95 | 106 | 201 | | | | 100 | 332 | 432 | 1,250 | 2,440 | 1,000 | 196 | 5,323 | | 848 | 975 |
| SAS15 | $ 24,412 | 15% | 105 | 106 | 211 | | | | 125 | 332 | 457 | 500 | 2,440 | 1,700 | 323 | 5,308 | | 803 | 924 |
| SAS16 | $ 35,049 | 15% | 47 | 26 | 73 | | | | 75 | | 75 | 500 | 2,440 | 3,500 | 580 | 6,588 | | 649 | 727 |

Alternative planning reserve margins (SAS01 and SAS02)

Allowing the CEM to optimize to alternative planning reserve margins, 12% and 18%, had the following impacts:

- The PVRR was lowest for the 15% PRM base case portfolio (CAF11); the cost difference between the 15% PRM portfolio and 18% PRM was $6.9 billion, while the difference between the 12% PRM portfolio and the 15% PRM portfolio was $6.3 billion.
- There was no difference in the amount of supercritical pulverized coal or IGCC capacity among the portfolios
- None of the portfolios included CCCT capacity; SCCT capacity was added for 15% and 18% PRM portfolios (both at 634 megawatts)
- The 12% PRM portfolio had no base load gas resources, but included CHP
- Relative to the 12% PRM portfolio, the 15% PRM portfolio had more wind (700 megawatts) and more front office transactions
- Relative to the 15% PRM portfolio, the 18% PRM portfolio had more front office transactions and slightly less wind and DSM

$CO_2$ adder implementation in 2016, compared to 2012 for the base case portfolio

Moving back the start of $CO_2$ regulation from 2012 to 2016 had the following impacts on the base case portfolio:

- The PVRR decreased by $1.9 billion
- The resulting portfolio had less Class 1 DSM, less SCCT capacity, less wind, and more front office transactions

Inclusion of the regional transmission project[52]

- The project resulted in a $424 million decrease in PVRR relative to the base case portfolio

[52] The project consisted of new 1,500 MW capacity lines from Wyoming to the SP15 transmission zone in California, and from Utah to NP15.

- Changes to the resource mix included elimination of all SCCT capacity, the addition of an IGCC unit, more wind, and a small increase in front office transactions

Resource mix impact of increasing the $CO_2$ adder

Increasing the $CO_2$ adder in a step-wise fashion for the base case portfolios had the following impacts:

- From \$8 to \$15: The CEM removed the Utah SCPC resource (600 megawatts), and added a CCCT and 700 megawatts of additional wind; PVRR increased by \$3.9 billion
- From \$15 to \$20: The CEM removed a Wyoming SCPC (750 megawatts), and added 600 megawatts of additional wind, 24 megawatts of Class 3 DSM, and additional front office transactions (63 average annual megawatts); PVRR increased by another \$3.8 billion
- From \$20 to \$25: The CEM removed the small Utah SCPC and the west IGCC (500 megawatts), and added another east CCCT as well as an intercooled aero SCCT; in addition, the model added 16 megawatts of Class 1 DSM, but decreased front office transactions by average annual 29 megawatts; PVRR increased by another \$3.7 billion

Low and high wind capital cost

Lowering the wind capital cost by 10% had the following effects relative to the base case portfolio:

- The CEM added 800 megawatts of wind
- The PVRR decreased by \$800 million
- Class 1 DSM is reduced by 50 megawatts
- Front office transactions are reduced by an average annual 70 megawatts

Increasing the wind capital cost by 11% had the following effects relative to the base case portfolio:

- The CEM removed 1,100 megawatts of wind capacity
- An east IGCC resource was added (497 megawatts)
- The PVRR increases by \$231 million
- Front office transactions increased by an average annual 21 megawatts
- Class 1 DSM is reduced by 50 megawatts, apparently displaced by the other resource additions

Low and high commodity coal prices

Lowering the coal price for new coal resources had the following effects relative to the base case portfolio:

- The PVRR decreases by \$204 million
- The CEM removed the west SCCT (332 megawatts) and 500 megawatts of wind (90 megawatts capacity contribution)
- Front office transaction were increased by an average annual 44 megawatts, while DSM decreases by 13 megawatts

Raising the coal price for new coal resources has the following effects relative to the base case portfolio:

- The Wyoming SCPC plants were moved up a year, and the large and small Utah SCPCs switched places: the large 600-megawatt unit moved from 2018 to 2012, while the small 340-megawatt unit moved from 2012 to 2018. (The coal price change adversely affected the economics of the small Utah SCPC unit to a greater degree than for the large Utah SCPC unit). The timing change of the coal plants resulted in removal of a west SCCT (332 megawatts) and 300 megawatts of wind (42-megawatt capacity contribution)
- The PVRR increased by $375 million
- Front office transaction increased by an average annual 44 megawatts, while DSM decreases by 61 megawatts

Low and high IGCC capital cost

Lowering the IGCC capital cost had the following effects relative to the base case portfolio:

- The CEM added an east IGCC (497 megawatts), and moved up the 200-megawatt west IGCC from 2017 to 2016
- The CEM removed 700 megawatts of wind (119-megawatt capacity contribution), and a SCCT (302 megawatts)
- The PVRR decreased by $46 million
- Front office transactions increased by an average annual 13 megawatts

Raising the IGCC capital cost had the following effects relative to the base case portfolio:

- The west IGCC is deferred from 2017 to 2018, which increases front office transactions by an average annual 46 megawatts and raises PVRR by $54 million

Impact of switching from an IGCC with a spare gasifier to one with a single gasifier

This change reduced PVRR by $4 million. Resource impacts included switching the location of a SCCT from the west location to the east location in 2012, reducing wind by 200 megawatts (32-megawatt capacity contribution), and reducing front office transactions by an average annual 87 megawatts.

Cost impact of building an IGCC with carbon sequestration

Replacing a carbon-capture-ready IGCC with one that has carbon sequestration increased PVRR by $541 million. The IGCC replacement resulted in minor resource selection impacts; namely, Class 1 DSM increased by 48 megawatts, and front office transactions increased by an average annual 19 megawatts.

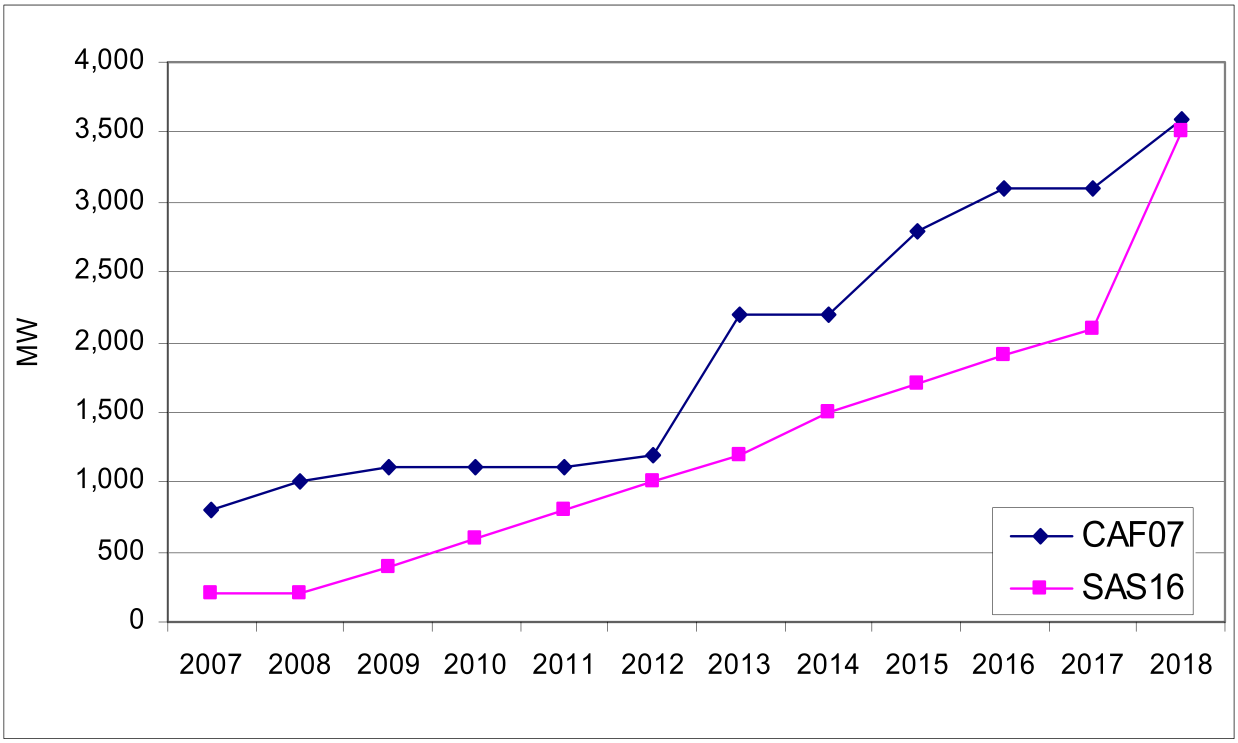
Plan to the average of the eight-hour super-peak period

Relative to the base case portfolio, CAF11, planning to the average of the eight-hour super-peak period decreases PVRR by $194 million. The resource impacts include: removal of a SCCT (302 megawatts), a decrease in wind capacity by 100 megawatts, and a reduction in front office transactions (103 megawatts on an average annual basis). DSM was unaffected.

Favorable wind development environment combined with expiration of the renewable production tax credit (PTC)

Comparing the portfolio PVRR for CAF07 and SAS16 indicates the impact of not renewing the PTC after 2008. The impact was found to be an additional $1.7 billion. Removing the PTC also significantly changed the wind investment schedule. Figure 7.2 compares the cumulative annual nameplate megawatt wind additions for CAF07 and SAS16. With no PTC in place (SAS16), the model chose to add wind in a smooth pattern until 2017, and then add 1,400 megawatts in 2018. This large capacity addition is an artifact of the timing of the generic growth stations, which start in 2019. With the PTC in place (CAF07), the wind addition schedule was lumpier, with significant additions in 2007, 2013, and 2015.

**Figure 7.2 – Cumulative Wind Additions for CAF07 and SAS16**



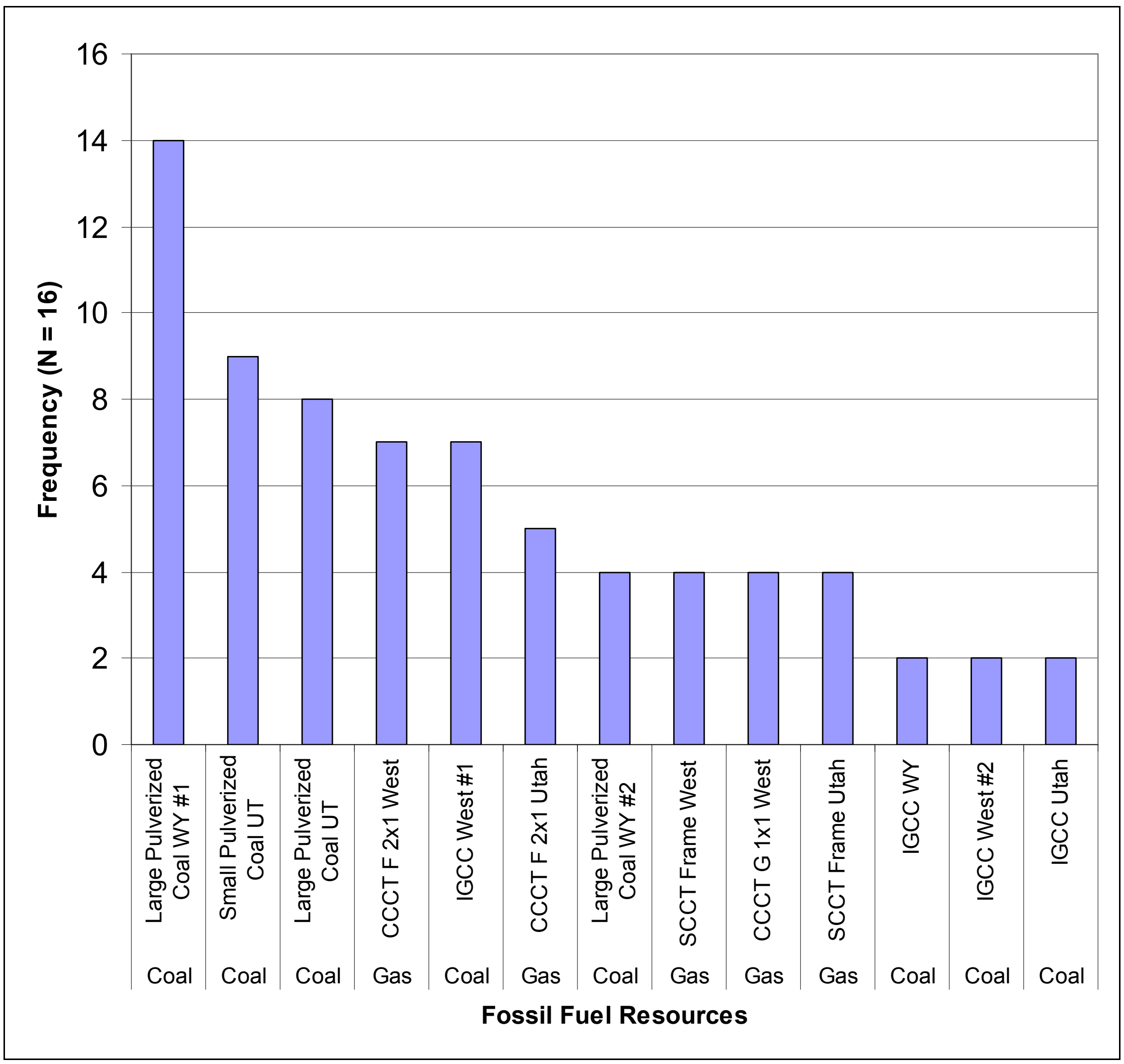

**<u>Resource Selection Conclusions</u>**

Based on the CEM modeling results, a number of general observations can be reached regarding the model's resource preferences, and what specific resources constitute robust selections to include in the risk analysis portfolios. First, supercritical pulverized coal was part of the resource stack in all the CEM portfolio solutions except for the three scenarios with high coal costs and low gas and electricity prices (CAF04, CAF05, and CAF06). Given that a high $CO_2$ adder is expected to put upward pressure on gas prices due to greater demand for cleaner power supplies, a scenario more in line with the "favorable wind environment" future (CAF07)—or the version of this scenario without renewable production tax credits (SAS16)—is a more realistic future. For these two scenarios, the model still selected supercritical pulverized coal and added it early in the study period.

A second observation concerns the model's selection frequency of the resources across the alternative future studies. Only two resources appeared in the majority of the studies: the large Wyoming and small Utah supercritical pulverized coal units. With few exceptions, the CEM added these coal units as soon as they were available for selection. Based on this result, PacifiCorp judged these coal resources to be robust options under the set of alternative futures evaluated. Figure 7.3 shows the selection frequency for all fossil fuel resources.

Regarding gas resource selection, CCCTs came into play only under scenarios that included low gas/electricity prices or high load growth. Selection of single-cycle combustion turbine frames appears to be sensitive to the level of load growth assumed; these resources were added for two scenarios with high load growth, as well as the medium load growth scenario. Given these selection patterns, gas plants are not judged to be robust resources under deterministic modeling conditions. However, it should be noted that the CEM deterministic runs do not capture the optionality value of gas resources; consequently, testing them in a stochastic modeling environment is necessary to estimate their full value in a diversified portfolio.

**Figure 7.3 – CEM Fossil Fuel Resource Selection Frequency**



Wind appeared in 15 out of the 16 alternative future studies. While this resource is considered robust as far as inclusion in the CEM's investment plans is concerned, unlike the pulverized coal resources, a robust *quantity* can't be determined due to the wide variance in selected wind capacities among the alternative future studies. Consequently, the company used measures of central tendency to determine an initial wind investment schedule for inclusion in the risk analysis portfolios. The development of the wind investment schedule is described in the next section.

The CEM chose IGCC for 10 out of the 16 alternative futures, with the west IGCC units (total of 500 megawatts) selected in seven futures and the east IGCC units selected in four futures. The model's selection of east-side IGCC resources was predicated on the high load growth assumption, and these resources were generally added beyond the 10-year investment horizon (2007–2016).

## RISK ANALYSIS PORTFOLIO DEVELOPMENT – GROUP 1

To develop the first risk analysis portfolio, PacifiCorp first combined the fixed wind, DSM, and CHP investment schedules described below, along with the other resource options. The CEM was then executed with this set of resources *using the medium-case assumptions adopted for the alternative future studies*. The resulting CEM investment plan, labeled as RA1, thus parallels the plan that resulted from the "medium case" alternative future (CAF11) run. To derive subsequent risk analysis portfolios, PacifiCorp applied one or a combination of alternative resource strategies to RA1 or other variants of RA1 prior to CEM execution.

Twelve portfolios were initially developed with input received from public stakeholders during the fall of 2006. PacifiCorp used the associated portfolio simulation results and the analysis supporting the 10-year Business Plan to formulate a "base case" resource proposal that was shared with regulators.

The feedback received on the resource proposal, as well as recent external events[53] and an assessment of state resource policy directions, prompted the company to investigate portfolio alternatives that recognize existing and expected state resource acquisition constraints. A new set of risk analysis portfolios was consequently created to address these constraints while still adhering to system planning principles and the states' IRP development guidelines. (The new risk analysis portfolios also account for the revised load forecast.)

This second portfolio group constitutes the "finalists" from which the preferred was selected. The original set of 12 risk analysis portfolios informed the construction of these new portfolios. This chapter documents both sets of portfolios, which are referenced as "Group 1" and "Group 2".

[53] These events, cited in Chapter 3, include the Oregon PUC rejection of the 2012 RFP for baseload resources and issuance of new IRP guidelines (January 2006), adoption of renewable portfolio standards in Washington, California's adoption of a green house gas emissions performance standard, and introduction of climate change legislation in both Oregon and Washington.

## Fixed Resource Additions for Risk Analysis Portfolios

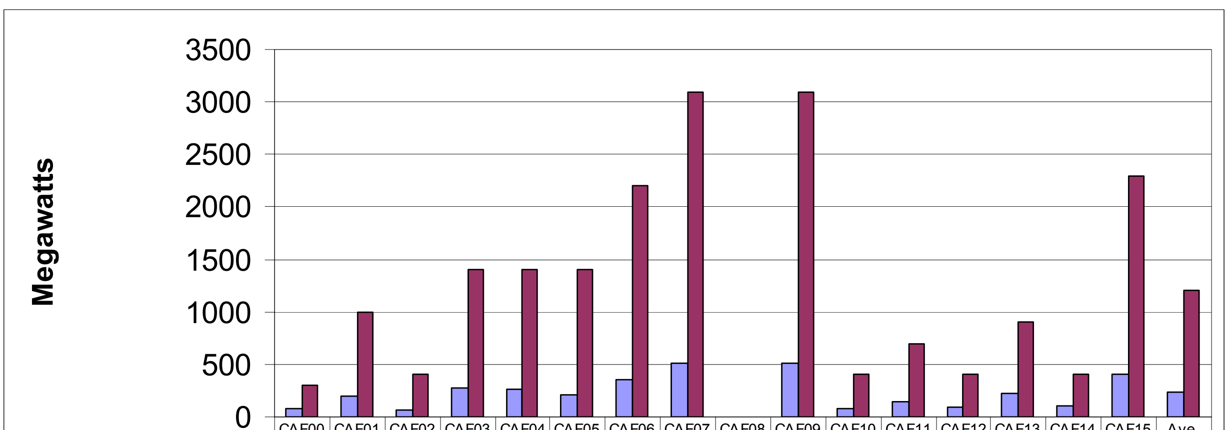
**Renewables**

A fixed wind resource investment schedule was included in all risk analysis portfolios. PacifiCorp developed an initial wind investment schedule based on a composite view of the resource addition patterns for the 16 alternative future scenarios covering the period 2007 through 2016. This initial wind investment schedule was modified as appropriate to support the testing of alternative resource strategies.

The CEM selected a wide range of wind resource capacities across the alternative future scenarios, from zero capacity for CAF08 ("unfavorable wind environment") to 3,100 megawatts of nameplate capacity for two scenarios (CAF07, "favorable wind environment" and CAF09, "high DSM potential"). The average nameplate amount for the 16 scenarios was 1,213 megawatts (for a capacity contribution of 235 megawatts), while the median amount was 950 megawatts. The amount selected for the medium case scenario was 700 megawatts. The most frequently occurring amount was 400 megawatts for four scenarios.

Figure 7.4 shows the amount of wind capacity that the CEM selected for each of the alternative future scenarios. Both nameplate capacity and capacity contribution are shown.

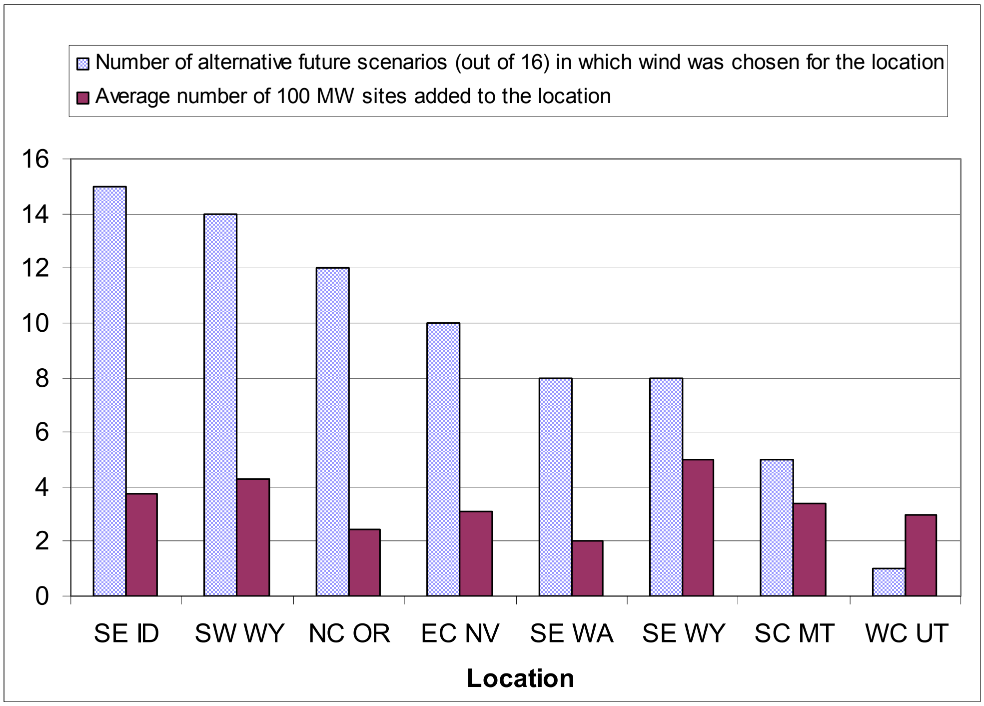
**Figure 7.4 – Wind Capacity Preferences for Alternative Future Scenarios**




| | CAF00 | CAF01 | CAF02 | CAF03 | CAF04 | CAF05 | CAF06 | CAF07 | CAF08 | CAF09 | CAF10 | CAF11 | CAF12 | CAF13 | CAF14 | CAF15 | Ave. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Wind Capacity Contribution | 82 | 196 | 60 | 277 | 259 | 215 | 354 | 514 | 0 | 514 | 85 | 148 | 95 | 222 | 99 | 410 | 235 |
| Renew ables Nameplate | 300 | 1,000 | 400 | 1,400 | 1,400 | 1,400 | 2,200 | 3,100 | - | 3,100 | 400 | 700 | 400 | 900 | 400 | 2,300 | 1213 |

Figure 7.5 profiles the CEM's location preferences for wind resources across the alternative future portfolios. It shows the number of scenarios in which wind was selected by location, and the average number of 100 megawatt project sites selected for each location four sites—Southeast Idaho, Southwest Wyoming, North Central Oregon, and East Central Nevada—appeared in the majority of the scenarios. The southeast Wyoming location (SE WY) had the largest number of sited added.

**Figure 7.5 – Wind Location Preferences for Alternative Future Scenarios**




Given these model results, a total nameplate capacity of 1,000 megawatts (capacity contribution of 217 megawatts) was added to each of the risk analysis portfolios and distributed among the sites favored by the model. Note that this capacity amount is in addition to the 400 megawatts considered a planned resource for 2007 and reflected in PacifiCorp's load and resource balance. Table 7.14 shows the resource addition schedule for 2008 through 2016 adopted for the risk analysis portfolios.

**Table 7.14 – Wind Resource Additions Schedule for Risk Analysis Portfolios**

| Year | Annual Additions, Nameplate Capacity (MW) | Location | Cumulative Wind Nameplate Capacity (MW) | Cumulative Wind Peak Capacity Contribution (MW) |
|---|---|---|---|---|
| 2008 | 200 | North Central Oregon; Southeast Idaho | 200 | 62 |
| 2009 | 200 | North Central Oregon; Southeast Idaho | 400 | 110 |
| 2010 | 100 | Southeast Idaho | 500 | 127 |
| 2011 | - | - | 500 | 127 |
| 2012 | 300 | Southwest Wyoming | 800 | 189 |
| 2013 | 200 | Southwest Wyoming | 1,000 | 217 |

## Class 1 Demand-side Management Programs

A fixed megawatt amount of certain Class 1 demand-side management programs were included in all risk analysis portfolios based on a review of DSM addition patterns covering the 2017-2016 investment horizon for the alternative future scenarios. In order to be selected for risk analysis portfolio inclusion, programs needed to have been chosen in the medium case scenario (CAF11) or a majority of the other alternative future scenarios, as well as have a capacity that exceeds 10 megawatts when selected. This combination of criteria is meant to strike a balance between a relatively aggressive DSM implementation pattern for the risk analysis portfolios (accounting for the fact that not all potential system benefits can be readily quantified and captured in the CEM solution) and constraining the entire set of CEM options to a reasonable number.

For the medium case scenario, the CEM chose the following programs, megawatt quantities (as measured at the customer meter), and installation years:

- East-side summer direct load control – 48 megawatts in 2013
- West-side summer direct load control – 8 megawatts in 2013
- East-side commercial/industrial direct load control – 2 megawatts in 2013
- East-side scheduled irrigation – 15 megawatts in 2012
- West-side scheduled irrigation – 32 megawatts in 2012

The only resources that the CEM selected for the majority of alternative future scenarios were the east-side and west-side scheduled irrigation programs. The CEM selected the east-side program in 11 out of 16 scenarios, while the west-side program was selected in 10 out of 16 scenarios. Figures 7.6 and 7.7 show the number of scenarios in which program types were selected by the CEM and the average megawatts for all scenarios, respectively.

Regarding the CEM's selection of program installation dates, 2012 and 2013 were the most common across the alternative future scenarios. Only under the high-cost bookend scenario (CAF15) are programs selected for implementation earlier than 2010. For this scenario, several programs are added in 2008, such as east-side scheduled irrigation and the three east-side direct load control programs (summer, winter, and commercial/industrial).

**Figure 7.6 – Class 1 DSM Selection Frequency for Alternative Future Scenarios, 2007-2016**

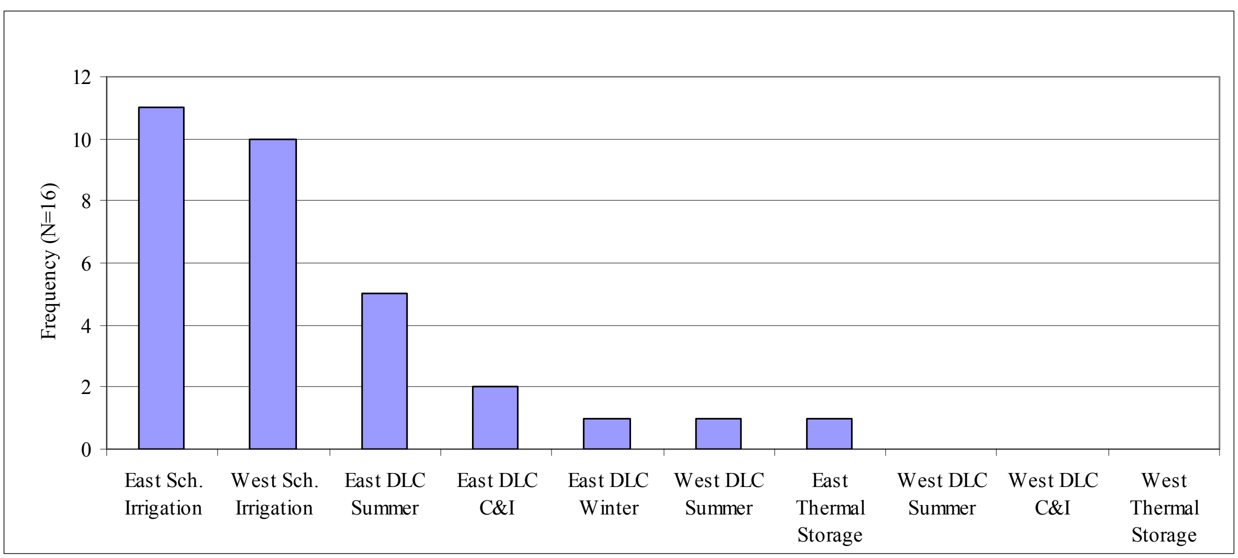
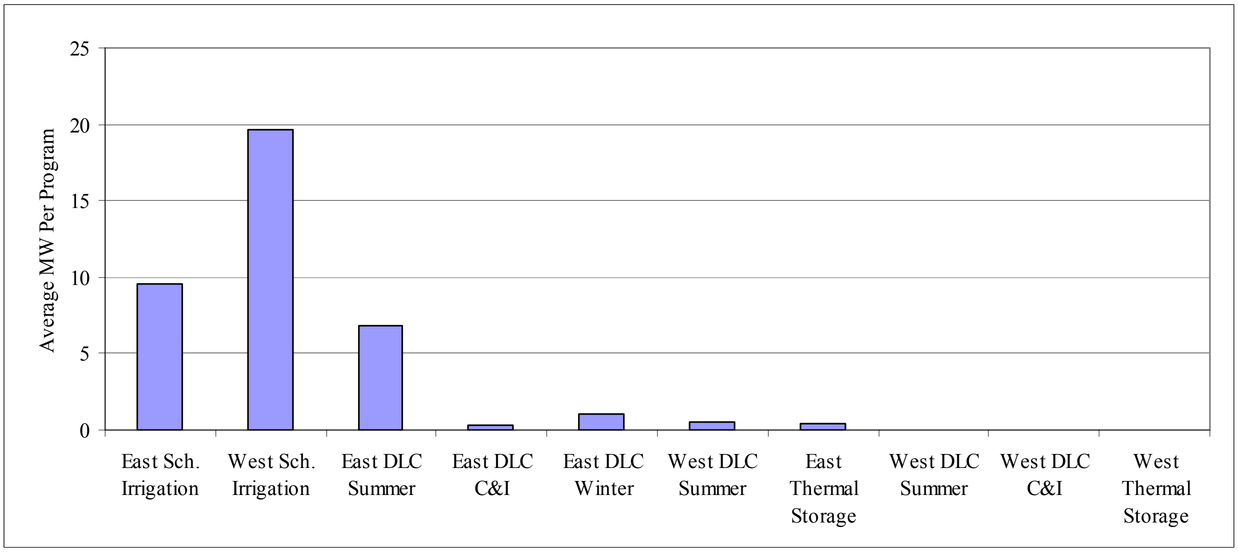


**Figure 7.7 – Class 1 DSM Average Megawatts for Alternative Future Scenarios, 2007-2016**




Based on these CEM results, and assuming a generic two or three-year phase-in period, Table 7.15 shows the Class 1 DSM resource addition schedule for each of the risk analysis portfolios.[54]

**Table 7.15 – Class 1 DSM Cumulative Resource Additions for Candidate Portfolios**

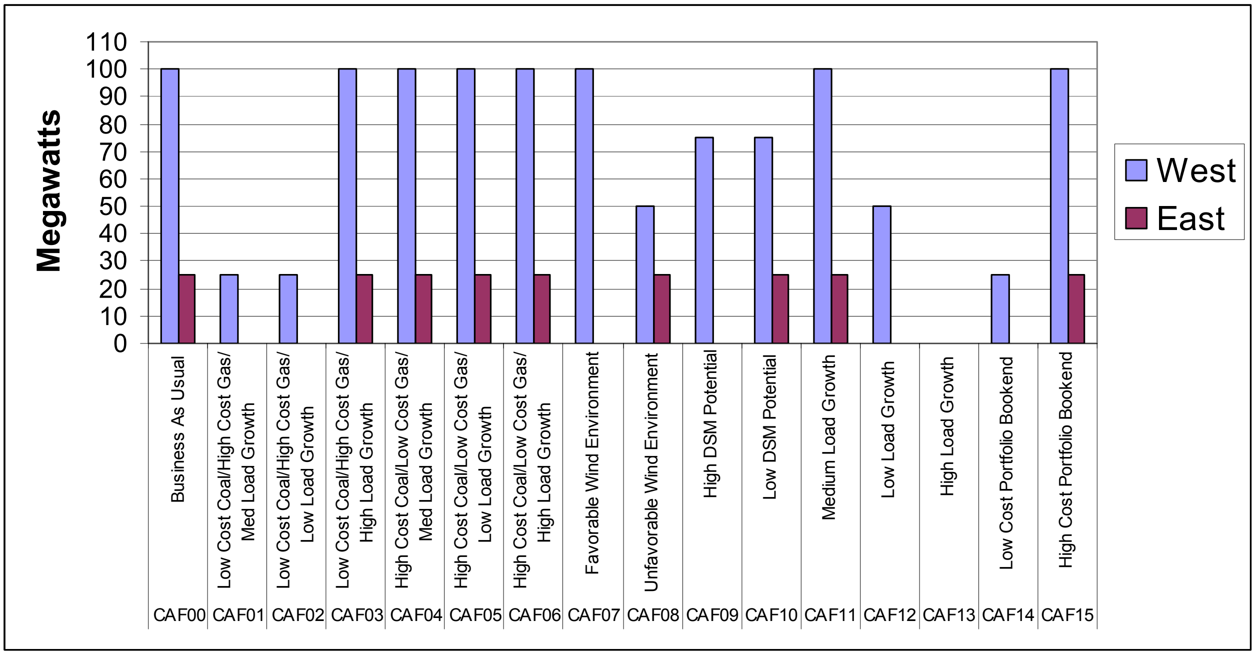
| Class 1 DSM Program | Location | Annual Cumulative Megawatt Additions (at the customer meter) | | | |
|---|---|---|---|---|---|
| | | 2010 | 2011 | 2012 | 2013 |
| Summer Direct Load Control | East | | 16 | 32 | 48 |
| Irrigation Control | East | | 8 | 15 | |
| Irrigation Control | West | 11 | 21 | 32 | |

**Combined Heat and Power Resources**

A fixed megawatt amount of combined heat and power (CHP) resources were included in all risk analysis portfolios based on a review of CHP addition patterns for the alternative future scenarios. Figure 7.8 shows the megawatts selected in each of the scenarios by location. (Note that the CHP resource included in the CEM was the 25-megawatt gas-fired topping cycle unit.) The most common resource selection pattern was 125 megawatts (100 megawatts installed in the west side and 25 megawatts installed in the east side), which occurred for seven of the 16 scenarios. The average quantity selected for all scenarios was 90 megawatts. For 11 out of the 16 scenarios, the CHP capacity was added in 2012. Based on these results, PacifiCorp chose a CHP resource investment schedule consisting of three 25-megawatt CHP units in the west in 2012 and one 25-megawatt CHP facility in the east control area in 2012.

[54] Selection of DSM programs or any other resource type for the candidate portfolios should not be construed as meaning that PacifiCorp is limiting program procurement in any way. Similarly, the resource additions schedule, including the phase-in period, is not indicative of the pace of actual program implementation once PacifiCorp identifies cost-effective programs through its procurement process.

**Figure 7.8 – CHP Quantities Selected for Each Alternative Future Scenario, 2007-2016**




## Alternative Resource Strategies

The original 12 risk analysis portfolios were developed according to five resource strategies. These portfolios are distinguished by the planning reserve margin level and the quantity and timing of wind, front office transactions, pulverized coal, and IGCC resources included. The five resource strategies are summarized below.

- Reduce $CO_2$ cost risk by deferring coal plants until low $CO_2$-emitting coal options with carbon sequestration are commercially proven (such as IGCC or pulverized coal with chill ammonia $CO_2$ removal)[55], or eliminating them as a resource option altogether.
- Reduce electricity market price risk by eliminating long-term reliance on front office transactions after 2011, the year that PacifiCorp's system becomes significantly capacity-short.
- Acquire additional wind resources above the amount contained in the initial wind investment schedule described above.
- Plan to a 12 percent planning reserve margin to reduce the risk of having excess generation capacity in the event that expected load growth does not materialize.
- Acquire base load coal resources in the near term to hedge against high gas and electricity prices and price volatility.

[55] This strategy is what the Oregon PUC calls a "coal plant delay scenario". It relies primarily on gas resources and market purchases to address any resource gaps until IGCC is available. (See OPUC IRP Acknowledgement Order, LC-39, Order No. 06-029, p. 51.)

Table 7.16 outlines the specifications for the 12 risk analysis portfolios (labeled RA1 through RA12), and presents the design rationale for each.

The CEM scenario definitions for the risk analysis portfolios include the "medium" forecast values for $CO_2$ costs, gas/electricity prices, load growth, RPS generation requirements, production tax credit availability, and DSM potential. Nevertheless, the risk analysis portfolios emulate many of the other scenario conditions modeled for the alternative future studies. For example, RA6, which entails removal of pulverized coal as an option, is representative of the coal resource outcome of the three alternative future scenarios based on high coal costs and low gas costs (CAF04, CAF05, and CAF06).

**Table 7.16 – Risk Analysis Portfolio Descriptions (Group 1)**

| ID | Description | Design Rationale |
|---|---|---|
| **RA1** | "Medium" alternative future portfolio, with wind, DSM, and CHP at fixed levels and front office transactions capped at quantities assumed for the 2004 IRP | By virtue of having the fewest constraints on resource choice, it serves as a performance benchmark and starting point for development of the other 11 portfolios. |
| **RA2** | RA1 with front office transactions removed as a resource option from 2012 onward (long-term asset-based portfolio) | Tests the strategy of eliminating the use of short-term market purchases (front office transactions) to meet long-term resource needs, and thereby reduce exposure to electricity market price risk. |
| **RA3** | RA1 with an additional 600 MW of wind added into the portfolio | Tests the strategy of using incremental amounts of wind to reduce $CO_2$, fuel, and market price risks. |
| **RA4** | RA2 with 12% planning reserve margin and front office transactions removed as a resource option from 2012 onward (long-term asset-based portfolio) | Represents a variant of the "long-term asset-based" portfolio (RA2), but with the lower planning reserve margin to determine the associated cost/risk tradeoff. |
| **RA5** | RA2 with the model constrained to select a second Utah pulverized coal plant in 2013 and an east-side IGCC in 2014. Front office transactions are removed as a resource option from 2012 onward (long-term asset-based portfolio) | Tests the relative economics and risk of building coal early as a hedge against gas and electricity market price risk; the IGCC plant replaces an east-side gas plant. |
| **RA6** | RA1 with pulverized coal removed as a resource option | Tests the strategy of reducing $CO_2$ cost risks, as well as testing the risk impact of relying on higher variable cost, shorter lead-time resources until IGCC is commercially ready (i.e., gas-fired generation and market purchases). |
| **RA7** | RA2 with 600 MW of additional wind as in RA3 and front office transactions removed as a resource option from 2012 onward (long-term asset-based portfolio) | Tests additional wind in combination with the construction pattern resulting from limiting front office transactions. |
| **RA8** | RA1 with a 12% planning reserve margin | Tests the medium alternative future portfolio (RA1) with the lower 12% planning reserve margin. |
| **RA9** | RA8 with the model restricted to select Wyoming IGCC plants in 2013 and 2016 | Tests an IGCC-intensive portfolio at the lower planning reserve margin level, assuming that the technology is commercially mature enough to acquire by 2013. |
| **RA10** | RA9 with a 15% planning reserve margin | Creates a version of RA9 that parallels others with the higher 15% planning reserve margin. Recommended by an IRP public stakeholder at the October 31, IRP public meeting. |

| ID | Description | Design Rationale |
|---|---|---|
| **RA11** | RA3 (600 MW additional wind and front office transactions included) with the model restricted to select gas resources in 2012 and 2013 and an IGCC resource in 2014 | Tests the strategy of reducing $CO_2$ cost risks with additional wind and restrictions on pulverized coal builds, as well as testing the risk impact of relying on gas resources and front office transactions to address resource deficits until an IGCC resource is acquired in 2014.[56] |
| **RA12** | RA11 with a 12% planning reserve margin | Creates a version of RA11 that parallels others with the lower 12% planning reserve margin. See the previous footnote. |

The CEM was allowed to optimize the timing of all resources, subject to the following conditions. First, the earliest in-service dates for resources reported in Chapter 5 (Table 5.1, East Side Supply-Side Resource Options) were observed with the exception of the Wyoming supercritical pulverized coal (SCPC) plant. Based on a more recent assessment of the acquisition timeline for this resource, the earliest in-service date was changed from 2013 to 2014 in the model. (Also note that the first Utah SCPC resource was modeled at 340 megawatts rather than the 600 megawatts reported in the Supply-Side Resource Options table to reflect a project scale similar to the Intermountain Power Project Unit 3 (IPP 3). This unit is thus referenced as the "small Utah SCPC resource.") Second, the timing of wind, class 1 DSM, and CHP was fixed according to the pre-defined investment schedules described earlier in the chapter.

Running the CEM for each of the 12 risk analysis portfolios resulted in a unique set of generating and transmission resources and timing patterns. Resource selections for 2012–2014 are profiled below.

- 2012 resources
  - The small Utah SCPC resource was selected in 10 of the 12 portfolios, or 9 of the 11 for which pulverized coal was not excluded as a model option
  - The east single-cycle combustion turbine (SCCT) frame was selected in 9 of the 12 portfolios
  - The east combined cycle combustion turbine (CCCT) was selected in 5 of the 12 portfolios
  - The west SCCT frame was selected in 10 of the 12 portfolios
  - The west CCCT was selected in 4 of the 12 portfolios
- 2013 and 2014 resources
  - The first Wyoming SCPC resource was selected in 6 of the 12 portfolios (replaced by IGCC in one and not allowed in another)
  - Only one gas resource was selected for 2013; all others were selected for 2012

Table 7.17 shows generation (coal and gas) and transmission resource additions for each of the risk analysis portfolios by general location and year.

[56] This portfolio, requested for study by OPUC staff, addresses the OPUC's 2004 IRP acknowledgement order mandate to "fully explore whether delaying a commitment to coal until IGCC technology is further commercialized is a reasonable course of action." (Order No. 06-029, p. 51)

## Table 7.17 – Generation and Transmission Resource Additions

| | Resource | RA1 | RA2 | RA3 | RA4 | RA5 | RA6 | RA7 | RA8 | RA9 | RA10 | RA11 | RA12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | Small Utah SCPC (340 MW) | 2012 | 2012 | 2012 | 2012 | 2012 | - | 2012 | 2012 | 2012 | 2012 | 2018 | - |
| | Large Utah SCPC (600 MW) | 2017 | 2018 | 2018 | 2018 | 2013 | - | 2018 | 2017 | 2018 | 2018 | 2018 | 2018 |
| | Wyoming SCPC 1 (750 MW) | 2013 | 2013 | 2015 | 2013 | 2013 | - | 2014 | 2014 | 2017 | 2017 | 2015 | 2016 |
| | Wyoming SCPC 2 (750 MW) | 2018 | 2018 | 2018 | 2018 | 2018 | - | 2018 | 2018 | - | - | 2018 | 2018 |
| | West IGCC (200 MW) | 2016 | 2017 | 2017 | 2016 | 2018 | 2016 | 2017 | 2018 | 2018 | 2018 | 2018 | 2018 |
| | West IGCC (300 MW) | 2018 | 2017 | 2018 | 2017 | 2018 | 2018 | 2017 | 2018 | 2018 | 2018 | 2018 | 2018 |
| | Wyoming IGCC 1 (497 MW) | - | - | - | - | 2014 | 2016 | - | - | 2013 | 2013 | 2014 | 2014 |
| | Wyoming IGCC 2 (497 MW) | - | - | - | - | - | 2017 | - | - | 2016 | 2016 | - | - |
| | Utah IGCC 1 (497 MW) | - | - | - | - | - | 2018 | - | - | - | - | - | - |
| | Utah IGCC 2 (497 MW) | - | - | - | - | - | 2018 | - | - | - | - | - | - |
| Gas | West SCCT Frame (332 MW) | 2012 | 2012 | 2012 | 2012 | 2012 | 2013 | 2012 | - | - | 2012 | 2012 | 2012 |
| | West CCCT F 2x1 w/DF (602 MW) | - | 2012 | - | - | 2012 | - | 2012 | - | - | - | - | - |
| | West CCCT G 1x1 w/DF (392 MW) | - | - | - | 2012 | - | - | - | - | - | - | - | - |
| | East SCCT Frame (302 MW) | - | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | - | - | 2012 | 2012 |
| | East CCCT F 2x1 w/DF (548 MW) | - | 2012 | - | - | 2012 | 2012 | 2012 | - | - | - | - | - |
| | East CCCT G 1x1 w/DF (357 MW) | - | - | - | 2012 | - | - | - | - | - | - | - | - |
| | Front Office Transactions Ave Annual MW, 2012-2016 | 1,063 | - | 1,005 | - | - | 1,024 | - | 1,000 | 1,115 | 1,097 | 1,009 | 863 |
| | Planning Reserve Margin | 15% | 15% | 15% | 12% | 15% | 15% | 15% | 12% | 12% | 15% | 15% | 12% |

| Transmission Project | RA1 | RA2 | RA3 | RA4 | RA5 | RA6 | RA7 | RA8 | RA9 | RA10 | RA11 | RA12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| West Main-Walla Walla (630 MW) | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 |
| Walla Walla-Yakima B (400 MW) | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 | 2012 |
| Mona-Utah North (500 MW increments) | 2012 x1 | 2018 x1 | 2012 x1 | 2018 x1 | 2018 x1 | 2018 x1 | 2018 x1 | 2018 x1 | 2018 x1 | 2012 x2 | - | - |
| Jim Bridger-Ben Lomond (500 MW increments) | 2015 x2 | 2016 x2 | 2016 x2 | 2016 x2 | 2014 x2 | 2014 x1 | 2014 x2 | 2016 x2 | 2015 x2 | 2016 x2 | 2015 x2 | 2016 x3 |
| Utah North-West Main (500 MW increments) | 2018 x1 | 2018 x1 | 2018 x1 | 2018 x1 | 2014 x1 | 2018 x1 | 2018 x1 | 2018 x1 | 2017 x1 | 2017 x1 | 2018 x1 | 2018 x1 |
| Wyoming-Bridger (500 MW increments) | - | - | 2018 x1 | - | 2018 x1 | - | - | - | 2018 x3 | 2015 x1 | 2018 x1 | 2018 x1 |
| Path-C Upgrade B[57] (600 MW) | - | - | - | - | - | 2018 | - | - | - | - | - | - |

## STOCHASTIC SIMULATION RESULTS – GROUP 1 PORTFOLIOS

The 12 risk analysis portfolios were run in stochastic simulation mode with varying loads, thermal outages, hydro availability, and electricity and natural gas wholesale prices across 100 itera-

[57] The original Path C upgrade and the Craig Hayden - Utah North transmission projects were treated as fixed assumptions in the CEM.

tions. The sections below show how the portfolios compare to one another on the basis of the stochastic cost, risk, reliability, and emissions measures. The section concludes with a summary portfolio performance assessment, as well as resource selection conclusions that informed the development of the second group of risk analysis portfolios.

**Stochastic Mean Cost**

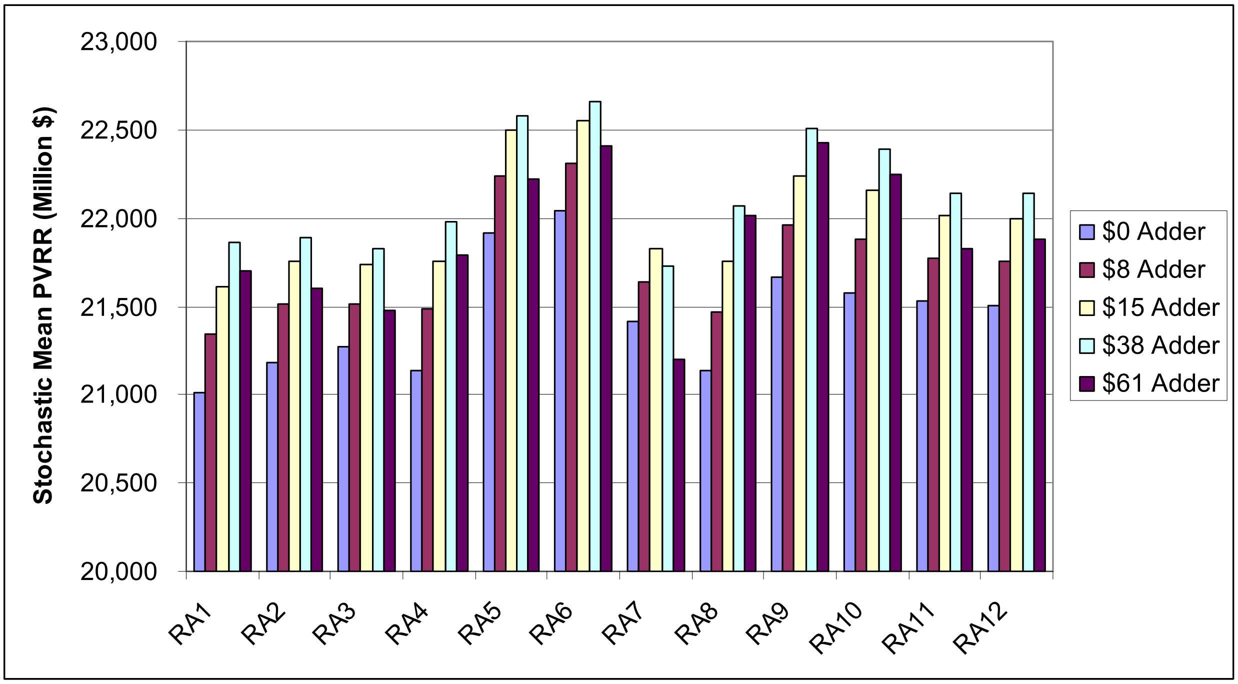
Table 7.18 reports the stochastic mean PVRR for each of the portfolios by $CO_2$ adder cases, and shows the portfolio rankings based on the PVRR average across the five adder cases. Portfolio RA1 has the lowest average PVRR, followed by RA7 and RA3. In contrast, RA5 and RA6 have the highest average PVRRs.

**Table 7.18 – Portfolio Cost by $CO_2$ Adder Case**

| ID | Stochastic Mean PVRR (Million $) | | | | | | Rank |
|---|---|---|---|---|---|---|---|
| | $0 Adder (2008$) | $8 Adder (2008$) | $15 Adder (2008$) | $38 Adder (2008$) | $61 Adder (2008$) | Average | |
| RA1 | 21,016 | 21,346 | 21,614 | 21,865 | 21,706 | 21,509 | 1 |
| RA2 | 21,183 | 21,514 | 21,758 | 21,893 | 21,601 | 21,590 | 4 |
| RA3 | 21,269 | 21,515 | 21,740 | 21,827 | 21,482 | 21,567 | 3 |
| RA4 | 21,140 | 21,489 | 21,753 | 21,975 | 21,789 | 21,629 | 5 |
| RA5 | 21,921 | 22,238 | 22,496 | 22,583 | 22,225 | 22,292 | 11 |
| RA6 | 22,042 | 22,313 | 22,548 | 22,658 | 22,411 | 22,394 | 12 |
| RA7 | 21,414 | 21,642 | 21,829 | 21,732 | 21,200 | 21,563 | 2 |
| RA8 | 21,140 | 21,472 | 21,758 | 22,072 | 22,018 | 21,692 | 6 |
| RA9 | 21,663 | 21,964 | 22,242 | 22,510 | 22,423 | 22,160 | 10 |
| RA10 | 21,573 | 21,882 | 22,158 | 22,392 | 22,244 | 22,050 | 9 |
| RA11 | 21,529 | 21,769 | 22,019 | 22,139 | 21,827 | 21,857 | 8 |
| RA12 | 21,505 | 21,754 | 21,999 | 22,143 | 21,881 | 21,856 | 7 |

Figure 7.9 shows the progression of each portfolio's stochastic cost as the $CO_2$ adder increases. For most of the portfolios, the cost peaks at the $38 adder level, and then declines at the $61 adder level. This cost behavior is driven by the influence of $CO_2$ allowance trading activity in the studies' out-years, where a significant amount of allowance credits are realized.

**Figure 7.9 – Stochastic Mean Cost by $CO_2$ Adder Case**




It is noteworthy that the CEM's deterministic portfolio solution without resource restrictions—Portfolio RA1—also has the lowest stochastic cost. Table 7.19 summarizes the cost impact of constraining CEM-selected resources in the reference portfolio according to the resource strategies defined for the other portfolios. The average PVRRs for the five $CO_2$ adder cases is used as the cost impact measure.

**Table 7.19 – Cost Impact of Portfolio Resource Strategies**

| ID | Resource Strategy Modeled in the CEM | Cost Impact Relative to Portfolio RA1<br>Ave. Stochastic Mean PVRR for $CO_2$ adder cases ( Million $) |
|---|---|---|
| RA1 | Reference Case: no resource constraints (FOT capped at 1200 MW) | - |
| RA2 | Remove FOT as a resource option after 2011 | 81 |
| RA3 | Additional wind | 57 |
| RA4 | Plan to a 12% PRM and remove FOT after 2011 | 120 |
| RA5 | Early SCPC and force IGCC in 2014 | 783 |
| RA6 | Remove SCPC as a resource option | 885 |
| RA7 | Additional wind and remove FOT after 2011 | 54 |
| RA8 | Plan to a 12% PRM | 183 |
| RA9 | Force IGCC in 2013 and 2016 | 651 |
| RA10 | Force IGCC in 2013 and 2016; plan to 12% PRM | 540 |
| RA11 | Additional wind; exclude SCPC for 2012-13 and force IGCC in 2014 | 348 |
| RA12 | Same as RA11 but plan to a 12% PRM | 347 |

As shown in the table, constraining the coal resources has the largest impact. Removing super-critical pulverized coal increases portfolio cost by $885 million relative to the RA1 portfolio. Portfolios with a 15 percent planning reserve margin that involved restricting the CEM to select IGCC in certain years (RA5, RA10, and RA11) averaged $557 million higher. The average cost increase for all the portfolios relative to RA1 was $368 million.

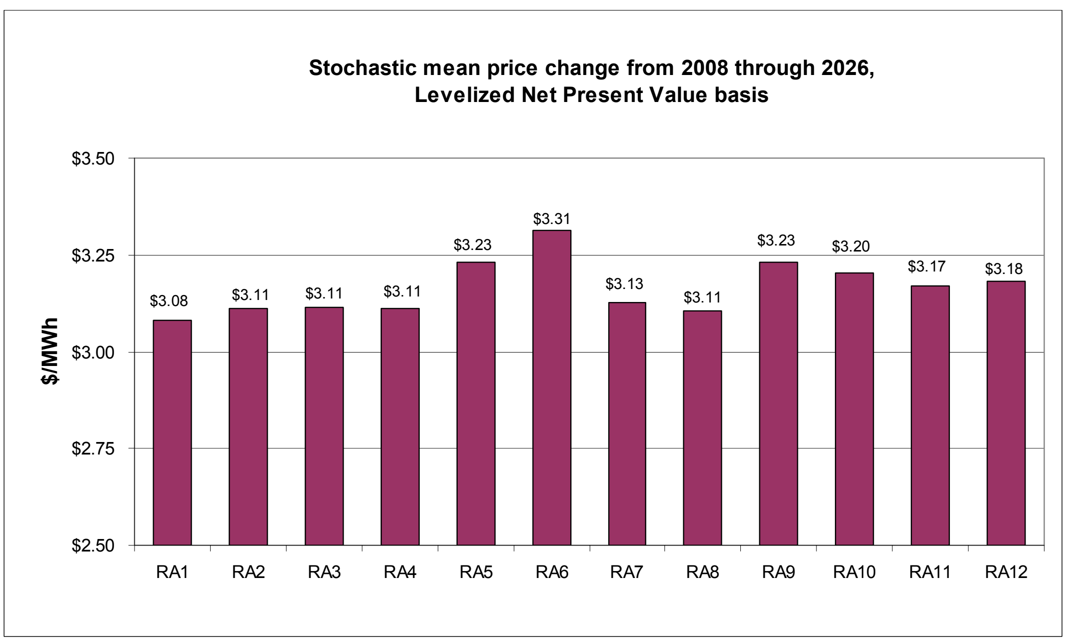
Other observations concerning the relationship between portfolio cost and resource mix and timing include the following.

- Building coal resources earlier or later than recommended by the CEM increases stochastic cost.
- Lowering the planning reserve margin increases stochastic PVRR due to the costs associated with higher Energy Not Served. Rather than reducing investment in base load plants to meet the lower load obligation, the CEM chooses to defer them.
- Acquiring the additional 600 megawatts of wind increases stochastic cost, although the amount is smaller than for the other resource strategies.
- Removing front office transactions after 2011 increases stochastic cost.

## Customer Rate Impact

Figure 7.10 shows the customer rate impact of each portfolio.[58] The rate impact measure is the change in the customer dollar-per-megawatt-hour price from 2008 through 2026 due to the portfolio resources, expressed on a levelized net present value basis. As indicated, RA1 has the smallest rate change at $3.08/MWh. RA6, which has no pulverized coal plants, has the highest at $3.31/MWh.

**Figure 7.10 – Customer Rate Impact**




[58] The revenue requirement calculated by the CEM uses a real levelized capital charge.

## Emissions Externality Cost

PacifiCorp calculates the emissions externality cost as the increase in stochastic mean PVRR relative to the $0 adder case for each $CO_2$ adder level. This externality cost measure captures (1) the increased variable operating costs for fossil fuel generation, (2) the system re-dispatch impact attributable to the cost adders, and (2) the net present value of the sum of the annual $CO_2$ allowance trading balances for 2007–2026. The externality costs are reported in Table 7.20 along with portfolio rankings based on the average of the incremental costs for the four adder levels. These cost estimates assume a cap-and-trade compliance strategy.

Portfolio RA7 performs the best with an average externality cost of $187 million. RA8 had the highest cost at $690 million. All the portfolios that included the extra wind—RA3, RA7, RA11, and RA12—had the lowest costs. In contrast, portfolios built according to the lower 12-percent planning reserve margin had the highest externality costs (RA8 and RA9). The lower reserve margin results in higher coal resource utilization to keep the system balanced.

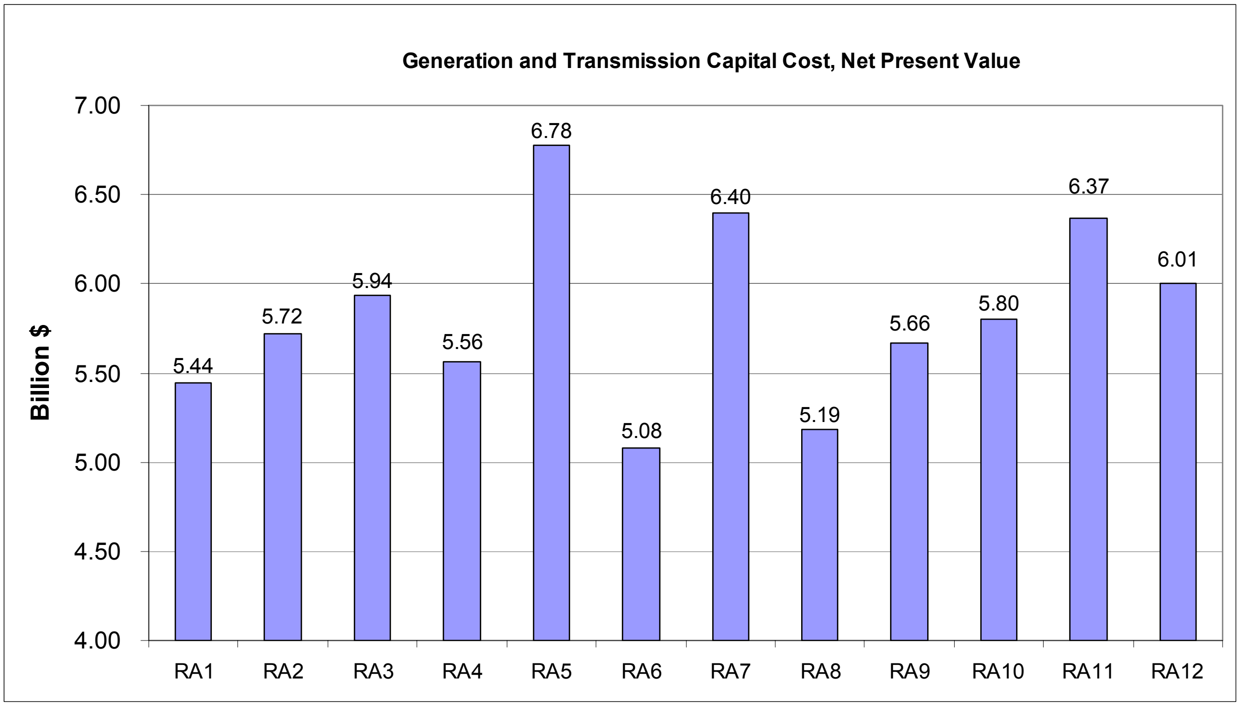
**Table 7.20 – Portfolio Emissions Externality Cost by $CO_2$ Adder Level**

| | Incremental Stochastic Mean PVRR by $CO_2$ Adder (Million $) | | | | | | |
|---|---|---|---|---|---|---|---|
| | $CO_2$ Adder Level (2008$) | | | | | | |
| ID | $0 | $8 | $15 | $38 | $61 | Average | Rank |
| RA1 | - | 330 | 598 | 849 | 690 | 617 | 10 |
| RA2 | - | 331 | 575 | 710 | 417 | 508 | 7 |
| RA3 | - | 246 | 471 | 558 | 213 | 372 | 2 |
| RA4 | - | 349 | 613 | 835 | 649 | 612 | 9 |
| RA5 | - | 317 | 575 | 662 | 304 | 465 | 6 |
| RA6 | - | 271 | 506 | 616 | 369 | 441 | 5 |
| RA7 | - | 228 | 415 | 318 | -214 | 187 | 1 |
| RA8 | - | 332 | 618 | 932 | 878 | 690 | 12 |
| RA9 | - | 301 | 579 | 847 | 760 | 622 | 11 |
| RA10 | - | 309 | 585 | 819 | 672 | 596 | 8 |
| RA11 | - | 240 | 490 | 610 | 298 | 410 | 3 |
| RA12 | - | 249 | 494 | 638 | 375 | 439 | 4 |

## Capital Cost

Figure 7.11 shows the total capital cost for each portfolio, expressed on a net present value of the sum of all capital costs accrued for 2007–2026. As expected, RA5 with its relatively larger coal plant investment schedule and earlier in-service dates exceeds all others at $6.78 billion. In contrast RA6—with no coal resources until 2016—has the lowest capital cost at $5.08 billion. The average capital for all portfolios is $5.83 billion.

**Figure 7.11 – Total Capital Cost by Portfolio**




## Stochastic Risk Measures

Tables 7.21 and 7.22 report the stochastic risk results for each of the 12 risk analysis portfolios. Table 7.21 shows risk exposure and standard deviation (production cost) averaged across the five $CO_2$ adder cases, as well as the portfolio rankings for these two measures. Table 7.22 shows the detailed statistics for each $CO_2$ adder case, and also includes fifth-percentile PVRR and ninety-fifth-percentile PVRR results.

**Table 7.21 – Average Risk Exposure and Standard Deviation for $CO_2$ Adder Cases**

| ID | Risk Exposure (Million $) | Rank | Standard Deviation (Million $) | Rank |
|---|---|---|---|---|
| | Average Across $CO_2$ Adder Cases | | | |
| RA1 | 41,928 | 6 | 13,246 | 6 |
| RA2 | 41,217 | 4 | 13,015 | 4 |
| RA3 | 41,690 | 5 | 13,149 | 5 |
| RA4 | 42,245 | 7 | 13,324 | 7 |
| RA5 | 36,706 | 1 | 11,891 | 1 |
| RA6 | 47,588 | 12 | 14,666 | 12 |
| RA7 | 39,856 | 2 | 12,658 | 2 |
| RA8 | 43,287 | 11 | 13,581 | 11 |
| RA9 | 42,784 | 9 | 13,503 | 9 |

| ID | Risk Exposure (Million $) | Rank | Standard Deviation (Million $) | Rank |
|---|---|---|---|---|
| | Average Across $CO_2$ Adder Cases | | | |
| RA10 | 42,247 | 8 | 13,337 | 8 |
| RA11 | 39,950 | 3 | 12,771 | 3 |
| RA12 | 42,952 | 10 | 13,576 | 10 |

### Table 7.22 – Risk Measure Results by $CO_2$ Adder Case (Million $)

| ID | Risk Exposure | Standard Deviation | 5th Percentile | 95th Percentile | Upper-Tail Mean |
|---|---|---|---|---|---|
| $0 $CO_2$ Adder (2008$) | | | | | |
| RA1 | 34,879 | 9,837 | 14,258 | 34,111 | 55,894 |
| RA2 | 34,096 | 9,608 | 14,504 | 33,989 | 55,279 |
| RA3 | 34,654 | 9,753 | 14,553 | 34,404 | 55,923 |
| RA4 | 35,063 | 9,886 | 14,355 | 34,358 | 56,203 |
| RA5 | 29,837 | 8,544 | 15,819 | 33,286 | 51,758 |
| RA6 | 39,971 | 11,060 | 14,221 | 36,155 | 62,013 |
| RA7 | 32,900 | 9,313 | 14,968 | 34,007 | 54,315 |
| RA8 | 36,192 | 10,154 | 14,014 | 34,725 | 57,332 |
| RA9 | 35,783 | 10,097 | 14,699 | 35,608 | 57,445 |
| RA10 | 35,210 | 9,939 | 14,862 | 35,075 | 56,783 |
| RA11 | 33,101 | 9,411 | 14,988 | 34,596 | 54,630 |
| RA12 | 35,860 | 10,130 | 14,588 | 35,370 | 57,366 |
| $8 $CO_2$ Adder (2008$) | | | | | |
| RA1 | 37,651 | 10,690 | 12,770 | 35,895 | 58,997 |
| RA2 | 36,957 | 10,484 | 12,974 | 35,812 | 58,471 |
| RA3 | 37,419 | 10,602 | 12,900 | 36,099 | 58,934 |
| RA4 | 37,923 | 10,761 | 12,691 | 36,176 | 59,412 |
| RA5 | 32,538 | 9,377 | 13,987 | 35,148 | 54,776 |
| RA6 | 43,026 | 11,992 | 12,892 | 37,837 | 65,339 |
| RA7 | 35,683 | 10,166 | 13,061 | 35,730 | 57,326 |
| RA8 | 38,949 | 11,008 | 12,824 | 36,481 | 60,420 |
| RA9 | 38,493 | 10,936 | 13,501 | 37,326 | 60,457 |
| RA10 | 37,974 | 10,787 | 13,313 | 36,817 | 59,856 |
| RA11 | 35,759 | 10,236 | 13,264 | 36,279 | 57,258 |
| RA12 | 38,638 | 10,984 | 13,001 | 37,029 | 60,391 |
| $15 $CO_2$ Adder (2008$) | | | | | |
| RA1 | 39,161 | 13,006 | 12,185 | 37,049 | 60,775 |
| RA2 | 38,449 | 12,737 | 12,340 | 36,953 | 60,207 |
| RA3 | 38,920 | 12,899 | 12,328 | 37,208 | 60,660 |
| RA4 | 39,432 | 13,053 | 12,232 | 37,327 | 61,186 |
| RA5 | 33,965 | 11,628 | 13,575 | 36,329 | 56,461 |
| RA6 | 44,615 | 14,400 | 12,701 | 38,930 | 67,163 |
| RA7 | 37,149 | 12,394 | 12,688 | 36,822 | 58,978 |

| ID | Risk Exposure | Standard Deviation | 5th Percentile | 95th Percentile | Upper-Tail Mean |
|---|---|---|---|---|---|
| RA8 | 40,469 | 13,332 | 12,361 | 37,624 | 62,226 |
| RA9 | 39,980 | 13,270 | 12,990 | 38,470 | 62,221 |
| RA10 | 39,479 | 13,103 | 12,800 | 37,967 | 61,637 |
| RA11 | 37,215 | 12,541 | 12,953 | 37,428 | 59,234 |
| RA12 | 40,127 | 13,340 | 12,544 | 38,142 | 62,126 |
| **\$38 $CO_2$ Adder (2008\$)** | | | | | |
| RA1 | 45,344 | 15,106 | 10,304 | 40,944 | 67,209 |
| RA2 | 44,675 | 14,873 | 10,218 | 40,799 | 66,568 |
| RA3 | 45,113 | 15,004 | 10,315 | 40,962 | 66,940 |
| RA4 | 45,733 | 15,202 | 10,249 | 41,207 | 67,708 |
| RA5 | 40,037 | 13,728 | 11,554 | 39,967 | 62,620 |
| RA6 | 51,296 | 16,633 | 9,933 | 42,604 | 73,953 |
| RA7 | 43,247 | 14,487 | 10,371 | 40,489 | 64,979 |
| RA8 | 46,741 | 15,455 | 10,211 | 41,521 | 68,813 |
| RA9 | 46,206 | 15,369 | 10,878 | 42,278 | 68,716 |
| RA10 | 45,674 | 15,193 | 10,975 | 41,781 | 68,066 |
| RA11 | 43,311 | 14,616 | 11,019 | 41,334 | 65,451 |
| RA12 | 46,418 | 15,465 | 10,586 | 41,935 | 68,561 |
| **\$61 $CO_2$ Adder (2008\$)** | | | | | |
| RA1 | 52,604 | 17,593 | 6,398 | 44,741 | 74,310 |
| RA2 | 51,911 | 17,372 | 6,453 | 44,526 | 73,511 |
| RA3 | 52,345 | 17,487 | 6,203 | 44,627 | 73,826 |
| RA4 | 53,076 | 17,720 | 6,267 | 44,987 | 74,865 |
| RA5 | 47,152 | 16,176 | 7,941 | 43,024 | 69,377 |
| RA6 | 59,029 | 19,245 | 6,505 | 46,249 | 81,440 |
| RA7 | 50,298 | 16,931 | 6,105 | 43,972 | 71,498 |
| RA8 | 54,084 | 17,956 | 6,452 | 45,323 | 76,102 |
| RA9 | 53,459 | 17,843 | 7,121 | 45,995 | 75,883 |
| RA10 | 52,896 | 17,663 | 7,112 | 45,514 | 75,141 |
| RA11 | 50,365 | 17,052 | 6,989 | 45,086 | 72,193 |
| RA12 | 53,717 | 17,963 | 6,559 | 45,628 | 75,597 |

Portfolio RA5 has the smallest average risk exposure due to the early addition of coal capacity. Other resource strategies that lower risk exposure include (1) increasing wind capacity, (2) eliminating or reducing reliance on market purchases, and (3) planning to a 15% reserve margin rather than 12%. For example, by comparing RA3 with RA1, the 600 megawatts of additional wind is shown to reduce risk exposure by an average of $238 million across the five $CO_2$ adder scenarios. The risk reduction benefit increases at successfully higher $CO_2$ adder levels ($224 million under the $0 adder to $260 million under the $61 adder). The benefit of reducing reliance on front office transactions after 2011 is evident from comparing portfolio RA2 with RA1. The average risk exposure decreases by an average of $711 million. Combining both extra wind and eliminating front office transactions after 2011 (RA7) decreases average risk exposure by $2.1

billion. Changing the planning reserve margin strategy (RA8) has a large impact on risk exposure: going from a 12% to 15% margin reduces average risk exposure by $1.4 billion.

In contrast to the risk exposure reduction strategies, removing pulverized coal as a resource option (RA5) increases average risk exposure by $5.7 billion. At the $61 $CO_2$ adder level, the risk exposure for RA6 reaches a high of $6.4 billion.

## Cost/Risk Tradeoff Analysis

The three figures below are scatter plots of portfolio cost (PVRR) and risk exposure, and illustrate the tradeoff between the two performance measures. Figure 7.12 plots the average PVRR and risk exposure across the $CO_2$ adder cases. Figure 7.13 shows the cost-risk relationship for the $0 $CO_2$ adder case, while Figure 7.14 shows the relationship for the $61 $CO_2$ adder case (representing the $CO_2$ scenario risk bookends).

The figures show that when considering exposure to potential high-cost outcomes, RA5 has the lowest portfolio risk regardless of the $CO_2$ adder level. However, when considering the balance between risk and cost, RA7 and RA1—and RA2 and RA3 right behind—perform the best among this portfolio set. Under the high $CO_2$ adder case, portfolio RA7 dominates the others by a significant amount.

**Figure 7.12 – Average Stochastic Cost versus Risk Exposure**

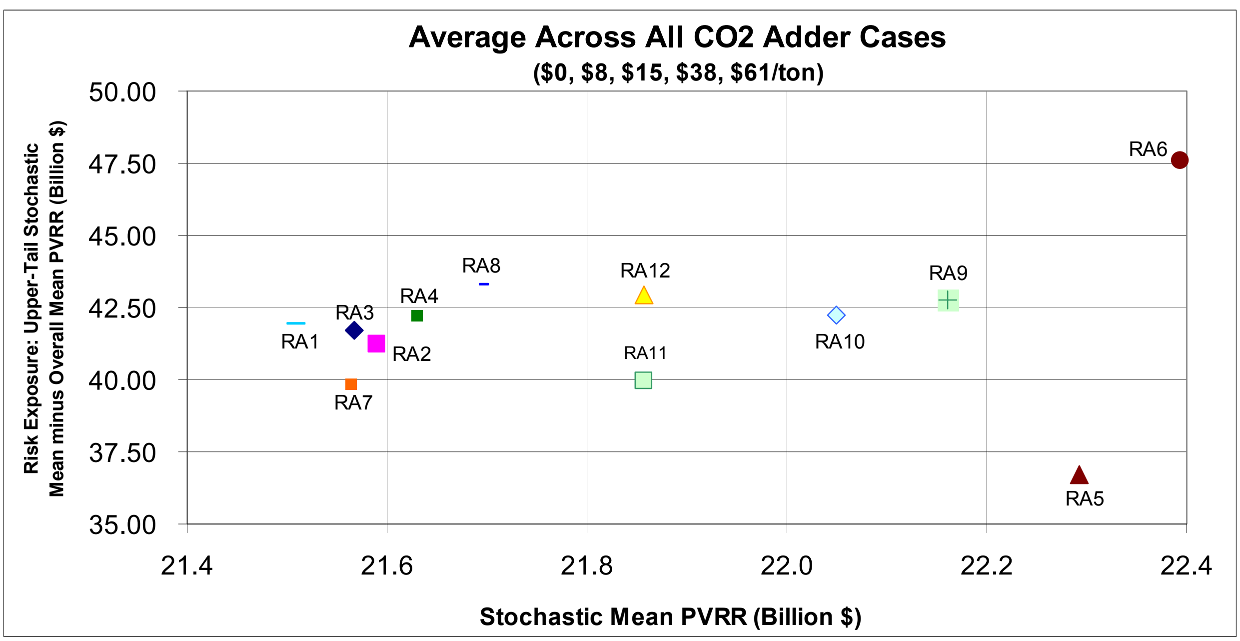


**Figure 7.13 – Stochastic Cost versus Risk Exposure for the $0 $CO_2$ Adder Case**

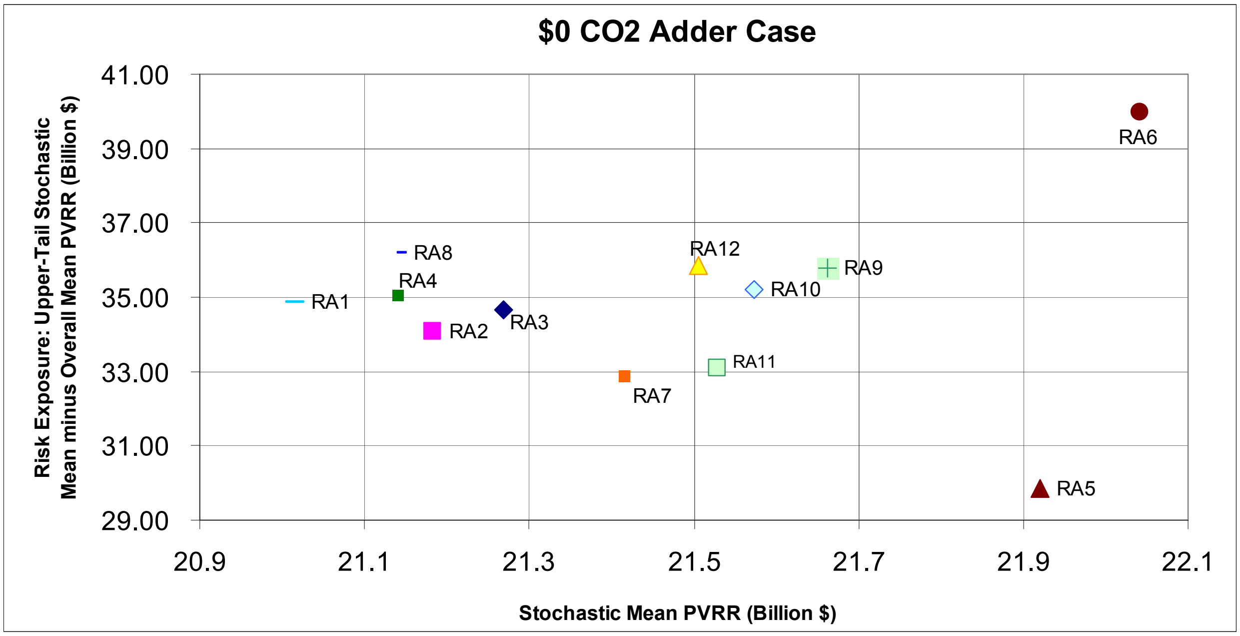
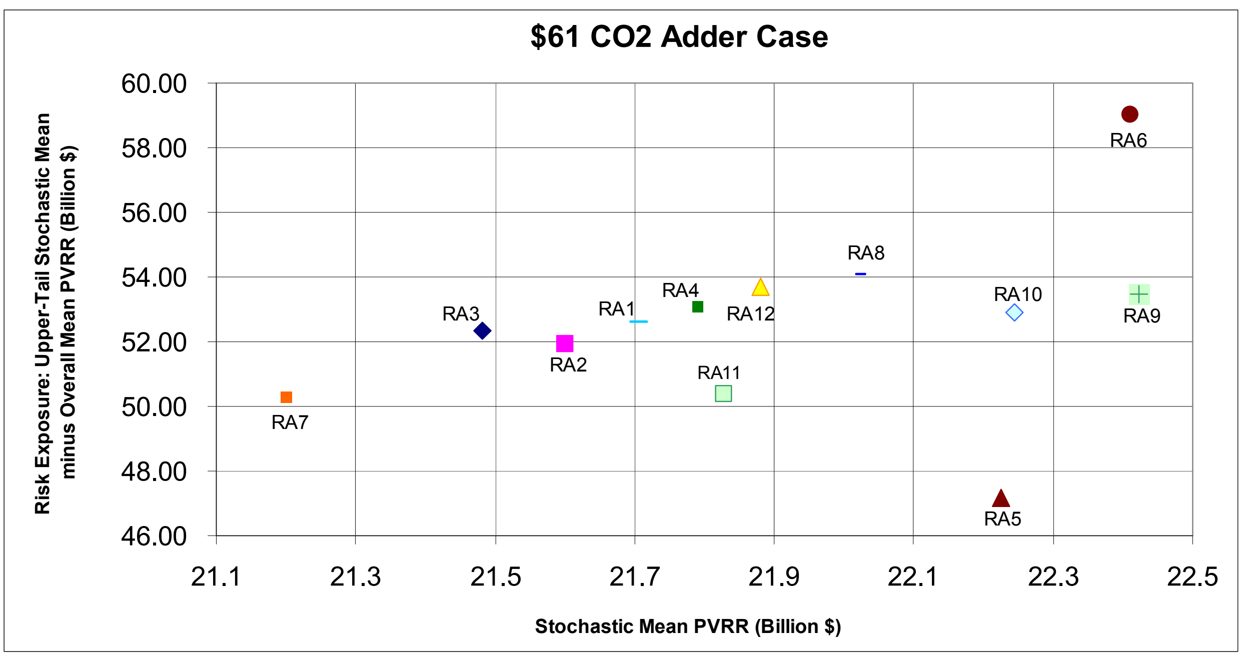



**Figure 7.14 – Stochastic Cost versus Risk Exposure for the $61 $CO_2$ Adder Case**




As far the resource strategies go, increasing wind capacity and reducing reliance on market purchases promotes a better balance of portfolio cost and risk. In contrast, eliminating pulverized coal yields the worst cost-risk balance in all cases; this strategy yields a portfolio with both higher-risk and higher-cost resources.

## Resource Strategy Risk Reduction

As described above, adding constraints to the reference portfolio results in a higher stochastic cost. Nevertheless, it can be desirable to choose portfolios or resource strategies that may be sub-optimal on the basis of expected stochastic cost, but that reduce risk exposure.

Several risk analysis portfolios were developed to evaluate the cost versus risk exposure implications of specific resource strategies. These resource strategies and the associated test portfolios are summarized in Table 7.23.

**Table 7.23 – Resource Strategies and Test Portfolios for Cost-Risk Exposure**

| Resource Strategy | Test Portfolio |
|---|---|
| Eliminate market purchases after 2012 to reduce electricity market price risk | RA2 |
| Include additional wind (600 MW) to reduce $CO_2$, fuel and market price risks | RA3 |
| Lower the planning reserve margin from 15% to 12% to reduce portfolio investment costs | RA8 |
| Remove pulverized coal plants as an option and fill the capacity gap with other resources | RA6 |

At issue is whether the resource strategies increase or decrease risk exposure relative to the reference portfolio, and by how much. If an extra dollar of PVRR spent on the resource strategy translates into more than a dollar in risk exposure reduction, then the extra portfolio cost could be considered a worthwhile insurance investment for customers. Comparing the PVRR and risk exposure at the $61 $CO_2$ adder level in these terms yields the following conclusions:

- **Eliminate market purchases after 2012 (RA2)** – this resource strategy lowers total risk exposure; the relative reduction is $4.15 for every additional PVRR dollar spent
- **Include an additional 600 megawatts of wind (RA3)** – this resource strategy lowers total risk exposure marginally; the relative reduction is $1.03 for every additional PVRR dollar spent
- **Lower the planning reserve margin from 15% to 12% (RA8)** – this resource strategy raises total risk exposure; the relative increase is $11.93 for every additional PVRR dollar spent
- **Remove pulverized coal plants as a resource option (RA6)** – this resource strategy raises total risk exposure; the relative increase is $6.26 for every additional PVRR dollar spent

## Carbon Dioxide and Other Emissions

The following tables and figures profile the $CO_2$ emissions footprint for the risk analysis portfolios, as well as for $SO_2$, $NO_X$, and mercury (Hg). For $CO_2$ emissions, results are shown by $CO_2$ adder level and for two periods, 2007–2016 and 2007–2026. The tables also report the separate $CO_2$ contributions from generators and market purchases (existing long term purchases, front office transactions and spot purchases). Figures 7.15 and 7.16 show how the cumulative $CO_2$ emission for each portfolio decline as the cost adder is increased.

The resource strategies had the following effect on generator $CO_2$ emissions relative to the reference portfolio, RA1:

- Removing all pulverized coal plants had the highest emission reduction benefit, lowering the generator $CO_2$ footprint by 12 million tons for 2007–2016 and 29 million tons for 2007–2026 on average
- Reducing front office transactions had a negligible impact on generator emissions for the first ten years; for 2007–2026, there was a decrease of 7 million tons
- The additional 600 megawatts of wind decreased emissions by 8 million tons for 2007–2016 and 22 million tons for 2007–2026
- Reducing the planning reserve margin from 15% to 12% decreased emissions by 2.5 million tons for 2007–2016, but the overall reduction for 2007–2026 was only 259,000 tons
- The IGCC bridging strategy (RA11) reduced emissions by 9 million tons for 2007–2016 and 14 million tons for 2007–2026

**Table 7.24 – Cumulative $CO_2$ Emissions by Cost Adder Level, 2007-2016**

| ID | Generator $CO_2$ Emissions, 2007-2016 (1000 Tons) | | | | | | Rank |
|---|---|---|---|---|---|---|---|
| | $0 Adder | $8 Adder | $15 Adder | $38 Adder | $61 Adder | Average | |
| RA1 | 520,275 | 498,032 | 494,673 | 488,422 | 483,805 | 497,041 | 9 |
| RA2 | 522,525 | 498,785 | 495,141 | 488,330 | 483,052 | 497,567 | 10 |
| RA3 | 511,893 | 490,290 | 486,868 | 480,446 | 475,651 | 489,030 | 4 |
| RA4 | 523,785 | 500,658 | 497,114 | 490,322 | 485,150 | 499,406 | 12 |
| RA5 | 526,226 | 501,006 | 497,079 | 488,500 | 481,903 | 498,943 | 11 |
| RA6 | 507,235 | 486,289 | 482,912 | 476,713 | 472,093 | 485,048 | 1 |
| RA7 | 515,681 | 492,030 | 488,377 | 481,337 | 475,995 | 490,684 | 5 |
| RA8 | 516,988 | 495,680 | 492,322 | 486,088 | 481,439 | 494,503 | 8 |
| RA9 | 515,118 | 493,741 | 490,461 | 484,494 | 480,148 | 492,792 | 6 |
| RA10 | 517,046 | 495,287 | 491,936 | 485,756 | 481,329 | 494,271 | 7 |
| RA11 | 511,198 | 489,590 | 486,177 | 479,694 | 474,732 | 488,278 | 3 |
| RA12 | 509,825 | 488,734 | 485,389 | 479,087 | 474,398 | 487,487 | 2 |

| ID | $CO_2$ Emissions from Market Purchases, 2007-2016 (1000 Tons) | | | | | | Rank |
|---|---|---|---|---|---|---|---|
| | $0 Adder | $8 Adder | $15 Adder | $38 Adder | $61 Adder | Average | |
| RA1 | 77,798 | 85,510 | 86,358 | 87,255 | 87,488 | 84,882 | 8 |
| RA2 | 65,301 | 73,831 | 74,758 | 75,742 | 76,068 | 73,140 | 4 |
| RA3 | 77,243 | 76,374 | 85,408 | 86,215 | 86,527 | 82,353 | 6 |
| RA4 | 65,133 | 73,603 | 74,517 | 75,581 | 75,909 | 72,949 | 3 |
| RA5 | 64,245 | 73,124 | 74,144 | 75,453 | 76,374 | 72,668 | 2 |
| RA6 | 80,586 | 87,870 | 88,673 | 89,468 | 89,673 | 87,254 | 12 |
| RA7 | 64,771 | 73,229 | 74,117 | 75,110 | 75,468 | 72,539 | 1 |
| RA8 | 78,715 | 86,342 | 87,195 | 88,136 | 88,605 | 85,799 | 9 |
| RA9 | 78,715 | 87,458 | 88,341 | 89,244 | 89,623 | 86,676 | 11 |
| RA10 | 79,001 | 86,627 | 87,511 | 88,348 | 88,461 | 85,990 | 10 |
| RA11 | 75,166 | 82,727 | 83,578 | 84,636 | 85,069 | 82,235 | 5 |
| RA12 | 76,470 | 83,904 | 84,761 | 85,768 | 86,233 | 83,427 | 7 |

## Table 7.25 – Cumulative $CO_2$ Emissions by Cost Adder Level, 2007-2026

| ID | Generator $CO_2$ Emissions, 2007-2026 (1000 Tons) | | | | | | Rank |
|---|---|---|---|---|---|---|---|
| | $0 Adder | $8 Adder | $15 Adder | $38 Adder | $61 Adder | Average | |
| RA1 | 1,121,716 | 1,071,110 | 1,051,661 | 1,005,991 | 983,131 | 1,046,722 | 11 |
| RA2 | 1,118,600 | 1,065,377 | 1,044,783 | 996,976 | 972,473 | 1,039,642 | 7 |
| RA3 | 1,100,779 | 1,050,767 | 1,030,985 | 983,391 | 959,728 | 1,025,130 | 3 |
| RA4 | 1,122,432 | 1,070,823 | 1,050,931 | 1,004,604 | 980,942 | 1,045,947 | 10 |
| RA5 | 1,122,352 | 1,066,931 | 1,045,768 | 993,546 | 966,702 | 1,039,060 | 6 |
| RA6 | 1,092,590 | 1,043,019 | 1,023,626 | 977,283 | 954,462 | 1,018,196 | 1 |
| RA7 | 1,098,664 | 1,045,400 | 1,024,659 | 976,320 | 951,671 | 1,019,343 | 2 |
| RA8 | 1,119,654 | 1,070,775 | 1,051,835 | 1,007,310 | 985,331 | 1,046,981 | 12 |
| RA9 | 1,117,852 | 1,068,445 | 1,049,168 | 1,004,509 | 983,189 | 1,044,632 | 8 |
| RA10 | 1,120,216 | 1,070,065 | 1,050,497 | 1,004,820 | 982,764 | 1,045,672 | 9 |
| RA11 | 1,109,142 | 1,058,370 | 1,038,568 | 990,992 | 967,452 | 1,032,905 | 5 |
| RA12 | 1,104,925 | 1,055,091 | 1,035,617 | 989,230 | 966,425 | 1,030,258 | 4 |

| ID | $CO_2$ Emissions from Market Purchases, 2007-2026 (1000 Tons) | | | | | | Rank |
|---|---|---|---|---|---|---|---|
| | $0 Adder | $8 Adder | $15 Adder | $38 Adder | $61 Adder | Average | |
| RA1 | 146,689 | 164,207 | 170,810 | 180,598 | 182,578 | 168,976 | 8 |
| RA2 | 134,276 | 153,061 | 160,118 | 170,663 | 173,411 | 158,306 | 2 |
| RA3 | 147,303 | 175,981 | 171,287 | 182,115 | 184,159 | 172,169 | 11 |
| RA4 | 136,267 | 154,743 | 161,760 | 172,140 | 174,792 | 159,940 | 4 |
| RA5 | 133,685 | 153,044 | 160,597 | 172,336 | 175,981 | 159,129 | 3 |
| RA6 | 152,525 | 169,071 | 175,514 | 184,348 | 187,453 | 173,782 | 12 |
| RA7 | 131,307 | 149,820 | 156,751 | 167,235 | 170,350 | 155,093 | 1 |
| RA8 | 149,653 | 166,984 | 173,528 | 182,981 | 185,322 | 171,694 | 10 |
| RA9 | 149,653 | 165,141 | 171,773 | 182,117 | 185,321 | 170,801 | 9 |
| RA10 | 145,724 | 162,544 | 169,099 | 179,515 | 182,473 | 167,871 | 5 |
| RA11 | 145,021 | 162,764 | 169,618 | 180,874 | 183,689 | 168,393 | 6 |
| RA12 | 145,335 | 163,064 | 170,005 | 181,359 | 183,821 | 168,717 | 7 |

**Figure 7.15 – Generator $CO_2$ Emissions by Cost Adder Level, Cumulative for 2007-2016**

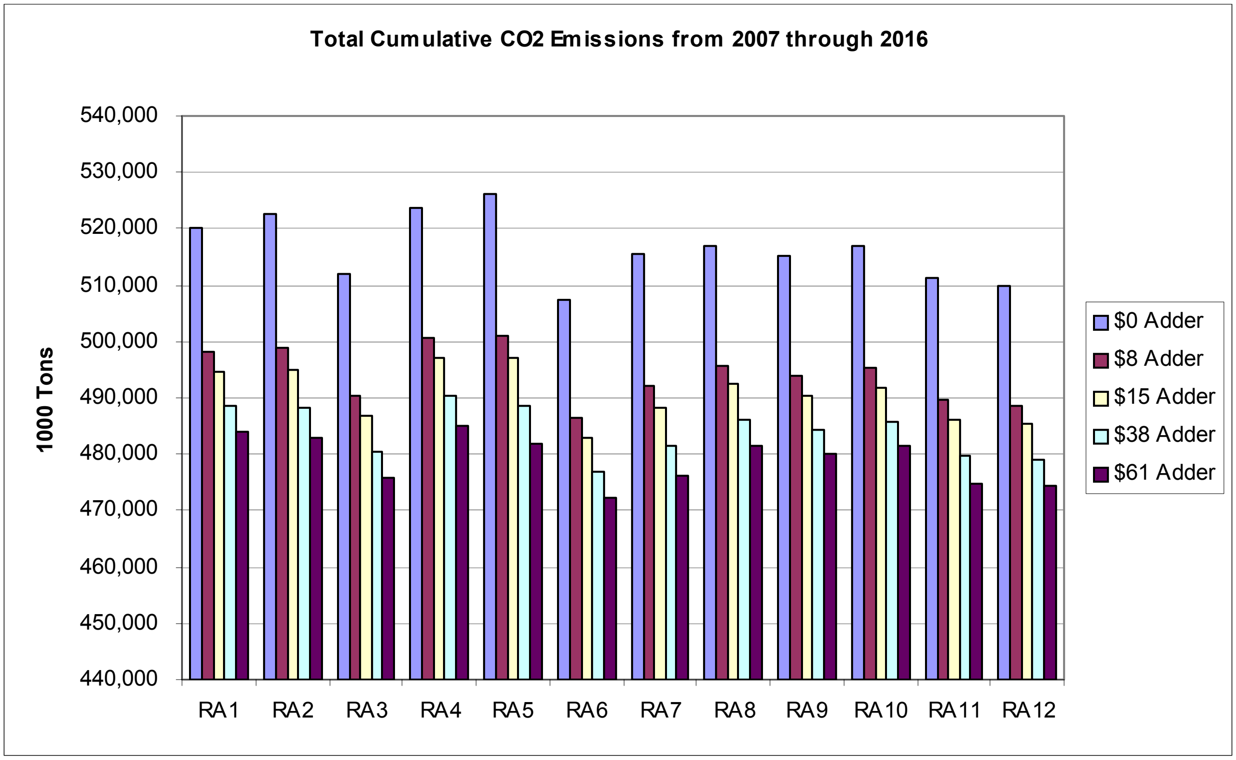
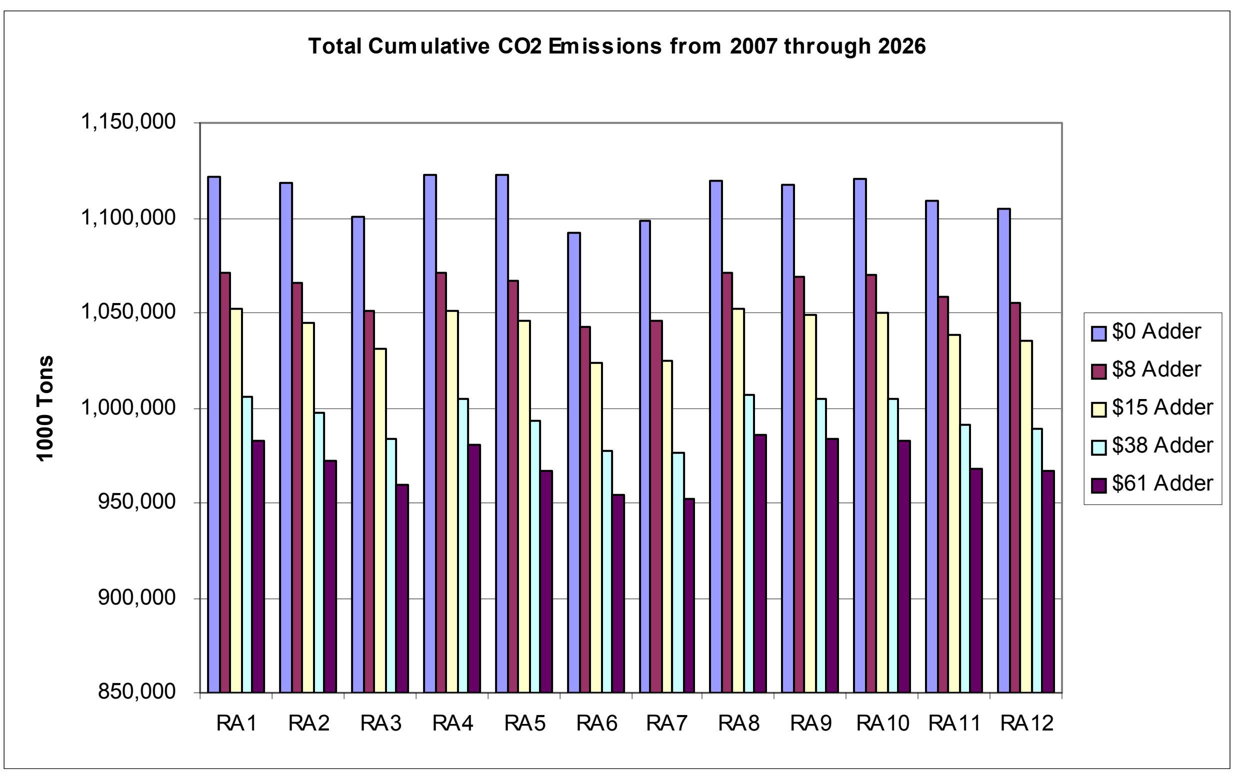



**Figure 7.16 – Generator $CO_2$ Emissions by Cost Adder Level, Cumulative for 2007-2026**



## Table 7.26 – System Generator Emissions Footprint, Cumulative Amount for 2007–2026

| ID | $SO_2$ 1000 Tons | $NO_X$ 1000 Tons | Hg Pounds | $CO_2$ 1000 Tons | $SO_2$ 1000 Tons | $NO_X$ 1000 Tons | Hg Pounds | $CO_2$ 1000 Tons |
|---|---|---|---|---|---|---|---|---|
| | $0 Adder (2008$) | | | | $8 Adder (2008$) | | | |
| RA1 | 822 | 1,161 | 8,340 | 1,121,716 | 781 | 1,099 | 7,560 | 1,071,110 |
| RA2 | 814 | 1,149 | 8,330 | 1,118,600 | 771 | 1,082 | 7,860 | 1,065,377 |
| RA3 | 817 | 1,156 | 8,228 | 1,100,779 | 775 | 1,093 | 8,060 | 1,050,767 |
| RA4 | 821 | 1,160 | 8,354 | 1,122,432 | 779 | 1,095 | 8,040 | 1,070,823 |
| RA5 | 796 | 1,122 | 8,293 | 1,122,352 | 749 | 1,049 | 7,953 | 1,066,931 |
| RA6 | 792 | 1,132 | 7,825 | 1,092,590 | 751 | 1,068 | 7,560 | 1,043,019 |
| RA7 | 805 | 1,135 | 8,228 | 1,098,664 | 762 | 1,068 | 7,985 | 1,045,400 |
| RA8 | 827 | 1,170 | 8,332 | 1,119,654 | 787 | 1,109 | 7,936 | 1,070,775 |
| RA9 | 805 | 1,138 | 8,130 | 1,117,852 | 764 | 1,075 | 7,860 | 1,068,445 |
| RA10 | 804 | 1,138 | 8,140 | 1,120,216 | 763 | 1,074 | 7,867 | 1,070,065 |
| RA11 | 805 | 1,135 | 8,186 | 1,109,142 | 763 | 1,071 | 7,909 | 1,058,370 |
| RA12 | 808 | 1,143 | 8,152 | 1,104,925 | 767 | 1,080 | 7,880 | 1,055,091 |

| ID | $SO_2$ 1000 Tons | $NO_X$ 1000 Tons | Hg Pounds | $CO_2$ 1000 Tons | $SO_2$ 1000 Tons | $NO_X$ 1000 Tons | Hg Pounds | $CO_2$ 1000 Tons |
|---|---|---|---|---|---|---|---|---|
| | $15 Adder (2008$) | | | | $38 Adder (2008$) | | | |
| RA1 | 769 | 1,079 | 7,962 | 1,051,661 | 725 | 1,011 | 7,712 | 1,005,991 |
| RA2 | 758 | 1,061 | 7,938 | 1,044,783 | 712 | 990 | 7,674 | 996,976 |
| RA3 | 761 | 1,072 | 7,853 | 1,030,985 | 711 | 998 | 7,593 | 983,391 |
| RA4 | 766 | 1,075 | 7,976 | 1,050,931 | 722 | 1,005 | 7,717 | 1,004,604 |
| RA5 | 735 | 1,027 | 7,890 | 1,045,768 | 680 | 944 | 7,610 | 993,546 |
| RA6 | 738 | 1,047 | 7,469 | 1,023,626 | 693 | 976 | 7,195 | 977,283 |
| RA7 | 749 | 1,047 | 7,834 | 1,024,659 | 703 | 975 | 7,567 | 976,320 |
| RA8 | 775 | 1,089 | 7,967 | 1,051,835 | 731 | 1,021 | 7,604 | 1,007,310 |
| RA9 | 752 | 1,056 | 7,766 | 1,049,168 | 711 | 990 | 7,506 | 1,004,509 |
| RA10 | 751 | 1,055 | 7,880 | 1,050,497 | 708 | 987 | 7,880 | 1,004,820 |
| RA11 | 750 | 1,052 | 7,812 | 1,038,568 | 701 | 979 | 7,549 | 990,992 |
| RA12 | 753 | 1,060 | 7,785 | 1,035,617 | 707 | 991 | 7,523 | 989,230 |

| ID | $SO_2$ 1000 Tons | $NO_X$ 1000 Tons | Hg Pounds | $CO_2$ 1000 Tons |
|---|---|---|---|---|
| | $61 Adder (2008$) | | | |
| RA1 | 705 | 975 | 7,598 | 983,131 |
| RA2 | 690 | 952 | 7,546 | 972,473 |
| RA3 | 688 | 961 | 7,475 | 959,728 |
| RA4 | 701 | 968 | 7,593 | 980,942 |
| RA5 | 655 | 901 | 7,472 | 966,702 |
| RA6 | 673 | 942 | 7,056 | 954,462 |
| RA7 | 681 | 938 | 7,438 | 951,671 |
| RA8 | 711 | 987 | 7,604 | 985,331 |
| RA9 | 692 | 958 | 7,387 | 983,189 |

| ID | $SO_2$ | $NO_X$ | Hg | $CO_2$ |
|---|---|---|---|---|
| | 1000 Tons | 1000 Tons | Pounds | 1000 Tons |
| | $61 Adder (2008$) | | | |
| RA10 | 689 | 953 | 7,880 | 982,764 |
| RA11 | 678 | 943 | 7,428 | 967,452 |
| RA12 | 685 | 957 | 7,403 | 966,425 |

## Supply Reliability

### Energy Not Served

Figures 7.17 and 7.18 below show, respectively, the average annual amount of Energy Not Served (ENS) and the upper-tail mean Energy Not Served for the $8 $CO_2$ adder case, a measure of high-end supply reliability risk. It is clear that the system reliability is generally reduced under a 12% planning reserve margin. Asset-based portfolios tended to have higher reliability than portfolios that allowed short-term market purchases to meet firm requirements. RA6, which had no pulverized coal resources, also had a somewhat reduced level of reliability likely due to the combination of including front office transactions and a higher number of less reliable IGCC units in the portfolio. From a reliability basis, measured by energy not served, Portfolio RA5 has the highest reliability.

**Figure 7.17 – Stochastic Average Annual Energy Not Served**

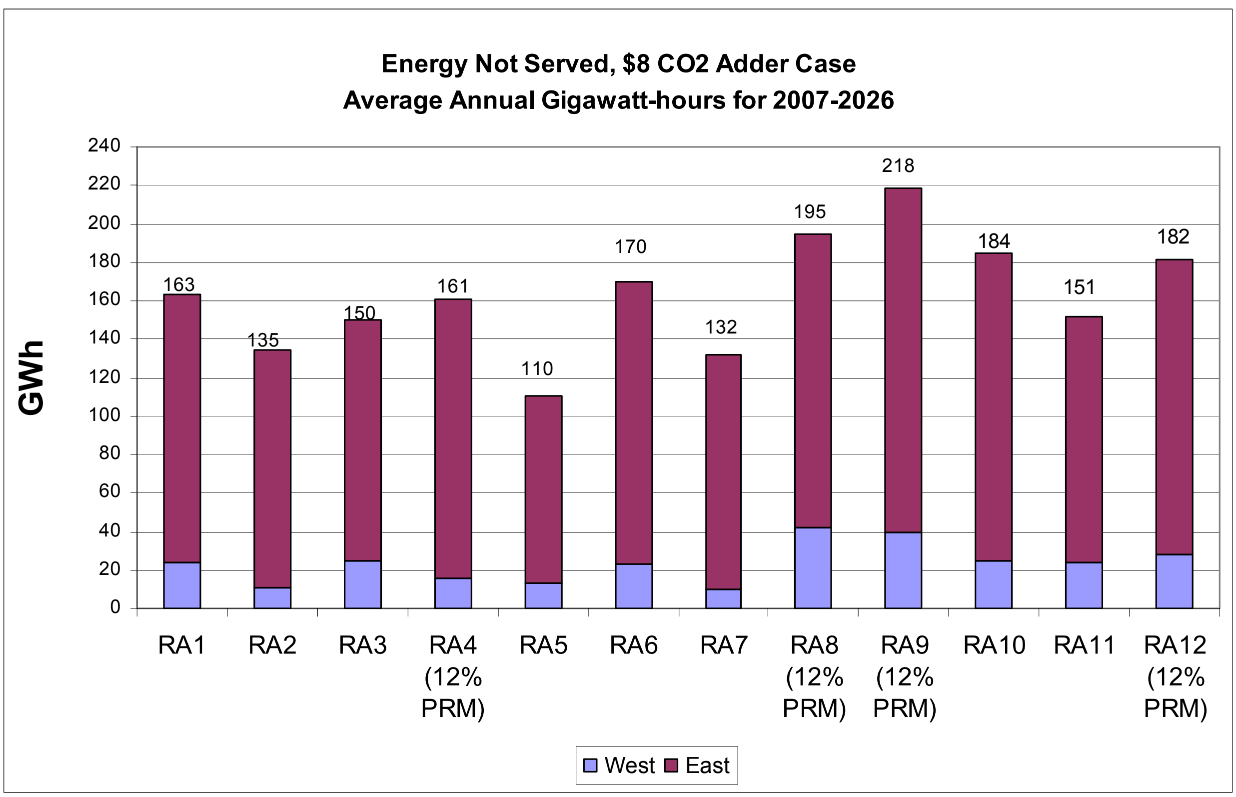
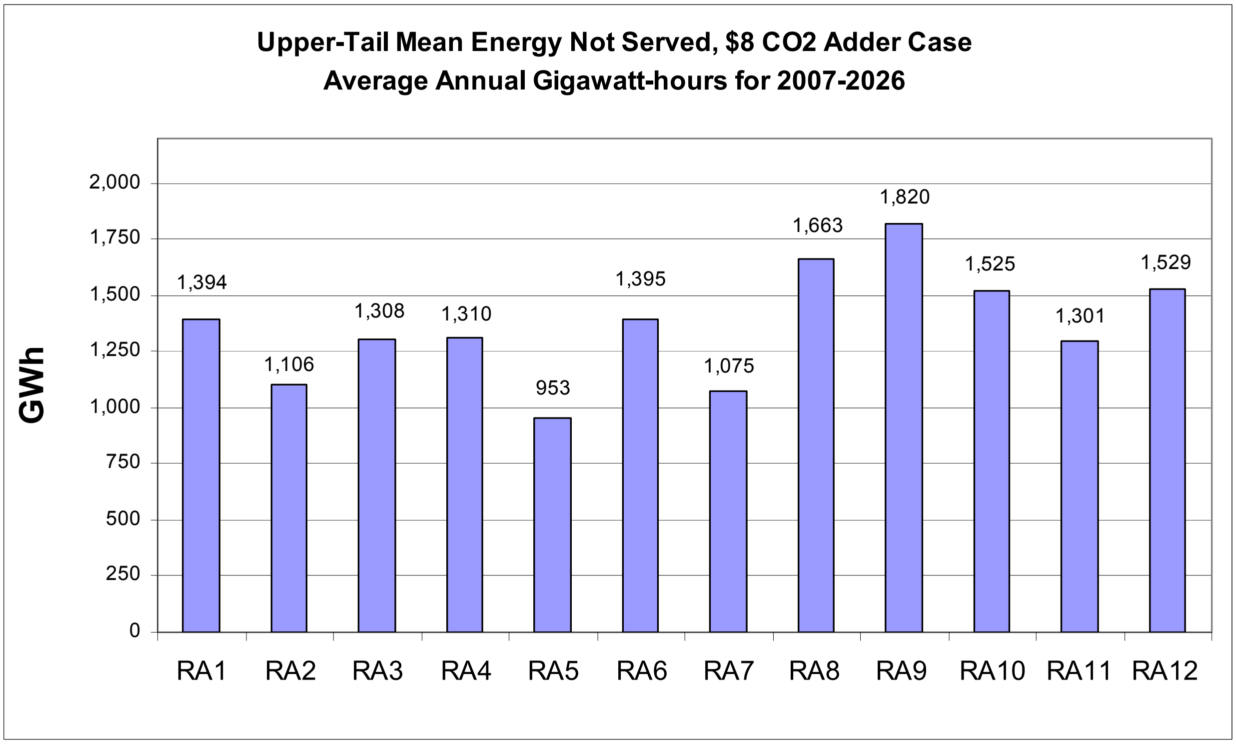


**Figure 7.18 – Upper-Tail Stochastic Mean Energy Not Served**




## Loss of Load Probability

As discussed in Chapter 6, the Loss of Load Probability (LOLP) parameter is best represented by the probability of an occurrence of Energy Not Served (ENS). Table 7.27 displays the average Loss of Load Probability for each of the risk analysis portfolios modeled using the $8 $CO_2$ adder case. 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. The data is summarized against multiple levels of lost load, which shows the likelihood of losing various amounts of load in a single event.

**Table 7.27 – Average Loss of Load Probability During Summer Peak**

| Average for operating years 2007 through 2016 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Event Size (MWh) | **RA1** | **RA2** | **RA3** | **RA4** | **RA5** | **RA6** | **RA7** | **RA8** | **RA9** | **RA10** | **RA11** | **RA12** |
| **> 0** | 37% | 34% | 36% | 35% | 34% | 37% | 34% | 37% | 39% | 37% | 36% | 38% |
| **> 1,000** | 30% | 26% | 29% | 27% | 26% | 30% | 26% | 30% | 32% | 30% | 29% | 31% |
| **> 10,000** | 17% | 13% | 17% | 14% | 12% | 17% | 13% | 17% | 18% | 17% | 17% | 18% |
| **> 25,000** | 13% | 10% | 13% | 11% | 8% | 13% | 10% | 13% | 14% | 13% | 12% | 14% |
| **> 50,000** | 10% | 7% | 9% | 7% | 5% | 10% | 7% | 10% | 11% | 10% | 9% | 10% |
| **> 100,000** | 7% | 5% | 6% | 5% | 3% | 7% | 4% | 7% | 8% | 7% | 7% | 8% |
| **> 500,000** | 1% | 0% | 1% | 0% | 0% | 1% | 0% | 1% | 1% | 1% | 1% | 1% |
| **> 1,000,000** | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

| Average for operating years 2007 through 2026 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Event Size (MWh) | **RA1** | **RA2** | **RA3** | **RA4** | **RA5** | **RA6** | **RA7** | **RA8** | **RA9** | **RA10** | **RA11** | **RA12** |
| **> 0** | 53% | 52% | 39% | 54% | 39% | 52% | 52% | 54% | 57% | 55% | 41% | 43% |
| **> 1,000** | 44% | 44% | 33% | 45% | 33% | 44% | 43% | 46% | 49% | 47% | 35% | 37% |
| **> 10,000** | 25% | 24% | 22% | 26% | 20% | 26% | 23% | 27% | 29% | 27% | 24% | 26% |
| **> 25,000** | 20% | 18% | 18% | 20% | 15% | 20% | 18% | 21% | 23% | 22% | 19% | 21% |
| **> 50,000** | 16% | 14% | 15% | 15% | 11% | 16% | 14% | 17% | 19% | 18% | 15% | 17% |
| **> 100,000** | 12% | 10% | 11% | 11% | 8% | 12% | 10% | 13% | 14% | 12% | 11% | 13% |
| **> 500,000** | 4% | 3% | 4% | 4% | 3% | 4% | 3% | 4% | 5% | 4% | 4% | 4% |
| **> 1,000,000** | 2% | 2% | 2% | 2% | 1% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |

Table 7.28 displays the year-by-year results for the threshold value of 25,000 MWh. (As mentioned in Chapter 6, the 25,000 MWh case was selected as an example to show the annual LOLP as required in the Oregon Commission's 2004 IRP acknowledgement order.) For each year, the LOLP value represents the proportion of the 100 iterations where the July ENS was greater than 25,000 MWhs. This is the equivalent of 2,500 megawatts for 10 hours.

**Table 7.28 – Year-by-Year Loss of Load Probability**

(Probability of ENS Event > 25,000 MWh in July)

| Year | RA1 | RA2 | RA3 | RA4 | RA5 | RA6 | RA7 | RA8 | RA9 | RA10 | RA11 | RA12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2007** | 3% | 3% | 3% | 3% | 3% | 3% | 3% | 3% | 3% | 3% | 3% | 3% |
| **2008** | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| **2009** | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% |
| **2010** | 13% | 13% | 13% | 15% | 13% | 13% | 13% | 15% | 15% | 13% | 13% | 15% |
| **2011** | 17% | 17% | 17% | 17% | 17% | 17% | 17% | 17% | 17% | 17% | 17% | 17% |
| **2012** | 9% | 5% | 9% | 6% | 5% | 7% | 5% | 10% | 12% | 9% | 9% | 11% |
| **2013** | 13% | 6% | 13% | 7% | 4% | 13% | 10% | 15% | 15% | 14% | 14% | 17% |
| **2014** | 14% | 6% | 17% | 8% | 3% | 17% | 6% | 14% | 15% | 16% | 15% | 15% |
| **2015** | 22% | 14% | 18% | 16% | 5% | 23% | 11% | 19% | 23% | 24% | 18% | 22% |
| **2016** | 19% | 13% | 16% | 14% | 6% | 19% | 13% | 19% | 21% | 18% | 16% | 17% |
| **2017** | 24% | 23% | 23% | 22% | 12% | 29% | 22% | 23% | 21% | 21% | 24% | 25% |
| **2018** | 22% | 17% | 19% | 19% | 17% | 21% | 17% | 22% | 22% | 23% | 19% | 19% |
| **2019** | 16% | 19% | 13% | 19% | 19% | 13% | 19% | 15% | 15% | 15% | 20% | 21% |
| **2020** | 23% | 22% | 18% | 23% | 21% | 15% | 22% | 22% | 23% | 23% | 22% | 23% |
| **2021** | 27% | 23% | 20% | 26% | 20% | 23% | 23% | 26% | 27% | 27% | 23% | 25% |
| **2022** | 35% | 37% | 33% | 38% | 31% | 39% | 37% | 39% | 40% | 39% | 36% | 39% |
| **2023** | 24% | 23% | 23% | 28% | 19% | 27% | 23% | 30% | 30% | 31% | 23% | 24% |
| **2024** | 40% | 39% | 31% | 41% | 26% | 40% | 39% | 42% | 43% | 42% | 30% | 38% |
| **2025** | 33% | 30% | 31% | 45% | 29% | 35% | 30% | 46% | 47% | 43% | 30% | 33% |
| **2026** | 31% | 31% | 31% | 30% | 28% | 33% | 31% | 32% | 48% | 48% | 28% | 36% |

**Portfolio Resource Conclusions**

Based on the stochastic simulation results, the best strategy for achieving a low-cost, risk-informed portfolio for PacifiCorp's customers is to include supercritical pulverized coal along with additional wind and natural gas to mitigate $CO_2$ cost risk. Although eliminating front office transactions after 2011 was found to be beneficial for reducing risk exposure, it also increased portfolio cost. On balance, PacifiCorp judges this resource type to be beneficial because it increases planning flexibility and resource diversity. Consequently, subsequent risk analysis portfolio development assumes that front office transactions will be available as a model option after 2011.

## RISK ANALYSIS PORTFOLIO DEVELOPMENT – GROUP 2

As mentioned above, PacifiCorp developed the Group 2 risk analysis portfolios to account for current and expected resource policies in several of its state jurisdictions, and to address the new load forecast (See Chapter 4). Similar to the process used to derive the Group 1 portfolios, the CEM was allowed to optimize investment plans subject to certain resource constraints and strategies.

The CEM optimization process for the Group 2 portfolio was conducted in two phases. The first phase consisted of a screening test to determine general resource selection patterns under a variety of planning assumptions, including the new March 2007 load forecast. Model runs for this phase were based on medium-case scenario conditions, and subject to the following resource assumptions.

*Coal Resources*

- At least two supercritical pulverized coal resources were included in all of the new portfolios. This decision reflects the following findings from the previous portfolio evaluation work:
  - For Group 1 risk analysis portfolio development, the CEM chose the small Utah resource and the Wyoming resource for 2012–2014 in all portfolios for which the CEM was allowed to optimize their selection and timing.
  - The stochastic simulations indicated that removing or deferring these coal resources raised both portfolio cost and risk, even under the higher $CO_2$ adder cases.

- The Wyoming supercritical pulverized coal resources were resized from 750 megawatts each to 527 megawatts. This size change is intended to mitigate the customer rate and carbon footprint impacts of new coal resources. Also, the large Utah SCPC resource was changed from 600 to 575 megawatts. These changes are consistent with the resource sizes assumed for PacifiCorp's 10-year Business Plan.[59]

- The second Utah and Wyoming supercritical pulverized coal units were removed as resource options for all portfolios.

[59] Other resource assumption changes made to conform to the PacifiCorp Business Plan included (1) removing the 100 MW Desert Power QF from the load and resource balance due to the project's owner declaring bankruptcy, and (2) excluding the Blundell expansion project. (PacifiCorp's economic evaluation of the Blundell project found it to not be cost-effective. This report was filed in all six states in March 2007 to comply with a PacifiCorp-MEHC acquisition commitment.)

- The west IGCC resources were removed as options for all portfolios. These IGCC units were patterned after the planned Pacific Mountain Energy Center IGCC project in Kalama, Washington. Reasons for exclusion included (1) regulatory uncertainties regarding siting of coal-based generation in Washington, (2) commercial uncertainties regarding capital costs, and (3) the unique project-specific characteristics (such as a proposed fuel supply that includes imported petroleum coke) that make it unsuitable as a generic IGCC resource.

*Wind Resources*

- PacifiCorp developed and applied a new fixed wind investment schedule for all Group 2 portfolios except for RA13, consisting of a total of 1,600 megawatts of wind resources beyond the 400 megawatts already reflected in the load and resource balance. This schedule is based on acquiring the 1,400 megawatts of wind by 2010 (reflecting an accelerated time table relative to the initial investment schedule developed for risk analysis portfolios) and the additional 600 megawatts tested as a resource strategy in the Group 1 analysis. Table 7.29 shows this new wind investment schedule for the 1,600 megawatts of wind, including the associated cumulative capacity contributions.[60]

**Table 7.29 – Wind Resource Additions Schedule for Risk Analysis Portfolios**

| Year | Annual Additions, Nameplate Capacity (MW) | Location | Cumulative Wind Nameplate Capacity (MW) | Cumulative Wind Peak Capacity Contribution (MW) |
|---|---|---|---|---|
| 2007 | 300 | Southeast Washington | 300 | 14 |
| 2008 | 300 | Wyoming; Southeast Washington | 600 | 38 |
| 2009 | 100 | North Central Oregon | 700 | 75 |
| 2010 | 300 | Wyoming; North Central Oregon | 1,000 | 119 |
| 2011 | 200 | Wyoming | 1,200 | 127 |
| 2012 | 100 | North Central Oregon | 1,300 | 146 |
| 2013 | 300 | Wyoming | 1,600 | 207 |

- The capacity factor for southeast Wyoming wind resources was increased from 32% to 40% to reflect updated operational expectations for these wind sites.

*Gas Resources*

- For initial CEM resource screening analysis, there were no restrictions placed on the type and timing of gas resources.

*Front Office Transactions*

- The model is able to select front office transactions after 2011.

*Transmission Resources*

- PacifiCorp incorporated the following set of transmission resources in all the Group 2 portfolios:

[60] The capacity contribution of this new investment schedule is smaller than the contribution for the previous schedule, even though there is more nameplate capacity added. This is due to the relocation of wind projects to areas for which incremental additions have less peak-hour load carrying capability.

- Path C Upgrade: Borah to Path-C South to Utah North
- Utah - Desert Southwest (Includes Mona - Oquirrh)[61]
- Mona - Utah North
- Craig-Hayden to Park City
- Miners - Jim Bridger - Terminal
- Jim Bridger - Terminal
- Walla Walla - Yakima
- West Main - Walla Walla

These resources are supported by previous portfolio analysis, and are consistent with both the PacifiCorp 10-year Business Plan and MEHC transmission commitments. Additionally, as mentioned in Chapter 2, these transmission resources represent proxies for future transmission requirements rather than specific projects.

*Planning Reserve Margin*

- Test portfolios with both a 12% and 15% planning reserve margin.

The second CEM portfolio optimization phase consisted of the development of the risk analysis portfolios to be simulated with the PaR module. The results of the CEM screening runs were used to inform the selection and timing of resources. Based on the resulting fixed generation resource investment schedule for each portfolio, a CEM run determined the front office transactions needed to meet the planning reserve margin. (See Figure 6.4 in Chapter 6 for a generic description of this two-stage CEM optimization process.)

**Alternative Resource Strategies**

Having already determined a new wind investment schedule and the coal resources to include in the Group 2 portfolios, PacifiCorp considered a relatively small set of alternative resource strategies to be evaluated. These strategies focus on the timing of the two supercritical coal resources and the mix of gas resources. Specifically, the strategies test (1) whether the new resource assumptions alter the CEM's optimal timing for the two supercritical coal plants, (2) reliance on only combined cycle combustion turbines versus a combination of CCCTs and non-base-load gas resources to meet the latest load growth projections, (3) the timing and type of resources needed to make up for the loss of the BPA peaking contract in August 2011 (i.e., determine the resource selection impact of removing the contract in 2011 rather than 2012 to ensure that new resources are selected to meet load by August 2011), and (4) alternative planning reserve margins—12% and 15%. For the pulverized coal resources, the CEM was allowed to select the small Utah unit for 2012 or 2013 only, while the Wyoming resource could be acquired in any year after 2013.

The major conclusions obtained from the associated CEM screening runs include the following.

- **Coal resource timing –** The Utah small supercritical coal resource was always selected in 2012, while the Wyoming supercritical coal resource (527 megawatts) was always selected in 2014.
- **Gas resource mix –** When the CEM was allowed to optimize the selection and timing of gas resources, it chose a combination of CCCTs and SCCT frames; the west CCCT was always

[61] This resource was included in the 10-year PacifiCorp Business Plan.

selected in 2012. Restricting the model to choose only CCCTs resulted in just one east CCCT selected in 2012. (This is in addition to the west CCCT selected in 2012.)

- **Timing of resource acquisition to address expiration of the BPA peak contract –** Removing the BPA contract in 2011 (as opposed to 2012) had no effect on the timing of the west CCCT assuming unlimited availability of front office transactions in 2011.
- **Alternative planning reserve margins –** Under a 12% planning reserve margin, allowing the model to choose its own gas resources resulted in two SCCT frames selected in 2012 – one in the east and one in the west; this is in addition to the west CCCT selected in 2012. Under a 15% planning reserve margin with no gas resource option restrictions, the CEM portfolio solution included about 200 megawatts of additional gas resources by 2016; east SCCT frames were selected in 2010 and 2012 in addition to an east CCCT in 2012.

Based on these results, PacifiCorp developed five portfolios for stochastic simulation. These portfolios are intended to compare CCCTs against reliance on the market to meet new forecasted loads under alternative planning reserve margin targets (12% and 15%). Combined cycle plants were chosen as the proxy gas-fired resource type for two reasons. First, the PaR stochastic simulation captures extrinsic (or optionality) value of a resource, while the CEM does not. A CCCT is expected to have a lower PVRR impact than a non-base-load gas resource with all else held constant. Second, the larger CCCT minimizes the number of gas resources added in a single year.

In addition, all five risk analysis portfolios have a west CCCT added in 2011 to ensure that a resource is available to meet west-side load by August 2011. Finally, the amount of annual front office transactions needed to balance the system is determined by CEM; no caps are placed on the resources.

Table 7.30 outlines the specifications for the five risk analysis portfolios (labeled RA13 through RA17), and presents the design rationale and common features for each.

**Table 7.30 – Risk Analysis Portfolio Descriptions (Group 2)**

| ID | Description | Design Rationale | Features |
|---|---|---|---|
| **RA13** | An updated "Base Case" resource proposal that mirrors the original PacifiCorp Business Plan's base load resources. This portfolio, based on a 12% planning reserve margin, includes four supercritical pulverized coal resources: the small Utah SCPC (2012), the Wyoming SCPC (2014), the large Utah SCPC (2017), and the second Wyoming SCPC (2018). | This portfolio serves as the reference portfolio for comparison with the other risk analysis portfolios. It reflects a coal- and market- intensive resource strategy. | • Based on the revised load forecast (March 2007)<br>• Wind investment schedule assumed for original Business Plan<br>• All portfolios use the same transmission investment schedule |

| ID | Description | Design Rationale | Features |
|---|---|---|---|
| **RA14** | This portfolio addresses the higher east load forecast by adding two east CCCTs: one in 2012 (2x1 F type) and one in 2016 (1x1 G type). | Tests the strategy of meeting east load growth with CCCTs as opposed to the market. | • Based on the revised load forecast (March 2007)<br>• Small Utah SCPC plant acquired in 2012<br>• Wyoming SCPC acquired in 2014<br>• West CCCT acquired in 2011<br>• Revised wind investment schedule (1,400 MW by 2010; 600 MW by 2013 – Total of 2,000 MW by 2013)<br>• All portfolios use the same transmission investment schedule<br>• 12% Planning reserve margin except RA16 |
| **RA15** | This portfolio addresses the revised east load forecast by adding just one east CCCT in 2012. A 12% planning reserve margin is met with front office transactions. | Tests the strategy of meeting east load growth with a mix of CCCT capacity and the market. | |
| **RA16** | RA14 based on a 15% planning reserve margin; the higher reserve margin is met with CCCT capacity and front office transactions | Tests the consequences of meeting the higher planning reserve margin with market resources. | |
| **RA17** | This portfolio addresses the revised load forecast by relying on front office transactions only. | Tests the strategy of using market purchases to meet the increased forecasted load. | |

Tables 7.31 through 7.35 present the detailed supply- and demand-side investment schedules for each portfolio. Table 7.36 provides the common transmission investment schedule for all the Group 2 portfolios.

### Table 7.31 – Resource Investment Schedule for Portfolio RA13

| | | | Nameplate Capacity, MW | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Resource** | **Type** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| **EAST** | Utah pulverized coal | Supercritical | | | | | | 340 | | | | | | |
| | Wyoming pulverized coal | Supercritical | | | | | | | | 527 | | | | |
| | Utah pulverized coal | Supercritical | | | | | | | | | | | 575 | |
| | Wyoming pulverized coal | Supercritical | | | | | | | | | | | | 527 |
| | Combined cycle CT | 2x1 F class with duct firing | | | | | | | | | | | | |
| | Combined cycle CT | 1x1 G class with duct firing | | | | | | | | | | | | |
| | Combined Heat and Power | Generic east-wide | | | | | | 25 | | | | | | |
| | Renewable | Wind, Wyoming and Idaho | 100 | 200 | | 100 | 200 | 100 | 100 | | | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | | 26 | 25 | 18 | | | | | |
| | Front office transactions** | Heavy Load Hour, 3rd Qtr | - | - | - | 451 | 550 | 281 | 281 | 911 | 1,054 | ,209 | 1,121 | 811 |
| **WEST** | Combined cycle CT | 2x1 F Type with duct firing | | | | | | | | | | | | |
| | Combined Heat and Power | Generic west-wide | | | | | | 75 | | | | | | |
| | Renewable | Wind, SE Washington | | | | | | | | | | | | |
| | Renewable | Wind, NC Oregon | 200 | | | | | | | | | | | |
| | Class 1 DSM* | Sch. irrigation | | | | 12 | 11 | 12 | | | | | | |
| | Front office transactions** | Flat annual product | - | - | - | 134 | 222 | 1,300 | 1,350 | 513 | 413 | 551 | 663 | 840 |
| | Annual Additions, Long Term Resources | | **300** | **200** | **-** | **112** | **237** | **577** | **118** | **527** | **-** | **-** | **575** | **527** |
| | Annual Additions, Short Term Resources | | **-** | **-** | **-** | **585** | **772** | **1,581** | **1,631** | **1,424** | **1,467** | **1,760** | **1,784** | **1,651** |
| | Total Annual Additions | | **300** | **200** | **0** | **697** | **1,009** | **2,158** | **1,749** | **1,951** | **1,467** | **1,760** | **2,359** | **2,178** |

* DSM is scaled up by 10% to account for avoided line losses.
** Front office transaction amounts reflect purchases made for the year, and are not additive.

## Table 7.32 – Resource Investment Schedule for Portfolio RA14

| | | | Nameplate Capacity, MW | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Resource** | **Type** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** |
| **East** | Utah pulverized coal | Supercritical | | | | | | 340 | | | | |
| | Wyoming pulverized coal | Supercritical | | | | | | | | 527 | | |
| | Combined cycle CT | 2x1 F class with duct firing | | | | | | 548 | | | | |
| | Combined cycle CT | 1x1 G class with duct firing | | | | | | | | | | 357 |
| | Combined Heat and Power | Generic east-wide | | | | | | 25 | | | | |
| | Renewable | Wind, Wyoming | | 200 | | 200 | 200 | | 300 | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | | 26 | 25 | 18 | | | |
| | Front office transactions** | Heavy Load Hour, 3rd Qtr | - | - | - | 393 | 272 | 97 | 3 | 149 | 192 | 165 |
| **West** | CCCT | 2x1 F Type with duct firing | | | | | 602 | | | | | |
| | Combined Heat and Power | Generic west-wide | | | | | | 75 | | | | |
| | Renewable | Wind, SE Washington | 300 | 100 | | | | | | | | |
| | Renewable | Wind, NC Oregon | | | 100 | 100 | | 100 | | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | 12 | 11 | 12 | | | | |
| | Front office transactions** | Flat annual product | - | - | - | 219 | 64 | 555 | 657 | 247 | 246 | 249 |
| | Annual Additions, Long Term Resources | | **300** | **300** | **100** | **312** | **839** | **1,125** | **318** | **527** | **-** | **357** |
| | Annual Additions, Short Term Resources | | **-** | **-** | **-** | **612** | **336** | **652** | **660** | **396** | **438** | **414** |
| | Total Annual Additions | | **300** | **300** | **100** | **924** | **1,175** | **1,777** | **978** | **923** | **438** | **771** |

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

## Table 7.33 – Resource Investment Schedule for Portfolio RA15

| | | | Nameplate Capacity, MW | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Resource** | **Type** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** |
| **East** | Utah pulverized coal | Supercritical | | | | | | 340 | | | | |
| | Wyoming pulverized coal | Supercritical | | | | | | | | 527 | | |
| | Combined cycle CT | 2x1 F class with duct firing | | | | | | 548 | | | | |
| | Combined cycle CT | 1x1 G class with duct firing | | | | | | | | | | |
| | Combined Heat and Power | Generic east-wide | | | | | | 25 | | | | |
| | Renewable | Wind, Wyoming | | 200 | | 200 | 200 | | 300 | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | | 26 | 25 | 18 | | | |
| | Front office transactions** | Heavy Load Hour, 3rd Qtr | - | - | - | 393 | 272 | 97 | 3 | 149 | 192 | 349 |
| **West** | Combined cycle CT | 2x1 F Type with duct firing | | | | | 602 | | | | | |
| | Combined Heat and Power | Generic west-wide | | | | | | 75 | | | | |
| | Renewable | Wind, SE Washington | 300 | 100 | | | | | | | | |
| | Renewable | Wind, NC Oregon | | | 100 | 100 | | 100 | | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | 12 | 11 | 12 | | | | |
| | Front office transactions** | Flat annual product | - | - | - | 219 | 64 | 555 | 657 | 247 | 246 | 384 |
| | Annual Additions, Long Term Resources | | **300** | **300** | **100** | **312** | **839** | **1,125** | **318** | **527** | **-** | **-** |
| | Annual Additions, Short Term Resources | | **-** | **-** | **-** | **612** | **336** | **652** | **660** | **396** | **438** | **733** |
| | Total Annual Additions | | **300** | **300** | **100** | **924** | **1,175** | **1,777** | **978** | **923** | **438** | **733** |

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

## Table 7.34 – Resource Investment Schedule for Portfolio RA16

| | | | Nameplate Capacity, MW | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Resource** | **Type** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** |
| **East** | Utah pulverized coal | Supercritical | | | | | | 340 | | | | |
| | Wyoming pulverized coal | Supercritical | | | | | | | | 527 | | |
| | Combined cycle CT | 2x1 F class with duct firing | | | | | 548 | | | | | |
| | Combined cycle CT | 2x1 F class with duct firing | | | | | | 548 | | | | |
| | Combined cycle CT | 1x1 G class with duct firing | | | | | | | | | | |
| | Combined Heat and Power | Generic east-wide | | | | | | 25 | | | | |
| | Renewable | Wind, Wyoming | | 200 | | 200 | 200 | | 300 | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | | 26 | 25 | 18 | | | |
| | Front office transactions** | Heavy Load Hour, 3rd Qtr | - | 108 | 111 | 553 | 103 | 73 | - | - | - | 272 |
| **West** | Combined cycle CT | 2x1 F Type with duct firing | | | | | 602 | | | | | |
| | Combined Heat and Power | Generic west-wide | | | | | | 75 | | | | |
| | Renewable | Wind, SE Washington | 300 | 100 | | | | | | | | |
| | Renewable | Wind, NC Oregon | | | 100 | 100 | | 100 | | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | 12 | 11 | 12 | | | | |
| | Front office transactions** | Flat annual product | - | - | - | 289 | - | 366 | 533 | 261 | 260 | 263 |
| | Annual Additions, Long Term Resources | | 300 | 300 | 100 | 312 | 1,387 | 1,125 | 318 | 527 | - | - |
| | Annual Additions, Short Term Resources | | - | 108 | 111 | 842 | 103 | 439 | 533 | 261 | 260 | 535 |
| | Total Annual Additions | | 300 | 408 | 211 | 1,154 | 1,490 | 1,564 | 851 | 788 | 260 | 535 |

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

## Table 7.35 – Resource Investment Schedule for Portfolio RA17

| | | | Nameplate Capacity, MW | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Resource** | **Type** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** |
| **East** | Utah pulverized coal | Supercritical | | | | | | 340 | | | | |
| | Wyoming pulverized coal | Supercritical | | | | | | | | 527 | | |
| | Combined cycle CT | 2x1 F class with duct firing | | | | | | | | | | |
| | Combined cycle CT | 1x1 G class with duct firing | | | | | | | | | | |
| | Combined Heat and Power | Generic east-wide | | | | | | 25 | | | | |
| | Renewable | Wind, Wyoming | | 200 | | 200 | 200 | | 300 | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | | 26 | 25 | 18 | | | |
| | Front office transactions** | Heavy Load Hour, 3rd Qtr | - | - | - | 393 | 272 | 281 | 255 | 394 | 616 | 706 |
| **West** | Combined cycle CT | 2x1 F Type with duct firing | | | | | 602 | | | | | |
| | Combined Heat and Power | Generic west-wide | | | | | | 75 | | | | |
| | Renewable | Wind, SE Washington | 300 | 100 | | | | | | | | |
| | Renewable | Wind, NC Oregon | | | 100 | 100 | | 100 | | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | 12 | 11 | 12 | | | | |
| | Front office transactions** | Flat annual product | - | - | - | 219 | 64 | 861 | 894 | 492 | 312 | 517 |
| | Annual Additions, Long Term Resources | | **300** | **300** | **100** | **312** | **839** | **577** | **318** | **527** | **-** | **-** |
| | Annual Additions, Short Term Resources | | **-** | **-** | **-** | **612** | **336** | **1,142** | **1,149** | **886** | **928** | **1,223** |
| | Total Annual Additions | | **300** | **300** | **100** | **924** | **1,175** | **1,719** | **1,467** | **1,413** | **928** | **1,223** |

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

**Table 7.36 – Transmission Resource Investment Schedule for All Group 2 Portfolios**

| | | Transfer Capability, Megawatts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Resource | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
| East | Path C Upgrade: Borah to Path-C South to Utah North | | | | 300 | | | | | | |
| | Utah - Desert Southwest (Includes Mona - Oquirrh) | | | | | | 600 | | | | |
| | Mona - Utah North | | | | | | 400 | | | | |
| | Craig-Hayden to Park City | | | | | | 176 | | | | |
| | Miners - Jim Bridger - Terminal | | | | | | 600 | | | | |
| | Jim Bridger - Terminal | | | | | | | | 500 | | |
| West | Walla Walla - Yakima | | | | 400 | | | | | | |
| | West Main - Walla Walla | | | | | 630 | | | | | |
| | Total Annual Additions | - | - | - | 700 | 630 | 1,776 | - | 500 | - | - |

## STOCHASTIC SIMULATION RESULTS

The five Group 2 risk analysis portfolios were run in stochastic simulation mode to determine cost, risk, reliability, and emission performance results. The tables and charts below show how the portfolios compare to one another on the basis of these results.

### Stochastic Mean Cost

Table 7.37 compares the stochastic mean PVRR for each portfolio across the $CO_2$ adder cases, as well as by $CO_2$ compliance strategy (per-ton $CO_2$ tax and cap-and-trade). Portfolio RA14 (two east CCCTs) has the lowest stochastic cost at each adder level. RA17 (no east CCCTs) has the highest cost under the $0, $8, $15, and $38 adder levels, while RA13 has the highest cost under the $61 adder. The average cost deviation among the portfolios is about $200 million for the $0 adder case, and increases to over $600 million at the $61 adder level.

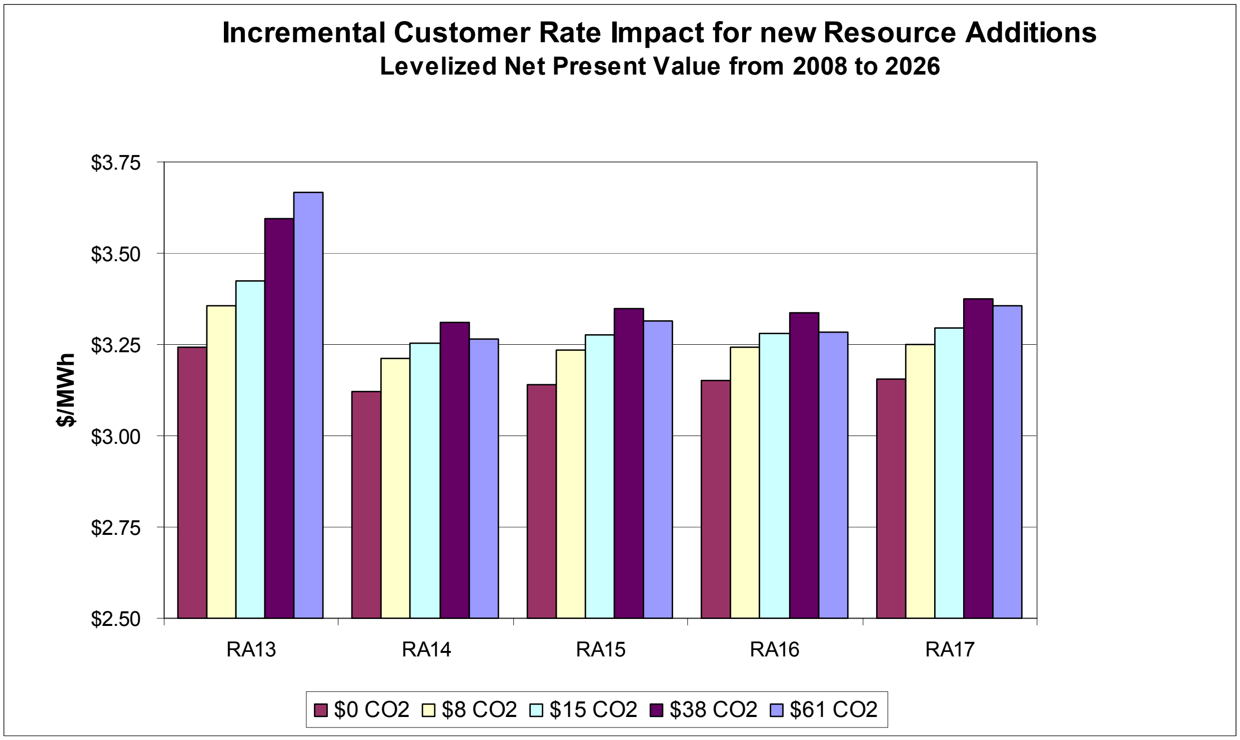
**Table 7.37 – Stochastic Mean PVRR by $CO_2$ Adder Case**

| ID | Tax Strategy (Million $) | | | | | | Rank |
|---|---|---|---|---|---|---|---|
| | $0 Adder (2008$) | $8 Adder (2008$) | $15 Adder (2008$) | $38 Adder (2008$) | $61 Adder (2008$) | Average | |
| RA13 | 22,917 | 26,930 | 29,002 | 36,161 | 43,368 | 31,676 | 5 |
| RA14 | 22,570 | 26,478 | 28,401 | 35,008 | 41,634 | 30,818 | 1 |
| RA15 | 22,631 | 26,551 | 28,482 | 35,139 | 41,820 | 30,925 | 3 |
| RA16 | 22,645 | 26,544 | 28,454 | 35,021 | 41,854 | 30,850 | 2 |
| RA17 | 22,737 | 26,669 | 28,616 | 35,351 | 42,137 | 31,102 | 4 |
| ID | Cap & Trade (Million $) | | | | | | Rank |
| | $0 Adder (2008$) | $8 Adder (2008$) | $15 Adder (2008$) | $38 Adder (2008$) | $61 Adder (2008$) | Average | |
| RA13 | 21,606 | 22,010 | 22,282 | 22,673 | 22,716 | 22,257 | 5 |
| RA14 | 21,260 | 21,559 | 21,682 | 21,521 | 20,983 | 21,401 | 1 |
| RA15 | 21,322 | 21,632 | 21,763 | 21,652 | 21,168 | 21,507 | 3 |
| RA16 | 21,336 | 21,625 | 21,736 | 21,534 | 20,933 | 21,433 | 2 |
| RA17 | 21,427 | 21,750 | 21,897 | 21,864 | 21,486 | 21,685 | 4 |

## Customer Rate Impact

The portfolio customer rate impact results for each $CO_2$ cost adder level are reported in Figure 7.19, and are based on a $CO_2$ cap-and-trade compliance strategy. Portfolio RA14 has the smallest impact across all the $CO_2$ adder levels. The difference between the lowest and highest impact (RA13) under the \$0 adder case is \$0.12/MWh, and increases to \$0.40/MWh for the \$61 adder case.

**Figure 7.19 – Customer Rate Impact**




## Emissions Externality Cost

For the Group 2 portfolios, PacifiCorp estimated the emissions externality cost given two regulatory strategies: cap-and-trade and a per-ton tax. For the tax strategy, each ton of emissions (pounds in the case of mercury) is assessed an emissions tax equivalent to the cost adder value. Table 7.38 shows the externality cost for each portfolio by $CO_2$ adder level and regulation type. Note that the portfolio rankings, based on the average externality cost across the $CO_2$ adder cases, did not change from one regulatory strategy to other.

Portfolio RA16 had the lowest externality cost, followed closely by RA14. In contrast, RA13 had the highest externality cost due to the two additional coal plants not included in the other portfolios. Nevertheless, the externality cost for RA13 under the tax basis is only six percent higher than that for the best-performing portfolio, RA16. Of note is that under the cap-and-trade scheme, RA14 and RA16 have a negative externality cost under the \$61 adder. This result is a consequence of large positive annual allowance balances that have accrued for part of the study period as a result of the cap-and-trade modeling assumptions. Future modeling work is expected to focus on alternative specifications for $CO_2$ compliance strategies.

**Table 7.38 – Portfolio Emissions Externality Cost by $CO_2$ Adder Level and Regulation Type**

| ID | Incremental Stochastic Mean PVRR by $CO_2$ Adder (Tax Strategy), Million $ | | | | | | |
|---|---|---|---|---|---|---|---|
| | $CO_2$ Adder Level (2008$) | | | | | Average | Rank |
| | $0 | $8 | $15 | $38 | $61 | | |
| RA13 | - | 4,013 | 6,085 | 13,244 | 20,451 | 10,948 | 5 |
| RA14 | - | 3,908 | 5,831 | 12,438 | 19,064 | 10,310 | 2 |
| RA15 | - | 3,920 | 5,850 | 12,507 | 19,188 | 10,366 | 3 |
| RA16 | - | 3,898 | 5,809 | 12,376 | 18,939 | 10,255 | 1 |
| RA17 | - | 3,933 | 5,879 | 12,614 | 19,400 | 10,457 | 4 |
| | | | | | | | |
| ID | Incremental Stochastic Mean PVRR by $CO_2$ Adder (Cap and Trade Strategy), Million $ | | | | | | |
| | $CO_2$ Adder Level (2008$) | | | | | Average | Rank |
| | $0 | $8 | $15 | $38 | $61 | | |
| RA13 | - | 404 | 676 | 1,067 | 1,110 | 814 | 5 |
| RA14 | - | 298 | 421 | 261 | (278) | 176 | 2 |
| RA15 | - | 310 | 441 | 330 | (154) | 232 | 3 |
| RA16 | - | 289 | 399 | 198 | (403) | 121 | 1 |
| RA17 | - | 323 | 470 | 437 | 59 | 322 | 4 |

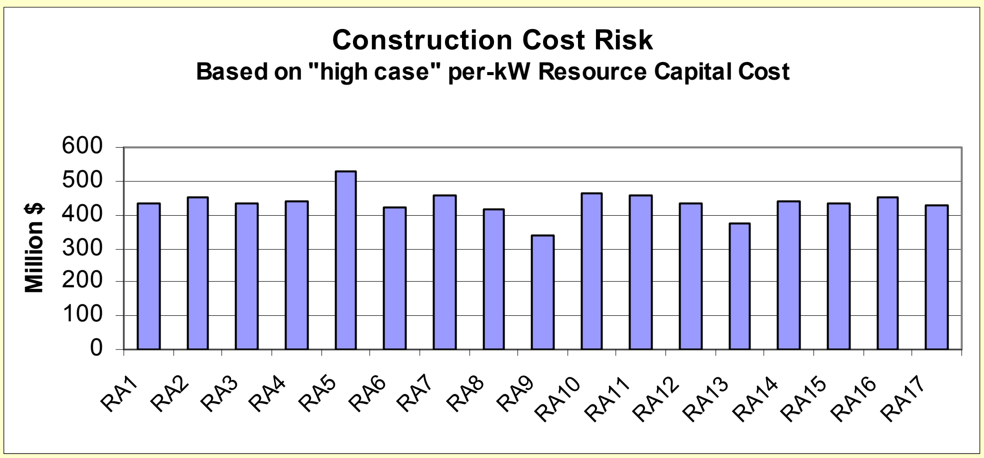
## Capital Cost

Figure 7.20 shows the total capital cost for each portfolio, expressed on a net present value of the sum of all capital costs accrued for 2007–2026. Portfolios RA14 and RA16 have the highest capital cost on account of the three CCCT resources acquired in the 2012-2016 timeframe. RA13 has the lowest capital cost—despite four coal plants—because of the lack of the east CCCT in 2011 and the accelerated wind investment schedule, as well as the cost discount impact of two coal resources acquired beyond 2016.

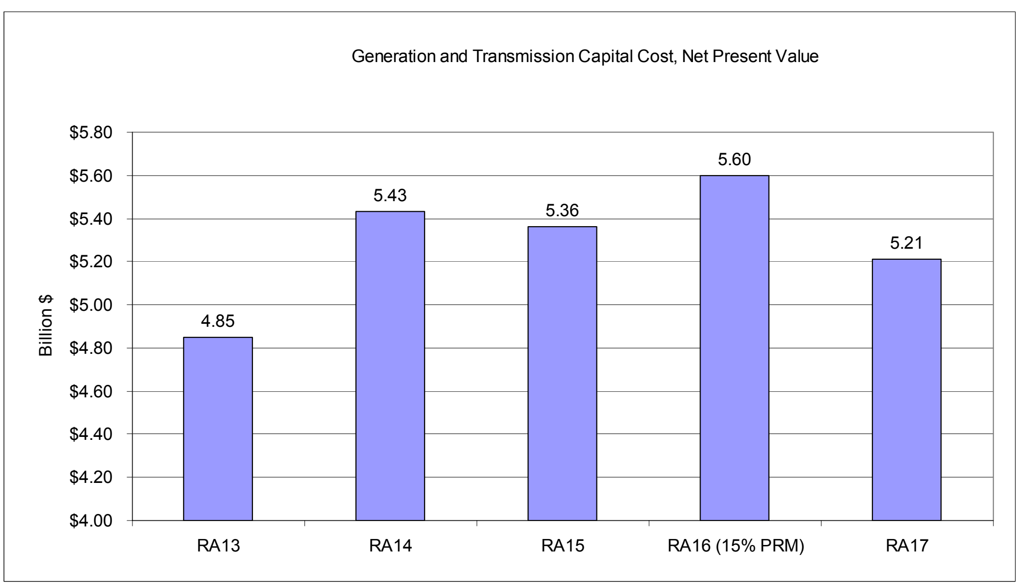
**Portfolio Construction Cost Risk**

PacifiCorp calculated a measure of portfolio construction cost risk using its "high case" per-kilowatt capital cost values. (These values are reported in Chapter 5, Tables 5.1 and 5.2.) The high capital cost ($/kW) estimates are comprised of a standard project construction cost contingency (10%), as well as technology-specific contingencies and "optimism" factors for first-of-a-kind technologies that account for the established tendency to underestimate actual costs (applicable to IGCC). The source for the technology cost contingency and optimism factors is the U.S. Energy Information Administration (*Assumptions to the Annual Energy Outlook 2006,* DOE/EIA-0554(2006), March 2006).

The risk value for each portfolio is the difference between the PVRR calculated with the high per-kW capital cost and the PVRR calculated with the average per-kW capital cost. The table shows the results for the 17 risk analysis portfolios. Portfolio RA9 had the lowest construction cost risk, while RA5 had the highest. Although RA9 includes the more expensive IGCC plants (on a per-kW basis), the smaller capacity sizes of these units, combined with deferral and removal of the supercritical pulverized coal plants, results in a lower overall capital cost.




## Figure 7.20 – Total Capital Cost by Portfolio



**Stochastic Risk Measures**

Table 7.39 reports the portfolio stochastic risk results for each of the $CO_2$ adder cases. Risk exposure, production cost standard deviation, fifth-percentile PVRR, ninety-fifth-percentile PVRR, and upper-tail PVRR are presented for the cap-and-trade compliance strategy. (Note that relative risk measure rankings are the same under both $CO_2$ emissions compliance strategies.)

Portfolio RA13, with four pulverized coal plants, performed the best overall on the risk measures, followed by RA16 with its two east CCCT resources and 15% planning reserve margin. As expected, RA17 has the highest risk due to its heavy reliance on the market. Interestingly, RA14 performed the best on the basis of the 5th percentile measure, indicating that it could be a good performer under a confluence of low-cost conditions.

**Table 7.39 – Stochastic Risk Results**

| ID | Risk Exposure (Upper-Tail PVRR minus Mean PVRR) | | Standard Deviation | 5th Percentile | 95th Percentile | Upper-Tail Mean |
|---|---|---|---|---|---|---|
| | Million $ | Rank | | | | |
| **$0 Adder (2008$)** | | | | | | |
| RA13 | 43,703 | 2 | 12,020 | 13,628 | 36,692 | 65,309 |
| RA14 | 44,056 | 3 | 12,094 | 13,584 | 35,315 | 65,316 |
| RA15 | 44,718 | 4 | 12,296 | 13,518 | 35,918 | 66,040 |
| RA16 | 43,638 | 1 | 11,987 | 13,732 | 35,196 | 64,974 |
| RA17 | 45,339 | 5 | 12,460 | 13,464 | 36,198 | 66,766 |
| **$8 Adder (2008$)** | | | | | | |
| RA13 | 46,984 | 1 | 13,016 | 11,846 | 38,652 | 68,994 |
| RA14 | 47,523 | 3 | 13,134 | 11,620 | 37,066 | 69,082 |
| RA15 | 48,198 | 4 | 13,339 | 11,576 | 37,665 | 69,830 |
| RA16 | 47,128 | 2 | 13,034 | 11,693 | 36,970 | 68,753 |
| RA17 | 48,812 | 5 | 13,501 | 11,661 | 37,935 | 70,562 |
| **$15 Adder (2008$)** | | | | | | |
| RA13 | 48,668 | 1 | 13,556 | 10,987 | 39,736 | 70,950 |
| RA14 | 49,195 | 3 | 13,666 | 10,725 | 38,038 | 70,977 |
| RA15 | 49,863 | 4 | 13,868 | 10,695 | 38,629 | 71,626 |
| RA16 | 48,775 | 2 | 13,560 | 10,840 | 37,933 | 70,510 |
| RA17 | 50,501 | 5 | 14,036 | 11,903 | 38,907 | 72,398 |
| **$38 Adder (2008$)** | | | | | | |
| RA13 | 55,855 | 2 | 15,852 | 9,908 | 43,993 | 43,993 |
| RA14 | 56,258 | 3 | 15,927 | 8,226 | 41,426 | 41,426 |
| RA15 | 56,971 | 4 | 16,136 | 8,223 | 42,019 | 42,019 |
| RA16 | 55,835 | 1 | 15,827 | 8,264 | 41,311 | 41,311 |
| RA17 | 57,704 | 5 | 16,322 | 8,357 | 42,326 | 42,326 |
| **$61 Adder (2008$)** | | | | | | |
| RA13 | 64,344 | 2 | 18,544 | 6,740 | 48,252 | 87,060 |
| RA14 | 64,614 | 3 | 18,584 | 4,562 | 44,875 | 85,596 |
| RA15 | 65,396 | 4 | 18,805 | 4,728 | 45,468 | 86,564 |
| RA16 | 64,159 | 1 | 18,482 | 4,481 | 44,719 | 85,093 |

| ID | Risk Exposure (Upper-Tail PVRR minus Mean PVRR) | | Standard Deviation | 5th Percentile | 95th Percentile | Upper-Tail Mean |
|---|---|---|---|---|---|---|
| | Million $ | Rank | | | | |
| RA17 | 66,238 | 5 | 19,010 | 5,611 | 45,870 | 87,724 |
| **Average across Adder Cases** | | | | | | |
| RA13 | 51,911 | 2 | 14,598 | 10,622 | 41,465 | 74,168 |
| RA14 | 52,329 | 3 | 14,681 | 9,743 | 39,344 | 73,730 |
| RA15 | 53,029 | 4 | 14,889 | 9,748 | 39,940 | 74,537 |
| RA16 | 51,907 | 1 | 14,578 | 9,802 | 39,226 | 73,340 |
| RA17 | 53,719 | 5 | 15,066 | 9,999 | 40,247 | 75,403 |

## Cost/Risk Tradeoff Analysis

The three figures below are scatter plots of portfolio cost (PVRR) and risk exposure. Figure 7.21 plots the average PVRR and risk exposure across the $CO_2$ adder cases. Figures 7.22 and 7.23 show the cost-risk relationship for the \$0 $CO_2$ adder case and the \$61 $CO_2$ adder case, respectively.

The figures indicate that RA14 has the best balance of cost and risk on an average basis across the five $CO_2$ adder cases, as well as for adders greater than \$0. Portfolio RA17 fares relatively poorly, having both a higher cost and risk than the other portfolios.

**Figure 7.21 – Average Stochastic Cost versus Risk Exposure**

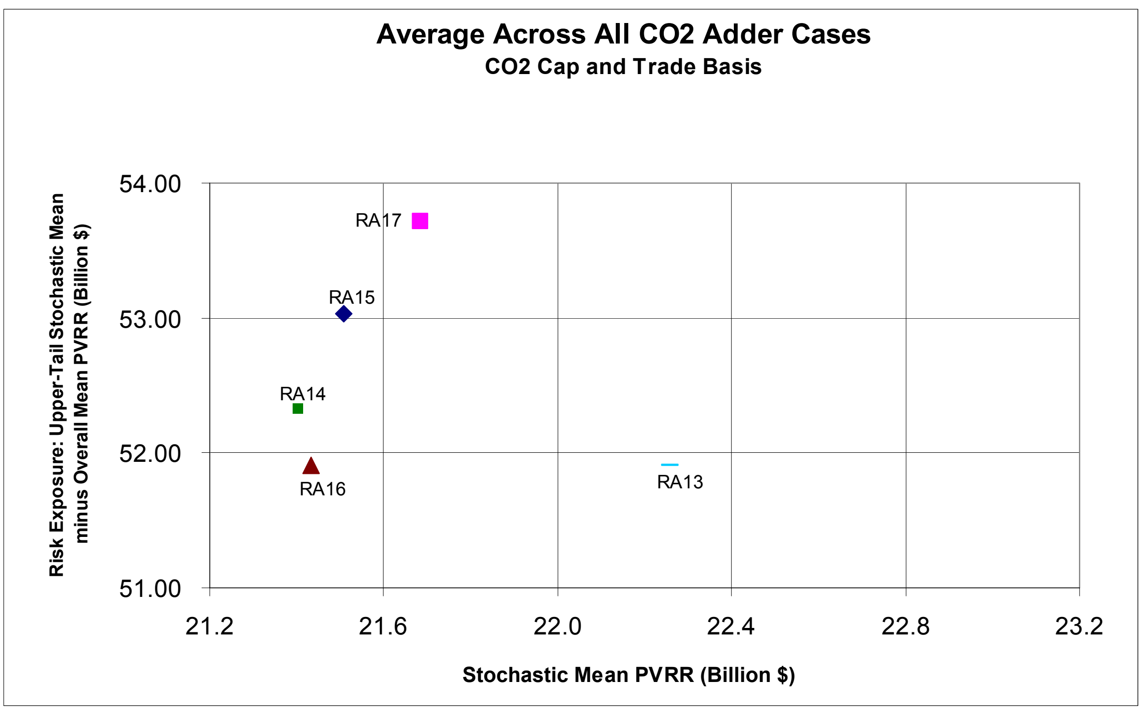


**Figure 7.22 – Stochastic Cost versus Risk Exposure for the $0 $CO_2$ Adder Case**

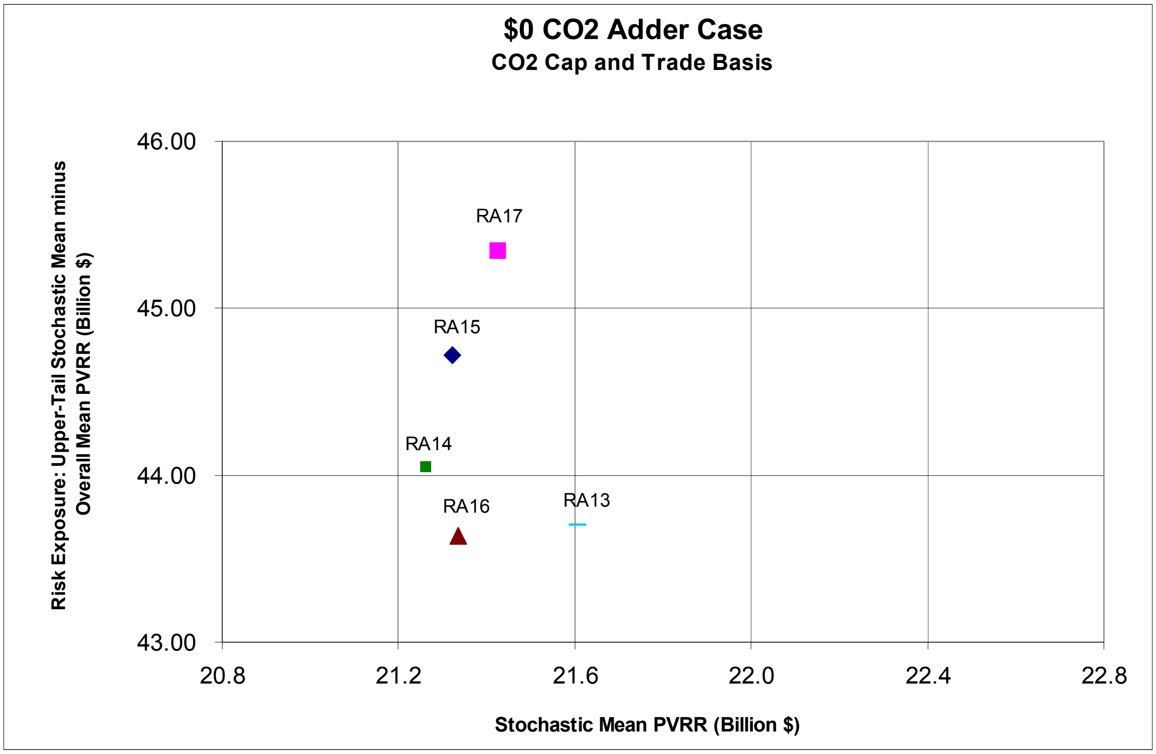
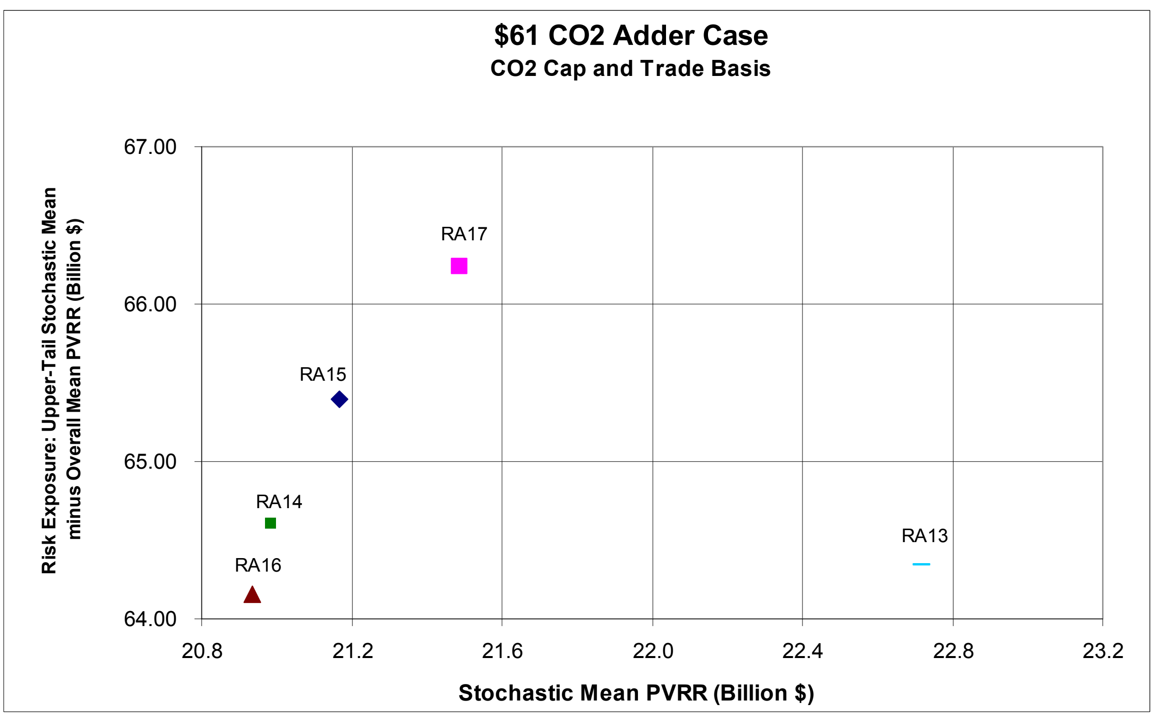



**Figure 7.23 – Stochastic Cost versus Risk Exposure for the $61 $CO_2$ Adder Case**



## Carbon Dioxide and Other Emissions

Table 7.40 reports for the portfolios the total system $CO_2$ emissions for the $8 adder and $61 adder cases. Total emissions are presented as the contribution from direct sources (generators) plus indirect emissions from purchases less emissions attributed to wholesale sales[62], and are reported for 2007-to-2016 and 2007-to-2026. Portfolio RA16 has the lowest $CO_2$ emissions for both $CO_2$ adder levels, followed closely by RA14. For RA16, the early addition of a CCCT displaces front office transactions, which have a slightly higher $CO_2$ emission rate than a CCCT. Portfolio RA13 has the highest $CO_2$ emissions because of the additional two coal plants.

### $CO_2$ Adder Breakeven Analysis for Coal versus Gas Combined Cycle

PacifiCorp conducted a study to determine the $CO_2$ adder level that causes the CEM to select a combined cycle combustion turbine over a supercritical pulverized coal plant. The model was executed at various $CO_2$ adders between $8/ton and $40/ton (in 2008 dollars) to converge on the breakeven point. The study was performed on a portfolio that had the 600 megawatts of extra wind and a Wyoming supercritical pulverized coal acquired in 2016. The simulations were designed to hold all influences constant except for the substitution of one coal plant with a CCCT. Study assumptions included the following:

- The pulverized coal and CCCT test resources were both sized at 575 megawatts
- The two resources were located in the same topology bubble (Utah South)
- The CEM was required to select either the coal or CCCT resource in 2016, but not both (mutually exclusive options)
- Each simulation used a set of forward natural gas and wholesale electricity prices that were adjusted to account for the effect of the $CO_2$ adder level tested

The breakeven $CO_2$ adder level was found to be $38/ton; up to this level, the CEM selected the coal plant rather than the CCCT. Over the range of $CO_2$ adders tested, a $1/ton increase in the adder translated into an average $373 million increase in deterministic Present Value of Revenue Requirements. (Note that the CEM treats the cost adder as an emissions tax.)

### Table 7.40 – $CO_2$ Emissions by Adder Case and Time Period (1,000 Tons)

| | $8 $CO_2$ Adder Case | | | | | |
|---|---|---|---|---|---|---|
| | 2007 to 2016 | | | 2007 to 2026 | | |
| Scenario ID | Direct (Generation only) | Total Direct and Net Indirect | Rank (Total Direct and Net Indirect) | Direct (Generation only) | Total Direct and Net Indirect | Rank (Total Direct and Net Indirect) |
| RA13 | 493,664 | 523,812 | 5 | 1,064,261 | 1,127,571 | 5 |
| RA14 | 495,099 | 507,807 | 2 | 1,019,946 | 1,064,710 | 2 |
| RA15 | 495,040 | 508,332 | 3 | 1,021,983 | 1,068,540 | 3 |
| RA16 | 493,225 | 503,148 | 1 | 1,017,187 | 1,057,885 | 1 |
| RA17 | 495,186 | 512,737 | 4 | 1,023,767 | 1,075,848 | 4 |

[62] Emissions imputed to purchases are based on a survey of 2005 PacifiCorp historical purchases, at 0.565 tons $CO_2$/MWh. Emissions imputed to sales are based on a year-by-year system weighted average rate: Thermal plus Purchases CO2 (tons)/Total System Generation (MWh).

| | $61 $CO_2$ Adder Case | | | | | |
|---|---|---|---|---|---|---|
| | 2007 to 2016 | | | 2007 to 2026 | | |
| **Scenario ID** | **Direct (Generation only)** | **Total Direct and Net Indirect** | **Rank (Total Direct and Net Indirect)** | **Direct (Generation only)** | **Total Direct and Indirect** | **Rank (Total Direct and Net Indirect)** |
| RA13 | 478,176 | 515,380 | 5 | 972,566 | 1,085,311 | 5 |
| RA14 | 476,743 | 496,788 | 2 | 922,926 | 1,016,625 | 2 |
| RA15 | 477,038 | 497,663 | 3 | 926,375 | 1,022,002 | 3 |
| RA16 | 474,074 | 491,563 | 1 | 918,006 | 1,008,456 | 1 |
| RA17 | 478,560 | 503,290 | 4 | 931,329 | 1,031,967 | 4 |

Figures 7.24 and 7.25 show the annual $CO_2$ emissions trend from 2007 through 2026 for the $8 and $61 $CO_2$ adder cases, respectively. The impact of the wind and CCCT additions is evident from the emissions drop from 2011 through 2012 for portfolios RA14, RA15, and RA16. The increasing annual emissions after this point are attributable to the addition of the Wyoming supercritical pulverized coal resource in 2014 and an increase in front office transactions. The significant emissions drop in 2019 for all the portfolios is caused by the addition of CCCT-based growth stations, which replace the acquisition of front office transactions.

For the $61 adder case, the large $CO_2$ emission decreases in 2013 through 2015 are due to the phasing in of the adder, which starts in 2010 but ramps up significantly in 2014 and 2015.

**Figure 7.24 – Annual $CO_2$ Emission Trends, 2007-2026, ($8 $CO_2$ Adder Case)**
(Generation plus the net indirect effect of wholesale purchases and sales)

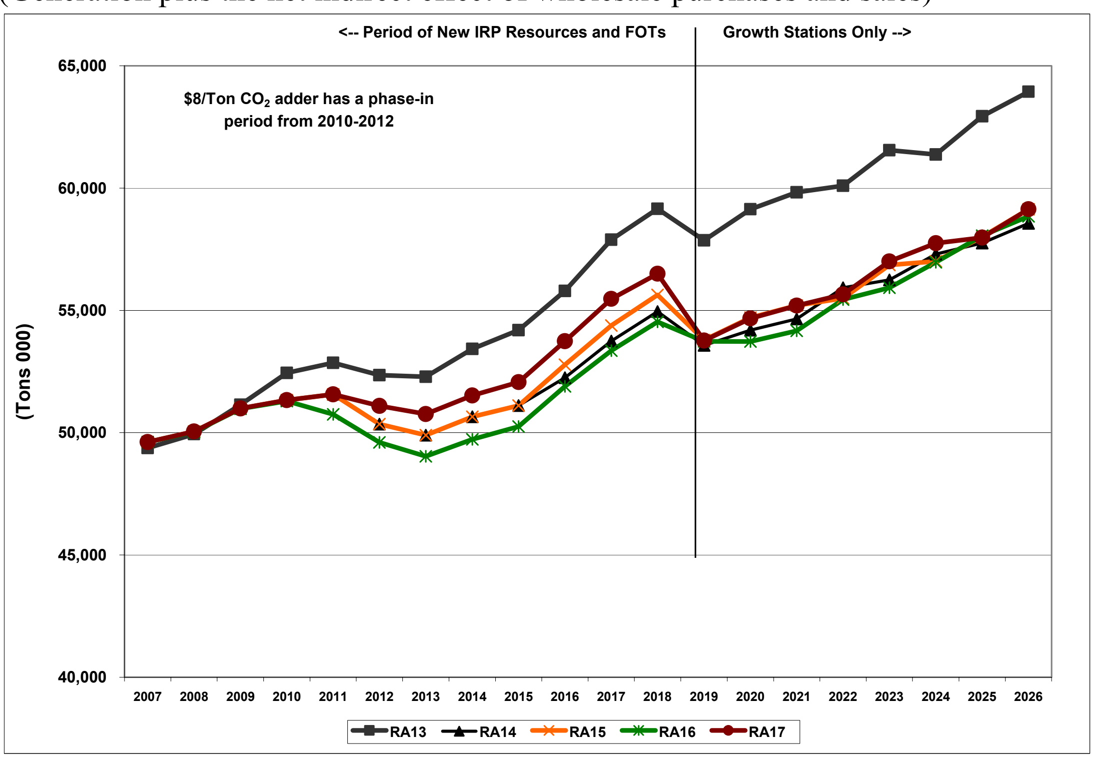
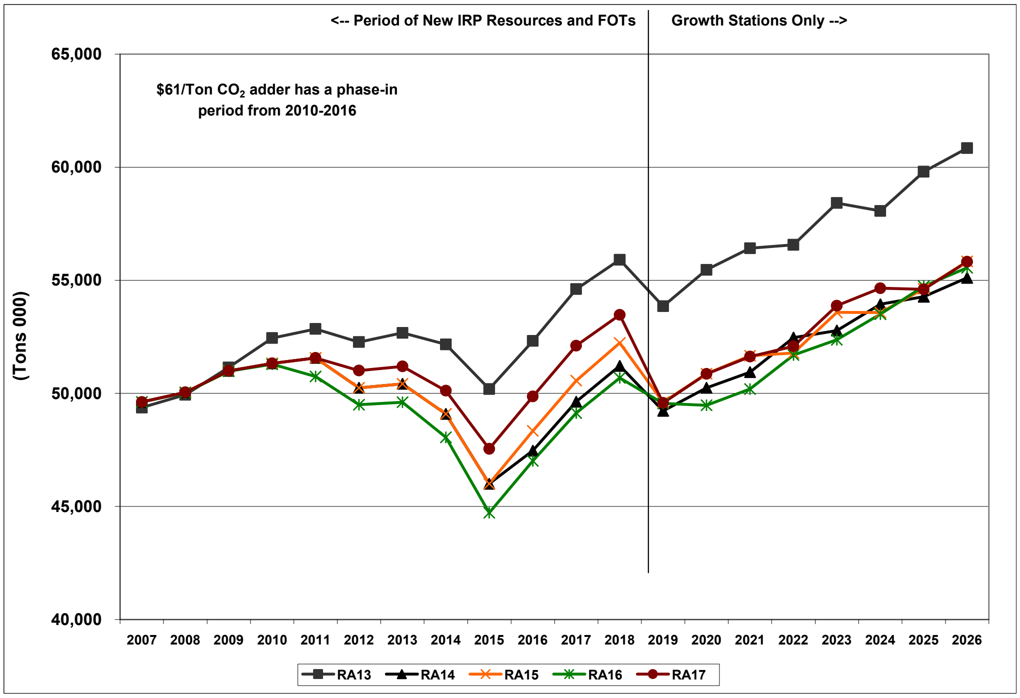


**Figure 7.25 – Annual $CO_2$ Emission Trends, 2007-2026, ($61 $CO_2$ Adder Case)**
(Generation plus the net indirect effect of wholesale purchases and sales)




Figures 7.26 through 7.29 show the annual system $CO_2$ emissions trends (generation plus net purchases) for 2007 through 2016 by $CO_2$ adder case, as well as the contributions from generators only.

**Figure 7.26 – Annual $CO_2$ Emissions Trends, 2007-2016 ($8 $CO_2$ Adder Case)**
(From generation only)

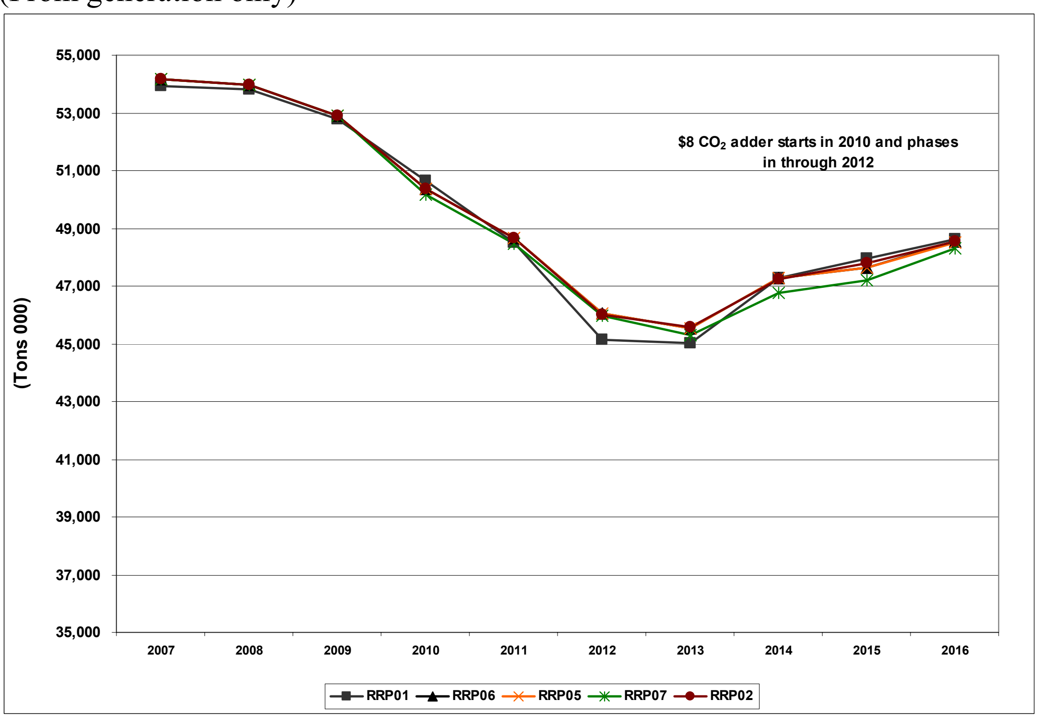


**Figure 7.27 – Annual $CO_2$ Emissions Trends, 2007-2016 ($61 $CO_2$ Adder Case)**
(From generation only)

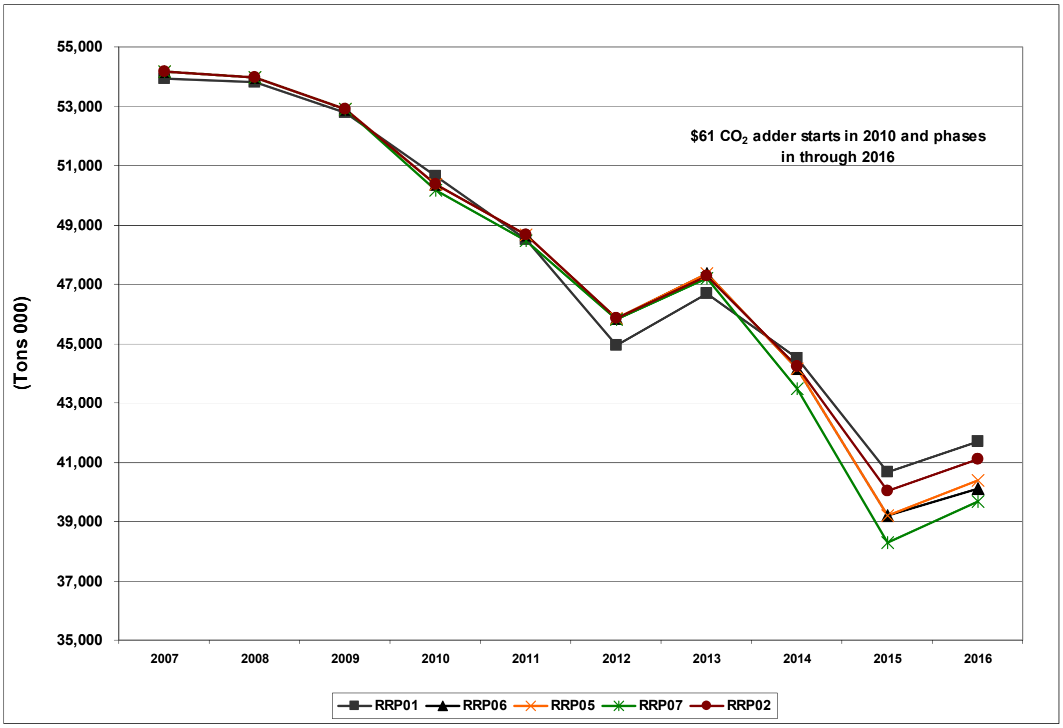



**Figure 7.28 – Annual $CO_2$ Emissions Trends, 2007-2016 ($8 $CO_2$ Adder Case)**
(Generation plus the net indirect effect of wholesale purchases and sales)

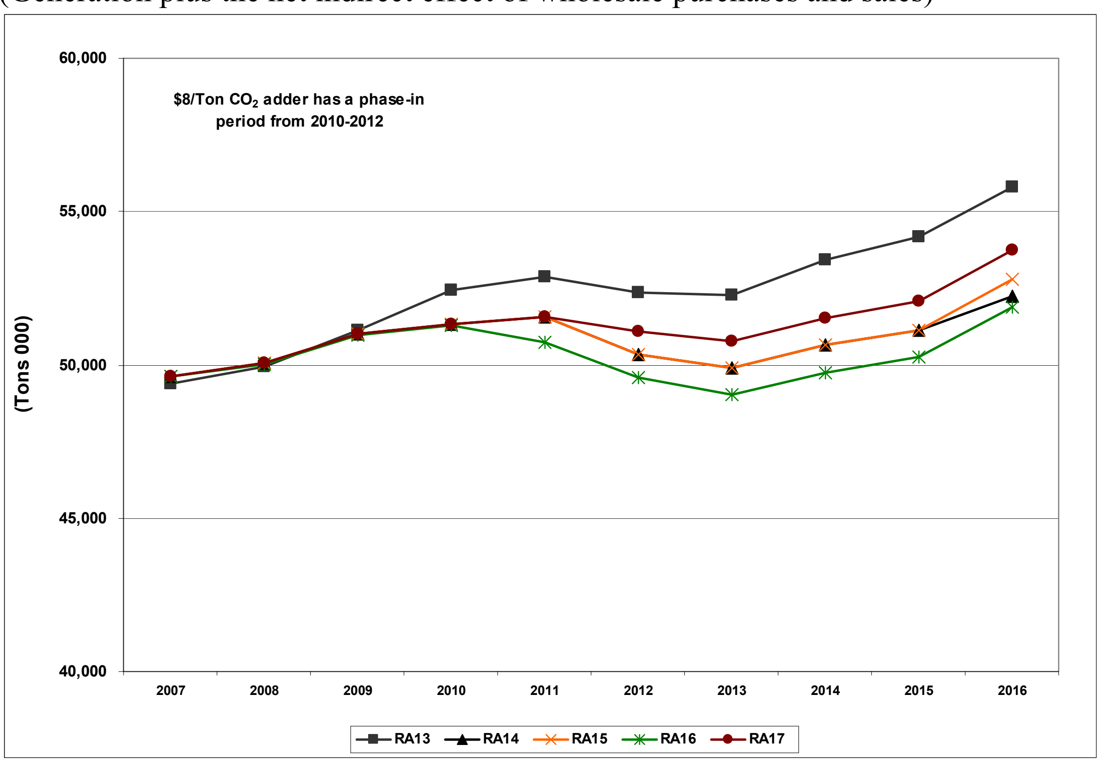


**Figure 7.29 – Annual $CO_2$ Emissions Trends, 2007-2016 ($61 $CO_2$ Adder Case)**
(Generation plus the net indirect effect of wholesale purchases and sales)

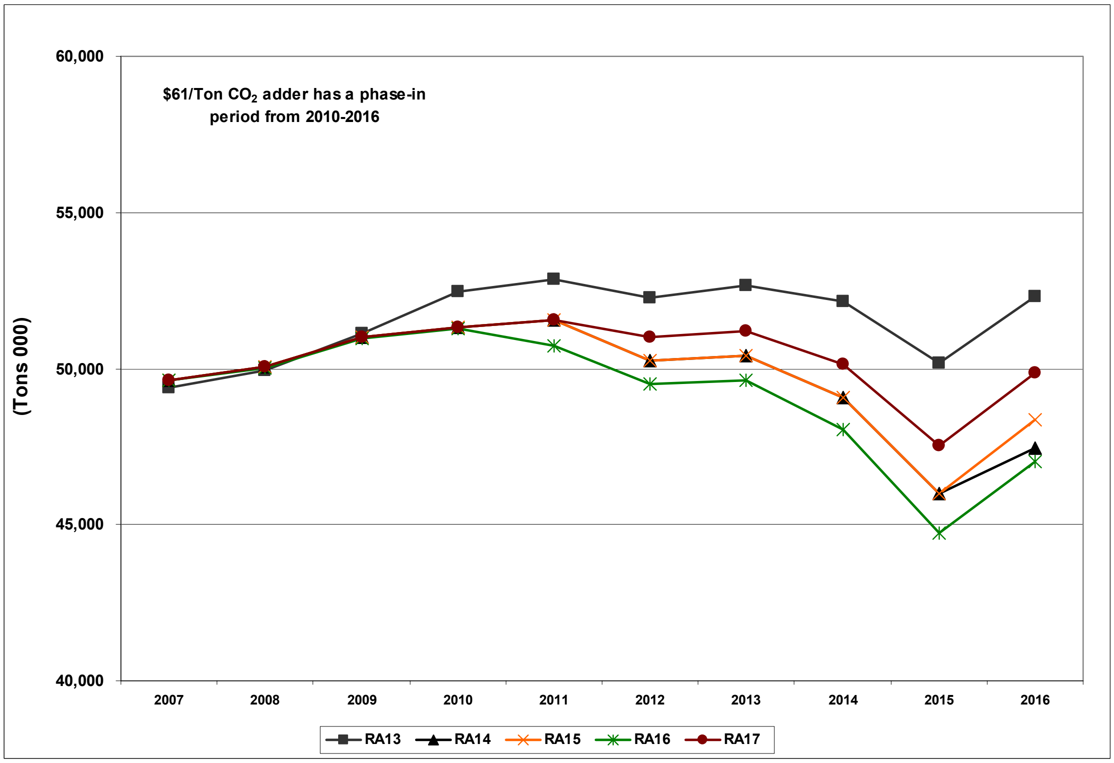



Table 7.41 shows the total portfolio emissions of $SO_2$, $NO_X$, mercury, and $CO_2$ from generators only, by $CO_2$ adder case, for 2007 through 2026. Portfolio RA16 performed the best across the emission types for most of the $CO_2$ adder cases. RA2 performed nearly as well, coming in second place on $SO_2$, $NO_X$, and mercury emissions for all $CO_2$ adders except the $61 case.

**Table 7.41 – Total Emissions Footprint by $CO_2$ Adder Case**
(From system generation for 2007-2026)

| ID | Emission Type and Units | | | |
|---|---|---|---|---|
| | $SO_2$ | $NO_X$ | Hg | $CO_2$ |
| | 1000 Tons | 1000 Tons | Pounds | 1000 Tons |
| **$0 $CO_2$ Adder Case** | | | | |
| RA13 | 844 | 1,196 | 8,325 | 1,118,625 |
| RA14 | 811 | 1,157 | 8,048 | 1,077,417 |
| RA15 | 814 | 1,162 | 8,053 | 1,079,015 |
| RA16 | 805 | 1,148 | 8,035 | 1,076,347 |
| RA17 | 820 | 1,170 | 8,056 | 1,079,240 |
| **$8 $CO_2$ Adder Case** | | | | |
| RA13 | 803 | 1,132 | 8,022 | 1,064,261 |
| RA14 | 766 | 1,088 | 7,729 | 1,019,946 |
| RA15 | 770 | 1,094 | 7,735 | 1,021,983 |
| RA16 | 759 | 1,077 | 7,742 | 1,017,187 |
| RA17 | 777 | 1,104 | 7,745 | 1,023,767 |
| **$15 $CO_2$ Adder Case** | | | | |

| ID | Emission Type and Units | | | |
|---|---|---|---|---|
| | $SO_2$ | $NO_X$ | Hg | $CO_2$ |
| | 1000 Tons | 1000 Tons | Pounds | 1000 Tons |
| RA13 | 790 | 1,111 | 7,913 | 1,043,467 |
| RA14 | 750 | 1,063 | 7,615 | 998,044 |
| RA15 | 754 | 1,070 | 7,623 | 1,000,419 |
| RA16 | 742 | 1,052 | 7,590 | 994,806 |
| RA17 | 762 | 1,081 | 7,635 | 1,002,900 |
| **\$38 $CO_2$ Adder Case** | | | | |
| RA13 | 751 | 1,047 | 7,651 | 996,446 |
| RA14 | 708 | 999 | 7,335 | 948,247 |
| RA15 | 712 | 1,007 | 7,347 | 951,276 |
| RA16 | 699 | 986 | 7,306 | 944,095 |
| RA17 | 722 | 1,020 | 7,367 | 955,222 |
| **\$61 $CO_2$ Adder Case** | | | | |
| RA13 | 730 | 1,011 | 7,529 | 972,566 |
| RA14 | 686 | 964 | 7,195 | 922,926 |
| RA15 | 691 | 972 | 7,210 | 926,375 |
| RA16 | 677 | 950 | 7,163 | 918,006 |
| RA17 | 702 | 987 | 7,236 | 931,329 |

## Supply Reliability

### Energy Not Served (ENS)

Figures 7.30 and 7.31 show the average annual ENS and upper-tail ENS by portfolio for 2007–2026, respectively. RA16 has the smallest ENS amount at 135 gigawatt hours, followed by RA14. Portfolios RA13 and RA17 have the highest ENS due to the heavier reliance on front office transactions to meet the load obligation. The ENS was also tested for the \$0/ton $CO_2$ and \$61/ton $CO_2$ and the amount of ENS was the same for each portfolio.

**Figure 7.30 – Energy Not Served for the \$8 $CO_2$ Adder Case**

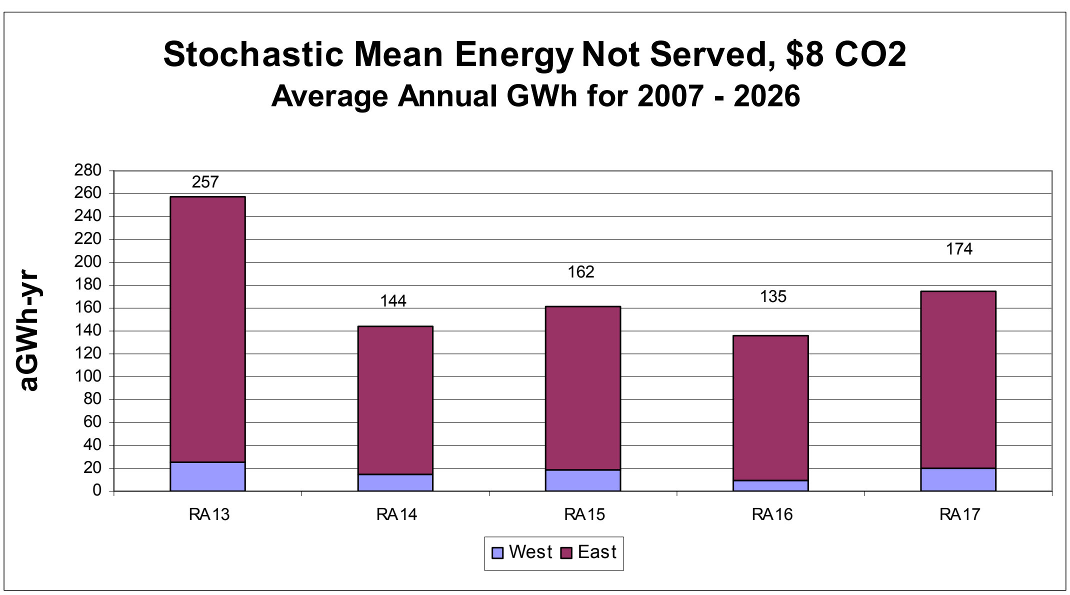
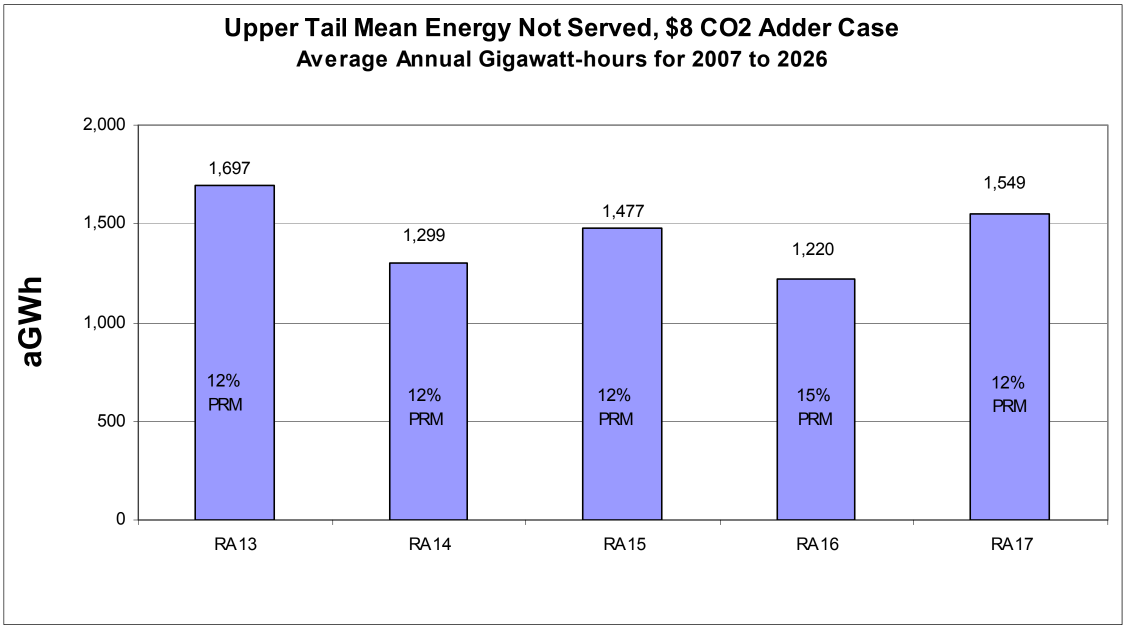


**Figure 7.31 – Upper-Tail Mean Energy Not Served for the \$8 $CO_2$ Adder Case**




## Loss of Load Probability

Table 7.42 displays the average Loss of Load Probability for each of the risk analysis portfolios modeled using the \$8 $CO_2$ adder case. 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 data is summarized against multiple levels of lost load, which shows the likelihood of losing various amounts of load in a single event.

**Table 7.42 – Average Loss of Load Probability During Summer Peak**
(Probability of ENS Event > 25,000 MWh in July)

| Average for operating years 2007 through 2016 | | | | | |
|---|---|---|---|---|---|
| **Event Size (MWh)** | **RA13** | **RA14** | **RA15** | **RA16** | **RA17** |
| **> 0** | 29% | 24% | 25% | 23% | 26% |
| **> 1,000** | 24% | 22% | 22% | 20% | 24% |
| **> 10,000** | 16% | 14% | 15% | 13% | 17% |
| **> 25,000** | 12% | 11% | 11% | 9% | 13% |
| **> 50,000** | 9% | 8% | 8% | 6% | 10% |
| **> 100,000** | 6% | 5% | 5% | 4% | 7% |
| **> 500,000** | 1% | 1% | 1% | 0% | 1% |
| **> 1,000,000** | 0% | 0% | 0% | 0% | 0% |

| Average for operating years 2007 through 2026 | | | | | |
|---|---|---|---|---|---|
| **Event Size (MWh)** | **RA13** | **RA14** | **RA15** | **RA16** | **RA17** |
| **> 0** | 53% | 38% | 42% | 36% | 44% |
| **> 1,000** | 47% | 33% | 38% | 32% | 40% |
| **> 10,000** | 28% | 22% | 25% | 22% | 29% |
| **> 25,000** | 21% | 18% | 19% | 18% | 24% |

| Average for operating years 2007 through 2026 | | | | | |
|---|---|---|---|---|---|
| Event Size (MWh) | RA13 | RA14 | RA15 | RA16 | RA17 |
| > 50,000 | 16% | 15% | 16% | 14% | 20% |
| > 100,000 | 11% | 11% | 12% | 11% | 16% |
| > 500,000 | 4% | 3% | 4% | 3% | 5% |
| > 1,000,000 | 2% | 2% | 2% | 2% | 2% |

Table 7.43 displays the year-by-year results for the threshold value of 25,000 megawatt-hours. For each year, the LOLP value represents the proportion of the 100 iterations where the July ENS was greater than 25,000 megawatt-hours. This is the equivalent of 2,500 megawatts for 10 hours.

**Table 7.43 – Year-by-Year Loss of Load Probability**

| Year | RA13 | RA14 | RA15 | RA16 | RA17 |
|---|---|---|---|---|---|
| 2007 | 1% | 2% | 2% | 2% | 2% |
| 2008 | 3% | 3% | 3% | 3% | 3% |
| 2009 | 8% | 10% | 10% | 10% | 10% |
| 2010 | 13% | 12% | 12% | 13% | 12% |
| 2011 | 16% | 16% | 16% | 10% | 16% |
| 2012 | 7% | 7% | 7% | 4% | 9% |
| 2013 | 13% | 12% | 12% | 8% | 13% |
| 2014 | 15% | 10% | 10% | 8% | 16% |
| 2015 | 23% | 18% | 18% | 15% | 22% |
| 2016 | 20% | 16% | 20% | 17% | 26% |
| 2017 | 23% | 26% | 29% | 25% | 30% |
| 2018 | 28% | 26% | 30% | 27% | 39% |
| 2019 | 15% | 18% | 19% | 20% | 30% |
| 2020 | 22% | 23% | 27% | 25% | 31% |
| 2021 | 24% | 22% | 25% | 23% | 33% |
| 2022 | 32% | 29% | 31% | 34% | 38% |
| 2023 | 28% | 23% | 28% | 22% | 36% |
| 2024 | 36% | 25% | 27% | 30% | 36% |
| 2025 | 41% | 28% | 33% | 32% | 32% |
| 2026 | 49% | 28% | 28% | 29% | 37% |

## STOCHASTIC SIMULATION SENSITIVITY ANALYSES

PacifiCorp performed several stochastic simulation studies to test the stochastic cost, risk, and reliability impacts of planning reserve margin and resource type assumptions against a reference portfolio. Table 7.44 lists the sensitivity analysis studies conducted and the reference portfolios used. The study assumptions and results are summarized below.

**Table 7.44 – Sensitivity Analysis Scenarios for Detailed Simulation Analysis**

| # | Name | Reference Case |
|---|---|---|
| 1 | Plan to a 12% capacity reserve margin, and include Class 3 DSM sufficient to eliminate ENS | RA8 (Consistent with the portfolio developed for SAS01) |
| 2 | Plan to 18% capacity reserve margin | SAS02, "Plan to 18% capacity reserve margin" |
| 3 | Replace a 2012 base load resource with front office transactions | Risk Analysis Portfolio RA1 |
| 4 | Replace a base load pulverized coal resource with a carbon-capture-ready IGCC resource | Risk Analysis Portfolio RA1 |
| 5 | Substitute a base load resource with CHP and aggregated dispatchable customer standby generation | Risk Analysis Portfolio RA1 |

## 12-Percent Planning Reserve Margin with Class 3 Demand-side Management Programs

For this study, 106 megawatts of Class 3 demand side management programs were added to the RA8 risk analysis portfolio in 2009. This DSM quantity reflects the total available to the model according to the base case proxy supply curve results reported by Quantec LLC, and includes capacity for curtailable rate, critical peak pricing, and demand buyback programs for both the east and west sides of the system. The Class 3 DSM programs were modeled in the PaR module as a "take" component during super-peak hours and a "return" component for all other hours.

The impact of the Class 3 DSM on portfolio performance was negligible. Compared to RA8, stochastic mean PVRR increased by $11 million, risk exposure decreased by $9 million, and Energy Not Served decreased by 0.1 percent.

## Plan to an 18-Percent Planning Reserve Margin

PacifiCorp modeled the CEM investment plan that resulted from planning to an 18-percent planning reserve margin (SAS02 study). The SAS02 study reflects the same scenario conditions as RA1 except for the 15-percent planning reserve margin. Relative to RA1, the SAS02 portfolio resulted in a $69 million increase in stochastic mean PVRR, while risk exposure decreased by $346 million. Energy Not Served also decreased by about 16 percent. The PVRR increase was mainly attributable to the addition of an east SCCT frame resource.

## Replace a 2012 Base Load Resource with Front Office Transactions

Using RA1 as the reference case, PacifiCorp replaced the small Utah pulverized coal resource acquired in 2012 (340 megawatts) with a comparable amount of front office transactions acquired at the Mona trading location (6x16 product over 3 month summer season) that continued over the remaining study period.

Compared to RA1, the new portfolio's stochastic mean PVRR was $4 million lower, while the risk exposure increased by $3.4 billion. Energy Not Served increased by nine percent. Based on this sensitivity study, PacifiCorp concluded that replacing a long-term asset outright with market purchases—holding other factors constant—is not a preferred east-side resource strategy given the cost-versus-risk tradeoff.

## Replace a Base Load Pulverized Coal Resource with a Carbon-Capture-Ready IGCC

Starting with portfolio RA1, PacifiCorp replaced the 750-megawatt Wyoming supercritical pulverized coal resource with an equivalently sized IGCC plant that has minimum carbon capture provisions. The coal resource replacement resulted in a $687 million increase in stochastic mean PVRR and a $411 million increase in risk exposure. The risk exposure increase is due to the two-percent lower availability of the IGCC relative to the Wyoming SCPC resource.

**Replace a Base Load Resource with CHP and Dispatchable Customer Standby Generation**

Using portfolio RA1 as the starting point, PacifiCorp replaced the small Utah pulverized coal resource with 280 megawatts of gas-fired CHP resources and 60 megawatts of west-side customer standby generation. (This sensitivity addresses an analysis requirement in the Oregon Public Utility Commission's 2004 Integrated Resource Plan acknowledgement order.) Table 7.45 reports the sizes, locations, and number of units used for the study.

**Table 7.45 – Combined Heat and Power Replacement Resources**

| CHP Resource Type | East Location | West Location | System Total |
|---|---|---|---|
| Large industrial – 25 MW | 75 MW (3 units) | 150 MW (6 units) | 225 MW (9 units) |
| Small industrial/commercial – 5 MW | 35 MW (7 units) | 20 MW (4 units) | 55 MW (11 Units) |
| **Total** | **110 MW** | **170 MW** | **280 MW** |

Comparing against portfolio RA1, the new portfolio with CHP and customer standby generation resources had a $168 million higher stochastic mean PVRR. Risk exposure was higher by $2.4 billion, while Energy Not Served was higher by about 7 percent.

## PREFERRED PORTFOLIO SELECTION AND JUSTIFICATION

Based on the stochastic analysis results for the Group 2 risk analysis portfolios, the company has chosen RA14 as the preferred portfolio. Table 7.46 shows the resulting load and resource balance with preferred portfolio resources and east-west transfers included.

This portfolio reflects a robust resource strategy that accounts for the major resource risk factors (specifically the form and cost impact of $CO_2$ regulations, and price volatility for natural gas plants and market purchases) as well as evolving state resource policies that are currently not coordinated with respect to PacifiCorp's system-wide integrated resource planning mandate. Portfolio RA14 is viewed as the least-cost and least economically risky proposition for reliably meeting PacifiCorp's load obligation while accommodating different state policies and interests.

In assessing the overall merits of this portfolio, PacifiCorp also concentrated on the value of the different resource types for managing portfolio risks in the short term, mid term, and long term. For the short term, the acquisition of renewables, DSM and CHP increases portfolio diversity and lays the groundwork for a resource base that can comply with early RPS and $CO_2$ compliance schedules. For the mid term—2012 through 2014, which is a period marked by significant resource need and escalating regulatory risks—the preferred portfolio is constituted with a mix of proxy long-term assets with complementary risk profiles (supercritical pulverized coal and CCCT resources), supplemented by new front office transactions to increase planning flexibility. For the long term, the preferred portfolio includes flexible long-term assets with a small emissions footprint and a moderate reliance on front office transactions. This resource mix is most in line with the company strategy to reduce its long-term reliance on the market, which is discussed in more detail later in this chapter.

**Planning Reserve Margin Selection**

While Portfolio RA14 is based on a target planning reserve margin of 12 percent, PacifiCorp is targeting a reserve margin range of 12 to 15 percent to increase planning flexibility given a time of rapid public policy evolution and wide uncertainty over the resulting down-stream cost impacts. While the portfolio analysis indicates that lowering the planning reserve margin increases portfolio stochastic risk and reduces reliability, the decision on what margin to adopt is a subjective one that depends on balancing portfolio risk against cost. Given the expected pressure on customer rates due to state resource constraints, as well as the rapid pace of construction cost increases for all resource types, near-term affordability of a resource plan is a consideration guiding the planning margin decision.

PacifiCorp's choice to adopt a 12 percent planning reserve margin is intended to keep the portfolio cost down while retaining the flexibility to adjust the margin upwards and acquire appropriate incremental resources. Market conditions, revised load growth projections, or new regional adequacy standards may prompt the company to increase the margin in response. Based on the Group 2 portfolio analysis and the resource outlook developed for this IRP, a higher planning reserve margin would be met with a combination of gas generation and front office transactions, as can be seen in Portfolio RA16.

An issue raised by public stakeholders is the impact of the planning reserve margin decision on supply reliability. PacifiCorp's view is that supply reliability is not materially impacted by a swing in the margin from 15 to 12 percent. The supply reliability analyses (Energy Not Served and Loss of Load Probability) indicate that, with the exception of "all coal" portfolios such as RA13, there are no significant differences among the portfolios with respect to reliability. As additional evidence of this finding, comparing portfolio pairs intended to test the impact of a 15 percent margin against a 12 percent margin (RA1 versus RA8, RA10 versus RA9, RA11 versus RA12, and RA16 versus RA14) yields small differences in average annual ENS of between 1.2 MWa to 3.9 MWa.

# Table 7.46 – Preferred Portfolio Capacity Load and Resource Balance

| Calendar Year | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** |
|---|---|---|---|---|---|---|---|---|---|---|
| **East** | | | | | | | | | | |
| Thermal | 6,134 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 | 5,941 |
| Hydro | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 |
| DSM | 153 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 |
| Renewable | 65 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 105 | 105 |
| Purchase | 904 | 679 | 778 | 548 | 543 | 343 | 343 | 343 | 343 | 322 |
| QF | 106 | 106 | 106 | 106 | 106 | 106 | 106 | 106 | 106 | 106 |
| Interruptible | 233 | 233 | 308 | 308 | 308 | 308 | 308 | 308 | 308 | 308 |
| Transfers | 534 | 797 | 731 | 898 | 1,162 | 955 | 1,111 | 597 | 701 | 777 |
| **East Existing Resources** | 8,264 | 8,163 | 8,271 | 8,208 | 8,467 | 8,060 | 8,216 | 7,702 | 7,802 | 7,857 |
| | | | | | | | | | | |
| Wind | 0 | 24 | 24 | 40 | 48 | 48 | 109 | 109 | 109 | 109 |
| DSM | 0 | 0 | 0 | 0 | 0 | 15 | 63 | 63 | 63 | 63 |
| CHP | 0 | 0 | 0 | 0 | 0 | 25 | 25 | 25 | 25 | 25 |
| Front Office Transactions | 0 | 0 | 0 | 393 | 272 | 97 | 3 | 149 | 192 | 165 |
| Thermal | 0 | 0 | 0 | 0 | 0 | 888 | 888 | 1,415 | 1,415 | 1,772 |
| **East Planned Resources** | 0 | 24 | 24 | 433 | 320 | 1,073 | 1,088 | 1,761 | 1,804 | 2,134 |
| | | | | | | | | | | |
| **East Total Resources** | 8,264 | 8,187 | 8,295 | 8,641 | 8,787 | 9,133 | 9,304 | 9,463 | 9,606 | 9,991 |
| | | | | | | | | | | |
| Load | 6,321 | 6,515 | 6,657 | 7,137 | 7,289 | 7,595 | 7,738 | 7,895 | 8,026 | 8,366 |
| Sale | 849 | 811 | 702 | 666 | 631 | 595 | 595 | 595 | 595 | 595 |
| **East Obligation** | 7,170 | 7,326 | 7,359 | 7,803 | 7,920 | 8,190 | 8,333 | 8,490 | 8,621 | 8,961 |
| | | | | | | | | | | |
| Planning reserves (12%) | 706 | 750 | 733 | 767 | 796 | 872 | 894 | 896 | 906 | 953 |
| Non-owned reserves | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 |
| **East Reserves** | 776 | 821 | 804 | 837 | 867 | 942 | 965 | 966 | 977 | 1,023 |
| | | | | | | | | | | |
| **st Obligation + Reserves (12%)** | 7,946 | 8,147 | 8,163 | 8,641 | 8,787 | 9,132 | 9,298 | 9,456 | 9,598 | 9,984 |
| **East Position** | 317 | 40 | 132 | 0 | 0 | 1 | 6 | 7 | 8 | 6 |
| **East Reserve Margin** | 16% | 13% | 14% | 12% | 12% | 12% | 12% | 12% | 12% | 12% |
| | | | | | | | | | | |
| **West** | | | | | | | | | | |
| Thermal | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 | 2,046 |
| Hydro | 1,421 | 1,421 | 1,414 | 1,328 | 1,357 | 1,225 | 1,249 | 1,243 | 1,244 | 1,242 |
| DSM | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Renewable | 108 | 108 | 108 | 108 | 108 | 84 | 84 | 84 | 84 | 84 |
| Purchase | 786 | 800 | 800 | 799 | 749 | 112 | 141 | 107 | 107 | 107 |
| QF | 40 | 40 | 40 | 40 | 40 | 40 | 38 | 38 | 38 | 38 |
| Transfers | (542) | (804) | (741) | (907) | (1,170) | (964) | (1,120) | (606) | (708) | (786) |
| **West Existing Resources** | 3,859 | 3,611 | 3,667 | 3,414 | 3,130 | 2,542 | 2,438 | 2,913 | 2,811 | 2,732 |
| | | | | | | | | | | |
| Wind | 14 | 14 | 51 | 79 | 79 | 98 | 98 | 98 | 98 | 98 |
| DSM | 0 | 0 | 0 | 0 | 0 | 32 | 32 | 32 | 32 | 32 |
| CHP | 0 | 0 | 0 | 0 | 0 | 75 | 75 | 75 | 75 | 75 |
| Front Office Transactions | 0 | 0 | 0 | 219 | 64 | 555 | 657 | 247 | 246 | 249 |
| Thermal | 0 | 0 | 0 | 0 | 548 | 548 | 548 | 548 | 548 | 548 |
| **West Planned Resources** | 14 | 14 | 51 | 298 | 691 | 1,308 | 1,410 | 1,000 | 999 | 1,002 |
| | | | | | | | | | | |
| **West Total Resources** | 3,873 | 3,625 | 3,718 | 3,712 | 3,821 | 3,850 | 3,848 | 3,913 | 3,810 | 3,734 |
| | | | | | | | | | | |
| Load | 2,922 | 2,924 | 3,095 | 3,124 | 3,199 | 3,240 | 3,251 | 3,262 | 3,271 | 3,252 |
| Sale | 299 | 299 | 299 | 290 | 290 | 258 | 258 | 258 | 158 | 108 |
| **West Obligation** | 3,221 | 3,223 | 3,394 | 3,414 | 3,489 | 3,498 | 3,509 | 3,520 | 3,429 | 3,360 |
| | | | | | | | | | | |
| Planning Reserves (12%) | 292 | 291 | 311 | 287 | 321 | 336 | 322 | 376 | 365 | 357 |
| Non-owned reserves | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| **West Reserves** | 299 | 297 | 318 | 294 | 328 | 342 | 328 | 383 | 372 | 363 |
| | | | | | | | | | | |
| **West Obligation + Reserves** | 3,513 | 3,514 | 3,705 | 3,701 | 3,810 | 3,834 | 3,831 | 3,896 | 3,794 | 3,716 |
| **West Position** | 360 | 111 | 12 | 11 | 11 | 16 | 17 | 17 | 16 | 18 |
| **West Reserve Margin** | 23% | 15% | 12% | 12% | 12% | 12% | 12% | 12% | 12% | 12% |
| | | | | | | | | | | |
| **System** | | | | | | | | | | |
| **Total Resources** | 12,137 | 11,811 | 12,013 | 12,353 | 12,608 | 12,983 | 13,152 | 13,376 | 13,416 | 13,725 |
| **Obligation** | 10,391 | 10,549 | 10,753 | 11,217 | 11,409 | 11,688 | 11,842 | 12,010 | 12,050 | 12,321 |
| **Reserves** | 1,075 | 1,118 | 1,122 | 1,131 | 1,194 | 1,285 | 1,293 | 1,349 | 1,348 | 1,386 |
| **Obligation + Reserves** | 11,466 | 11,667 | 11,874 | 12,348 | 12,603 | 12,973 | 13,135 | 13,359 | 13,398 | 13,707 |
| **System Position** | 671 | 144 | 138 | 5 | 5 | 10 | 17 | 17 | 18 | 18 |
| **Reserve Margin** | 18% | 13% | 13% | 12% | 12% | 12% | 12% | 12% | 12% | 12% |

### The Role of Front Office Transactions and Market Availability Considerations

In parallel with the decision on an appropriate planning reserve margin level, the degree to which PacifiCorp relies on firm market transactions is a decision that requires balancing portfolio cost and risk. As demonstrated by comparing risk analysis portfolios with differing front office transaction assumptions, less reliance on front office transactions tends to reduce market price risk exposure, but can increase or decrease mean stochastic cost depending on the make-up of the portfolio. As mentioned earlier in this chapter, PacifiCorp believes that a limited amount of front office transactions benefit the preferred portfolio by increasing planning flexibility and resource diversity. Nevertheless, the company is concerned about long-term reliance on the market and exposure to market price risk, and therefore seeks to reduce that reliance as part of its overall resource management strategy. This concern stems from two sources of market price risk and uncertainty. The first source is the shifting resource mix outlook in the Western Interconnection, driven principally by new or expected state regulatory requirements. Specific trends include extensive expansion of renewable and gas-fired capacity and a counterpart reduction in coal capacity development. The second source of risk and uncertainty is the potential tightening of the regional capacity balance in the next decade due to planned resources not being built as more utilities rely on the market to meet their future needs. This is the time frame when a significant amount of base load capacity is needed by PacifiCorp and other utilities.

The preferred portfolio is consistent with this strategic view on market reliance. The system-wide front office transaction amount in the preferred portfolio peaks at 660 megawatts in 2013, representing just over 55 percent of the transactions amount included as a planned resource in PacifiCorp's 2004 IRP (1,200 megawatts). Additionally, the company no longer plans for a fixed annual target amount of new firm market purchases in the load and resource balance as was done for the previous IRP; rather, front office transactions are evaluated on a comparable basis with other resources and are subject to the company's stochastic risk analysis. Finally, the reliance on front office transactions drops off significantly after 2013, declining over one-third by 2016.

Regarding market availability to support the level of front office transactions in the preferred portfolio, PacifiCorp points to purchase offer activity in response to recent periodic requests for proposals issued by the company's commercial and trading department. Requests in 2007 for third-quarter products for 2007-2012 delivery yielded over 5,000 megawatts in offers.

## FUEL DIVERSITY PLANNING

Pursuant to the Utah Public Service Commission's order on the PURPA Fuel Source Standard (Docket no. 06-999-03, issued on March 13, 2007), this section describes how fuel source diversity is addressed in the 2007 Integrated Resource Plan.[63]

The IRP standards and guidelines require PacifiCorp to evaluate all resource options on a consistent and comparable basis, which explicitly implies consideration of coal, natural gas, demand-side management, and renewable resources (See Appendix I). In addition, the new Oregon Public

[63] As directed by the Utah Commission and agreed to by PacifiCorp, all future IRPs will include a section on fuel source diversity to comply with the new fuel source standard under Title 1 Subtitle B of PURPA. See Chapter 3 for more details.

Utility Commission IRP guidelines issued in January 2007 require the company to consider "all known resources for meeting the utility's load", as well as compare different fuel types.[64] As discussed in Chapter 2, one of PacifiCorp's planning principles is to seek a diversified, low-cost mix of resources that minimizes risks for customers and the company. The company's portfolio optimization studies, using a range of planning scenarios, adhered to this planning principle.

This IRP fulfills the PURPA requirement for a fuel diversity plan in the following ways:

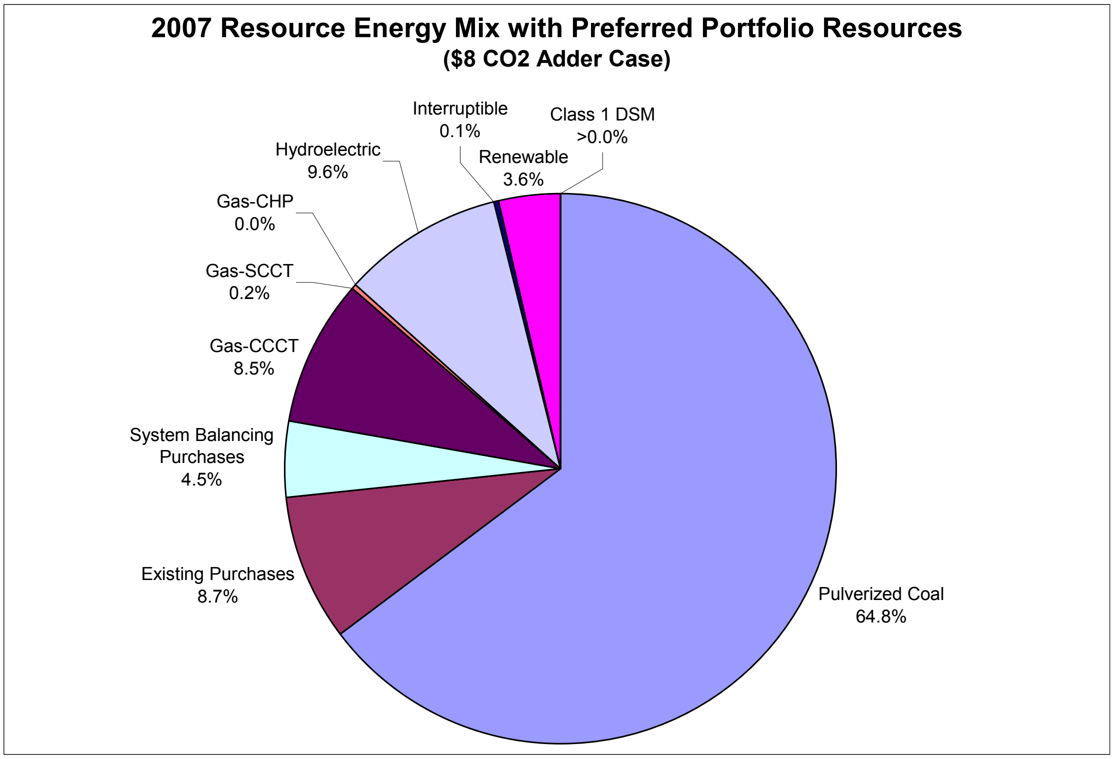
- PacifiCorp considered a comprehensive range of resource options for the IRP, including transmission resources. With the exception of Class 2 DSM, these resources were evaluated on a comparable basis using the CEM model.
- PacifiCorp conducted alternative future studies to derive optimal resource investment plans under a wide range of conditions. As a result of these deterministic scenario studies, PacifiCorp selected a variety of DSM programs, wind, and CHP resources to be included in subsequent portfolio evaluations and the preferred portfolio.
- To account for state resource policies in the areas of renewable generation and climate change, the company evaluated portfolios with an additional 600 megawatts of nameplate wind capacity. Based on the associated stochastic modeling results, PacifiCorp decided to include this additional wind capacity in its preferred portfolio.[65]
- PacifiCorp validated with its stochastic production cost modeling that a balanced mixture of new wind, gas, and coal resources is optimal from a cost and portfolio risk management standpoint.
- Although the preferred portfolio includes 867 megawatts of supercritical pulverized coal capacity, the amount of natural gas-fired capacity added exceeds this amount (1,553 megawatts) as does the nameplate renewables capacity (2,000 megawatts).

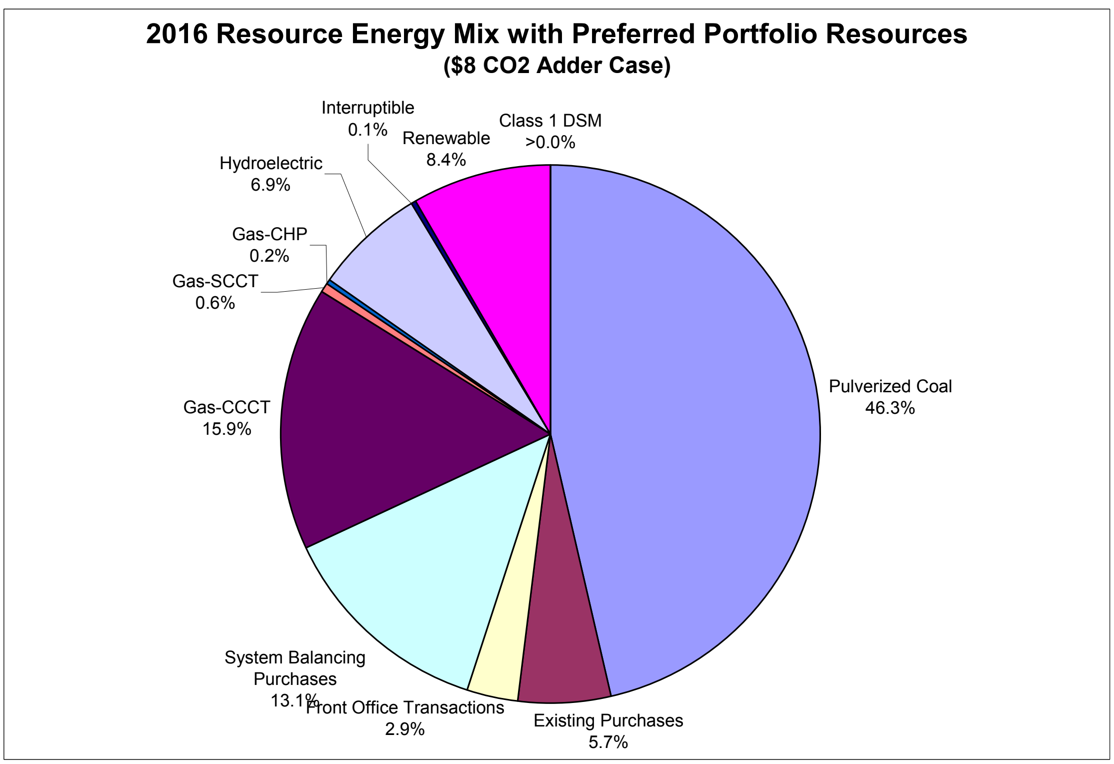
Figure 7.32 compares the resource energy mix for 2007 and 2016; the latter including preferred portfolio resources. The 2016 results are shown for generation under an \$8/ton $CO_2$ adder and the average generation across the five $CO_2$ adders modeled. The comparison highlights the large decrease in coal-fired generation and the offsetting increase in renewable, gas-fired, and front office transaction generation. (Note that only the system balancing purchases are shown; for example, under the \$8/ton $CO_2$ adder case, accounting for system balancing sales results in a net sales amount of 9,843 gigawatt-hours in 2007 and a net purchase amount of 3,518 gigawatt-hours in 2016.)

Figure 7.33 provides a resource mix comparison on the basis of capacity for the \$8/ton $CO_2$ adder case. For the renewables category, the capacity contribution of wind resources is used.

[64] Public Utility Commission of Oregon, "Investigation Into Integrated Resource Planning" UM 1056, Order No. 07-002, Appendix A, p. 7.
[65] The preferred portfolio was also tested to determine the cost and risk impact of removing the 600 MW of wind. Stochastic PVRR increased by \$0.9 billion and risk exposure increased by \$5.5 billion due to the increase in spot market purchases.

**Figure 7.32 – Current and Projected PacifiCorp Resource Energy Mix**



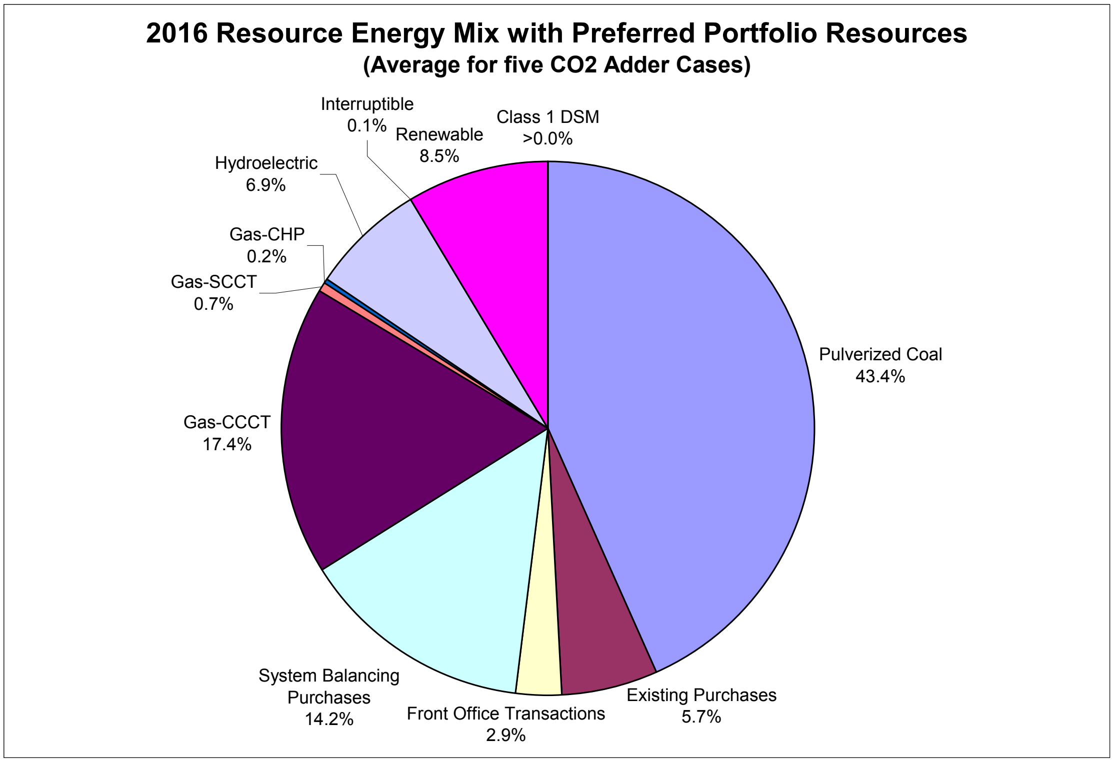
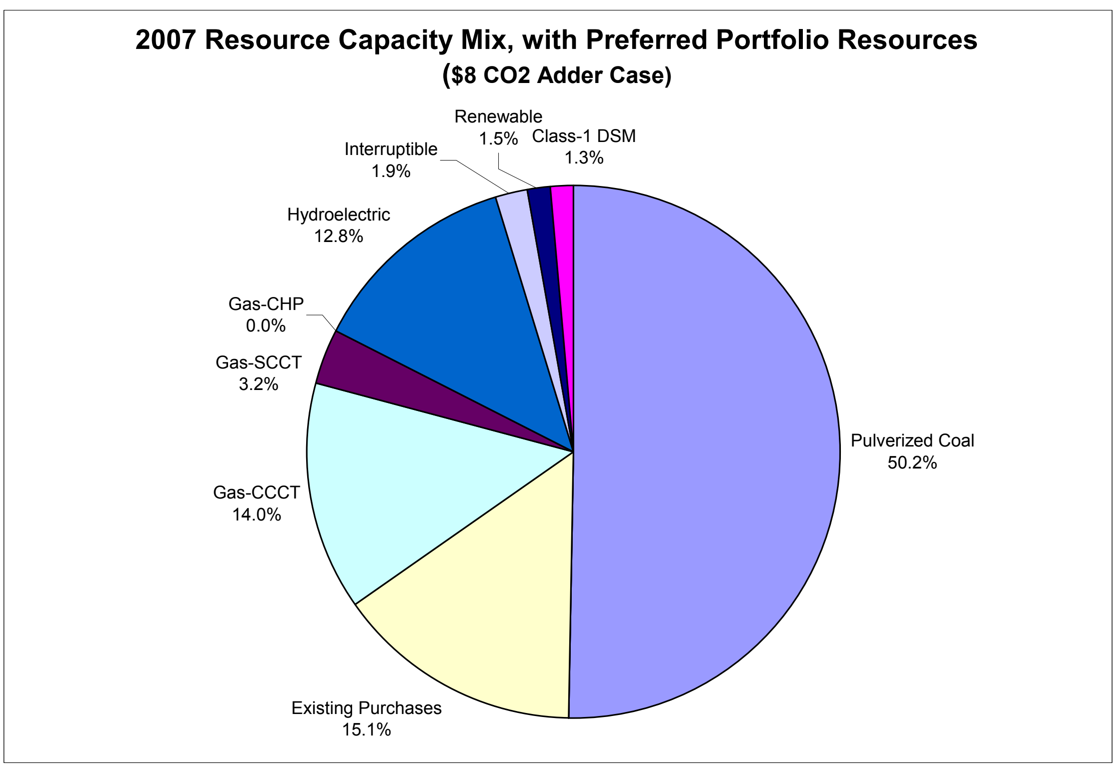
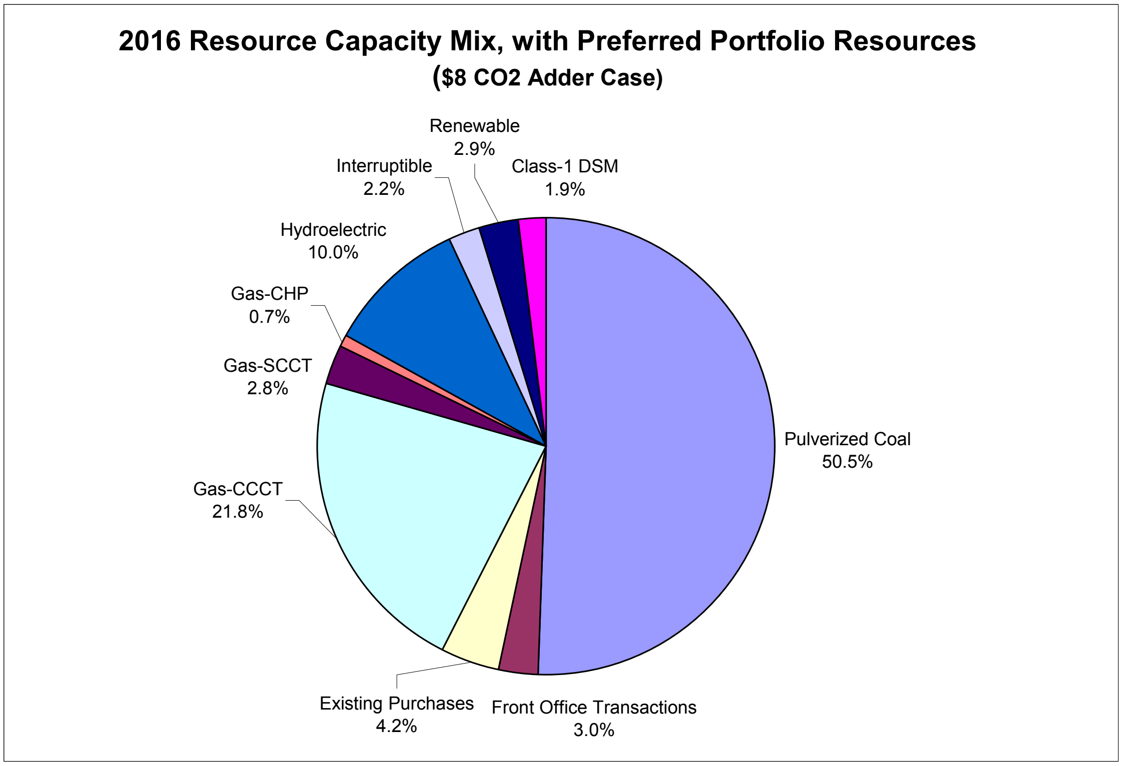



**Figure 7.33 – Current and Projected PacifiCorp Resource Capacity Mix**



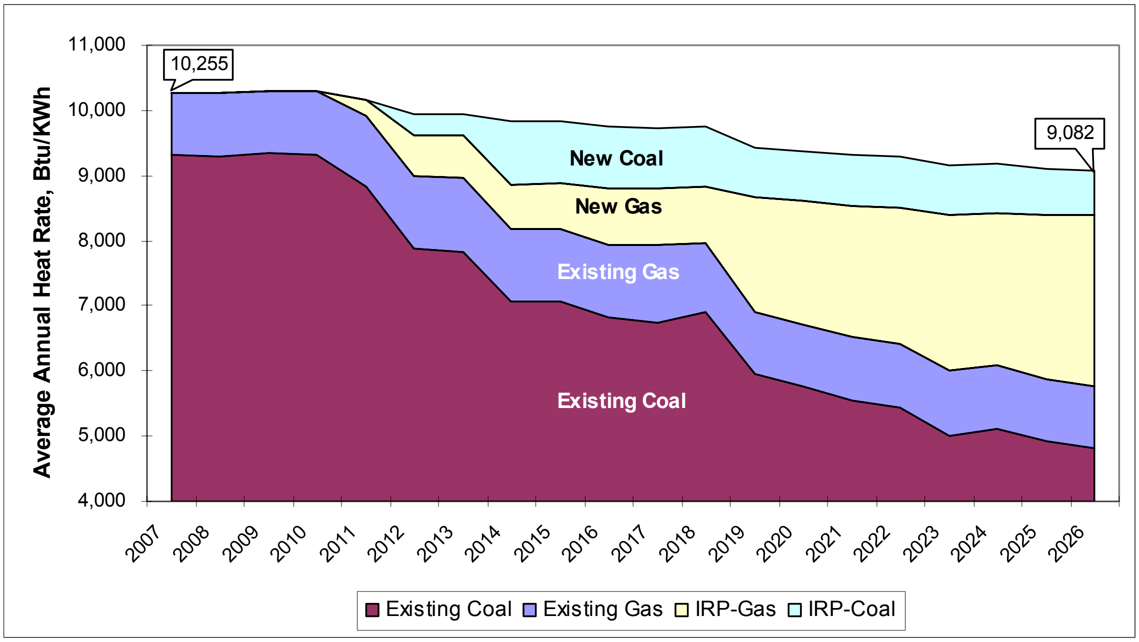



## FORECASTED FOSSIL FUEL GENERATOR HEAT RATE TREND

Pursuant to the Utah Public Service Commission's order on the PURPA Fuel Sources Standard (Docket no. 06-999-03), this section reports the forecasted average heat rate trend for the company's fossil fuel generator fleet on an annual basis, accounting for new IRP resources and current planned retirements of existing resources. The fleet-wide heat rate represents the individual generator heat rates weighted by their annual generation. (Note that system dispatch accounts for an $8/ton $CO_2$ cost adder). For existing fossil fuel resources, four-year average historical heat rate curves are used, whereas new resources use expected heat rates accounting for degradation over time.

Figure 7.34 shows the fleet weighted-average fossil fuel generator heat rate trend from 2007 through 2026, indicating the contributions from existing coal resources, existing gas resources, new coal resources, and new gas resources (including CHP). The average heat rate declines from 10,255 to 9,082 Btu/kWh, a compounded average annual decrease of 0.6 percent. As indicated in Figure 7.34, the heat rate contribution of existing coal plants drops significantly, declining from 91 percent of the system total in 2007 to only 53 percent by 2026. Also underlying the trend is increasing reliance on generation from new gas and wind resources, the later displacing generation from existing coal plants.

**Figure 7.34 – Fleet Average Fossil Fuel Heat Rate Annual Trend by Generator Type**




## CLASS 2 DSM DECREMENT ANALYSIS

This section presents the results of the Class 2 demand-side management decrement analysis. For this analysis, the preferred portfolio, RA14, was used to calculate the decrement value of various types of Class 2 programs following the methodology described in Chapter 6. PacifiCorp will use these decrement values when evaluating the cost-effectiveness of potential new programs between IRP cycles. Note that for the next IRP, the company intends to model Class 2 DSM programs as options in the CEM.

### Modeling Results

Tables 7.47 and 7.48 show the nominal results of the 12 decrement cases for each year of the 20-year study period. Although no resources were deferred or eliminated from the portfolio due to the addition of Class 2 decrements, there is value in having to produce less generation to meet a smaller load. Consistent with the results for the 2004 IRP, the residential air conditioning decrements produce the highest value for both the east and west locations. The commercial lighting, residential lighting, and system load shapes provide the lowest avoided costs. Much of their end use shapes reduce loads during a greater percentage of off-peak hours than the other shapes and during all seasons, not just the summer.

**Table 7.47 – Annual Nominal Avoided Costs for Decrements, 2010-2017**

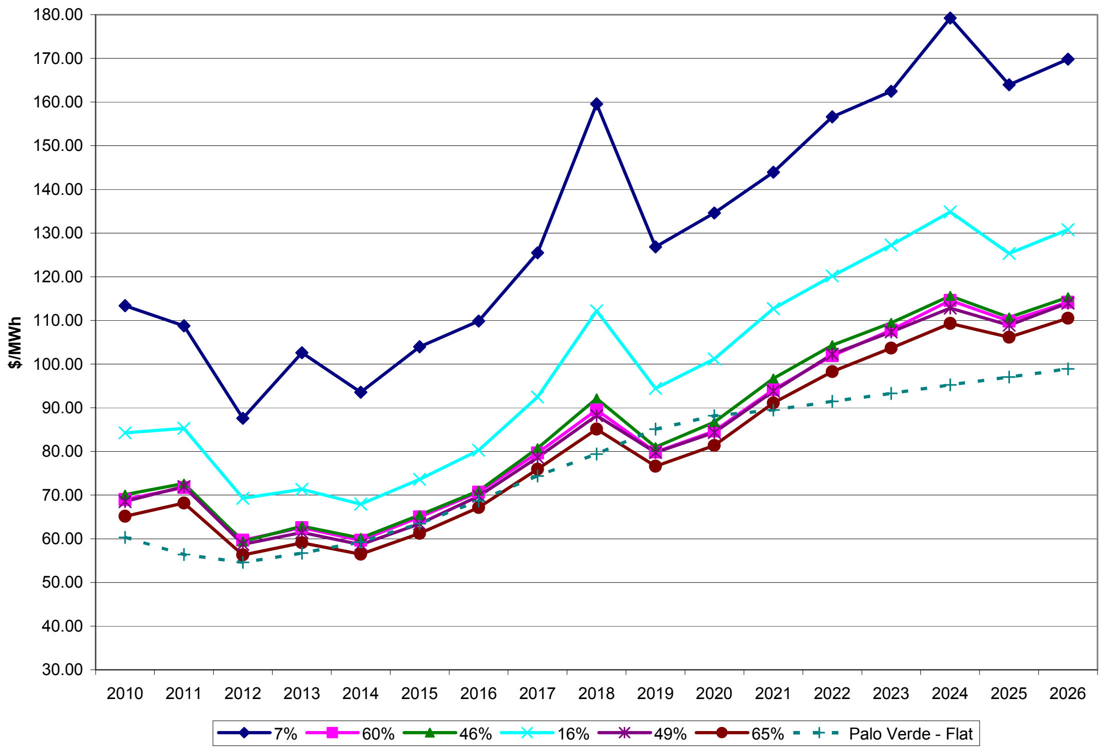
| Decrement Name | Actual Load Factor | Decrement Values (Nominal $/MWh) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| **EAST** | | | | | | | | | |
| Residential Cooling | 7% | 113.38 | 108.78 | 87.59 | 102.59 | 93.54 | 103.99 | 109.84 | 125.48 |
| Residential Lighting | 60% | 68.98 | 71.73 | 59.68 | 62.57 | 59.64 | 64.99 | 70.69 | 79.62 |
| Residential Whole House | 46% | 70.15 | 72.66 | 59.42 | 62.88 | 60.20 | 65.45 | 70.96 | 80.75 |
| Commercial Cooling | 16% | 84.24 | 85.30 | 69.27 | 71.34 | 67.94 | 73.62 | 80.28 | 92.47 |
| Commercial Lighting | 49% | 68.54 | 71.97 | 58.73 | 61.46 | 58.68 | 63.41 | 69.75 | 78.65 |
| System Load Shape | 65% | 65.18 | 68.16 | 56.32 | 59.07 | 56.47 | 61.24 | 67.18 | 75.95 |
| **WEST** | | | | | | | | | |
| Residential Cooling | 20% | 53.78 | 51.87 | 46.99 | 48.02 | 53.67 | 61.06 | 64.64 | 71.75 |
| Residential Heating | 28% | 39.61 | 51.06 | 46.11 | 41.06 | 46.09 | 49.83 | 58.15 | 62.73 |
| Residential Lighting | 60% | 44.34 | 48.56 | 43.70 | 42.10 | 47.45 | 52.78 | 58.20 | 64.16 |
| Commercial Cooling | 16% | 51.66 | 51.53 | 46.13 | 45.39 | 50.85 | 56.96 | 61.81 | 68.73 |
| Commercial Lighting | 49% | 43.70 | 49.34 | 44.49 | 42.02 | 47.47 | 53.32 | 59.31 | 64.67 |
| System Load Shape | 67% | 43.30 | 47.26 | 42.03 | 40.37 | 45.83 | 50.94 | 56.26 | 61.72 |

**Table 7.48 – Annual Nominal Avoided Costs for Decrements, 2018-2026**

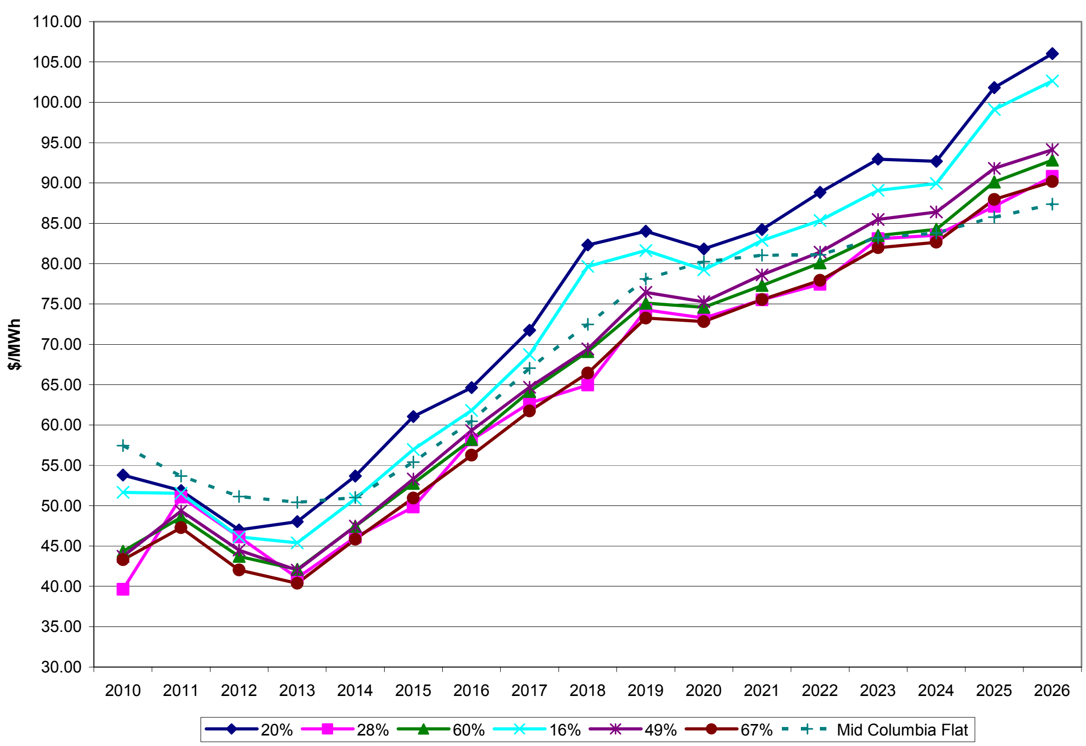
| Decrement Name | Decrement Values (Nominal $/MWh) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
| **EAST** | | | | | | | | | |
| Residential Cooling | 159.57 | 126.86 | 134.61 | 143.92 | 156.62. | 162.45 | 179.23 | 163.99 | 169.83 |
| Residential Lighting | 89.48 | 79.87 | 84.65 | 94.16 | 101.92 | 107.82 | 114.58 | 109.87 | 114.15 |
| Residential Whole House | 92.15 | 80.99 | 86.70 | 96.72 | 104.36 | 109.46 | 115.60 | 110.67 | 115.30 |
| Commercial Cooling | 112.19 | 94.43 | 101.17 | 112.70 | 120.17 | 127.26 | 134.85 | 125.33 | 130.80 |
| Commercial Lighting | 88.24 | 79.76 | 84.34 | 93.77 | 102.27 | 107.34 | 112.81 | 108.90 | 113.99 |
| System Load Shape | 85.11 | 76.64 | 81.36 | 91.08 | 98.25 | 103.65 | 109.32 | 106.14 | 110.51 |
| **WEST** | | | | | | | | | |
| Residential Cooling | 82.31 | 84.03 | 81.81 | 84.23 | 88.84 | 92.96 | 92.68 | 101.82 | 106.02 |
| Residential Heating | 64.95 | 74.27 | 73.25 | 75.52 | 77.45 | 83.09 | 83.53 | 87.11 | 90.81 |
| Residential Lighting | 69.12 | 75.11 | 74.60 | 77.29 | 80.09 | 83.49 | 84.27 | 90.13 | 92.83 |
| Commercial Cooling | 79.65 | 81.63 | 79.24 | 82.88 | 85.36 | 89.09 | 89.94 | 99.11 | 102.64 |
| Commercial Lighting | 69.44 | 76.45 | 75.28 | 78.62 | 81.44 | 85.47 | 86.40 | 91.81 | 94.13 |
| System Load Shape | 66.44 | 73.25 | 72.82 | 75.55 | 77.92 | 81.97 | 82.64 | 87.95 | 90.18 |

Figures 7.35 and 7.36 show the decrement costs for each end use along with the average annual forward market price for that location: Palo Verde (PV) for the east and Mid-Columbia (Mid-C) for the west.

## Figure 7.35 – East Decrement Price Trends




## Figure 7.36 – West Decrement Price Trends



## REGULATORY SCENARIO RISK ANALYSIS – GREENHOUSE GAS EMISSIONS PERFORMANCE STANDARDS

Chapter 2 identified $CO_2$ regulation as an important scenario risk facing the company. In addition to the $CO_2$ externality cost scenarios investigated for this IRP, PacifiCorp also conducted a portfolio scenario study using the CEM and PaR models where a generator-based greenhouse gas emissions performance standard, such as the one in place in California, is instituted in all of PacifiCorp's service territory. The purpose of the study was to determine the comparative stochastic cost, risk, and $CO_2$ emission impacts of a portfolio that meets performance standard requirements as modeled using the CEM. This section first outlines the study approach and then presents comparative results with respect to the preferred portfolio (RA14) and the other Group 2 portfolios.

### Scenario Study Approach

For this study, PacifiCorp first used the CEM to determine a deterministically optimized portfolio on the basis of GHG performance standard constraints, and then manually constrained the CEM resources to yield a portfolio with an improved cost and risk profile as determined by stochastic PaR model runs. This process is similar to the one used to develop the risk analysis portfolios.

The CEM was allowed to optimize resource selection and timing subject to assumptions designed to restrict resources to those that can comply with a $CO_2$ emission performance standard (a per-ton emissions amount comparable or less than a CCCT). The specific CEM portfolio assumptions for the study are as follows:

- Resources available for selection by the CEM include CCCT (F and G types with duct firing), IGCC with carbon capture and sequestration (CCS), renewables, DSM (both Class 1 and Class 3), and combined heat and power; pulverized coal was excluded as a resource option.
- No constraints were placed on resource amounts, timing, or location, except for earliest available in-service dates.
- A total of 3,700 megawatts of renewables was made available for selection.
- Renewable portfolio standards for California, Oregon, and Washington were assumed to be in place. The RPS requirements were handled as state contributions to a gross percentage on system retail loads—the same method used for previous RPS portfolio modeling. The percentages were updated based on the March 2007 load forecast.
- The quantity of front office transactions was limited to 1,200 megawatts after 2011 (700 in the east and 500 megawatts in the west).
- A 12 percent planning reserve margin and \$8/ton $CO_2$ cost adder were assumed.

Table 7.49 shows the cumulative capacity by resource type and simulation period for the resulting CEM portfolio solution.

**Table 7.49 – Capacity Additions for the Initial CEM GHG Emissions Performance Standard Portfolio**

| Resource | Cumulative Nameplate Capacity by Period (MW) | |
|---|---|---|
| | 2007-2016 | 2007-2026 |
| Gas - CCCT | 1,507 | 6,410 |
| Renewables | 1,900 | 3,100 |
| DSM | 137 | 156 |
| IGCC with CCS | - | - |

As noted above, the CEM was not constrained to select certain resource amounts in certain years or areas. One consequence of this model set-up is that the resulting CEM portfolio does not reflect an investment schedule that is advantageous from a stochastic cost and risk standpoint. Another consequence is that the model's wind investment pattern differs significantly from what was identified in PacifiCorp's preferred portfolio. For example, the model did not recognize geographical RPS requirements in placing renewable resources; all wind resources were added in the east side until 2018. Additionally, the CEM included more renewables in 2007 than the preferred portfolio (700 megawatts versus 400 megawatts in the preferred portfolio), which is not practical from a procurement perspective.

To address these two issues, PacifiCorp first subjected this portfolio to stochastic simulation to create baseline stochastic results. Then, the CEM was executed again after applying resource constraints to the portfolio. These constraints include (1) limiting renewables to 300 megawatts in 2007[66], (2) adding an east-side CCCT in 2011 to replace a portion of front office transactions, and (3) fixing the east-side CCCT resource selected in 2011. The resulting CEM portfolio was simulated with the PaR model, and stochastic results compared against those of the original CEM portfolio. These resource constraints reduced stochastic mean PVRR by $144 million, risk exposure by $671 million, and upper-tail risk by $816 million. Table 7.50 shows the resource additions for the final GHG emission performance standard portfolio from 2007 through 2026. As with the other risk analysis portfolios, load growth and capacity reserve requirements are met with CCCT growth stations after 2018.

## Stochastic Cost and Risk Results

Table 7.51 provides the stochastic cost and risk results for the GHG emission performance standard portfolio by $CO_2$ cost adder case. Results are shown for both the $CO_2$ tax and cap-and-trade compliance scenarios. Figures 7.37 through 7.39 show the cost-versus-risk trade-off of the portfolio in relation to the other Group 2 risk analysis portfolios assuming the $CO_2$ cap-and-trade scenario. Figure 7.37 is a scatter plot of the cost and risk measures based on the average of the five $CO_2$ adder cases, while Figures 7.38 and 7.39 show the cost and risk results for the $0 and $61 $CO_2$ adder cases, respectively.

[66] The remainder of the renewables investment schedule was not altered in order to minimize manual portfolio changes.

## Table 7.50 – Resource Investment Schedule for the Final GHG Emissions Performance Standard Portfolio

| | | Nameplate Capacity, MW | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Resource | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
| East | CCCT, 2 x 1 F Class | - | - | - | - | 548 | 548 | - | - | - | - | 548 | - | 1,096 | - | - | 548 | - | - | - | 548 |
| | Renewables, SE ID | 200 | - | - | - | - | - | - | - | - | 200 | - | - | - | - | - | - | - | - | - | - |
| | Renewables, WY | 100 | 700 | - | 200 | - | 100 | - | - | 200 | - | - | - | - | - | - | - | - | - | - | - |
| | Renewables, NV | - | - | - | - | - | - | - | - | - | - | 200 | 200 | - | - | - | - | - | - | - | - |
| | DSM, Class 1 and 3 | - | - | - | - | - | 7 | 7 | 7 | - | - | 52 | 52 | 52 | - | - | - | - | - | - | - |
| | Front office transactions | - | - | - | 486 | 550 | 158 | 130 | 563 | 98 | 700 | 505 | 556 | - | - | - | - | - | - | - | - |
| West | CCCT, 2 x 1 F Class | - | - | - | - | - | 602 | - | - | - | - | - | - | 602 | - | - | - | 602 | - | 602 | - |
| | CCCT, 1x1 G Class | - | - | - | - | - | - | - | - | - | - | 392 | - | - | - | - | - | - | - | - | - |
| | Renewables, SE WA | - | - | - | - | - | - | - | - | - | - | 200 | - | - | - | - | - | - | - | - | - |
| | Renewables, MT | - | - | - | - | - | - | - | - | - | - | - | 400 | - | - | - | - | - | - | - | - |
| | Renewables, NC OR | - | - | - | - | - | - | 100 | - | - | - | - | 300 | - | - | - | - | - | - | - | - |
| | DSM, Class 1 and 3 | - | - | - | - | - | 3 | 3 | 3 | - | - | 19 | 19 | 20 | - | - | - | - | - | - | - |
| | Front office transactions | - | - | - | 69 | 311 | 400 | 500 | 250 | 250 | 416 | 250 | 250 | - | - | - | - | - | - | - | - |
| | Total Annual Additions | 300 | 700 | - | 755 | 1,409 | 1,818 | 740 | 823 | 1,048 | 1,316 | 2,167 | 1,778 | 1,770 | - | - | 548 | 602 | - | 602 | 548 |

## Table 7.51 – Stochastic Cost and Risk Results for the Final GHG Emissions Performance Standard Portfolio

| $CO_2$ Cost Adder Case (2008 $) | Stochastic Results (Million $) – $CO_2$ Tax Basis | | | | | |
|---|---|---|---|---|---|---|
| | Stochastic Mean PVRR | 5th Percentile | 95th Percentile | Upper-Tail Mean | Risk Exposure | Standard Deviation |
| $0 | 23,230 | 14,637 | 37,387 | 70,858 | 47,628 | 13,046 |
| $8 | 26,950 | 16,244 | 42,547 | 78,253 | 51,303 | 14,152 |
| $15 | 28,731 | 17,754 | 45,152 | 81,756 | 53,026 | 14,695 |
| $38 | 34,956 | 21,172 | 54,802 | 95,420 | 60,465 | 17,063 |
| $61 | 41,227 | 24,484 | 64,948 | 110,445 | 69,218 | 19,823 |
| $CO_2$ Cost Adder Case (2008 $) | Stochastic Results (Million $) – $CO_2$ Cap and Trade Basis | | | | | |
| | Stochastic Mean PVRR | 5th Percentile | 95th Percentile | Upper-Tail Mean | Risk Exposure | Standard Deviation |
| $0 | 21,922 | 13,330 | 36,080 | 69,550 | 47,628 | 13,046 |
| $8 | 22,033 | 11,327 | 37,630 | 73,336 | 51,303 | 14,152 |
| $15 | 22,014 | 11,037 | 38,435 | 75,039 | 53,026 | 14,695 |
| $38 | 21,470 | 7,687 | 41,316 | 81,935 | 60,465 | 17,063 |
| $61 | 20,577 | 3,834 | 44,298 | 89,795 | 69,218 | 19,823 |

**Figure 7.37 – Average Stochastic Cost versus Risk Exposure Across All $CO_2$ Adder Cases**

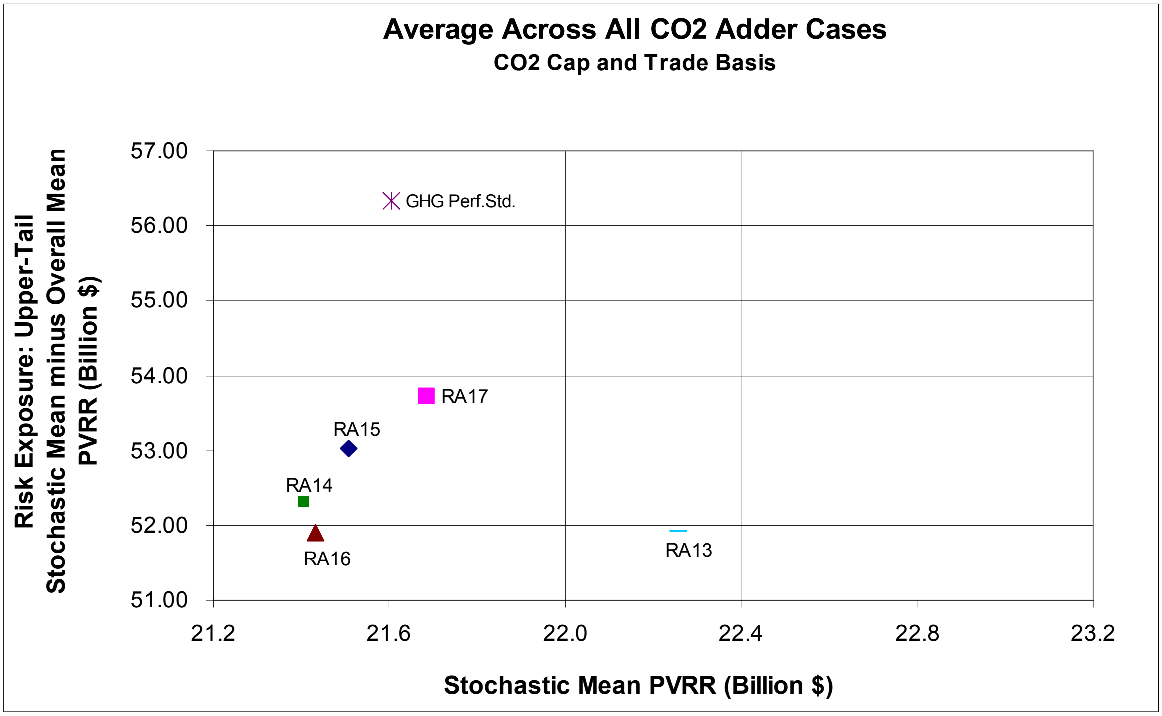



**Figure 7.38 – Stochastic Cost versus Risk Exposure for the \$0 $CO_2$ Adder Case**

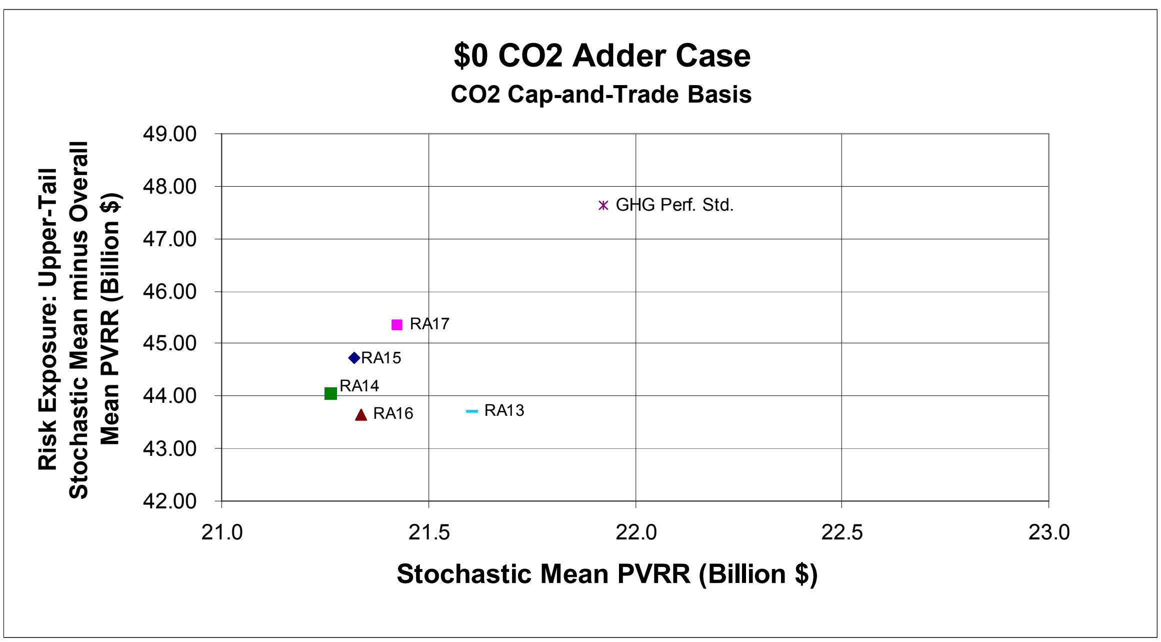
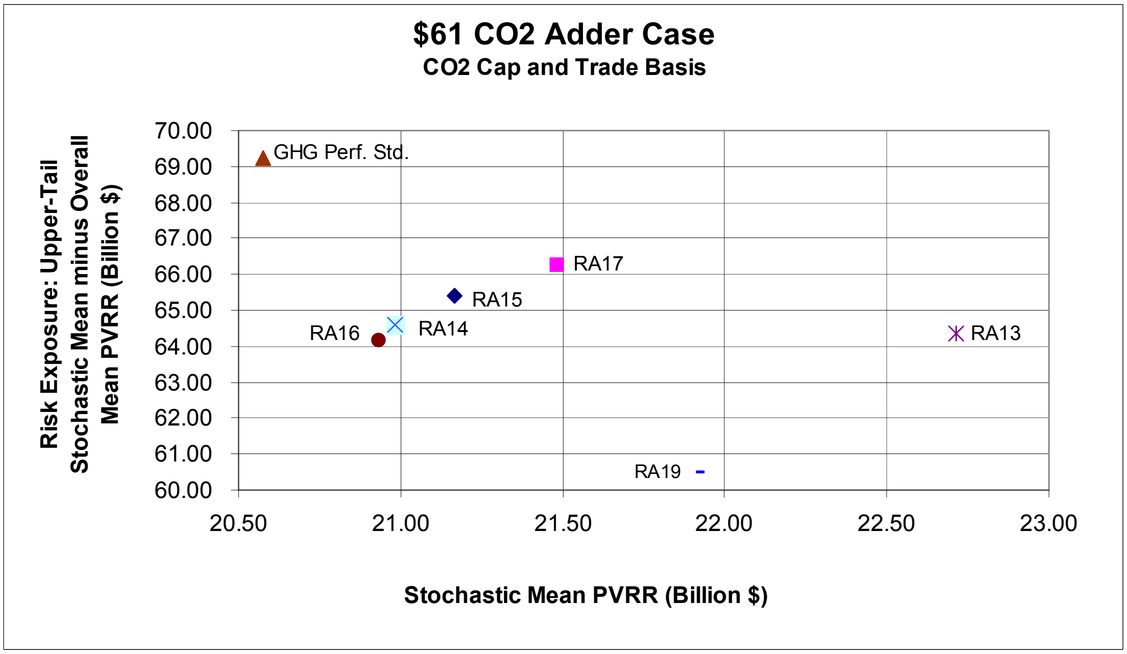


**Figure 7.39 – Stochastic Cost versus Risk Exposure for the \$61 $CO_2$ Adder Case**




As can be seen from the figures, the stochastic cost ranking of the GHG emissions performance standard portfolio relative to the Group 2 risk analysis portfolios is sensitive to the $CO_2$ cost adder level. Under the \$0/ton $CO_2$ adder case, the stochastic PVRR of the GHG emissions performance standard portfolio is \$662 million higher than that of the preferred portfolio. In contrast, under the \$61/ton $CO_2$ adder case, the preferred portfolio stochastic PVRR is \$406 million higher. When averaging stochastic PVRR results across the $CO_2$ adder cases, the GHG emissions performance standard portfolio falls within the middle of the pack.

The GHG emissions performance standard portfolio has the highest risk among the Group 2 portfolios for all $CO_2$ adder scenarios. In comparison to the preferred portfolio, risk is about \$3.6 billion higher under the \$0/ton $CO_2$ adder and \$4.6 billion higher under the \$61/ton $CO_2$ adder.

## Carbon Dioxide Emissions Results

As expected, the GHG emissions performance standard portfolio has a smaller $CO_2$ footprint than the other risk analysis portfolios due to the lack of new coal plants. Relative to the preferred portfolio, the GHG emissions performance standard portfolio emits about 49 million fewer tons of $CO_2$ on a cumulative basis from 2007 through 2026 when averaged across the five $CO_2$ adder cases.

The annual $CO_2$ emissions impact of the adder can be seen by comparing Figures 7.40 and 7.41, which show emissions under the \$0 and \$61/ton $CO_2$ adders, respectively. (Annual emission quantities are reported as the contribution from retail sales; that is, net of wholesale sales.) Figure 7.42 shows annual $CO_2$ emission trends as the average of the results for the six portfolios.

**Figure 7.40 – Annual $CO_2$ Emission Trends, 2007-2026 (\$0 $CO_2$ Adder Case)**

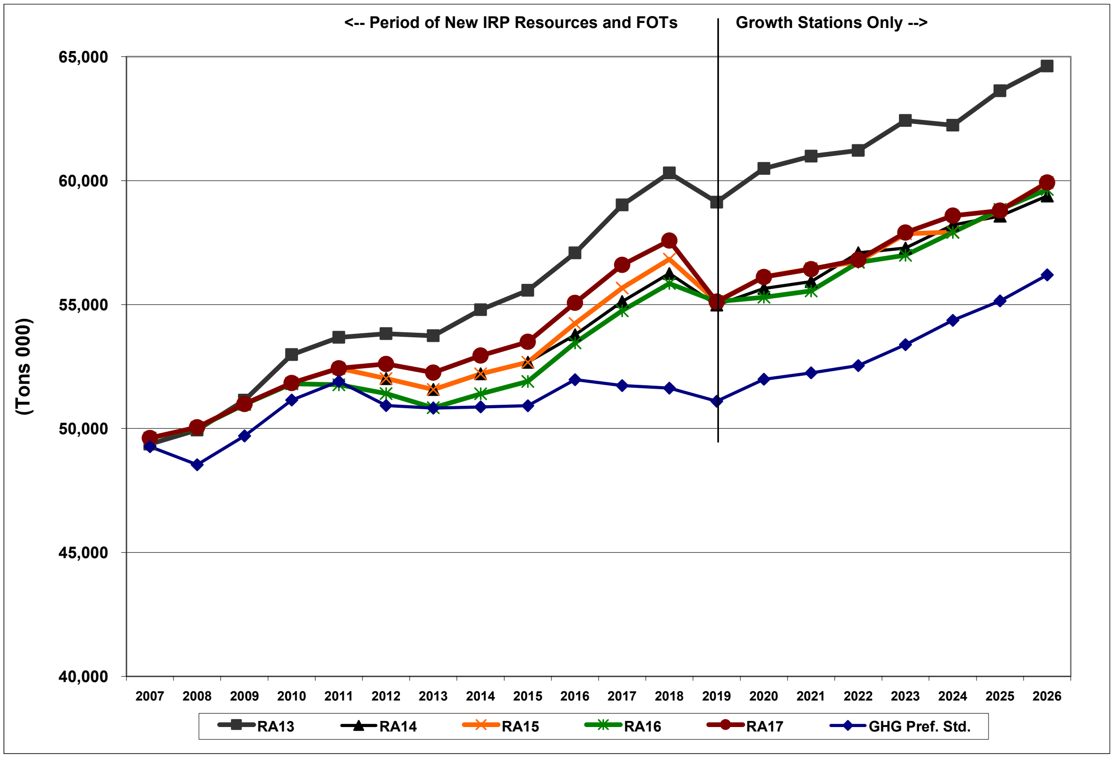



**Figure 7.41 – Annual $CO_2$ Emission Trends, 2007-2026 (\$61 $CO_2$ Adder Case)**

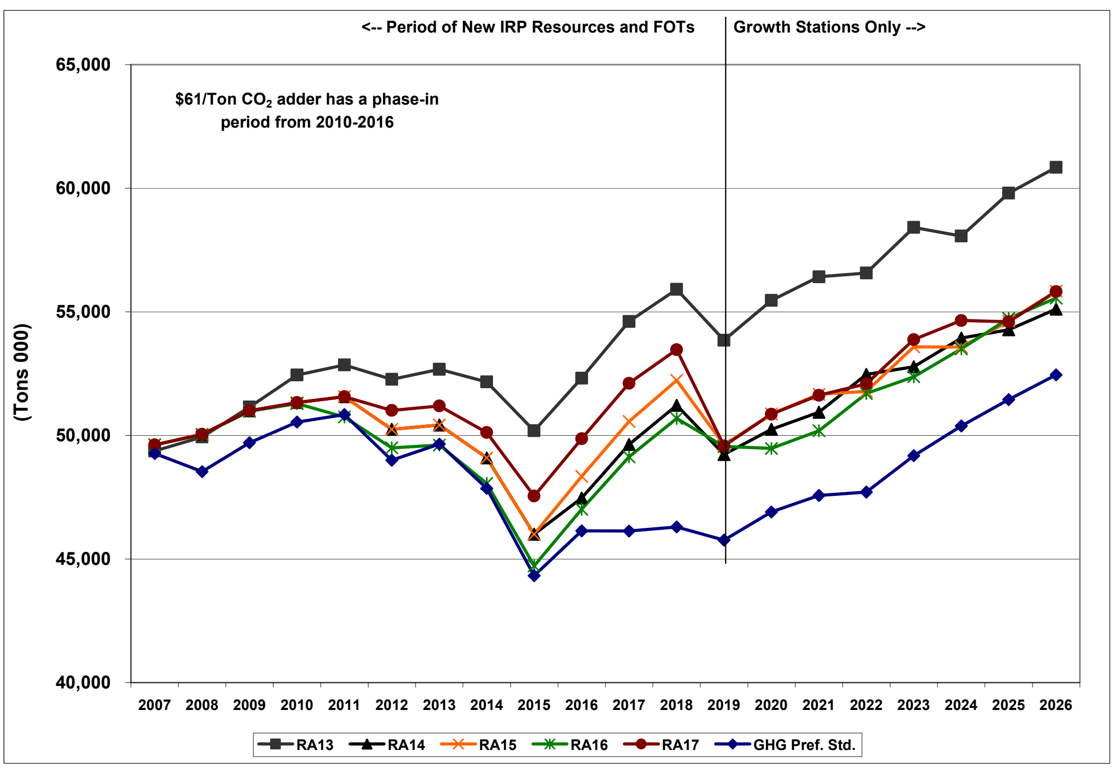
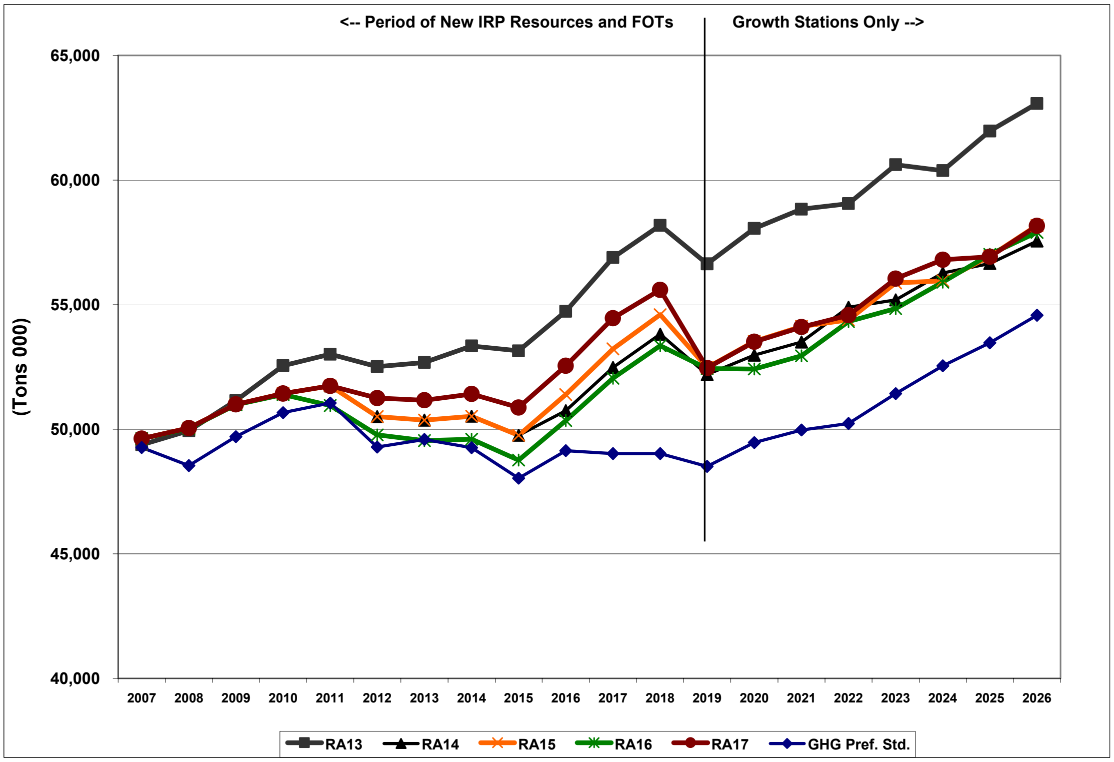


**Figure 7.42 – Annual $CO_2$ Emission Trends, 2007-2026 (Average for all $CO_2$ Adder Cases)**



# 8. ACTION PLAN

**Chapter Highlights**

- The company plans to accelerate its previous commitment to acquire 1,400 megawatts of cost-effective renewable resources from 2015 to 2010, and increase this amount to 2,000 megawatts of cost-effective renewable resources by 2013.
- The company will seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources since it is expected that wind will comprise a large portion of the company's accelerated and expanded renewable portfolio.
- The company will continue to run programs to acquire 250 average megawatts of cost-effective energy efficiency, and an additional 200 average megawatts if cost-effective initiatives can be identified.
- The company plans to maintain and build upon the existing 150 megawatts of irrigation and air conditioning load control in Utah and Idaho, and add 100 megawatts of additional irrigation load control split between system-East and system-West beginning in 2010.
- The company will seek to leverage voluntary demand-side measures, such as demand buyback, to improve system reliability during peak load hours.
- The company plans to acquire up to 1,700 megawatts of base load resources on the east side of its system for the term 2012 through 2014, consistent with the filed request for proposal.
- The company plans to acquire 200 to 1,300 megawatts of base load resource on the west side of its system in 2010 to 2014 through a mix of thermal resources and purchases.
- The company plans to expand its transmission system to allow the resources identified in the preferred portfolio to serve customer loads in a cost-effective and reliable manner.
- The company will incorporate the results of the demand-side management potential study into its business and into future integrated resource plans.
- The company will continue to take a leadership role in discussions on global climate change and will continue to investigate carbon reduction technology, including nuclear power.
- The company plans to enhance its integrated resource planning modeling to better address emerging issues on renewable portfolio standards and carbon regulation.
- The company will continue to work with stakeholders on cost allocation issues in order to achieve a portfolio that meets each state's energy policy.

## INTRODUCTION

This chapter presents the company's 2007 action plan, which identifies the steps the company will take during the next two years to implement this plan. It is based on the guidance provided by the company's analysis and results described in Chapters 1 through 7 of this document as well as feedback from stakeholders. In large part, the action plan is used to map out the steps required to acquire the resources identified in the preferred portfolio and to identify ways to improve the company's future integrated resource planning.

To develop the action plan, the company used the preferred portfolio as shown in Table 8.1 (Portfolio RA14) along with issues raised by stakeholders during the course of the 2007 integrated resource planning process.

**Table 8.1 – Resource Investment Schedule for Portfolio RA14**

| Supply and Demand-side Proxy Resources | | | Nameplate Capacity, MW | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Resource** | **Type** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** |
| **East** | Utah pulverized coal | Supercritical | | | | | | 340 | | | | |
| | Wyoming pulverized coal | Supercritical | | | | | | | | 527 | | |
| | Combined cycle CT | 2x1 F class with duct firing | | | | | | 548 | | | | |
| | Combined cycle CT | 1x1 G class with duct firing | | | | | | | | | | 357 |
| | Combined Heat and Power | Generic east-wide | | | | | | 25 | | | | |
| | Renewable | Wind, Wyoming | | 200 | | 200 | 200 | | 300 | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | | 26 | 25 | 18 | | | |
| | Front office transactions** | Heavy Load Hour, 3rd Qtr | - | - | - | 393 | 272 | 97 | 3 | 149 | 192 | 165 |
| **West** | CCCT | 2x1 F Type with duct firing | | | | | 602 | | | | | |
| | Combined Heat and Power | Generic west-wide | | | | | | 75 | | | | |
| | Renewable | Wind, SE Washington | 300 | 100 | | | | | | | | |
| | Renewable | Wind, NC Oregon | | | 100 | 100 | | 100 | | | | |
| | Class 1 DSM* | Load control, Sch. irrigation | | | | 12 | 11 | 12 | | | | |
| | Front office transactions** | Flat annual product | - | - | - | 219 | 64 | 555 | 657 | 247 | 246 | 249 |
| | Annual Additions, Long Term Resources | | 300 | 300 | 100 | 312 | 839 | 1,125 | 318 | 527 | - | 357 |
| | Annual Additions, Short Term Resources | | - | - | - | 612 | 336 | 652 | 660 | 396 | 438 | 414 |
| | Total Annual Additions | | 300 | 300 | 100 | 924 | 1,175 | 1,777 | 978 | 923 | 438 | 771 |

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

| Transmission Proxy Resources* | | Transfer Capability, Megawatts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Resource** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** |
| **East** | Path C Upgrade: Borah to Path-C South to Utah North | | | | 300 | | | | | | |
| | Utah - Desert Southwest (Includes Mona - Oquirrh) | | | | | | 600 | | | | |
| | Mona - Utah North | | | | | | 400 | | | | |
| | Craig-Hayden to Park City | | | | | | 176 | | | | |
| | Miners - Jim Bridger - Terminal | | | | | | 600 | | | | |
| | Jim Bridger - Terminal | | | | | | | | 500 | | |
| **West** | Walla Walla - Yakima | | | | 400 | | | | | | |
| | West Main - Walla Walla | | | | | 630 | | | | | |
| | Total Annual Additions | - | - | - | 700 | 630 | 1,776 | - | 500 | - | - |

* Transmission resource proxies represent a range of possible procurement strategies, including new wheeling contracts or construction of transmission facilities by PacifiCorp or as a joint project with other parties.

## THE INTEGRATED RESOURCE PLAN ACTION PLAN

The IRP action plan, detailed in Table 8.2, provides the company with a road map for moving forward with new resource acquisitions over the next two years. The IRP action plan is based upon the latest and most accurate information available at the time the integrated resource plan is filed. The resources identified in the plan are proxy resources and act as a guide to resource procurement. As resources are acquired, the resource type, timing, size, and location may vary from the proxy resource identified in the plan. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition.

### Table 8.2 – 2007 IRP Action Plan

| Action Item | Category | Action Type | Calendar-Year Timing | Size (rounded to the nearest 50 MW for generation resources) | Location | IRP Proxy Resource Modeled | Action |
|---|---|---|---|---|---|---|---|
| 1 | Renewables | New Renewables | 2007 - 2013 | 2,000 | System | Wind | 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. |
| 2 | DSM | Existing and New Class 2 programs | 2007 - 2014 | 450 MWa | System | 100 MW decrements at various load shapes | Use decrement values to assess cost-effectiveness of new program proposals. Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and up to an additional 200 MWa if cost-effective initiatives can be identified. Will reassess Class 2 objectives upon completion of system-wide DSM potential study to be completed by June 2007. Will incorporate potentials study findings into the 2007 update and 2008 integrated resource planning processes. |
| 3 | DSM | New Class 1 programs | 2007 - 2014 | 100 | East - 50<br>West - 50 | East and West irrigation load control, East summer loads | Targets were established through potential study work performed for the 2007 IRP. A new potential study is expected to be completed by June 2007, and associated findings will be incorporated into the 2007 update and the 2008 integrated resource planning processes. |

| Action Item | Category | Action Type | Calendar-Year Timing | Size (rounded to the nearest 50 MW for generation resources) | Location | IRP Proxy Resource Modeled | Action |
|---|---|---|---|---|---|---|---|
| 4 | DSM | Existing and New Class 3 programs | 2007 - 2014 | To be determined | System | Class 3: demand buy-back, hourly pricing, seasonal pricing, etc.<br>Class 4: system messaging and education | 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. Will incorporate potential study findings into the 2007 update and/or 2008 integrated resource planning processes. |
| 5 | Distributed Generation | Combined Heat and Power (CHP) | 2007-2014 | 100 | System | 25 MW steam topping cycle CHP; 5 MW gas combustion turbine CHP | 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 |
| 6 | Distributed Generation | Standby Generators | 2007-2014 | To be determined | System | 60 MW of diesel engine capacity on the west side | Will incorporate potential study findings into the 2007 update and 2008 integrated resource planning processes |
| 7 | Supply-Side | Base Load / Intermediate Load | 2012 | 550 | East | CCCT (Wet "F" 2X1) with duct firing | Procure a base load / intermediate load resource in the east by the summer of 2012. This is part of the requirement included in the Base Load RFP |
| 8 | Supply-Side | Base Load / Intermediate Load | 2012 | 350 | East | Supercritical pulverized coal (340 MW Utah unit) | Procure a base load / intermediate load resource in the east by the summer of 2012. This is part of the requirement included in the Base Load RFP |
| 9 | Supply-Side | Base Load / Intermediate Load | 2014 | 550 | East | Supercritical pulverized coal (527 MW Wyoming unit) | Procure a base load / intermediate load resource in the east by the summer of 2014. This is part of the requirement included in the Base Load RFP |

| Action Item | Category | Action Type | Calendar-Year Timing | Size (rounded to the nearest 50 MW for generation resources) | Location | IRP Proxy Resource Modeled | Action |
|---|---|---|---|---|---|---|---|
| 10 | Supply-Side | Base Load / Intermediate Load | 2016 | 350 | East | CCCT (Wet "G" 1X1) with duct firing | Investigate a base load / intermediate load resource in the east by the summer of 2016. This is not part of the requirement included in the Base Load RFP |
| 11 | Supply-Side | Base Load / Intermediate Load | 2011 | 600 | West | CCCT (Wet “F” 2X1) with duct firing | Procure a base load / intermediate load resource in the west by the summer of 2011 - 2012 |
| 12 | Supply-Side | Base Load / Intermediate Load | 2010-2014 | 350-650 | East / West | Front office transactions:<br>West - flat annual products<br>East - 3rd quarter products | Procure base load / intermediate load resource beginning in the summer of 2010, use the Base Load RFP as appropriate to fill the need in the east |
| 13 | Transmission | Transmission | 2010 and beyond | Various | System | Path C Upgrade<br>Utah - Desert Southwest<br>Mona - Utah North<br>Craig Hayden - Utah North<br>Miners - Utah North<br>Jim Bridger - Utah North<br>Walla Walla - Yakima<br>Walla Walla - West Main | 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 |
| 14 | Climate Change | Strategy and Policy | Ongoing | Not applicable | System | Not applicable | Continue to have dialogue with stakeholders on Global Climate Change issues |
| 15 | Carbon-Reducing Technology | Strategy and Policy | Ongoing | Not applicable | System | Not applicable | 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 |

| **Action Item** | **Category** | **Action Type** | **Calendar-Year Timing** | **Size** (rounded to the nearest 50 MW for generation resources) | **Location** | **IRP Proxy Resource Modeled** | **Action** |
|---|---|---|---|---|---|---|---|
| 16 | IRP Planning | Modeling and Analysis | 2007-2008 | Not applicable | System | Not applicable | Continue to investigate implications of integrating at least 2,000 MW of wind to PacifiCorp's system |
| 17 | IRP Planning | Modeling and Analysis | 2007-2008 | Not applicable | System | Not applicable | Update modeling tools and assumptions to reflect policy changes in the area of renewable portfolio standards and carbon dioxide emissions |
| 18 | IRP Acknowledgement | Policy and cost recovery | 2007 | Not applicable | System | Not applicable | Work with states to gain acknowledgement or acceptance of the 2007 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 |

## RESOURCE PROCUREMENT

### Overall Resource Procurement Strategy

To implement resource decisions in the action plan, PacifiCorp intends to use a formal and transparent procurement program in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates. The IRP has determined the need for resources with considerable specificity and identified the desirable portfolio resource characteristics and timing of need. The IRP has not identified specific resources to procure, or even determined a preference between asset ownership versus contracted resources. These decisions will be made subsequently on a case-by-case basis with an evaluation of competing resource options including updated available information on technological, environmental and other external factors such as electric and natural gas price projections. These options will be fully developed using competitive bidding with a request for proposal (RFP) process, or other procurement methods as appropriate.

For demand-side resources, 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 project 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. As with supply-side resources, the company may resort to competitive bidding with an RFP process to uncover new program opportunities.

### Renewable Resources

The 2007 integrated resource plan identifies 2,000 megawatts of renewable resources to be acquired by 2013. Under this plan, the company seeks to acquire 1,400 megawatts of new renewable resources by 2010, with an additional 600 megawatts in place by 2013. The 2,000 megawatts of renewable resources is inclusive of the 1,400 megawatts of cost-effective renewable resources identified in the company's renewable plan. In order to fill this requirement, the company will continue to aggressively pursue the acquisition of these resources through various approaches including new requests for proposals, bi-lateral negotiations, the Public Utilities Regulatory Policy Act, and self-development. While the company used wind for modeling purposes in the integrated resource planning process, renewable generation includes other fuel sources such as biomass and landfill gas. In addition, the company will actively seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources and work to continuously improve its understanding of how to integrate large amounts of wind into its portfolio in a reliable and cost-effective manner.

### Demand-side Management

The company has a variety of ongoing programs and associations to procure energy efficiency measures (Class 2 demand-side resources) from industrial, commercial and residential customers. These programs will be leveraged, and company-offered programs extended to other states, as the means to acquire the majority of the 250 average megawatts of Class 2 demand-side resources identified in the 2007 integrated resource plan. The company will continue these programs as long as they are cost-effective, and will seek to add new cost-effective programs in order to meet this target. The company will also continue to pursue an additional 200 average megawatts of energy efficiency measures if cost-effective.

With regard to load control (Class 1 demand-side resources), the company is actively working to retain the existing customers and continue expanding participation in these programs to achieve and build upon the 150 megawatts currently identified in the 2007 plan as an existing resource. The company will pursue acquisition of an additional 100 megawatts of load control identified in the preferred portfolio starting in 2010.

The company plans to leverage voluntary load control programs (Class 3 demand-side resources) such as demand buyback, hourly pricing and seasonal pricing, as well as system messaging and education (Class 4 demand-side resources), to improve system reliability during peak load hours.

Finally, the company will be completing a demand-side management potential study in June 2007, which will provide updated information on the potential for acquiring cost-effective demand-side resources across all major resource types (load management, energy efficiency, demand response and system messaging and education). Information learned from the demand-side management potential study will be incorporated in the company's demand-side management programs and in future integrated resource plans.

### Combined Heat and Power

The 2007 integrated resource plan includes 100 megawatts of new combined heat and power in 2012. Combined heat and power facilities are allowed to bid into the company's current east side base load request for proposal, and can become part of the company's resource portfolio as qualifying facilities under the Public Utilities Regulatory Policy Act. Additional information on the potential for combined heat and power will be available from the demand-side management potential study and will be incorporated into the company's future integrated resource plans.

### Distributed Generation

The company investigated the potential of adding distributed generation on the east side of its system and was informed by the Utah Department of Air Quality that it was not feasible to rely on existing standby generators at customer sites due to air quality considerations. On the west side of the system, the company found using sensitivity analysis that replacing a new resource with combined heat and power and aggregated dispatchable customer-owned standby generators marginally increased cost and risk. The company will have additional information on distributed generation potential as part of the demand-side management potential study. Based on this information, the company will determine what further steps to take with regard to distributed generation.

### Thermal Base Load/Intermediate Load Resources

The company has an outstanding request for proposals that is aimed at acquiring up to 1,700 megawatts of cost-effective base load resource by 2014 on the east side of its system. The 2007 integrated resource plan identifies 1,450 megawatts of base load / intermediate load thermal resources needed on the east side of the system during this time frame based on a 12 percent planning reserve margin. Another 357 megawatts of base load / intermediate resource are identified in 2016. The 2007 integrated resource plan fully supports the outstanding Base Load Request for Proposal.

The 2007 integrated resource plan identified the need for 677 megawatts of base load / intermediate load thermal resources for the west side. The thermal resources consist of a 602 megawatt combined cycle natural gas plant in 2011 and 75 megawatts of combined heat and power in 2012. These proxy resources identified in the integrated resource plan will be used to guide the procurement of resources for the west side of the system such that the company can meet its deficit in the 2011-to-2012 time frame in a manner that is cost-effective, adjusted for risk. The actual mix and quantity of resources procured by the company to satisfy this need in the west may differ from the proxy resources identified in the integrated resource plan. Consistent with state guidelines for resource procurement, the company will perform updated analyses at the time new resources are acquired.

## Front Office Transactions

The 2007 integrated resource plan identified the annual need for 50 to 650 megawatts of front office transactions on the west side of its system for 2010 to 2014. The front office transactions are modeled as flat annual purchases[67] and serve as a proxy for base load / intermediate load resources. Acquisition of front office transactions in the west will be considered in the context of the overall base load / intermediate load resource need in the west.

On the east side, the integrated resource plan identified the annual need for up to 400 megawatts of front office transactions for the 2010-to-2014 period. The need may be addressed using the Base Load Request for Proposals. Beyond this time frame, the annual need drops to no more than 200 megawatts.

## Transmission Expansion

The 2007 integrated resource plan has identified a need for additional transmission as part of the preferred portfolio. In general, transmission additions reflect the need to meet retail load requirements, integrate wind and provide system reliability. Specific enhancements are required to integrate both the Wyoming and southern Utah areas with the Wasatch front, create additional integration with markets in the desert southwest, and integrate new resources and front office transactions with loads on the west side of the company's system.

The transmission additions identified in the preferred portfolio are proxy transmission additions. They are included as options that can be selected by the company's integrated resource planning models on a comparable basis with supply-side and demand-side resources. The proxy transmission additions included in the preferred portfolio serve as a guide to the company's transmission planners and may ultimately result in construction of new facilities by the company, partnering in regional transmission projects with others, or the execution of third party wheeling contracts. The timing and size of new transmission facilities may vary from the proxy transmission addi-

[67] Market purchases are assumed to be delivered at market hubs, primarily Mid-Columbia, and not at the load. For front office transactions to reach load, additional transmission is required.

tions included in the preferred portfolio due to specific siting, permitting and construction issues associated with a given project.

## OTHER ISSUES

### Global Climate Change

As discussed elsewhere in this IRP, one of the most challenging resource planning issues facing the company is how to address risk associated with the regulation of greenhouse gas emissions. As new climate policies and laws are adopted by state legislatures, utility commissions or the federal government to limit the utilization of higher carbon-emitting resources, PacifiCorp will adjust its capacity expansion model to account for those new policies.

To address this challenge, PacifiCorp has formed a Global Climate Change Working Group to analyze and discuss utility best practices in managing emissions of greenhouse gases and identify cost-effective opportunities to reduce greenhouse gas emissions within the respective states' regulatory framework. The company expects to have filed, with all six commissions, a preliminary Global Climate Change Action Plan by the fourth quarter 2007.

PacifiCorp employees will continue to have dialogue with stakeholders on this issue, explaining the various efforts already underway, and with stakeholder partners offering guidance and feedback on how the company might improve upon the efforts identified within the Global Climate Change Action Plan.

Separately, PacifiCorp is engaged in several partnerships, such as the Big Sky Carbon Sequestration Partnership and the Electric Power Research Institute, to explore energy, climate change, economic growth and carbon sequestration opportunities. The company also continues to participate in groups organized at state government levels that are designed to develop global climate change policy such as Oregon Docket UM 1302 that is investigating the treatment of carbon dioxide risk in integrated resource planning.

### Carbon Reducing Technologies

Since the second quarter of 2006, the company has sponsored a workgroup to specifically investigate integrated gasification combined cycle technology and carbon dioxide sequestration. As the company moves forward, it will expand its view to all feasible technologies that can potentially reduce carbon dioxide emissions in a cost-effective manner, including nuclear power. For example, the Wyoming Infrastructure Authority and PacifiCorp are pursuing joint project development activities for an IGCC facility in Wyoming.

### Modeling Improvements

While the 2007 integrated resource plan addresses renewable portfolio standards and carbon risk, it is becoming increasingly important to refine the modeling capabilities in this area. The company will pursue enhancements to the integrated resource planning models to potentially incorporate more sophisticated methods to address new resource portfolio standards and carbon regulations.

**Cost Assignment and Recovery**

The preferred portfolio is based on the premise of a single integrated system with rolled-in costs for new resources as prescribed under the Revised Protocol allocation methodology. Acknowledgement or acceptance of a single plan is a prerequisite for use of the Revised Protocol when the company is acquiring new resources. To the extent states acknowledge or accept different plans, the company will work with the states to find ways to deliver different plans to different states, while maintaining the highest possible level of system integration benefits and assuring full cost recovery of prudently incurred costs required to serve retail customers.

## 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 the 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.

## RESOURCE ACQUISITION PLAN PATH ANALYSIS

The Utah Public Service Commission's IRP standards and guidelines require that PacifiCorp's IRP contain a "plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds."

PacifiCorp's resource acquisition path analysis plan for this IRP consists of the use of the IRP models for the Base Load Request For Proposals issued on April 5, 2007. The modeling plan entails evaluating bid resources on a portfolio basis similar to how portfolios were evaluated in the 2007 IRP. The timing of the RFP, with a consequent refreshing of analysis inputs and inclusion of PacifiCorp's benchmark resources, represents a logical and efficient strategy to address this requirement.

To formulate and analyze different resource acquisition paths, the RFP modeling process includes two deterministic scenario analysis steps in which bid resources, including PacifiCorp benchmark resources, are evaluated with the Capacity Expansion Module under a range of scenario assumptions. The scenarios capture a combination of alternative electricity/gas prices, $CO_2$ cost adders, and planning reserve margins.

The first scenario analysis step involves running the CEM with the full set of short-listed bid resources to assist in screening the resources. The second scenario analysis step occurs after stochastic simulation has been used to select bid resource finalists. The portfolio of bid resource finalists is subjected to another round of CEM runs using the same scenario set applied to initially screen the bid resources. In contrast to the first scenario analysis step, the bid resources are fixed, and CEM use is limited to just determining the dispatch solution and PVRR under different economic conditions. This path analysis step is intended to help assure the company that the bid resource finalists are robust with respect to cost and cost variability under alternative economic and planning assumptions.