



2013

Integrated Resource Plan

Volume I

*Let's turn the answers **on.***

April 30, 2013



Rocky Mountain Power
Pacific Power
PacifiCorp Energy

This 2013 Integrated Resource Plan 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.

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Cover Photos (Top to Bottom):

Transmission: Sigurd to Red Butte Transmission Segment G

Hydroelectric: Lemolo 1 on North Umpqua River

Wind Turbine: Leaning Juniper I Wind Project

Thermal-Gas: Chehalis Power Plant

Solar: Black Cap Photovoltaic Solar Project

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CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp’s 2013 Integrated Resource Plan (2013 IRP), representing the 12th plan submitted to state regulatory commissions, presents a framework for future actions that PacifiCorp will take to provide reliable, reasonable-cost service with manageable risks to its customers. It was developed with participation from numerous public stakeholders, including regulatory staff, advocacy groups, and other interested parties.

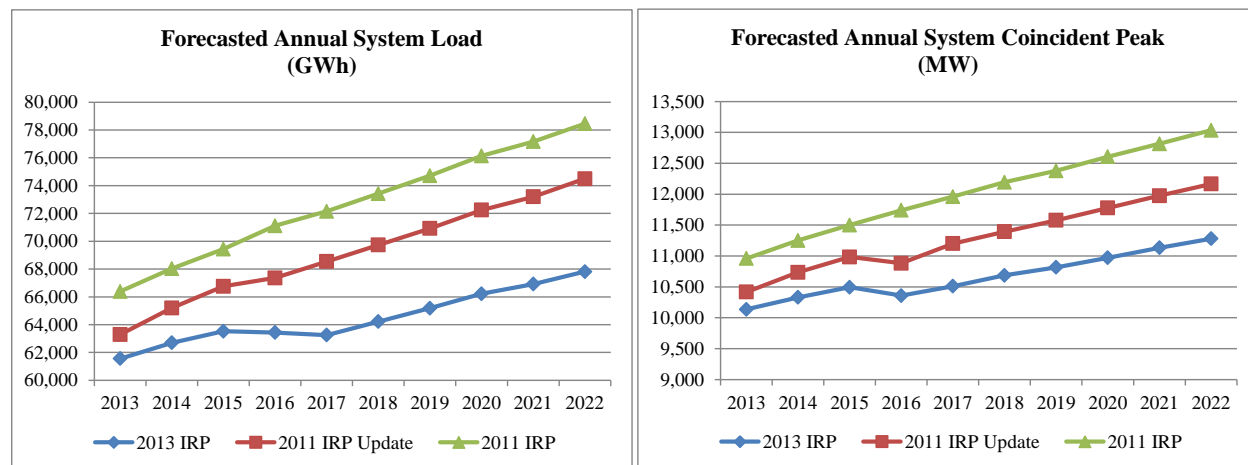
The key elements of the 2013 IRP include (1) a finding of resource need, focusing on the 10-year period 2013-2022, (2) the preferred portfolio of incremental supply-side and demand-side resources to meet this need, and (3) an action plan that identifies the steps the Company will take during the next two to four years to implement the plan. The process and outcome of the IRP—the preferred portfolio and action plans—meet applicable state IRP standards and guidelines. PacifiCorp continues to plan on a system-wide basis while accommodating state resource acquisition mandates and policies.

2013 IRP Highlights

Development of the 2013 IRP involved balanced consideration of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. Key drivers to the 2013 IRP preferred portfolio and associated action plan include the following:

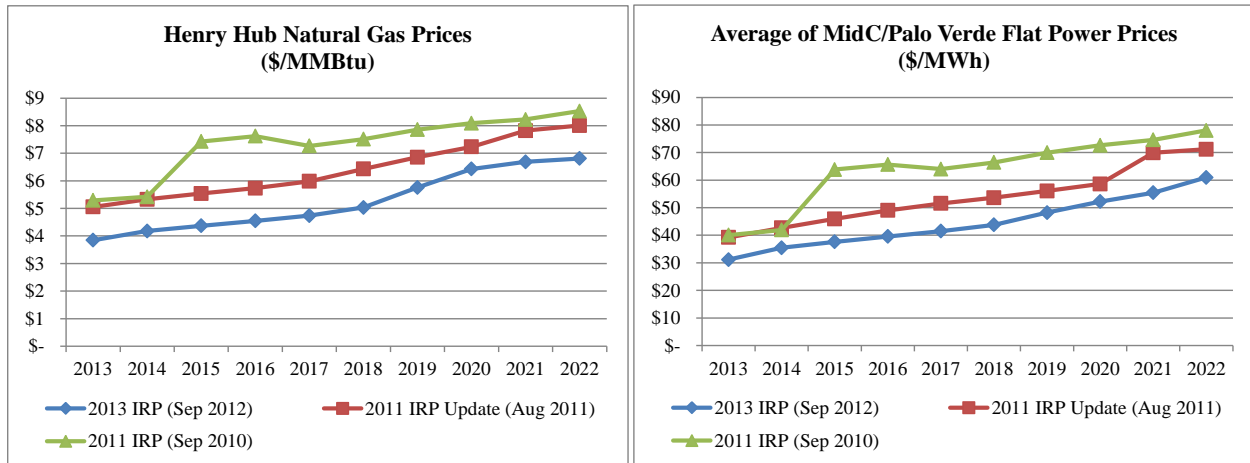
- As shown in Figure ES.1, the Company’s load forecast in the 2013 IRP is down in relation to projected loads used in the 2011 IRP and 2011 IRP Update. The lower load forecast is driven significantly by industrial self generation taking advantage of low natural gas prices, as well as by load request cancellations in Utah and Wyoming and postponements prompted by prolonged recessionary impacts and permitting issues. The reduced load forecast has greatly mitigated, but not eliminated the need for resources in the front ten years of the planning horizon, and is a significant driver in resource portfolio modeling performed for the 2013 IRP.

Figure ES.1 – Load Forecast Comparison among Recent IRPs



- Figure ES.2 shows that base case wholesale power prices and natural gas prices used in the 2013 IRP are significantly lower than the base case market prices used in the 2011 IRP and 2011 IRP Update. The decline in forward natural gas prices has largely been influenced by continued growth in prolific shale gas plays in North America. With continued declines in natural gas prices and reduced regional loads, forward power prices have also declined significantly over the past two years. Given these favorable market conditions, front office transactions play a critical role in meeting coincident peak loads throughout the front ten years of the planning horizon.

Figure ES.2 – Power and Natural Gas Price Comparison among Recent IRPs



- In all portfolios evaluated in the 2013 IRP, energy efficiency resources play an important role in meeting load growth throughout the front ten years of the planning horizon. In the 2013 IRP preferred portfolio, the accumulated acquisition of incremental energy efficiency resources meets 67 percent of currently forecasted load growth from 2013 levels by 2022, and the 2013 IRP action plan identifies steps the Company will take in the next two to four years to accelerate acquisition of cost-effective energy efficiency resources.
- Policy and market developments have contributed to higher renewable resource costs and reduced benefits. On the policy front, policy makers continue to debate Federal budget deficits, and deep philosophical differences have thus far proven to be a barrier to budgetary compromise, making the long-term outlook for federal tax incentives that have traditionally benefited new renewable resources highly uncertain. Policy makers have also not succeeded in passing federal greenhouse gas legislation for consideration by the President. While the U.S. Environmental Protection Agency (EPA) has proposed new source performance standards to regulate greenhouse gas emissions from new sources, it has not finalized those standards, nor has it established a schedule to promulgate rules applicable to existing sources. With higher after-tax costs, lower power prices, and continued greenhouse gas regulation uncertainty, the need for new renewable resources will be driven by state-specific renewable portfolio standard (RPS) regulations. To mitigate the cost of RPS compliance, analyses in the 2013 IRP supports the use of unbundled renewable energy credits (RECs) to meet state RPS obligations through the first ten years of the planning period.

- On March 15, 2013, the Utah Public Service Commission approved the Company's application for a Certificate of Public Convenience and Necessity (CPCN) for the Sigurd to Red Butte transmission project. The Company began construction of the Sigurd to Red Butte transmission project in April, 2013 with a scheduled in-service date of June, 2015. For the 2013 IRP, the Company has completed preliminary analysis of the Windstar to Populus transmission project (Energy Gateway Segment D) that supports on-going permitting activities. Permitting activities for other Energy Gateway transmission segments will continue in parallel with the on-going development of analytical tools that can be used to evaluate transmission benefits that are not traditionally captured in the resource portfolio modeling process used in the IRP.
- The Company has analyzed in the 2013 IRP environmental investments required to meet known and prospective compliance obligations across PacifiCorp's existing coal fleet. Supported by analyses performed as part of the 2013 IRP and analyses performed in recent regulatory filings, the Company plans to convert Naughton Unit 3 to a natural gas-fired facility and to install environmental investments required to meet near term compliance obligations at the Hunter Unit 1, Jim Bridger Unit 3, and Jim Bridger Unit 4 generating units. Installation of emission control equipment at these facilities will reduce emissions of nitrous oxides (NO_x) and sulfur dioxide (SO₂) and contribute to improved visibility in the region. The Company plans to continue to evaluate environmental investments required to meet known and prospective environmental compliance obligations at existing coal units in future IRPs and future IRP Updates.

Modeling and Process Improvements

In developing the 2013 IRP, the Company has significantly advanced its analytical methods and portfolio development approach. The notable improvements that are summarized below have very much influenced the 2013 IRP and establish a sound foundation for analysis in future IRPs.

- Energy Gateway Transmission

In contrast to the 2011 IRP, where analysis of Energy Gateway transmission investments preceded resource portfolio modeling, Energy Gateway transmission investments have been integrated into the portfolio modeling process for the 2013 IRP. This was achieved by replicating the development of resource portfolios among five different Energy Gateway transmission scenarios. Consequently, 94 unique core case resource portfolios were produced in the 2013 IRP, nearly five times the number of core case portfolios developed for the 2011 IRP.

In addition to incorporating Energy Gateway transmission investments into the resource portfolio modeling process, the 2013 IRP introduces the System Operational and Reliability Benefits Tool (SBT), which identifies and quantifies transmission benefits that are not captured using production cost dispatch models traditionally used for IRP analyses. In this way, the SBT identifies, measures, and monetizes benefits that are incremental to those identified in the resource portfolio modeling process. Analysis using the SBT supports investment in the Sigurd to Red Butte transmission project and preliminary application of the SBT to the Windstar to Populus transmission project

supports continued permitting of Energy Gateway Segment D. The SBT will continue to be developed and will be applied to additional Energy Gateway transmission projects for analysis in future IRPs.

- Existing Coal Resources

Building upon modeling techniques developed in the 2011 IRP and 2011 IRP Update, environmental investments required to achieve compliance with known and prospective regulations at existing coal resources have been integrated into the portfolio modeling process in the 2013 IRP. Potential alternatives to environmental investments associated with known and prospective compliance obligations tied to Regional Haze rules, Mercury and Air Toxics Standards (MATS), regulation of coal combustion residuals (CCR), and regulation of cooling water intakes are considered in the development of *all* resource portfolios developed for the 2013 IRP. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. In addition to integrating coal unit environmental investment decisions into the portfolio development process, the Company has completed detailed financial analysis of near-term investment decisions in Confidential Volume III of the 2013 IRP.

- Energy Efficiency

PacifiCorp continues to evaluate energy efficiency as a resource that competes with traditional supply-side resource alternatives when developing resource portfolios that are compared under a range of cost and risk metrics. The 2013 IRP includes for the first time core case resource portfolios developed assuming accelerated acquisition of energy efficiency resources. While the assumptions developed for these cases require further validation and review, cost and risk analysis of these portfolios have led to action items in the 2013 IRP action plan to accelerate acquisition of cost-effective energy efficiency resources.

In addition to evaluating acceleration of energy efficiency resources in the 2013 IRP, the Company greatly expanded its representation of energy efficiency resource attributes that influence selection in any given portfolio. Energy efficiency resources were modeled with additional cost granularity by increasing the number of cost steps that delineate groupings of different energy efficiency measures. In the 2011 IRP, energy efficiency resources for a given state were grouped into nine different cost levels, whereas the 2013 IRP modeling was performed using 27 different cost levels to represent energy efficiency resource opportunities in each state. Implementation of this modeling refinement deteriorated model performance, and the Company has developed an action item to study trade-offs between resource selections and model run-times at different levels of granularity.

- Renewable Portfolio Standards

The 2013 IRP includes portfolios with and without renewable portfolio standard (RPS) requirements to isolate how system costs and portfolio risks are affected when new

renewable resources are added to a portfolio for the sole purpose of meeting state-specific RPS compliance targets. In those cases where RPS compliance targets are assumed and incremental renewable resources are needed for the sole purpose of achieving RPS targets, the RPS Scenario Maker model was introduced into the 2013 IRP. The RPS Scenario Maker model was used to establish a minimum level of new renewable resources needed to meet RPS compliance targets while considering compliance flexibility mechanisms such as “banking” unique to each state RPS program.

- Public Process

The involvement of stakeholders is a critical element of the IRP process. Over the course of developing the 2013 IRP, the Company expanded its open and collaborative approach to resource planning by increasing opportunities for stakeholder participation. The Company hosted 15 public input meetings, more than twice the number of public input meetings held for the 2011 IRP, supplemented communications with stakeholder conference calls, and held five state meetings. In addition, the Company made available to stakeholders a website used to provide data and to communicate Company responses to stakeholder questions received throughout the public process.

Resource Need

PacifiCorp’s need for new resources is determined by developing a capacity load and resource balance that considers the coincident system peak load hour capacity contribution of existing resources, forecasted loads and sales, and reserve requirements. For capacity expansion planning, the Company uses a 13 percent planning reserve margin, which is applied to PacifiCorp’s obligation net of offsetting “load resources” such as dispatchable load control capacity.¹

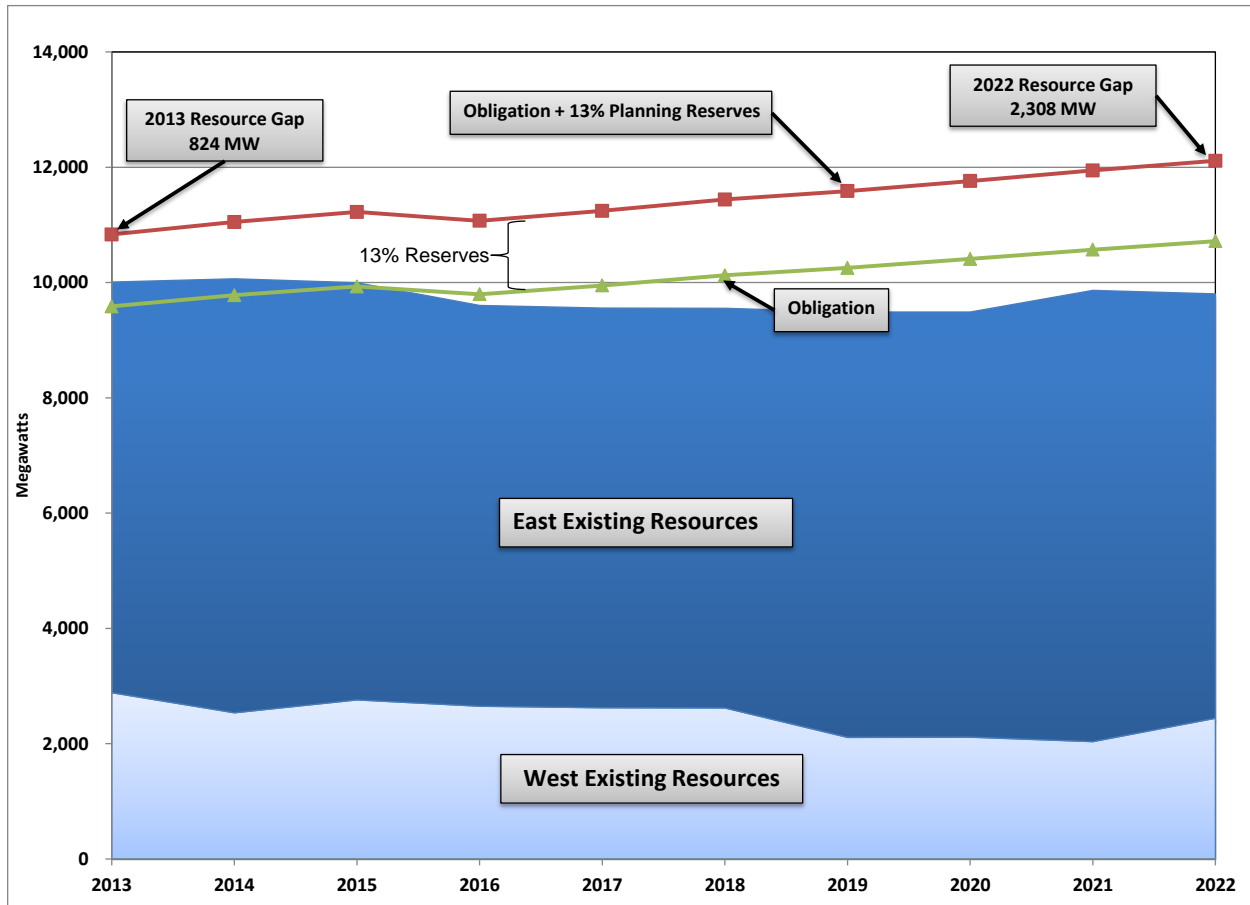
Table ES.1 shows the Company’s annual capacity position for 2013 through 2022, and Figure ES.3 graphically highlights the capacity resource gap in relation to currently owned and contracted east and west-side resources. Without new resources, the system experiences a capacity deficit of 824 megawatts in 2013, down by 57 percent as compared to the 2011 IRP and down by 39 percent as compared to the 2011 IRP Update. By 2022, the system capacity deficit reaches 2,308 megawatts. Over the 2013 to 2022 timeframe, the system peak load is forecasted to grow at a compounded annual rate of 1.2 percent (prior to forecasted load reductions from energy efficiency). On an energy basis, PacifiCorp expects system-wide average load growth of 1.1 percent per year.

Table ES.1 – PacifiCorp 10-year Capacity Position Forecast (Megawatts)

System	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Resources	10,010	10,065	9,996	9,602	9,556	9,553	9,487	9,488	9,864	9,803
Obligation	9,588	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718
Reserves (Based on 13% Target)	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Obligation + 13% Planning Reserves	10,834	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)
Reserve Margin	4.4%	2.9%	0.6%	(2.0%)	(4.0%)	(5.6%)	(7.5%)	(8.8%)	(6.7%)	(8.5%)

¹The 13 percent planning reserve margin is supported by a stochastic loss of load probability study that is summarized in Volume II, Appendix I of the 2013 IRP.

Figure ES.3 – PacifiCorp Capacity Resource Gap



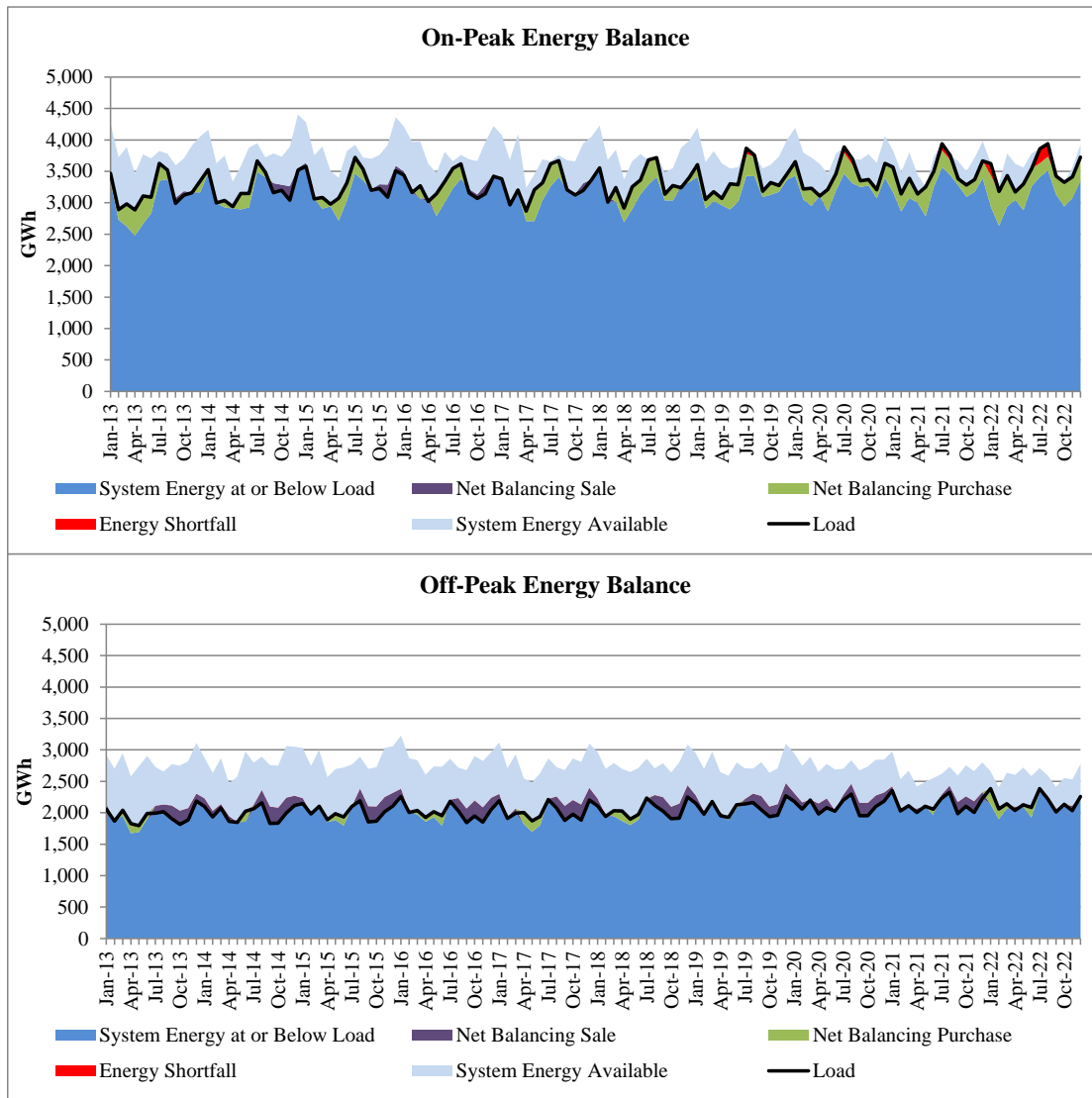
The capacity position shows how existing resources and loads balance during the coincident peak load hour of the year inclusive of a planning reserve margin. Outside of the peak hour, the Company economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, the Company can dispatch resources that in aggregate exceed then-current load obligations, facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs fall below prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how the Company manages net power costs.

Figure ES.4 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and current wholesale power and natural gas prices.² The figure shows expected monthly energy production from system resources during on-peak and off-peak periods in relation to load assuming no additional resources are added to PacifiCorp’s system. At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak

² On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday, excluding NERC-observed holidays. All other hours define off-peak periods.

periods. Figure ES.4 also shows how much system energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and are indicative of short energy positions absent the addition of incremental resources to the portfolio. During on-peak periods, the first energy shortfall appears in July 2018, and by 2022 available system energy falls short of monthly loads in January, July, August, and October. During off-peak periods, there are no energy shortfalls through the 2022 timeframe.

Figure ES.4 – Economic System Dispatch of Existing Resources in Relation to Monthly Load



Future Resource Options and Portfolio Modeling

In line with state IRP standards and guidelines, PacifiCorp included a wide variety of resource options in portfolio modeling covering generation, demand-side management and transmission. Cost and performance assumptions for resource alternatives were developed using multiple sources, including: third party estimates, data from actual and projected PacifiCorp or utility

industry installations, and data from recent request for proposals and requests for information. Table ES.2 summarizes the wide range of resource alternatives evaluated in the 2013 IRP.

Table ES.2 – 2013 IRP Resource Options*

Natural Gas	Other Thermal	Renewable	Energy Storage	Distributed Generation	Class 1 DSM (Direct Load Control)	Class 2 DSM (Energy Efficiency)	Class 3 DSM (Demand Response)
<ul style="list-style-type: none"> ▪ SCCT Aero ▪ Intercooled SCCT Aero ▪ SCCT Frame ▪ IC Recip. Engine ▪ CCCT (2x1) F-class ▪ CCCT (2x1) G/H-class ▪ CCCT (1x1) G/H-class ▪ CCCT (1x1) J-class ▪ CCCTs with and without duct firing 	<ul style="list-style-type: none"> ▪ IGCC with carbon capture and sequestration ▪ Nuclear fission 	<ul style="list-style-type: none"> ▪ Geothermal (PPAs) ▪ Wind ▪ Solar PV (fixed tilt & tracking) ▪ Biomass 	<ul style="list-style-type: none"> ▪ Pumped Storage ▪ Sodium-Sulfur Battery ▪ Advanced Fly Wheel ▪ Compressed Air Energy Storage 	<ul style="list-style-type: none"> ▪ Reciprocating Engines ▪ Gas Turbine ▪ Microturbine ▪ Fuel Cell ▪ Commercial Biomass, Anaerobic Digester ▪ Industrial Biomass, Waste ▪ Rooftop Solar PV ▪ Solar Water Heaters 	<ul style="list-style-type: none"> ▪ Residential Central Air & Water Heating ▪ Small Commercial Central Air & Water Heating ▪ Irrigation Load Curtailment ▪ Commercial Curtailment ▪ Industrial Curtailment 	<ul style="list-style-type: none"> ▪ Residential, Commercial, Industrial, Irrigation, and Street Lighting Measures ▪ 27 measure bundles grouped by cost among five states ▪ Energy Trust of Oregon Energy Efficiency Measures as Applicable for Oregon 	<ul style="list-style-type: none"> ▪ Residential time-of-use rates ▪ Commercial Critical Peak Pricing ▪ Commercial and Industrial Demand Buyback ▪ Voluntary Irrigation Time-of-Use

*SCCT = simple cycle combustion turbine; CCCT = combined cycle combustion turbine; IGCC = integrated gasification combined cycle, PPA = power purchase agreement; PV = photo voltaic, DSM = demand side management

PacifiCorp’s IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios, and consists of eight phases:

- Define input scenarios for portfolio development
- Price forecast development (natural gas and wholesale electricity by market hub)
- Optimize portfolio development using PacifiCorp’s *System Optimizer* capacity expansion model for cases without RPS requirements
- Develop a renewable resource floor, reflecting renewable resource additions chosen in optimized portfolios from cases that exclude RPS requirements needed to achieve compliance for cases that do include RPS assumptions
- Optimize portfolio development using PacifiCorp’s *System Optimizer* capacity expansion model for cases with RPS requirements
- Stochastic Monte Carlo production cost simulation of optimized portfolios
- Selection of top-performing portfolios using a three-phase screening process that incorporates stochastic portfolio cost and risk assessment measures
- Preliminary preferred portfolio selection, followed by additional analysis and determination of the final preferred portfolio

PacifiCorp worked with stakeholders to define 19 input scenarios, or “core cases”, which were applied across five different Energy Gateway transmission scenarios totaling 94 different variations of resource portfolios.³ The 19 different core cases were categorized into four different themes:

- (1) Reference: There are three different core cases developed for the Reference Theme. Each case relied upon base case assumptions for market prices, environmental policy inputs, energy efficiency assumptions, and load projections. RPS assumptions differentiate the three cases in the Reference Theme, with one case assuming no state or federal RPS requirements, one case assuming only state RPS requirements, and one case assuming both state and federal RPS requirements must be met.
- (2) Environmental Policy: There are 11 different core cases developed for the Environmental Policy Theme. Five of the 11 cases reflect base case assumptions for Regional Haze requirements on existing coal units, and six of the 11 cases assume more stringent Regional Haze requirements. Differentiating the sets of cases with different Regional Haze compliance requirements are varying assumptions for market prices (low, medium, and high), CO₂ prices (zero, medium, and high), RPS requirements (with and without state and federal RPS), and energy efficiency.
- (3) Targeted Resources: There are four different core cases developed for the Targeted Resource Theme. Each of the cases is characterized by alternative assumptions for specific resource types to understand how these assumptions influence resource portfolios, costs, and risk. One of the four cases prevents combined cycle resources from being added to the resource portfolio and assumes energy efficiency resources can be acquired at an accelerated rate. The second of the four cases in this theme assumes that geothermal power purchase agreement resources will be used to meet RPS requirements. The third of four cases in this theme assumes a spike in power prices over the period 2017 through 2022 and assumes natural gas prices will rise above base case levels over the entirety of the planning horizon. The fourth case in this theme targets clean energy resources and assumes CO₂ prices rise consistent with a federal hard cap scenario, that natural gas prices rise above those assumed in the base case, that federal tax incentives for renewable resources are extended through 2019, and that energy efficiency resources can be acquired at an accelerated rate.
- (4) Transmission: The Transmission Theme included one core case, which assumes that third party transmission can be purchased from a newly built line as an alternative to the Company’s Gateway Segment D project. This case was only analyzed in four of the five Energy Gateway scenarios that include the Gateway Segment D project.

PacifiCorp selected top-performing portfolios on the basis of system costs using Monte Carlo simulations of each portfolio over a twenty year planning horizon. The Monte Carlo runs capture stochastic behavior of electricity prices, natural gas prices, loads, thermal unit availability, and hydro availability. The relative average cost among portfolios and the upper tail cost among portfolios are used to evaluate cost and risk metrics among candidate portfolios and are used to identify top performing resource portfolios that inform the Company’s selection of the preferred

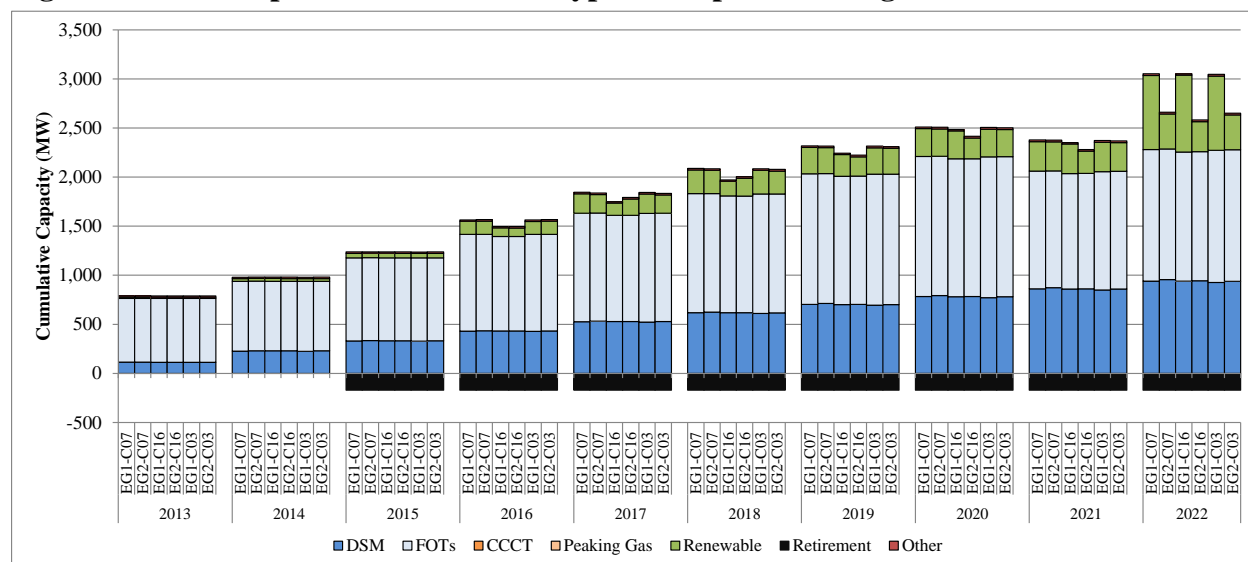
³ One of the input scenarios is applicable to four out of the five Energy Gateway transmission scenarios.

portfolio. In making its preferred portfolio selection, the Company considers measures of risk-adjusted portfolio costs, customer rate impacts, CO₂ emissions, and supply reliability.

In the 2013 IRP, some portfolios developed under the assumption that acquisition of demand side management (DSM) resources can be accelerated performed well on a risk adjusted cost basis. However, given uncertainties in incentive and administrative costs and delivery risks associated with accelerating acquisition of DSM resources, these portfolios were not selected as the preferred portfolio. Nonetheless, the potential benefits of accelerating acquisition of DSM resources has prompted the Company to develop action items in 2013 IRP Action Plan targeting accelerated acquisition of cost effective DSM resources.

Figure ES.5 summarizes the nameplate capacity of cumulative resource selections through 2022 among top performing portfolios developed under base case DSM acquisition ramp rate assumptions. With reduced load expectations and market prices, resource selections among the top performing portfolios over the first 10 years of the planning horizon are dominated by energy efficiency and front office transaction (FOT) resources, and there are no new CCCT resources required over this timeframe. Among these cases, renewable resources are added in different quantities and at different times for the sole purpose of meeting west side state RPS requirements. The variability in quantity, type, and timing of new renewable resources is dependent on whether the Windstar to Populus transmission project is built.

Figure ES.5 – Comparison of Resource Types in Top Performing Portfolios



In the final screening stage of the 2013 IRP portfolio analysis, the Company evaluated an alternative strategy to meet Washington RPS requirements with unbundled RECs. This analysis shows that a compliance strategy focused on acquiring unbundled RECs is favorable on a cost and risk basis, and supports 2013 IRP action items to issue competitive market solicitations for unbundled REC products over the next two to four years.

The 2013 IRP Preferred Portfolio

Table ES.3 lists the resource types and annual nameplate megawatt capacity additions over the period 2013 through 2032. Figure ES.4 shows how the preferred portfolio, along with existing resources, meets capacity requirements at the time of system peak through 2022. The drop in obligation and reserves in 2016 and 2021 coincides with termination of two exchange contracts. With reduced loads and favorable market conditions, incremental resource needs in the front 10 years of the planning horizon are met largely with cost-effective energy efficiency acquisitions and firm market purchases.

As informed by portfolio modeling completed for the 2013 IRP, the Company's action plan focuses on accelerating acquisition of cost effective DSM measures, to take advantage of the risk mitigation benefits of DSM resources by reducing the need for new firm market purchases in the near-term. With policy and market drivers contributing to unfavorable economics for new renewable resources, renewable resource additions in the 2013 IRP preferred portfolio reflect a near-term unbundled REC compliance strategy. Near-term renewable resources include small scale utility solar resources needed to meet Oregon requirements and distributed solar resources associated with the Utah Solar Incentive Program. Over the long-term, the 2013 IRP preferred portfolio includes additional wind resources, totaling 650 megawatts in the 2024 to 2025 timeframe, which contribute to meeting long-term state and assumed RPS obligations.

Table ES.3 – 2013 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
Resource	Installed Capacity, MW																				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Expansion Options																					
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	423	-	-	-	661	-	1,084	-	-	2,813
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181	362
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	70	67	67	69	66	63	54	57	56	1,593
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	19	88	-	-	-	193
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	650
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	15	15	15	15	15	15	15	15	15	293
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	21
Front Office Transactions	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246	n/a
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(502)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	(1,535)
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14
Total	791	1,486	802	1,102	1,218	1,315	1,427	1,515	1,287	1,431	1,511	2,054	1,606	1,509	1,640	1,648	1,639	1,685	1,281	1,500	

Figure ES.6 – Addressing PacifiCorp’s Peak Capacity Deficit, 2013 through 2022

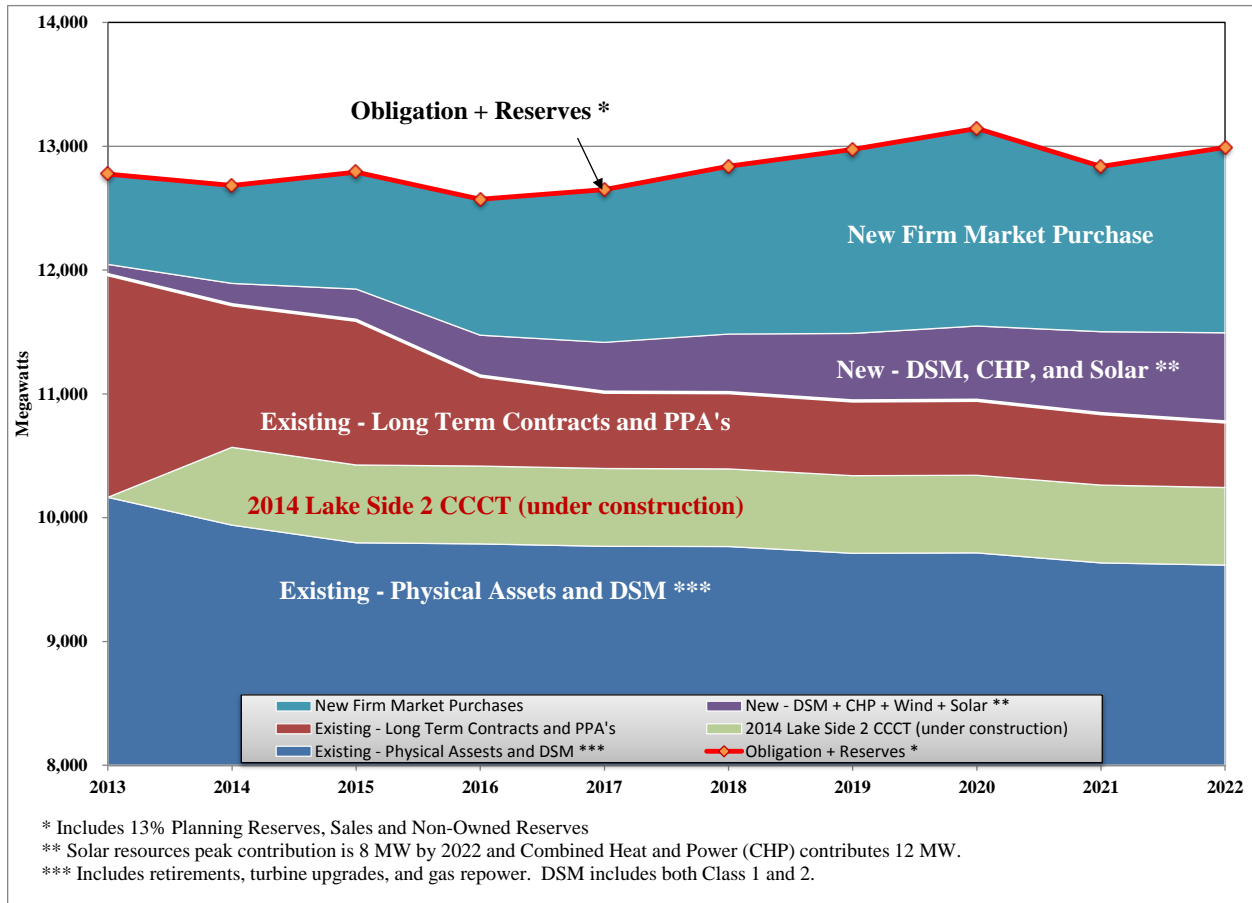
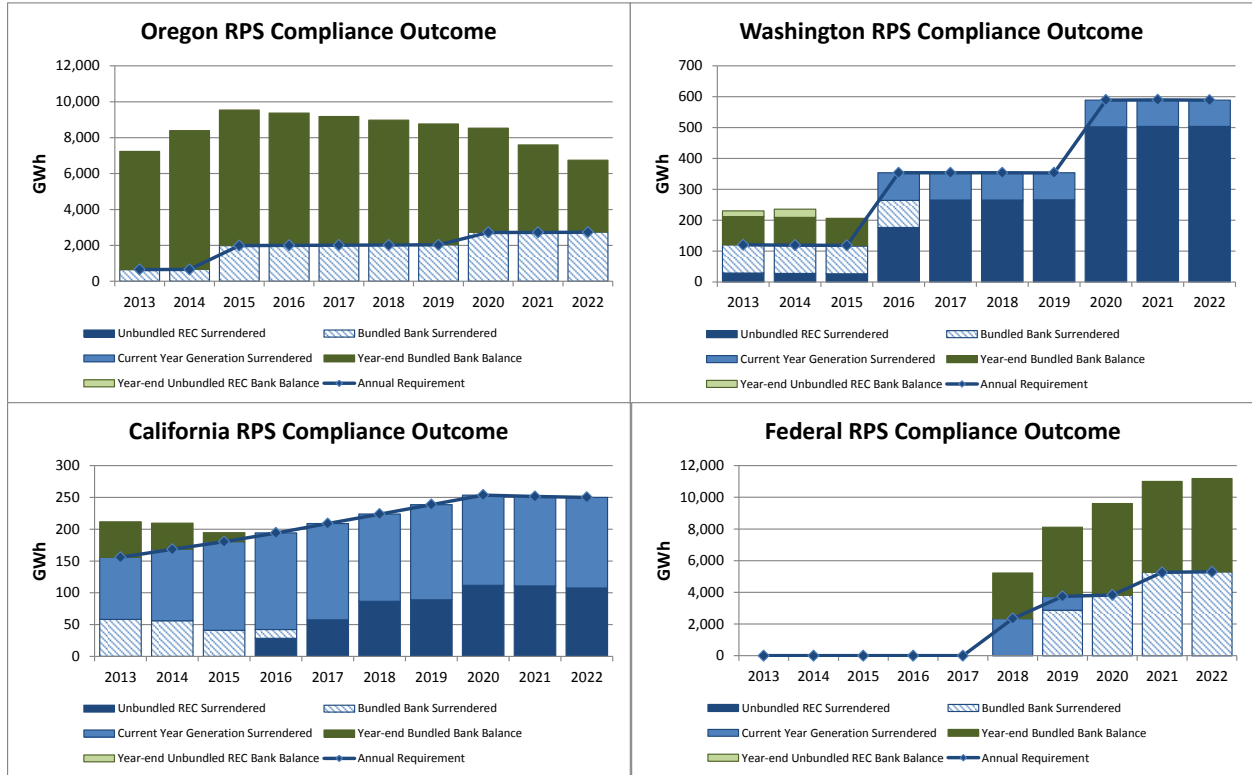


Figure ES.7 shows PacifiCorp’s forecasted RPS compliance position for the California, Oregon, and Washington⁴ programs, along with a federal RPS program scenario⁵, covering the period 2013 through 2022 based on the preferred portfolio. Utah’s RPS goal is tied to a 2025 compliance date, so the 2013 to 2022 position is not shown below. However, PacifiCorp meets the Utah 2025 state target of 20 percent based on eligible Utah RPS resources, and has significant levels of banked RECs to sustain continued future compliance. PacifiCorp anticipates utilizing flexible compliance mechanisms such as banking and/or tradable RECs where allowed, to meet RPS requirements.

⁴ The Washington RPS requirement is tied to January 1st of the compliance year.

⁵ The assumed federal RPS requirements are applied to retail sales, with a target of 4.5 percent beginning in 2018, 7.1 percent in 2019-2020, 9.8 percent in 2021-2022, 12.4 percent in 2023-2024, and 20 percent in 2025

Figure ES.7 – Annual State and Federal RPS Position Forecasts



The 2013 IRP Action Plan

The 2013 IRP Action Plan identifies specific actions the Company will take over the next two to four years. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2013 IRP process. Table ES.4 details specific 2013 IRP action items by category.

Table ES.4 – 2013 IRP Action Plan

Action Item	1. Renewable Resource Actions
1a.	<p><u>Wind Integration</u></p> <ul style="list-style-type: none"> • Update the wind integration study for the 2015 IRP. The updated wind integration study will consider the implications of an energy imbalance market along with comments and feedback from the technical review committee and IRP stakeholders provided during the 2012 Wind Integration Study.
1b.	<p><u>Renewable Portfolio Standard Compliance</u></p> <ul style="list-style-type: none"> • With renewable portfolio standard (RPS) compliance achieved with unbundled renewable energy credit (REC) purchases, the preferred portfolio does not include incremental renewable resources prior to 2024. Given that the REC market lacks liquidity and depth beyond one year forward, the Company will pursue unbundled REC requests for proposal (RFP) to meet its state RPS compliance requirements. <ul style="list-style-type: none"> – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard obligations. – Issue at least annually, RFPs seeking historical, then current-year, or forward-year vintage unbundled RECs that will qualify for Oregon renewable portfolio standard obligations. As part of the solicitation and bid evaluation process, evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify for California renewable portfolio standard obligations.
1c.	<p><u>Renewable Energy Credit Optimization</u></p> <ul style="list-style-type: none"> • On a quarterly basis, issue reverse RFPs to sell RECs not required to meet state RPS compliance obligations.

<p>1d.</p>	<p><u>Solar</u></p> <ul style="list-style-type: none"> • Issue an RFP in the second quarter of 2013 soliciting Oregon solar photovoltaic resources to meet the Oregon small solar compliance obligation (Oregon House Bill 3039). Coordinate the selection process with the Energy Trust of Oregon to seek 2014 project funding. Complete evaluation of proposals and select potential winning bids in the fourth quarter of 2013. • Issue a request for information 180 days after filing the 2013 IRP to solicit updated market information on utility scale solar costs and capacity factors.
<p>1e.</p>	<p><u>Capacity Contribution</u></p> <ul style="list-style-type: none"> • Track and report the statistics used to calculate capacity contribution from wind resources and available solar information as a means of testing the validity of the peak load carrying capability (PLCC) method.
<p>Action Item</p>	<p style="text-align: center;">2. Distributed Generation Actions</p>
<p>2a.</p>	<p><u>Distributed Solar</u></p> <ul style="list-style-type: none"> • Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity. Beginning in June 2014, as stipulated in the Order in Docket No. 11-035-104, the Company will file an Annual Report with program results, system costs, and production data. These reports will also provide an opportunity to evaluate and improve the program as the Company will use this opportunity to recommend changes. Interested parties will have an opportunity to comment on the report and any associated recommendations.
<p>2b.</p>	<p><u>Combined Heat & Power (CHP)</u></p> <ul style="list-style-type: none"> • Pursue opportunities for acquiring CHP resources, primarily through the Public Utilities Regulatory Policies Act PURPA Qualifying Facility contracting process. For the 2013 IRP Update, complete a market analysis of CHP opportunities that will: (1) assess the existing, proposed, and potential generation sites on PacifiCorp’s system; (2) assess availability of fuel based on market information; (3) review renewable resource site information (i.e. permits, water availability, and incentives) using available public information; and (4) analyze indicative project economics based on avoided cost pricing to assist in ranking probability of development.
<p>Action Item</p>	<p style="text-align: center;">3. Firm Market Purchase Actions</p>
<p>3a.</p>	<p><u>Front Office Transactions</u></p> <ul style="list-style-type: none"> • Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017. <ul style="list-style-type: none"> – Resources will be procured through multiple means, such as periodic market RFPs that seek resources less than five years in term, and bilateral negotiations.

	<ul style="list-style-type: none"> – Include in the 2013 IRP Update a summary of the progress the Company has made to acquire front office transactions over the 2014 to 2017 forward period.
Action Item	4. Flexible Resource Actions
4a.	<p><u>Energy Imbalance Market (EIM)</u></p> <ul style="list-style-type: none"> • Continue to pursue the EIM activities with the California Independent System Operator and the Northwest Power Pool to further optimize existing resources resulting in reduced costs for customers.
Action Item	5. Hedging Actions
5a.	<p><u>Natural Gas Request for Proposal</u></p> <ul style="list-style-type: none"> • Convene a workshop for stakeholders by October 2013 to discuss potential changes to the Company’s process in evaluating bids for future natural gas RFPs, if any, to secure additional long-term natural gas hedging products.
Action Item	6. Plant Efficiency Improvement Actions
6a.	<p><u>Plant Efficiency Improvements</u></p> <ul style="list-style-type: none"> • Production efficiency studies have been conducted to satisfy requirements of the Washington I-937 Production Efficiency Measure that have identified categories of cost effective production efficiency opportunity. <ul style="list-style-type: none"> – By the end of the first quarter of 2014, complete an assessment of the plant efficiency opportunities identified in the Washington I-937 studies that might be applicable to other wholly owned generation facilities. – Prior to initiating modeling efforts for the 2015 IRP, determine a multi-state “total resource cost test” evaluation methodology to address regulatory recovery among states with identified capital expenditures. – Prior to initiating modeling efforts for the 2015 IRP, present to IRP stakeholders in a public input meeting the Company’s recommended approach to analyzing cost effective production efficiency resources in the 2015 IRP.
Action Item	7. Demand Side Management (DSM) Actions
7a.	<p><u>Class 2 DSM</u></p> <ul style="list-style-type: none"> • Acquire 1,425 – 1,876 GWh of cost-effective Class 2 energy efficiency resources by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017. <ul style="list-style-type: none"> – Collaborate with the Energy Trust of Oregon on a pilot residential home comparison report program to be offered to Pacific Power customers in 2013 and 2014. At the conclusion of the pilot program and the associated impact

	<p>evaluation, assess further expansion of the program.</p> <ul style="list-style-type: none"> – Implement an enhanced consolidated business program to increase DSM acquisition from business customers in all states excluding Oregon. <ul style="list-style-type: none"> ▪ Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. ▪ Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014. ▪ Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014. – Accelerate to the 2nd quarter of 2014, an evaluation of waste heat to power where generation is used to offset customer requirements – investigate how to integrate opportunities into the DSM portfolio. – Increase acquisitions from business customers through prescriptive measures by expanding the “Trade Ally Network”. <ul style="list-style-type: none"> ▪ Base case target in all states is 3rd quarter 2014, with an accelerated target of 4th quarter 2013 – Accelerate small-mid market business DSM acquisitions by contracting with third party administrators to facilitate greater acquisitions by increasing marketing, outreach, and management of comprehensive custom projects by 1st quarter 2014. – Increase the reach and effectiveness of “express” or “typical” measure offerings by increasing qualifying measures, reviewing and realigning incentives, implementing a direct install feature for small commercial customers, and expanding the residential refrigerator and freezer recycling program to include commercial units. <ul style="list-style-type: none"> ▪ Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. ▪ Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014. ▪ Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014. – Increase the reach of behavioral DSM programs: <ul style="list-style-type: none"> ▪ Evaluate and expand the residential behavioral pilot. <ul style="list-style-type: none"> ◆ Utah base case schedule is 2nd quarter 2014, with an accelerated target of 4th quarter 2013. ▪ Accelerate commercial behavioral pilot to the end of the first quarter 2014. ▪ Expand residential programs system-wide pending evaluation results. <ul style="list-style-type: none"> ◆ System-wide target is 3rd quarter 2015, with an accelerated target of 3rd quarter 2014. – Increase acquisition of residential DSM resources: <ul style="list-style-type: none"> ▪ Implement cost effective direct install options by the end of 2013. ▪ Expand offering of “bundled” measure incentives by the end of 2013. ▪ Increase qualifying measures by the end of 2013. ▪ Review and realign incentives. <ul style="list-style-type: none"> ◆ Utah schedule is 1st quarter 2014
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	<ul style="list-style-type: none"> ◆ Washington base case schedule is 2nd quarter 2014, with accelerated target of 1st quarter 2014. ◆ Wyoming, California, and Idaho base case schedule is 3rd quarter 2014, with an accelerated target of 2nd quarter 2014 – Accelerate acquisitions by expanding refrigerator and freezer recycling to incorporate retail appliance distributors and commercial units – 3rd quarter 2013. – By the end of 2013, complete review of the impact of accelerated DSM on Oregon and the Energy Trust of Oregon, and re-contract in 2014 for appropriate funding as required. – Include in the 2013 IRP Update Class 2 DSM decrement values based upon accelerated acquisition of DSM resources. – Include in the 2014 conservation potential study an analysis testing assumptions in support of accelerating acquisition of cost-effective Class 2 DSM resources, and apply findings from this analysis into the development of candidate portfolios in the 2015 IRP.
7b.	<p><u>Class 3 DSM</u></p> <ul style="list-style-type: none"> • Develop a pilot program in Oregon for a Class 3 irrigation time-of-use program as an alternative approach to a Class 1 irrigation load control program for managing irrigation loads in the west. The pilot program will be developed for the 2014 irrigation season and findings will be reported in the 2015 IRP.
Action Item	8. Coal Resource Actions
8a.	<p><u>Naughton Unit 3</u></p> <ul style="list-style-type: none"> • Continue permitting and development efforts in support of the Naughton Unit 3 natural gas conversion project. The permit application requesting operation on coal through year-end 2017 is currently under review by the Wyoming Department of Environmental Quality, Air Quality Division. • Issue a request for proposal to procure gas transportation for the Naughton plant as required to support compliance with the conversion date that will be established during the permitting process. • Issue an RFP for engineering, procurement, and construction of the Naughton Unit 3 natural gas retrofit as required to support compliance with the conversion date that will be established during the permitting process.
8b.	<p><u>Hunter Unit 1</u></p> <ul style="list-style-type: none"> • Complete installation of the baghouse conversion and low NO_x burner compliance projects at Hunter Unit 1 as required by the end of 2014.
8c.	<p><u>Jim Bridger Units 3 and 4</u></p> <ul style="list-style-type: none"> • Complete installation of selective catalytic reduction (SCR) compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4 as required by the end of 2015 and 2016, respectively.

<p>8d.</p>	<p><u>Cholla Unit 4</u></p> <ul style="list-style-type: none"> • Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency’s Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives in the 2013 IRP Update.
<p>Action Item</p>	<p style="text-align: center;">9. Transmission Actions</p>
<p>9a.</p>	<p><u>System Operational and Reliability Benefits Tool (SBT)</u></p> <ul style="list-style-type: none"> • 60 days after filing the 2013 IRP, establish a stakeholder group and schedule workshops to further review the System Benefit Tool (SBT). <ul style="list-style-type: none"> – For the 2013 IRP Update, complete additional analysis of the Energy Gateway West Segment D that evaluates staging implementation of Segment D by sub-segment. – In preparation for the 2015 IRP, continue to refine the SBT for Energy Gateway West Segment D and develop SBT analyses for additional Energy Gateway segments.
<p>9b.</p>	<p><u>Energy Gateway Permitting</u></p> <ul style="list-style-type: none"> • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: <ul style="list-style-type: none"> – Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – Segment D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach projected through the next 2 to 4 years. – Segment H Cascade Crossing, complete benefits analysis in 2013. – Segment H Boardman to Hemingway, continue to support the project under the conditions of the Boardman to Hemingway Transmission. Project Joint Permit Funding Agreement, projected through 2015.
<p>9c.</p>	<p><u>Sigurd to Red Butte 345 kilovolt Transmission Line</u></p> <ul style="list-style-type: none"> • Complete project construction per plan.
<p>Action Item</p>	<p style="text-align: center;">10. Planning Reserve Margin Actions</p>
<p>10a.</p>	<p><u>Planning Reserve Margin</u></p> <ul style="list-style-type: none"> • Continue to evaluate in the 2015 IRP the results of a System Optimizer portfolio sensitivity analysis comparing a range of planning reserve margins considering both cost and reliability impacts of different levels of planning reserve

	margin assumptions. Complete for the 2015 IRP an updated planning reserve margin analysis that is shared with stakeholders during the public process.
Action Item	11. Planning and Modeling Process Improvement Actions
11a.	<p><u>Modeling and Process</u></p> <ul style="list-style-type: none"> • Within 90 days of filing the 2013 IRP, schedule an IRP workshop with stakeholders to discuss potential process improvements that can more efficiently achieve meaningful cost and risk analysis of resource plans in the context of the IRP and implement process improvements in the 2015 IRP.
11b.	<p><u>Cost/Benefit Analysis of DSM Resource Alternatives</u></p> <ul style="list-style-type: none"> • Complete a cost/benefit analysis on the level of detail used to evaluate prospective DSM resources in the IRP. The analysis will consider the tradeoffs between model run-time and resulting resource selections, will be shared with stakeholders early in the 2015 IRP public process, and will inform how prospective DSM resources will be aggregated in developing resource portfolios for the 2015 IRP.

CHAPTER 2 – INTRODUCTION

PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. This IRP, the 12th plan submitted, fulfills the Company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. It was developed through a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties. As the owner of the IRP and its action plan, all policy judgments and decisions concerning the IRP are ultimately made by PacifiCorp in light of its obligations to its customers, regulators, and shareholders.

This IRP also builds on PacifiCorp's prior resource planning efforts and reflects continued advancements in portfolio modeling and analytical methods. These advancements include:

- Implementation of the Enterprise Production Model (EPM) interface, combining the functionality of System Optimizer and Planning and Risk components into a single model;
- Integration of Energy Gateway transmission investments into the portfolio modeling process;
- Introduction of the System Operational and Reliability Benefits Tool (SBT) to complement IRP modeling for a more complete picture of transmission costs and benefits of each IRP scenario;
- Enhancements to new resource modeling in System Optimizer resulting in improvement to resource selection, including modeling of environmental investments required to achieve compliance with known and prospective environmental regulations at existing coal resources, and increased granularity in the definition of bundle price breakpoints for energy efficiency measures;
- Addition of core case resource portfolios that assume accelerated acquisition of energy efficiency resources; and
- Use of the Renewable Portfolio Standard Scenario Maker, a new Excel spreadsheet tool for developing RPS-compliant renewable resource schedules.

Significant studies conducted to support the IRP include:

- An update of the 2010 demand-side management (DSM) and dispersed generation potentials study;
- An update of the 2011 loss of load study for determining an adequate capacity planning reserve margin for load and resource balance development;
- A state-of-the-art wind integration study;
- Market reliance scenario analysis; and
- Evaluation of price hedging strategies.

Finally, this IRP reflects continued alignment efforts with the Company's annual ten-year business planning process. The purpose of the alignment, initiated in 2008, is to:

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

The planning alignment strategy also follows the 2008 adoption of the IRP portfolio modeling and analysis approach for requests for proposals (RFP) bid evaluation. This latter initiative was part of PacifiCorp’s effort to unify planning and procurement under the same analytical framework. The Company used this analytical framework for bid evaluation in support of the all-source RFP reactivated in December 2009.

This chapter outlines the components of the 2013 IRP, summarizes the role of the IRP, and provides an overview of the public process.

2013 Integrated Resource Plan Components

The basic components of PacifiCorp’s 2013 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 (this chapter).
- An assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3).
- A description of PacifiCorp’s transmission planning efforts and description of IRP modeling studies conducted to support Energy Gateway transmission financial evaluation (Chapter 4).
- A resource needs assessment covering the Company’s load forecast, status of existing resources, and determination of the load and energy positions for the 10-year resource acquisition period (Chapter 5).
- A profile of the resource options considered for addressing future capacity and energy deficits (Chapter 6).
- A description of the IRP modeling, risk analysis, and portfolio performance assessment processes (Chapter 7).
- Presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp’s preferred portfolio (Chapter 8).
- An IRP action plan linking the Company’s preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource risks (Chapter 9).

The IRP appendices, included as a separate volume, comprised of a detailed load forecast report (Appendix A), fulfillment of IRP regulatory compliance requirements, (Appendix B), the public

input process (Appendix C), energy efficiency modeling (Appendix D), conservation voltage reduction and voltage optimization projects update (Appendix E), flexible resource needs assessment (Appendix F), historical plant water consumption data (Appendix G), 2012 wind integration cost study (Appendix H), 2012 stochastic loss of load study (Appendix I), an assessment of resource adequacy for western power markets, including a market reliance “stress” scenario analysis (Appendix J), detailed capacity expansion tables (Appendix K), stochastic simulation results (Appendix L), case study fact sheets (Appendix M), DSM decrement studies (Appendix N), and wind, and solar peak contributions (Appendix O).

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.”⁶ The main role of the IRP is to serve as a roadmap for determining and implementing the Company’s long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, risk, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting RFP bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp’s preferred portfolio of generation, demand-side, and transmission resources.

While PacifiCorp continues to plan on a system-wide basis, the Company recognizes that new state resource acquisition mandates and policies add complexity to the planning process and present challenges to conducting resource planning on this basis.

Public Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public process allowing stakeholder involvement in all phases of plan development. The Company held 26 public meetings/conference calls during 2012 and early 2013 designed to facilitate information sharing, collaboration, and expectations setting for the IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Table 2.1 lists the public meetings/conferences and major agenda items covered.

⁶ The Public Utility Commission of Oregon and Public Service Commission of Utah 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 Public Service Commission of Utah cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decision-making process.

Table 2.1 – 2013 IRP Public Meetings

Meeting Type	Date	Main Agenda Items
General Meeting	5/7/2012	2013 IRP kickoff meeting
General Meeting	6/20/2012	Demand-side management; portfolio development; wind integration
State Meeting	7/11/2012	Idaho state stakeholder comments
State Meeting	7/12/2012	Wyoming state stakeholder comments
General Meeting	7/13/2012	Portfolio case development; transmission scenarios and benefit analysis
State Meeting	7/19/2012	Oregon state stakeholder comments
State Meeting	7/20/2012	Washington state stakeholder comments
General Meeting	8/2/2012	Conservation voltage reduction; resource adequacy workshop; portfolio case development
General Meeting	8/13/2012	Supply-side resources; renewable portfolio standards; wind integration study
State Meeting	8/14/2012	Utah state stakeholder comments
General Conference Call	8/24/2012	Distributed generation resource assumptions
General Meeting	9/14/2012	Environmental compliance; load forecast; capacity load and resource balance; portfolio case development
General Conference Call	9/24/2012	Planning reserve margins; price curve scenarios and modeling methodology
General Conference Call	10/3/2012	Solar photovoltaic resources
General Meeting	10/24/2012	Utility-scale resource options; wind integration study; planning reserve margin
General Meeting	11/5/2012	Transmission benefit evaluation; stochastic modeling; preferred portfolio selection
General Meeting	11/27/2012	Planning reserve margin; methodology update overview
General Conference Call	12/6/2012	US Environmental Protection Agency and impacts on IRP modeling
General Conference Call	12/14/2012	Smart Grid
General Conference Call	12/18/2012	IRP filing schedule; core case fact sheet and price curve scenario updates
General Meeting	1/31/2013	Core case portfolio results; wind integration study
General Meeting	2/27/2013	Transmission system benefits tool; IRP modeling results update; class 2 DSM supply curves
General Meeting	3/21/2013	Modeling update; draft preferred portfolio
General Meeting	4/5/2013	Draft preferred portfolio; draft action plan
General Meeting (Confidential)	4/17/2013	2013 IRP Confidential Volume 3
General Meeting	4/17/2013	Draft IRP document; sensitivity analysis results

Appendix C provides more details concerning the public meeting process and individual meetings.

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

requests, PacifiCorp has also introduced an additional IRP comments website intended for PacifiCorp's IRP public participants only (<http://www.pacificorp.com/es/irp/irpcomments.html>)

CHAPTER 3 – THE PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- Significantly lower wholesale power prices and natural gas prices in the 2013 IRP than market prices in the 2011 IRP, caused mainly by a decline in forward natural gas prices as a result of the continued growth in prolific shale gas plays in North America and reduced regional loads. Loss of momentum in federal efforts to develop comprehensive federal energy and climate change compliance requirements, leading to continued uncertainty regarding the long-term investment climate for clean energy technologies.
- The U.S. Environmental Protection Agency (EPA) has promulgated new source performance standards to regulate greenhouse gas emissions from new sources, it has not established a schedule to promulgate rules applicable to existing sources. Nevertheless, public and legislative support for clean energy policies at the state level remains robust.
- Aggressive efforts by the EPA to regulate electric utility plant emissions, including greenhouse gases, criteria pollutants and other emissions.
- Near-term procurement activities related to natural gas supply and transportation and Oregon solar resources.

Introduction

This chapter profiles the major external influences that impact PacifiCorp's long-term resource planning as well as recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Sluggish economic growth continues to influence load growth expectations throughout the 2013 IRP planning cycle. In light of current economic conditions, the Company continues to evaluate capital projects for least cost adjusted for risk resources based on known and measurable compliance requirements.

Concerning the power industry marketplace, the major issues addressed include capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). 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, a significant issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter focuses on climate change regulatory initiatives, particularly at the state level. A high-level summary of the Company's greenhouse gas emissions mitigation strategy, as well as an overview of the Electric Power Research Institute's study on carbon dioxide price impacts on

western power markets, follows. This chapter also reviews the significant policy developments for currently-regulated pollutants

Other topics covered in this chapter include regulatory updates on the Environmental Protection Agency, regional and state climate change regulation, the status of renewable portfolio standards, and resource procurement activities.

Wholesale Electricity Markets

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

PacifiCorp participates in the wholesale market in this fashion, making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on time scales ranging from hourly to years in advance. Without the wholesale market, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supplies that would go unutilized in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand. The market is not without its risks, as the experience of the 2000-2001 market crisis, followed by the rapid price escalation during the first half of 2008 and subsequent demand destruction and rapid price declines in the second half of 2008, have underscored. Unanticipated paradigm shifts in the market place can also cause significant changes in market prices as evidenced by advancements in the ability of natural gas producers to cost-effectively access abundant shale gas supplies over the past several years.

As with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. For example, WECC publishes an annual assessment of power supply and any number of data services are available that track the status of new resource additions. A review of the WECC power supply assessments is provided in Appendix J. The latest assessment, published in October 2012, indicates that with the exception of Northern and Southern California, US WECC has adequate resources through 2022. If only existing units and those under construction are considered, then Northern and Southern California will need capacity in 2015 and 2017, respectively.

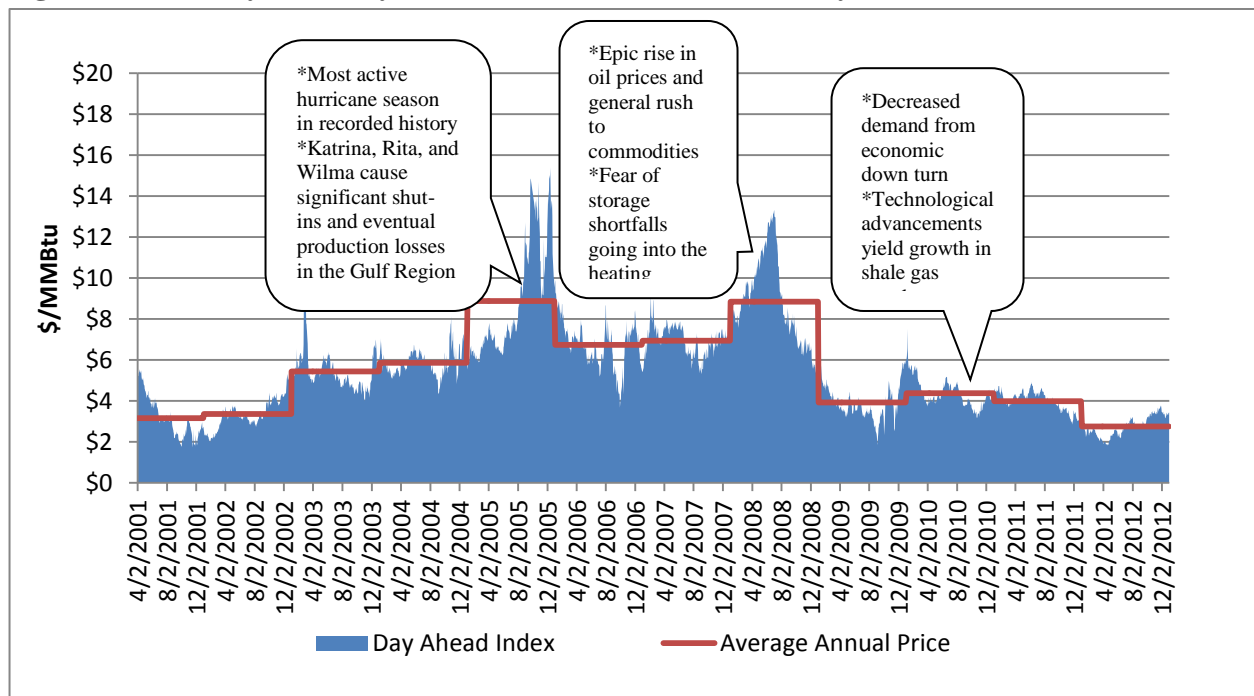
There are other uncertainties that are more difficult to analyze and that possess heavy influence on the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Given the increased role of natural gas-fired generation, gas prices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

consequently, future electricity prices. Each of these uncertainties is explored in the cases developed for this IRP and are discussed in more detail below.

Natural Gas Uncertainty

Over the last twelve years, North American natural gas markets have demonstrated exceptional price volatility. Figure 3.1 shows historical day-ahead prices at the Henry Hub benchmark from April 2, 2001 through December 28, 2012. Over this period, day-ahead gas prices settled at a low of \$1.72 per million British thermal units (MMBtu) on November 16, 2001 and at a high of \$18.41 per MMBtu on February 25, 2003. During the fall and early winter of 2005, prices breached \$15 per MMBtu after a wave of hurricanes devastated the gulf region in what turned out to be the most active hurricane season in recorded history. Prices later topped \$13 per MMBtu in the summer of 2008 when oil prices began their epic climb above \$140 per barrel in the months preceding the global credit crisis. By early 2009 slow economic growth coupled with abundant shale gas supplies pressured natural gas prices to dip below \$5 per MMBtu; day-ahead prices averaged \$3.92 per MMBtu for 2009. Prices rose modestly and then ticked down with day-ahead natural gas prices averaging \$4.37, \$3.99, and \$2.75 per MMBtu for 2010 through 2012, respectively. Today’s natural gas prices are not adequate to incent new drilling; the continued supply of natural gas is a result of improvements in well productivity, production from wells being “held by production”, and large amounts of price insensitive dry gas produced as a byproduct in wet gas and shale oil plays.

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

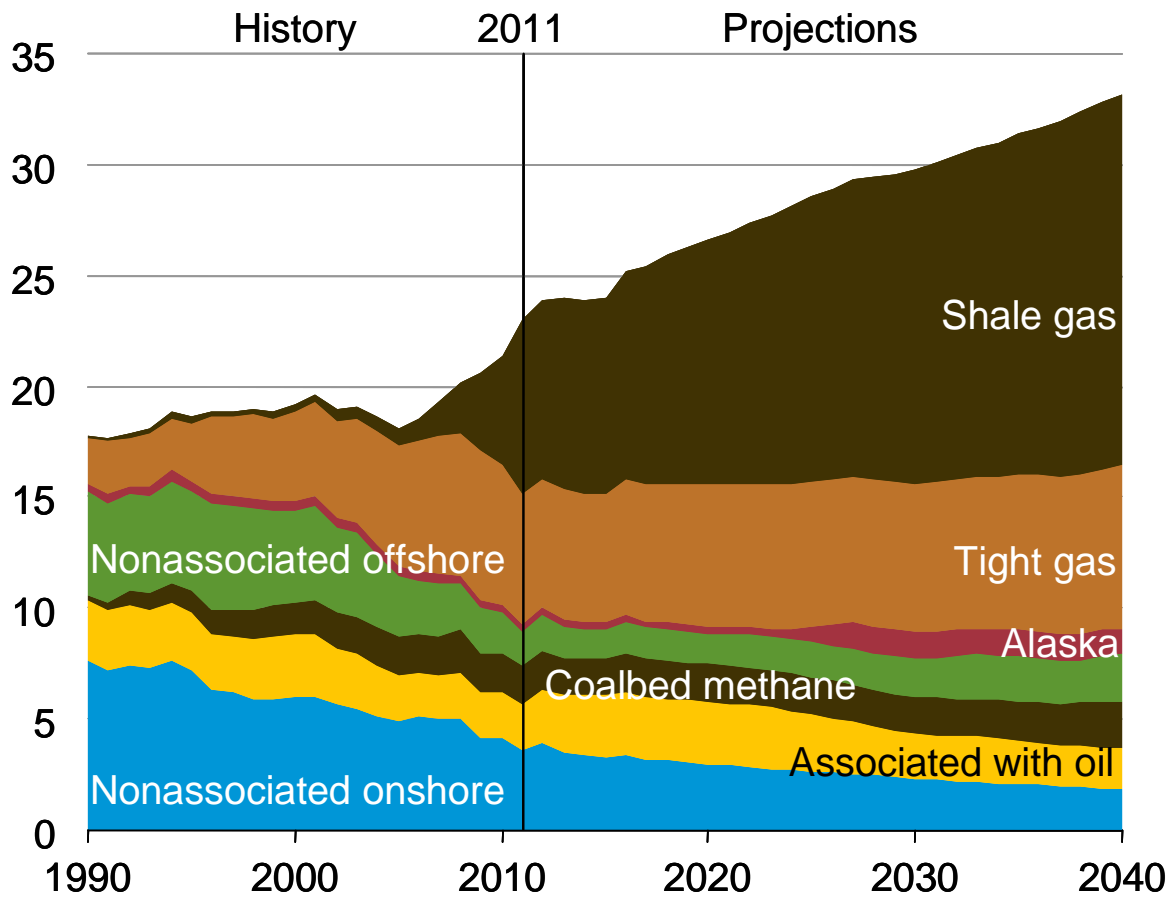


Source: Intercontinental Exchange (ICE), Over the Counter Day-ahead Index

Beyond the geopolitical, extreme weather, and economic events that spawned day-ahead prices above \$13 per MMBtu, as recently as summer 2008, natural gas prices have exhibited an upward trend from approximately \$3 per MMBtu in 2002 to nearly \$9 per MMBtu in 2008 followed by a downward trend starting 2009. Over much of the former period, declining volumes from

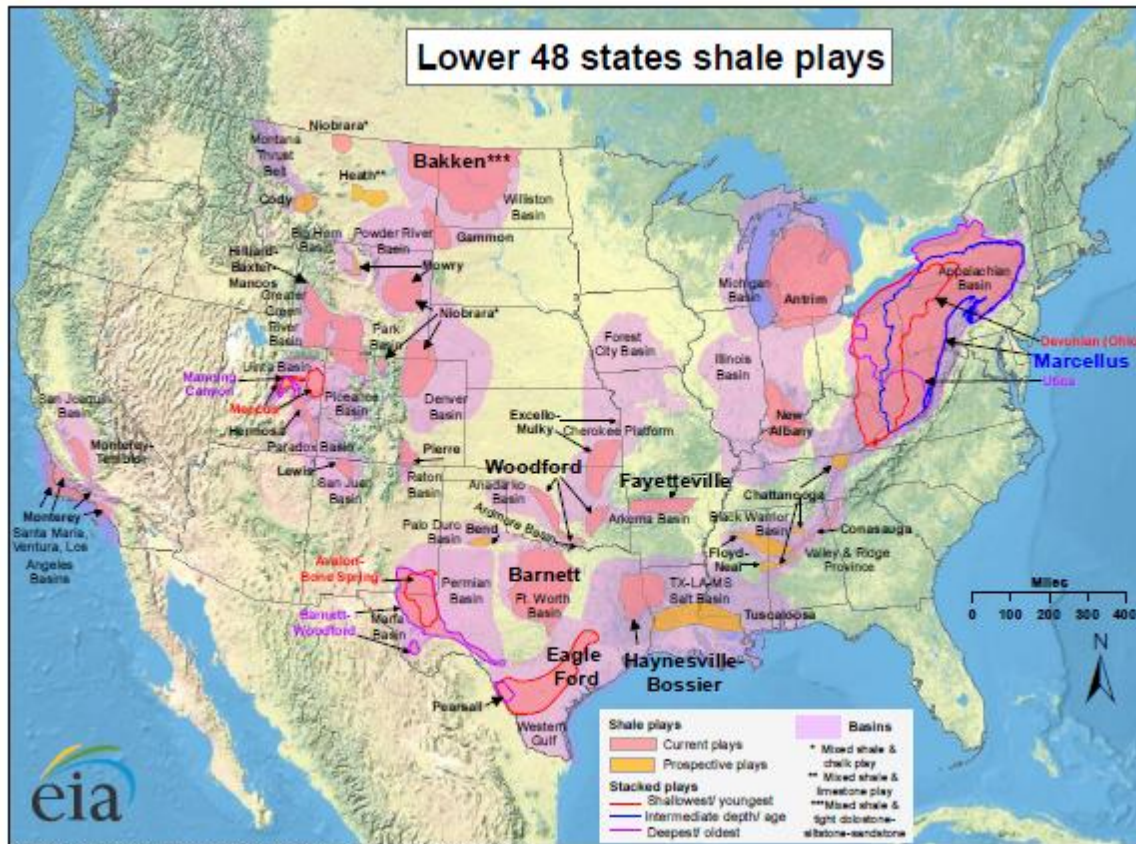
conventional, mature producing regions largely offset growth from unconventional resources. However, prices in 2009 through 2012 reflect reduced demand and significant production gains from unconventional domestic supplies such as tight and shale gas. Figure 3.2 shows a breakdown of U.S. supply; Figure 3.3 illustrates the shale plays in the lower 48 states.

Figure 3.2 - U.S. Dry Natural Gas Production (TCF) by Source



Source: U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2013, Early Release, December 5, 2012.

Figure 3.3 – Shale Plays in Lower 48 States



Source: Energy Information Administration based on data from various published studies. Updated: May 9, 2011

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

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

Prior to 2009, forecasters expected that a gradual restoration of improved supply/demand balance would be achieved largely with growth in liquefied natural gas (LNG) imports. Indeed, there has been tremendous growth in global liquefaction facilities located in major producing regions. This expectation led to significant investments in regasification capacity to accommodate the need for future LNG imports. However, the evolution of unconventional supplies and continually growing estimates of shale gas reserves has significantly changed the need for LNG imports. Today, liquefaction, not regasification, facilities are being proposed with one having already been approved. As such, the U.S. is anticipated to export 0.6 billion cubic feet per day (BCF/D) by 2016 reaching 4.5 BCF/D by 2027. Several factors contribute to a wide range of price uncertainty in the mid- to long-term. Supporting downside price risk, technological

advancements underlying the recent expansion of unconventional supplies opens the door to tremendous growth potential in both production and proven reserves from shale formations across North America. Increasing well productivity, technological innovations, and large volumes of price insensitive associated gas have flattened the supply curve. In the long-term, moderated oil prices from large oil shale finds could dampen demand for LNG exports and for oil-to-gas substitution in the transportation sector. Supporting upside price risk, the next generation of unconventional supplies may prove to be more difficult or costly to extract with the possibility of drilling restrictions due to environmental concerns associated with hydraulic fracturing, which would raise marginal costs, and consequently, raise prices. In addition, high oil prices could incent increased LNG exports and increased oil-to-gas substitution in the transportation sectors.

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

The Future of Federal Environmental Regulation and Legislation

PacifiCorp faces a continuously-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. PacifiCorp monitors these regulations to determine the potential impact on the company's generating assets and participates in the rulemaking process by filing comments on various proposals and participating in scheduled hearings to provide the company's assessment on such proposals.

Timing of Environmental Protection Agency (EPA) Regulation

The U.S. EPA has undertaken a multi-pronged approach to minimize air, land, and water-based environmental impacts. Many environmental regulations from the EPA are in various parallel stages of development. Even in cases where the EPA has established deadlines for proposal or finalization of a rule, these deadlines are frequently extended, making it difficult to determine not only the final outcome of a rule, but when it may ultimately impact the Company.

Aside from potential greenhouse gas regulations, few of the environmental regulations under consideration are likely to materially impact the industry in isolation; in aggregate, however, they are expected to have a significant impact – especially on the coal-fueled generating units that supply approximately 42 percent of the nation's electricity. As such, each of these regulations will have a significant impact on the utility industry and could affect environmental

control requirements, limit operations, change dispatch, and could ultimately determine the economic viability of PacifiCorp’s coal-fueled generation assets.

Federal Climate Change Legislation

PacifiCorp continues to evaluate the potential impact of climate change legislation at the federal level. The impact of a given legislative proposal varies significantly depending on its selection of key design criteria (i.e., level of emissions cap, rate of decline of the cap, the use of carbon offsets, allowance allocation methodology, the use of safety valves, and etc.) and macro-economic assumptions (i.e., electricity load growth, fuel prices – especially natural gas, commodity prices, new technologies, etc.).

To date, no federal legislative climate change proposal has successfully been passed by both the U.S. House of Representatives and the U.S. Senate for consideration by the President. The two most prominent legislative proposals introduced for attempted passage through Congress have been the Waxman-Markey bill in 2009 and the Kerry-Lieberman bill in 2010; neither measure was able to accumulate enough support to pass.

In the 112th Congress, several bills were introduced designed to limit, remove, or suspend EPA’s asserted regulatory authority over greenhouse gases, none of which were successful. In the President’s State of the Union Address, the 113th Congress was challenged by the President to pursue a bipartisan, market-based solution to climate change, indicating if Congress did not act soon, the President would direct his Cabinet to implement executive action to reduce greenhouse gas emissions. On February 14, 2013, Senators Bernie Sanders and Barbara Boxer introduced climate legislation, the Climate Protection Act of 2013, which would, among other things, impose a carbon fee of 20 dollars per ton on coal, petroleum and natural gas producers beginning in 2014.

EPA Regulatory Update – Greenhouse Gas Emissions

In conjunction with its greenhouse gas endangerment finding in 2009, the EPA has aggressively pursued the regulation of greenhouse gas (GHG) emissions. Key recent initiatives include the following:

New Source Review / Prevention of Significant Deterioration (NSR / PSD)

On May 13, 2010, the EPA issued a final rule that addresses GHG emissions from stationary sources under the Clean Air Act (CAA) permitting programs, known as the “tailoring” rule. This final rule sets thresholds for GHG emissions that define when permits under the New Source Review (NSR) / Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs are required for new and existing industrial facilities. This final rule “tailors” the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. The rule also establishes a schedule that will initially focus CAA permitting programs on the largest sources with the most CAA permitting experience. Finally, the rule expands to cover the largest sources of GHGs that may not have been previously covered by the CAA for other pollutants.

Guidance for Best Available Control Technology (BACT)

On November 10, 2010, the EPA published a set of guidance documents for the tailoring rule to assist state permitting authorities and industry permitting applicants with the Clean Air Act PSD and Title V permitting for sources of GHGs. Among these publications was a general guidance document entitled “PSD and Title V Permitting Guidance for Greenhouse Gases,” which included a set of appendices with illustrative examples of Best Available Control Technology (BACT) determinations for different types of facilities, which are a requirement for PSD permitting. The EPA also provided white papers with technical information concerning available and emerging GHG emission control technologies and practices, without explicitly defining BACT for a particular sector. In addition, the EPA has created a “Greenhouse Gas Emission Strategies Database,” which contains information on strategies and control technologies for GHG mitigation for two industrial sectors: electricity generation and cement production.

The guidance does not identify what constitutes BACT for specific types of facilities, and does not establish absolute limits on a permitting authority’s discretion when issuing a BACT determination for GHGs. Instead, the guidance emphasizes that the five-step top-down BACT process for criteria pollutants under the CAA generally remains the same for GHGs. While the guidance does not prescribe BACT in any area, it does state that GHG reduction options that improve energy efficiency will be BACT in many or most instances because they cost less than other environmental controls (and may even reduce costs) and because other add-on controls for GHGs are limited in number and are at differing stages of development or commercial availability. Utilities have remained very concerned about the NSR implications associated with the tailoring rule (the requirement to conduct BACT analysis for GHG emissions) because of great uncertainty as to what constitutes a triggering event and what constitutes BACT for GHG emissions.

New Source Performance Standards (NSPS) for Greenhouse Gases

On December 23, 2010, in a settlement reached with several states and environmental groups in *New York v. EPA*, the EPA agreed to promulgate emissions standards covering GHGs from both new and existing electric generating units under Section 111 of the CAA by July 26, 2011 and issue final regulations by May 26, 2012.⁷ NSPS are established under the CAA for certain industrial sources of emissions determined to endanger public health and welfare and must be reviewed every eight years. While NSPS were intended to focus on new and modified sources and effectively establish the floor for determining what constitutes BACT, the emission guidelines will apply to existing sources as well. In April 2012, the EPA proposed a NSPS for new fossil-fueled generating facilities that would limit emissions of carbon dioxide to 1,000 pounds per megawatt hour (MWh). The proposal exempted simple cycle combustion turbines from meeting the standards. The public comment period closed in June 2012 and a final rule is expected by April 2013. While the EPA is also under a consent decree obligation to establish GHG NSPS for modified and existing sources, EPA has indicated it has not established a schedule for doing so.

⁷ The deadlines for EPA to take proposed and final actions have since been extended. EPA also entered into a similar settlement the same day to address greenhouse gas emissions from refineries with proposed regulations by December 15, 2011 and final regulations by November 15, 2012.

The emissions guidelines issued by the EPA will be used by states to develop plans for reducing emissions and include targets based on demonstrated controls, emission reductions, costs and expected timeframes for installation and compliance, and may be less stringent than the requirements imposed on new sources. States must submit their plans to the EPA within nine months after the guidelines' publication unless the EPA establishes a different schedule. States have the ability to apply less stringent standards or longer compliance schedules if they demonstrate that following the federal guidelines is unreasonably cost-prohibitive, physically impossible, or that there are other factors that reasonably preclude meeting the guidelines. States may also impose more stringent standards or shorter compliance schedules.

EPA Regulatory Update – Non-Greenhouse Gas Emissions

Several categories of EPA regulations for non-GHG emissions are discussed below:

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

Currently, PacifiCorp's generation units must comply with the federal CAA, which is implemented by the States subject to EPA approval and oversight. The CAA requires the EPA to set National Ambient Air Quality Standards (NAAQS) for certain pollutants considered harmful to public health and the environment. For a given NAAQS, the EPA and/or a state identifies various control measures that once implemented are meant to achieve an air quality standard for a certain pollutant, with each standard rigorously vetted by the scientific community, industry, public interest groups, and the general public.

Particulate matter (PM), sulfur dioxide (SO₂), ozone (O₃), nitrogen dioxide (NO₂), carbon monoxide (CO), and lead are often grouped together because under the CAA, each of these categories is linked to one or more National Ambient Air Quality Standards (NAAQS). These "criteria pollutants", while undesirable, are not toxic in typical concentrations in the ambient air. Under the CAA, they are regulated differently from other types of emissions, such as hazardous air pollutants and greenhouse gases.

Within the past few years, the EPA established new standards for particulate matter, sulfur dioxide, and nitrogen dioxide. While the EPA had proposed to implement new ozone standards in 2011, it was determined that the standards should be deferred until the next regularly scheduled review in 2013.

Clean Air Transport Rule

In July 2009, EPA proposed its Clean Air Transport Rule (Transport Rule), which would require new reductions in SO₂ and nitrogen oxide (NO_x) emissions from large stationary sources, including power plants, located in 31 states and the District of Columbia beginning in 2012. The Transport Rule was intended to help states attain NAAQS set in 1997 for ozone and fine particulate matter emissions. The rule replaced the Bush administration's Clean Air Interstate Rule (CAIR), which was vacated in July 2008 and rescinded by a federal court because it failed to effectively address pollution from upwind states that is hampering efforts by downwind states to comply with ozone and PM NAAQS. While the rule was finalized as the Cross-State Air Pollution Rule (CSAPR) in July 2011, litigation in the D.C. Circuit Court of Appeals resulted in a stay on the implementation of the CSAPR in December 2011; Ultimately, in August 2012, the

D.C. Circuit Court of Appeals vacated the CSAPR in a 2-1 decision after it determined the rule exceeded the EPA's statutory authority. The EPA sought a full review of the CSAPR ruling by the entire D.C. Circuit; however, in January 2013, the court denied the request. Until a replacement rule is adopted and implemented, the CAIR remains in place.

PacifiCorp does not own generating units in states identified by the CAIR or CSAPR and thus will not be directly impacted; however, the Company intends to monitor amendments to these rules closely in the event that the scope of a replacement rule extends the geographic scope of impacted states.

Regional Haze

EPA's rule to address Regional Haze visibility concerns will drive additional NO_x reductions particularly from facilities operating in the Western United States, including the states of Utah and Wyoming where PacifiCorp operates generating units and Arizona, where PacifiCorp owns a generating unit subject to the Regional Haze Rule. Unlike CAIR or CSAPR, which have no direct impact on PacifiCorp's states with generation, the finalized Regional Haze regulatory activity will have an impact.

On June 15, 2005, EPA issued final amendments to its July 1999 Regional Haze rule. These amendments apply to the provisions of the Regional Haze rule that require emission controls known as Best Available Retrofit Technology (BART), for industrial facilities meeting certain regulatory criteria that with emissions that have the potential to impact visibility. These pollutants include PM_{2.5}, NO_x, SO₂, certain volatile organic compounds, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART as well as establishing BART emissions limits for those facilities.

The state of Utah issued a regional haze state implementation plan (SIP) requiring the installation of SO₂, NO_x and particulate matter (PM) controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO₂ portion of the Utah Regional Haze SIP and disapproved the NO_x and PM portions. Certain groups have appealed the EPA's approval of the SO₂ SIP. The date for appealing the disapproval of the NO_x and PM portions of the SIP is March 25, 2013. In addition, and separate from the EPA's approval process and related litigation, the Utah Division of Air Quality is undertaking an additional BART analysis for each of Hunter Units 1 and 2 and Huntington Units 1 and 2, which will be provided to the EPA as a supplement to the existing Utah SIP. It is unknown whether and how the Utah Division of Air Quality's supplemental analysis will impact the EPA's approval and disapproval of the existing SIP.

In Wyoming, the state issued two regional haze SIPs requiring the installation of SO₂, NO_x and PM controls on certain PacifiCorp coal-fueled generating facilities in Wyoming. The EPA approved the SO₂ SIP in December 2012, but initially proposed to disapprove portions of the NO_x and PM SIP and instead issue a federal implementation plan (FIP). The EPA proposed to approve the installation of selective catalytic reduction (SCR) equipment and a baghouse at Naughton Unit 3 by December 31, 2014; to approve the installation of SCR equipment at Jim Bridger Unit 3 by December 31, 2015; and to approve the installation of SCR equipment at Jim

Bridger Unit 4 by December 31, 2016. The EPA proposed to disapprove the NO_x and PM SIP for Jim Bridger Units 1 and 2 and instead accelerate the installation of SCR equipment to 2017 from 2021 and 2022, but agreed to accept comment on maintaining the original schedule as the state proposed. In addition, the EPA proposed to reject the SIP for the Wyodak facility and Dave Johnston Unit 3 and require the installation of selective non-catalytic reduction (SNCR) equipment within five years, as well as require the installation of low-NO_x burners and overfire air systems at Dave Johnston Units 1 and 2. Since the EPA's initial proposal, which was to have been final in October 2012 and was extended to December 2012, the EPA has withdrawn its proposed action on the SIP and its proposed FIP and has indicated its intent to re-propose action on the Wyoming NO_x and PM SIP by March 29, 2013, and take final action by September 27, 2013. In the meantime, certain groups have appealed the EPA's approval of the Wyoming SO₂ SIP which, consistent with the Utah SO₂ SIP, required emission reductions of SO₂ to be enforced through a three-state milestone and backstop trading program.

In Arizona, the state issued a Regional Haze SIP requiring, among other things, the installation of SO₂, NO_x and PM controls on Cholla Unit 4, which is owned by PacifiCorp but operated by Arizona Public Service. The EPA approved in part, and disapproved in part, the Arizona SIP and issued a FIP for the disapproved portions. PacifiCorp filed an appeal in the Ninth Circuit Court of Appeals regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests.

Other cases are pending before the Tenth Circuit Court of Appeals with regard to similar appeals of FIPs issued by the EPA in New Mexico and Oklahoma.

Mercury and Hazardous Air Pollutants

In March 2005, the EPA issued the Clean Air Mercury Rule (CAMR) to permanently limit and reduce mercury emissions from coal-fired power plants under a market-based cap-and-trade program. However, the CAMR was vacated in February 2008, with the court finding the mercury rules inconsistent with the stipulations of Section 112 of the CAA.

The vacated CAMR was replaced by EPA with the more extensive Mercury and Air Toxics Standards (MATS) with an effective date of April 16, 2012. The MATS rule requires that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. While the final MATS requirements continue to be reviewed by PacifiCorp, the Company believes its emission reduction projects completed to date or currently permitted or planned for installation, including the scrubbers, baghouses and electrostatic precipitators required under other EPA requirements, are consistent with achieving the MATS requirements and will support PacifiCorp's ability to comply with the final standards for acid gases and non-mercury metallic hazardous air pollutants. PacifiCorp will be required to take additional actions to reduce mercury emissions through the installation of controls or use of sorbent injection at certain of its coal-fueled generating facilities and otherwise comply with the standards.

PacifiCorp currently anticipates that retiring the Carbon plant in early 2015 will be least-cost alternative to comply with the MATS and other environmental regulations. PacifiCorp continues to assess other issues, such as potential transmission system impacts, that could impact its ultimate decision regarding the Carbon plant, including the timing of retirement and decommissioning.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants.

CCRs are currently considered exempt wastes under an amendment to the Resource Conservation and Recovery Act (RCRA); however, EPA proposed in 2010 to regulate CCRs for the first time. EPA is considering two possible options for the management of CCRs. Both options fall under the RCRA. Under the first option, EPA would list these residual materials as special wastes subject to regulation under Subtitle C of RCRA with requirements from the point of generation to disposition including the closure of disposal units. Under the second option, EPA would regulate coal combustion residuals as nonhazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of coal combustion residuals. Under either option for regulation, surface impoundments utilized for coal combustion byproducts would have to be closed unless they could meet more stringent regulatory requirements. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts.

While the public comment period on EPA's proposal to regulate coal combustion byproducts closed in November 2010, the EPA has not indicated when the rule will be finalized, and the substance of the final rule is not known. In briefs filed in litigation pending in the D.C. Circuit Court of Appeals to force the EPA to meet a deadline to issue final coal combustion byproduct rules, the EPA indicated it needs until at least 2014 to review comments, formulate a risk assessment and coordinate the rule with the effluent limit guidelines discussed herein.

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new technology-based performance standards for existing electricity generating facilities that take in more than 50 million gallons of water per day. These rules were aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the Court of Appeal for the Second Circuit remanded almost all aspects of the rule to the EPA without addressing whether companies with cooling water intake structures were required to comply with these requirements. On appeal from the Second Circuit, in April 2009, the U.S. Supreme Court ruled that the EPA permissibly relied on a cost-benefit analysis in setting the national performance standards regarding best technology available for minimizing

adverse environmental impact at cooling water intake structures and in providing for cost-benefit variances from those standards as part of the §316(b) Clean Water Act Phase II regulations. The Supreme Court remanded the case back to the Second Circuit Court of Appeals to conduct further proceedings consistent with its opinion.

In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The proposed rule establishes requirement for electric generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the U.S. and use at least 25 percent of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the U.S. Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers but withdraw more than two million gallons of water per day. The proposed rule includes impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards to be met through average impingement mortality or intake velocity design criteria and entrainment (i.e., when organisms are drawn into the facility) standards to be determined on a case-by-case basis. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. While the rule was required to be finalized by the EPA by July 2012, the deadline for finalizing the rule was extended to June 2013. Assuming the final rule is issued by June 2013, PacifiCorp's generating facilities impacted by the final rule will be required to complete impingement and entrainment studies in 2014.

Effluent Limit Guidelines

EPA first issued effluent guidelines for the Steam Electric Power Generating Point Source Category (i.e., the Steam Electric effluent guidelines) in 1974 with subsequent revisions in 1977 and 1982. The EPA is currently under a deadline of April 19, 2013 to propose revised effluent limit guidelines and sent the proposed rulemaking package to the Office of Management and Budget for interagency review in January 2013. The EPA is required, under the terms of a stipulated extension to a consent decree, to finalize the rule by May 2014. While the EPA has indicated that the growing use of flue-gas desulfurization systems has increased the amount of toxic metals discharged from power plants, until the required technology-based effluent limitations and standards are proposed and finalized, PacifiCorp cannot determine the potential impact of the rules on its facilities. In addition, the effluent limit guidelines will apply to gas-fired generation.

State Climate Change Regulation

While national greenhouse gas legislation has yet to be successfully adopted, state initiatives continue with the active development of climate change regulations that will impact PacifiCorp.

California

An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. In 2006, the California Legislature passed and Governor Schwarzenegger signed Assembly Bill 32, the Global Warming Solutions Act of 2006, which set the 2020 greenhouse gas emissions reduction goal into law. It directed the California Air Resources Board to begin

developing discrete early actions to reduce greenhouse gases while also preparing a scoping plan to identify how best to reach the 2020 limit.

Pursuant to the authority of the Global Warming Solutions Act, in October 2011, the California Air Resources Board adopted a greenhouse gas cap-and-trade program with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of greenhouse gas allowances was held in California in November 2012 and the second auction in February 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances, and purchase the required amount of allowances necessary to meet its compliance obligations.

Oregon and Washington

In 2007, the Oregon Legislature passed HB 3543 Global Warming Actions which establishes greenhouse gas reduction goals for the state that (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75 percent below 1990 levels. In 2009, the Legislature passed SB 101 which requires the Public Utility Commission of Oregon (OPUC) to report to the Legislature before November 1 of each even-numbered year on the estimated rate impacts for Oregon's regulated electric and natural gas companies associated with meeting the greenhouse gas reduction goals of 10 percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2012.

During the 2013 session, the Oregon Legislature is considering a number of bills relating to the implementation of a carbon tax; it is unknown whether those bills will be passed. In addition, Oregon is considering the viability of establishing a voluntary greenhouse gas emission program that would allow utilities to consider alternative forms of regulation designed to lower greenhouse gas emissions.

In 2008, the Washington State Legislature approved the Climate Change Framework E2SHB 2815, which establishes state greenhouse gas emissions reduction limits. Washington's emission limits are to (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25 percent below 1990 levels; and (iii) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050. In the 2013 session, the Washington Legislature is considering a bill that would develop recommendations to achieve the state's greenhouse gas emission limits.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted greenhouse gas emission performance standards applicable to all electricity generated within the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility. The standards are currently set at 1,100 pounds of carbon dioxide equivalent per MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based upon their global warming potential. The Washington Department of Commerce is pursuing a rulemaking process to lower the emissions performance standard; while the rulemaking is not yet final, the Department of Commerce most

recently proposed an emission performance standard of 970 pounds of carbon dioxide per MWh. Efforts are also underway in Oregon to effectuate changes to the state’s emission performance standard to broaden its applicability.

Renewable Portfolio Standards

A renewable portfolio standard (RPS) requires each retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind, geothermal and solar energy. The retailer can satisfy this obligation by using renewable energy from its own facility, purchasing renewable energy from someone else's facility, using renewable energy credits (RECs) which certify renewable energy has been created, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their requirements with respect to timeframe, resource eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and whether they allow REC trading. By the end of 2012, twenty-nine states, the District of Columbia and two territories had adopted a mandatory RPS, eight states and two territories had adopted RPS goals.⁸

Within PacifiCorp’s service territory, California, Oregon, and Washington have adopted a mandatory RPS and Utah has adopted an RPS goal. Each of these states’ legislation and requirements are summarized in Table 3.1, with additional discussion below.

Table 3.1 – State RPS Requirements

	CA	OR	WA	UT
Legislation	<ul style="list-style-type: none"> Senate Bill 1078 (2002) Assembly Bill 200 (2005) Senate Bill 107 (2006) Senate Bill 2 First Extraordinary Session (2011) 	<ul style="list-style-type: none"> Senate Bill 838, Oregon Renewable Energy Act (2007) House Bill 3039 (2009) 	<ul style="list-style-type: none"> Initiative Measure No. 937 (2006) 	<ul style="list-style-type: none"> Senate Bill 202 (2008)
Requirement or Goal	<ul style="list-style-type: none"> 20% by 2010 Average of 20% through 2013 25% by December 31, 2016 33% by December 31, 2020 and beyond Based on the retail load for that compliance period 	<ul style="list-style-type: none"> At least 5% of load by December 31, 2014 At least 15% by December 31, 2019 At least 20% by December 31, 2024 At least 25% by December 31, 2025 and thereafter Based on the retail load for that year Invest in 20 MW solar by January 1, 2020 -- PGE, PacifiCorp and Idaho Power combined 	<ul style="list-style-type: none"> At least 3% of load by January 1, 2012 At least 9% by January 1, 2016 At least 15% by January 1, 2020 Annual targets are based on the average of the utility’s load for the previous two years 	<ul style="list-style-type: none"> Goal of 20% by 2025 (must be cost effective) Annual targets are based on the adjusted retail sales for the calendar year 36 month prior to the target year Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture sequestration and DSM

⁸ Database of State Incentives for Renewables & Efficiency (DSIRE)

California

California originally established its RPS program with passage of Senate Bill 1078 in 2002. There have been several bills that have since been passed into law to amend the program. In the 2011 1st Extraordinary Special Session, the California Legislature passed Senate Bill 2⁹ (SB 2 (1x)) to increase California’s RPS to 33 percent by 2020. SB 2 (1x) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities, and established the following targets for renewable procurement based on retail load:

- Extends the current 2010 mandate of procuring 20 percent of electricity from renewable resources out to December 31, 2013;
- Requires 25 percent of electricity to come from renewable resources by December 31, 2016; and,
- Requires 33 percent of electricity to come from renewable resources by December 31, 2020, and each year thereafter.

Qualifying renewable resources include solar thermal electric, photovoltaic, landfill gas, wind, biomass, geothermal, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. The RECs must be certified as eligible for the California RPS by the California Energy Commission and tracked in the Western Renewable Energy Generation Information System (WREGIS).

In addition to increasing the target from 20 percent in 2010 to 33 percent in 2020 and each year thereafter, SB 2 (1x) also created multi-year compliance periods. The California Public Utilities Commission approved the methodology for calculating the multi-year compliance periods and years thereafter; this is provided below in Table 3.2.

Table 3.2 – California Compliance Period Requirements

California RPS Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1: 2011-2013	20% * 2011 Retail Sales + 20% * 2012 Retail Sales + 20% * 2013 Retail Sales
Compliance Period 2: 2014-2016	21.7% * 2014 Retail Sales + 23.3% * 2015 Retail Sales + 25% * 2016 Retail Sales
Compliance Period 3: 2017-2020	27% * 2017 Retail Sales + 29% * 2018 Retail Sales + 31% * 2019 Retail Sales + 33% * 2020 Retail Sales
2021 and Beyond	33% * Annual Retail Sales

SB 2 (1x) also established new “portfolio content categories” for RPS procurement, which delineated the type of renewable product that may be used for compliance and also set minimum

⁹ http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf

and maximum limits on certain procurement content categories that can be used for compliance. The portfolio content categories pursuant to SB 2 (1x) are described below:

Portfolio Content Category 1 includes energy and RECs that meet either of the following criteria (a) have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source. The use of another source to provide real-time ancillary services required to maintain an hourly or sub-hourly import schedule into a California balancing authority shall be permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource shall count toward this portfolio content category; or (b) have an agreement to dynamically transfer electricity to a California balancing authority.

Portfolio Content Category 2 includes firm and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled¹⁰ renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.

Additionally, the California Public Utilities Commission established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period.

Table 3.3 – California Balanced Portfolio Requirements

California RPS Compliance Period	Balanced Portfolio Requirement
Compliance Period 1: 2011-2013	Category 1 – Minimum of 50% of Requirement Category 3 – Maximum of 25% of Requirement
Compliance Period 2: 2014-2016	Category 1 – Minimum of 65% of Requirement Category 3 – Maximum of 15% of Requirement
Compliance Period 3: 2017-2020	Category 1 – Minimum of 75% of Requirement Category 3 – Maximum of 10% of Requirement

In December 2011, the California Public Utilities Commission adopted a decision confirming that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits within the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the California Public Utilities Commission and annual procurement reports with the California Energy Commission.

¹⁰ A REC can be sold either "bundled" with the underlying energy or "unbundled", as a separate commodity from the energy itself, into a separate REC trading market.

The California Public Utilities Commission is in the process of an extensive rulemaking to implement the remaining requirements under SB 2 (1x).

The full California RPS statute is listed under Public Utilities Code Section 399.11-399.32. Additional information on the California RPS can be found on the California Public Utilities Commission and California Energy Commission websites.

Oregon

Oregon established the Oregon RPS with passage of Senate Bill 838 in 2007. The law, called the Oregon Renewable Energy Act¹¹ was adopted in June 2007 and provides a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least five percent in 2011 through 2014, 15 percent in 2015 through 2019, 20 percent in 2020 through 2024, and 25 percent in 2025 and subsequent years. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation.

Eligible renewable resources include electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, certain types of biomass and biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia. Electricity generated by a hydroelectric facility is eligible, if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

Utilities can bank RECs from qualifying resources beginning January 1, 2007 for the purpose of carrying them forward for future compliance. The RECs must be certified as eligible for the Oregon RPS by the Oregon Department of Energy and tracked in WREGIS.

In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. Qualifying solar photovoltaic systems must be at least 500 kilowatts in capacity with no single project greater than five megawatts of alternating current. Any qualifying solar photovoltaic systems that are online before January 1, 2016 will be credited with two megawatt-hours for every one megawatt-hour generated. The Oregon Public Utility Commission determined that PacifiCorp's share of the Oregon Solar Initiative is 8.7 megawatts.

¹¹ <http://www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf>

PacifiCorp files an annual RPS compliance report by June 1 of every year and in every odd year by January 1 PacifiCorp files a renewable implementation plan. PacifiCorp’s compliance reports and implementation plans are made available on PacifiCorp’s website¹².

The full Oregon RPS statute is listed in Oregon Revised Statutes (ORS) Chapter 469A and the solar capacity standard is listed in ORS Chapter 757. The Public Utility Commission of Oregon rules are included within Oregon Administrative Rules (OAR) Chapter 860 Division 083 for the RPS and OAR Chapter 860 Division 084 for the solar photovoltaic program. The Oregon Department of Energy rules are under OAR Chapter 330 Division 160.

Utah

In March 2008, Utah’s governor signed Utah Senate Bill 202¹³, “Energy Resource and Carbon Emission Reduction Initiative;” legislation. Among other things, this law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Eligible renewable resources include electricity generation or a generation facility from a facility or upgrade that becomes operational on or after January 1, 1995 that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low impact hydro facility and in state geothermal and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024. PacifiCorp filed a progress report on December 31, 2009. The Utah Division of Public Utilities is required to provide the Legislature with a summary report on the progress made by these electrical corporations by January 1 of the years 2011, 2016, 2021, 2025. In the Utah Division of Public Utilities’ report to the Legislature, it was stated that, “Given PacifiCorp’s projections of its loads and qualifying electricity for 2025, PacifiCorp is well positioned to meet a target of 20 percent renewable energy by 2025.”

PacifiCorp’s next Carbon Reduction Progress Report is expected to be filed by January 1, 2015.

In 2027, the legislation requires a commission report to the Utah Legislature which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation requires that any recommendation for a penalty must provide that the penalty funds be used for demand-side management programs for the customers of the utility paying the penalty.

¹² www.pacificpower.net/ORrps

¹³ <http://le.utah.gov/~2008/bills/sbillenr/sb0202.pdf>

The Energy Resource and Carbon Emission Reduction Initiative is codified in Utah Code Title 54 Chapter 17.

Washington

In November 2006, Washington voters approved Initiative 937,¹⁴ a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp. The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015, nine percent of retail sales by January 1, 2016 through 2019 and 15 percent of retail sales by January 1, 2020 and every year thereafter.

Eligible renewable resources include electricity produced from water, wind, solar energy, geothermal energy, landfill gas, wave, ocean, or tidal power, gas from sewage treatment facilities, biodiesel fuel with limitation, and biomass energy based on organic byproducts of the pulp and wood manufacturing process, animal waste, solid organic fuels from wood, forest, or field residues, or dedicated energy crops. Qualifying renewable energy sources must be located within the Pacific Northwest or delivered into Washington on a real-time basis without shaping, storage, or integration services. Moreover, the only hydroelectric resource eligible for compliance is electricity associated with efficiency upgrades to hydroelectric facilities. Utilities may use eligible renewable resources, RECs or a combination of both to meet the RPS requirement.

PacifiCorp is required to file an annual RPS compliance report demonstrating compliance with the Energy Independence Act by June 1 of every year with the Washington Utilities and Transportation Commission. PacifiCorp's compliance reports are made available on PacifiCorp's website¹⁵.

The Washington Utilities and Transportation Commission adopted final rules to implement the initiative; the rules are listed in the Revised Code of Washington (RCW) 19.285 and the Washington Administrative Code (WAC) 480-109.

Federal Renewable Portfolio Standard

The United States Congress has considered a federal RPS or a national clean energy standard in the past several years. This type of national policy could increase investment in a broad range of renewable energy resources and advanced technologies. Proponents of a national clean energy standard argue that it would provide a range of benefits including fostering the creation of clean energy industries, creating clean energy jobs, enabling the advancement of new technologies, diversifying energy portfolio, and providing positive public health and environmental impacts. If a national clean energy standard is considered, several key challenges exist including but not limited to how a national clean energy standard can be harmonized with existing state RPS programs, balancing the benefits of the policy with the costs of such policy. However, Congress has not yet adopted a national clean energy standard.

¹⁴ <http://www.secstate.wa.gov/elections/initiatives/text/I937.pdf>

¹⁵ www.pacificpower.net/WArps

Hydroelectric Relicensing

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

The value to relicensing hydroelectric facilities is continued availability of hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility as they can be called upon to meet peak customer demands almost instantaneously and provide back-up for intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation. With the exception of the Klamath River and Wallowa Falls hydroelectric projects, all of PacifiCorp's applicable generating facilities now operate under contemporary licenses from the Federal Energy Regulatory Commission (FERC). The 169 MW Klamath River hydroelectric project continues to operate under its existing license while PacifiCorp works with parties to implement a 2010 settlement agreement that would result in removal of the project. The assumed date of the removal in the IRP is January 1, 2021. The 1.1 MW Wallowa Falls project is currently undergoing the FERC relicensing process.

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. The usual alternative to relicensing is 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 resources, 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 process to require installation of fish passage facilities (fish ladders and screens) at projects. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other leading to potentially contrary, or additive, licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in settlement negotiations with stakeholders, the results of which are submitted to the FERC for incorporation into a new license. The FERC welcomes settlement agreements into the relicensing process, and with associated recent license orders, has generally accepted agreement

terms. Recently, the FERC has promoted that project owners seeking a new license do so through the Integrated Licensing Process (ILP). The ILP involves the FERC at early stages of the relicensing and seeks to resolve stakeholder issues in a timely manner.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2012, PacifiCorp had incurred approximately \$49 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and/or settlement efforts continue for the Klamath River, Wallowa Falls, and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Also, new requirements from contemporary FERC orders and expected requirements from ongoing or new relicensing processes could amount to over \$978 million over the 30 to 50 year terms of these orders. Such costs include capital investments, and related operations and maintenance costs 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 aquatic resources resulting in lost generation. The majority of these relicensing and settlement 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 related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 5.

PacifiCorp's Approach to Hydroelectric Relicensing

PacifiCorp continues to manage this process by pursuing interest-based resolutions and/or negotiated settlements as part of relicensing. 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.

Rate Design Information

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission in Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No. 11-035-200. Generally, the goals for rate design are to reflect the costs to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. The Company currently has a number of rate design elements that take into consideration these

objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

Residential Rate Design – Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through volumetric-based energy charges. Energy charges for residential customers are designed with an inclining tier rate structure such that high usage during a billing month is charged a higher rate than low usage. In this way, customers face a price signal to encourage reduced consumption. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. Currently, less than one percent of customers have opted to participate in the time-of-day rate option.

Changes in residential rate design that might facilitate IRP objectives include deploying a mandatory time-of-day rate design that reflects the higher costs of on-peak usage to all residential customers rather than a self-selected few. Time-of-day rates are discussed in more detail in Chapter 6 (Resource Options). Any changes in residential rate design to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs in order to ensure the price signals are economically efficient.

Commercial and Industrial Rate Design – Commercial and industrial rates in Utah are comprised of customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are intended to recover costs that don't vary with usage. Power charges are applied to a customer's monthly demand on a kW basis and are intended to recover the costs associated with demand or capacity needs. Energy charges are applied to the customer's metered usage on a kWh basis. All commercial and industrial rates employ seasonal variations in power and/or energy charges with higher rates in the summer months to reflect the higher costs to serve during the summer peak period. Additionally, for customers with load 1,000 kW or more, rates are further differentiated by on-peak and off-peak periods for both power and energy charges. For commercial and industrial customers with load less than 1,000 kW, the Company offers two optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage and one that differentiates power charges by on- and off-peak usage. Currently, approximately 15 percent of the eligible customers are on the energy time-of-day option and less than one percent are on the power time-of-day option.

Changes in rate design that might facilitate IRP objectives include evaluating current rates in light of the growing interest in self generation by commercial and industrial customers, which is captured in the load forecast in IRP. Ensuring that partial requirements rates for customers with self generation that better reflect the costs of providing backup service to these customers is expected to be addressed in the Company's next general rate case. Partial requirements rate design is important so that customers face a true economic price as they make decisions regarding self generation.

Irrigation Rate Design – Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, seasonal power charge and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through a seasonal power charge and energy charges. Power charge is for the irrigation season only and is designed to recover demand-related costs and to encourage irrigation customers to control and reduce their power consumption. Energy charges for irrigation customers are designed with two options. One is a time-of-day program with higher rates for on-peak consumption than for off-peak consumption. In this way, customers face a price signal to encourage reduced consumption during the on-peak period when energy costs are higher. Irrigation customers also have an option to participate in a third party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate in the program and give the Company the right to interrupt the service to the participating customers when energy costs are higher.

Energy Imbalance Market

PacifiCorp signed a memorandum of understanding with the California Independent System Operator Corporation (ISO) February 12, 2013 to outline terms for the implementation of an energy imbalance market (EIM) by October 2014. A benefit study was completed by Energy and Environmental Economics which shows a range of benefits to PacifiCorp and the ISO in 2017 from \$21.4m to \$128.7m per year. The Company’s cost payable to the CAISO is a \$2.1m one-time start-up and \$1.3m per year on-going, in addition to internal Company costs for items such as metering, software and additional staffing.

An energy imbalance market is a five-minute market administered by a single market operator using an economic dispatch model to issue instructions to generating resources to meet the load for the entire footprint of the EIM. Market participants voluntarily bid their resources into the EIM. The market operator, in addition to providing dispatch instructions, provides five-minute locational marginal prices to the market participants to be used for settlement of the energy imbalance. Energy imbalance is the difference between the forecast load or generation and the actual load or generation. The benefits of an EIM include economic efficiency of an automated dispatch, savings due to diversity of loads and variable resources in the expanded footprint, and favorable impacts to reliability or operational risk.

Recent Resource Procurement Activities

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources and / or transact on various energy and environmental attribute products. Table 3.4 summarizes current RFP activities.

Table 3.4 – PacifiCorp’s Request for Proposal Activities

RFP	RFP Objective	Status	Issued	Completed
All Source RFP for 2016 Resource	600MW	Canceled	January 2012	October 2012

RFP	RFP Objective	Status	Issued	Completed
Demand-side Resources				
Oregon Solar 2010S	2 MW	Closed		October 2012
Oregon Solar 2013S	6.7 MW	Pending	1 st Quarter 2013	December 2014
Natural Gas	Long-term physical and financial products	Open	May 2012	May 2013
Natural Gas Transportation	Firm natural gas supply to Naughton starting 2015	Pending	2 nd Quarter 2013	December 2013
Natural Gas Transportation	Long-term gas transportation for Lake Side II resource	Complete	July 2011	May 2013
Renewable energy credits (Sale)	Excess system RECs	Open	Quarterly	Ongoing
Renewable energy credits (Purchase)	Oregon compliance needs	Open	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Washington compliance needs	Open	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Open	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Open	Quarterly	Ongoing

All-Source Request for Proposals

PacifiCorp issued an all source RFP for a 2016 resource up to 600 megawatts on a system-wide basis in four categories: base load, intermediate, renewable and summer peaking, which are required to be on-line by June 2016. The RFP was issued to market in January 2012 for Utah and April 2012 for Oregon with a bid due date in May 2012. The bidders on the initial shortlists were notified in July 2012 and best and final pricing received in August 2012. As part of the all source RFP process, PacifiCorp filed an updated needs assessment in Oregon and Utah in September 2012, which included an update to the load and resource balance. For 2016, the load and resource balance was reduced, resulting in no significant resource need in 2016. As a result, PacifiCorp provided notice to terminate the all source RFP in Utah and withdrew PacifiCorp's all source RFP application in Oregon. A technical conference was held in October 2012 to explain the cancellation of the RFP.

Demand-side Resources

The comprehensive demand-side management RFP (2008 DSM RFP) released in November 2008 produced several proposals that at the time the 2011 Integrated Resource Plan (2011 IRP) was filed were still under consideration. Since that time the Company successfully implemented

two proposals from the 2008 DSM RFP; a small business project facilitator proposal designed to simplify and improve participation in the Company's business programs for small business customers, and a home energy report program (HER Program). The HER program is currently available to select residential customers in the states of Utah and Washington¹⁶. A third proposal, a commercial and industrial curtailment program (Class 1 load control proposal), was pursued to the point of executing a contract but was cancelled in 2012 following preliminary 2013 IRP modeling results, used to inform the 2012 All Source Supply-Side Request for Proposals, which indicated the Company would not have the need for new Class 1 DSM until at least 2018.

A revised 2011 IRP Action Plan (Action Plan) was provided in January, 2012, as part of the state acknowledgement process. A new procurement in that Action Plan called for the Company to issue a system-wide request for proposal (excluding Oregon) for specific direct install/direct distribution programs targeting savings from the residential and small commercial sectors, program savings that could be delivered beginning in 2013 and help defer the need of the 2016 resource identified in the 2011 IRP. The RFP was issued in March, 2012; however, as a result of the Company's revised load and resource position, final evaluation of the short-listed proposals was suspended in the third quarter of 2012, pending the outcome of the 2013 IRP's Preferred Portfolio and revised valuation of demand side resources (updated decrement values).

Other key procurements in 2011 and 2012 included the re-procurement of delivery for the Company's residential Home Energy Savings program, Utah New Homes program, refrigerator recycling program, Idaho irrigation Energy Savers program, Utah and Wyoming Self-Direction Credit programs, Utah and Washington energy education programs, and Utah and Idaho irrigation load management programs¹⁷.

The Company also issued a request for proposals in December, 2012, for the re-procurement of delivery services for Utah's Cool Keeper air conditioner load management program.

Oregon Solar Request for Proposal

PacifiCorp secured a 2.0 MW solar photovoltaic project in 2012 located in Lakeview, Oregon as a result of its 2010 solar RFP to meet Oregon Statute ORS 757.370 pertaining to the solar photovoltaic generating capacity standard, which requires Oregon utilities to acquire at least 20 MW (alternating current). PacifiCorp's share of the total is 8.7 MW. A second solar RFP is proposed to be issued in second quarter 2013 with resources required to be on line by December 31, 2014. The RFP will seek a total of 6.7 MW to meet PacifiCorp's remaining share of the standard. Due to the 5.0 MW limit per project under the Statute, the Company is seeking multiple projects through the RFP.

Natural Gas Transportation Request for Proposals

PacifiCorp issued a natural gas transportation RFP to secure firm natural gas transportation service to its Lake Side II power plant on July 5, 2011. The request for proposals bids were

¹⁶ Home energy reports began being delivered in August, 2012, and following performance evaluations scheduled by June 2014 may be expanded to other company jurisdictions. The Energy Trust of Oregon in collaboration with the Company is launching a pilot in Pacific Power's service area beginning in August, 2013.

¹⁷ The Utah and Idaho procurement included pricing for program delivery in the west, Oregon, Washington and California, pending the resource selections results of the 2013 integrated resource plan,

delivered August 15, 2011. As a result of the RFP bid evaluation, Questar Gas and Questar Pipeline Company were selected. Agreements were executed by both gas parties February 15, 2012 and submitted to the regulatory authorities for preapproval. The Questar Gas agreement was approved June 20, 2012, by the Utah Public Service Commission. On March 13, 2013, the Federal Energy Regulatory Commission issued an order and certificate, approving Questar Pipeline Company's application, subject to a condition that Questar Pipeline Company executes transportation agreements prior to commencing construction. The transportation agreements are on track to be signed by May 15, 2013 to meet the construction schedule.

Natural Gas Request for Proposals

Stakeholder feedback in the hedging collaborative indicated that the Company should investigate hedging some portion of its natural gas requirements for a term longer than the 36-month hedging window, as natural gas prices were perceived to be historically low. In response, the Company issued the 2012 Natural Gas RFP on May 14, 2012 for natural gas hedging and supply products ranging from four to ten years. The market response was robust, with the Company receiving hundreds of bids in a range of physical and financial products. The bids were analyzed by determining expected value to customers based on the Company's forward price and volatility curves.

Favorable bids that were Fixed-price bids or collars with terms of six years or less were selected for the initial shortlist. Credit cost was then determined for these bids. The final shortlist was then created by selecting the most favorable physical and financial bids comprising four-to-six year fixed-price bids, four-to-six year collar bids, and seven-to-ten year fixed price bids. The final shortlists showed the most benefit for customers, and were ultimately selected for refreshed pricing. On April 4, 2013, both bids were refreshed. The final shortlist was evaluate and was not favorably to the Company's forward price curves, and no deals were executed. The Company therefore entered a six-month predefined "market-monitoring window," during which the Company could continue to request refreshed bids if market movements suggest it worthwhile. Based on the experience of this RFP process, subsequent similar RFPs are expected in the future.

Natural Gas Transportation Request for Proposals

PacifiCorp will issue a natural gas transportation RFP to secure firm natural gas supply to its Naughton Unit 3 power plant after the planned plant conversion to natural gas in April 2015. The RFP is expected to be released in second quarter 2013. Final RFP schedule will be dependent upon the terms and the schedule of the plant conversion.

Renewable Energy Credit (REC) Request for Proposals

PacifiCorp issued multiple REC RFPs in 2011 and 2012 for two purposes; (i) the sale of RECs in excess of compliance needs to market and, (ii) purchase of RPS-eligible RECs to fulfill specific short-term needs to PacifiCorp's RPS obligation in Oregon, Washington, and California. The REC sale RFPs are typically issued on a quarterly basis and will continue in that format for 2013. The RPS-eligible REC purchase RFPs are issued specific to address a state compliance short.

Renewable Energy Credit (REC) Request for Proposals – Oregon

PacifiCorp issued a request for proposal to the market in December 2012, seeking offers of renewable energy credits from generation facilities that are certified by the Oregon Department of Energy as eligible for the Oregon Renewable Portfolio Standard. Procurement of unbundled RECs were completed to partially defer qualified resource additions in the future to comply with Oregon RPS requirements.

Renewable Energy Credit (REC) Request for Proposals - Washington

PacifiCorp issued a request for proposal to the market in May 2011, seeking offers of renewable energy credits from generation facilities that are eligible for Washington’s renewable portfolio program (Washington Initiative 937). Procurement of unbundled RECs were completed to comply with Washington’s renewable portfolio program requirements.

Renewable Energy Credit (REC) Request for Proposals - California

PacifiCorp issued a request for proposal to the market in May 2011, seeking offers of renewable energy credits from generation facilities that are eligible for California’s renewable portfolio standard.

Short-term Market Power Request for Proposals

PacifiCorp issued multiple short-term market power RFPs in 2011 and 2012 to sell power for system balancing purposes. These RFPs are typically issued on a quarterly basis and will continue through 2013.

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp is obligated to plan for and meet its customers' future needs, despite uncertainties surrounding environmental and emissions regulations and potential new renewable resource requirements. Regardless of future policy direction, the Company's planned transmission projects are well aligned to respond to changing policy direction, comply with increasing reliability requirements while providing sufficient flexibility to ensure investments cost-effectively and reliably meet its customers' future needs.
- Given the long periods of time necessary to site, permit and construct major new transmission lines, these projects need to be planned well in advance and developed in time to meet customer need.
- The Company's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and are responsive to commission and stakeholder requests for a robust evaluation process and criteria for evaluating transmission additions.
- A System Operational and Reliability Benefits Tool (SBT) has been developed to measure the benefits associated with transmission that are incremental to those benefits measured by traditional IRP modeling tools.
- PacifiCorp requests acknowledgment of its plan to construct the Sigurd to Red Butte transmission project (Energy Gateway Segment G) based on the regulatory and compliance requirements driving the project's need and timing, and supported by the project's benefits as quantified using the SBT.
- While construction of future Energy Gateway segments (i.e., Gateway West and Gateway South) is beyond the scope of acknowledgement for this IRP, these segments continue to offer benefits under multiple, future resource scenarios. Thus, the Company believes continued permitting of these segments is warranted to ensure it is well positioned to advance these projects as required to meet customer need. As such, a preliminary SBT analysis summary is provided for the next major segment of Energy Gateway, the Windstar to Populus transmission project (Gateway West Segment D), to support the Company's continued permitting of Gateway West.

Introduction

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

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

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

Regulatory Requirements

Open Access Transmission Tariff

Consistent with the requirements of its OATT, approved by the Federal Energy Regulatory Commission (FERC), PacifiCorp plans and builds its transmission system based on its network customers' 10-year load and resource (L&R) forecasts. Each year, the Company solicits L&R data from each of its network customers in order to determine future load and resource requirements for all transmission network customers. These customers include PacifiCorp Energy (which serves PacifiCorp's retail customers and comprises the bulk of the Company's transmission network customer needs), Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Generation & Transmission Cooperative (including Moon Lake Electric Association), Bonneville Power Administration, Basin Electric Power Cooperative, Black Hills Power and Light, and Western Area Power Administration.

The Company uses its customers' L&Rs and best available information to determine project need and investment timing. In the event that customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios and/or schedules for its project investment as appropriate. Per FERC guidelines, the Company is able to reserve transmission network capacity based on this 10-year forecast data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required for significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year

timeframe of load and resource forecasts.¹⁸ A 20-year planning horizon and ability to reserve transmission capacity to meet forecasted need over that timeframe is more consistent with the time required to plan for and build large scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

Reliability Standards

PacifiCorp is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements.¹⁹ The Company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where parts of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, the Company identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities in order to meet NERC reliability criteria.

IRP Feedback

In response to Commission feedback to PacifiCorp's 2011 Integrated Resource Plan, the Company committed to a revised action plan, which included the following action item for transmission:

In the scenario definition phase of the IRP process, the Company will address with stakeholders the inclusion of any transmission projects on a case-by-case basis.

Develop an evaluation process and criteria for evaluating transmission additions.

Review with stakeholders which transmission projects should be included and why.

Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgement.

PacifiCorp has since developed and discussed with stakeholders a new transmission System Operational and Reliability Benefits Tool (SBT) for the purpose of identifying and quantifying transmission benefits that are not captured using traditional IRP analysis tools. Traditional means of least cost transmission planning and net power cost modeling help identify the IRP scenario with the lowest present value revenue requirement, but have historically failed to capture the full

¹⁸ For example, PacifiCorp's application to begin the Environmental Impact Statement process for Energy Gateway West was filed with the Bureau of Land Management in late 2007 as of the 2013 IRP the federal permit has not been issued.

¹⁹ FERC requirements; NERC standards; WECC standards.

range of benefits associated with additional transmission capabilities. The SBT identifies, measures and monetizes benefits that are incremental to those identified via models used in the IRP process.

The Company is working to improve its ability to quantify these additional transmission benefits, both in response to the directives of FERC Order No. 1000 and to feedback received from state regulators, customers and stakeholders. However, transmission benefit evaluation is no simple task. There is no “off the shelf” transmission benefit calculator readily available to the Company. Development of the SBT is a long-term objective that will continue to require adjustments based on utility industry experience, and regulator and stakeholder input. In the near term, the SBT will be used to help support transmission segments for which the Company is seeking regulatory acknowledgment, which for the 2013 IRP includes the Sigurd to Red Butte transmission project. Ultimately, this tool will be used to complement future IRP modeling efforts, compare project options and support regulatory acknowledgment by providing a more complete picture of the benefits of additional transmission capability.

In addition to a comprehensive overview of the SBT approach, this chapter provides:

- The justification supporting acknowledgement of the Company’s plan to construct the Sigurd to Red Butte transmission project, including the SBT-calculated benefits for the project;
- A preliminary SBT analysis for the Windstar to Populus transmission project (Energy Gateway Segment D) supporting the Company’s plan to continue permitting Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of how the Company’s investments in short-term system improvements have helped to maximize efficient use of the existing system and to defer the need for larger scale infrastructure investment.

System Operational and Reliability Benefits Tool

Background

Federal and state regulators, customers and stakeholders alike have expressed a need for improved methods of measuring transmission benefits and identifying beneficiaries. The traditional IRP System Optimizer and Planning and Risk models identify the IRP scenario with the lowest present value revenue requirement from an energy delivery view, but these models are not intended to capture a broader range of “day to day” operational and reliability benefits provided by transmission. A different approach is required to identify and quantify the benefits not captured by these traditional tools, and to better inform the Company’s transmission planning process in the context of integrated resource planning.

While there is no “off the shelf” transmission benefit calculator to use, there are various approaches used by other transmission planning entities that are informative. PacifiCorp, both independently and as part of the Northern Tier Transmission Group’s FERC Order No. 1000 compliance effort, looked to other regional transmission planning groups to understand how various metrics are used to evaluate transmission project benefits, impacts to existing

transmission systems and customer benefits. These groups include the Southwest Power Pool, California Independent System Operator (ISO), Midwest ISO, New York ISO, ISO New England, PJM Interconnection, and Georgia Power. By no means have these groups perfected the measurement of transmission benefits, nor is there a “one size fits all” approach for assessing these benefits, but their efforts are several years in the making and, through their own stakeholder processes, they have developed and vetted several common metrics that were considered as part of PacifiCorp’s efforts to develop a tool to measure transmission project benefits.

Informed by these approaches, PacifiCorp has developed the SBT to help quantify the operational and reliability benefits directly associated with new transmission projects and their integration into the existing transmission system. The metrics that comprise the SBT will continue to improve and evolve over time, with stakeholder input and through utility industry experience.

Provided below is a description of the SBT metrics the Company is working with initially, plus the SBT-calculated benefits for the Sigurd to Red Butte transmission project, for which the Company is seeking acknowledgment in this IRP.

Benefits Evaluated

Each transmission project has its own unique set of objectives, physical characteristics and benefits, and therefore may require a unique set of metrics for evaluation. A larger, more complex project may involve more metrics—or derive higher values from the same metrics—than a smaller, less complex project. For example, not all of the metrics described below derive benefit values for the Sigurd to Red Butte transmission project, whereas they may derive values for other Energy Gateway segments.

Operational Cost Savings (economic driven)

Where the IRP model topology can evaluate the specific transmission project, results from the IRP modeling process may be used to determine economic benefits (i.e. net power cost savings) of new transmission. However, in situations where the IRP model topology cannot recognize the project due to granularity limitations, a system production cost modeling program, with detailed system topology and assumptions, may be relied upon to determine the economic benefits of the specific transmission project. Alternatively, where operational cost savings are not derived specifically from production cost benefits, this metric may be used to compare operational cost savings of potential solutions. For the Sigurd to Red Butte project, the IRP model topology did not recognize the project which exists within a single IRP topology load bubble. For example, potential alternatives identified could include the addition of a new generation resource, the purchase of firm energy and wheeling costs or an alternative transmission project.

It is important to note that benefits will only be included as part of the SBT analysis to the extent they are incremental and not already captured in the production cost benefits identified through the IRP modeling process. The purpose of the SBT is to identify and measure transmission benefits not already captured via the IRP modeling—*i.e., no duplication of benefits.*

Segment Loss Savings (energy and capacity)

Energy – The addition of a new transmission line operated in parallel with an existing line(s) reduces the electrical impedance of the transmission system, resulting in lower energy line losses (megawatt-hours) over the life of the project. Depending on the amount of power flow, line loss savings can be substantial. Losses for any transmission line are determined according to the formula I^2R (where I is the current flow and R is resistance). To calculate current (I), megavolt amperes are divided by ($\sqrt{3}$ x voltage). Since the predominant flow on the Company's transmission lines is real power (megawatts), the difference when calculating current is small between megawatts (MW) and megavolt amperes (MVA). Hence, megawatt flow can be used rather than megavolt amperes as a close approximation. Factors such as line length and conductor type, material and size determine change in system impedance. The electrical impedance of parallel lines is determined by calculating an equivalent resistance ($R_{\text{Equivalent}}$) before and after a transmission project is placed in service.

In the SBT analysis, the Company's assessment of energy line losses is based on actual power flow (megawatts) as a proxy for a typical year, with line flow increasing in future years as determined by network customers' load forecast submittals. Line losses are compared before and after the addition of new transmission and are calculated between the connection points, with the difference being the loss savings attributed to the new line(s). A forward energy price curve is used to monetize the value of line loss energy savings as an avoided market purchase of energy and the present value of the annual savings is then calculated.

Capacity – Lower line segment losses reduce the overall system demand and the amount of generation capacity needed to meet that demand, thereby reducing the need for new incremental generation. To determine generation capacity related savings due to reduced line segment losses, average demand savings (megawatts) are calculated for a segment using system peak flow data from previous years. To monetize these savings, the base capital cost of a combined cycle gas generating plant (\$1,026 per installed megawatt)²⁰ is multiplied by the capacity value (megawatts) of the line loss savings and the present value of the annual savings is then calculated.

System Reliability Benefits

The SBT calculates system reliability benefits gained by adding new transmission between points in the existing system. The addition of new transmission results in new incremental capacity, but also results in improved performance of the existing system. These performance benefits are derived using Company historical transmission line outage data, for both scheduled and unscheduled line outages, and then determining the improved system performance with the new segment(s) in service during outages of a single transmission line (N-1) or multiple transmission lines (N-1-1). Benefits are measured as:

- Avoidance of transmission system capacity reductions or “derates”
To calculate this benefit, the impact to the transmission system capacity—or “derate”—is evaluated for each line outage. These figures are then compared to the system capability with the new line segment(s) in service. The difference between capacities (megawatts) is the “derate” benefit.

²⁰ Cost from PacifiCorp's 2013 Integrated Resource Plan.

- Reductions in forced generator outages caused by transmission outages or limitations
Reductions in forced generator outages is calculated using the same methodology used to calculate the “derate” benefit, but the analysis instead looks at the impacts on affected generation resources. The amount of generation that is reduced due to transmission system capacity limitations is determined with and without the new segment(s) in service. The impacts from transmission capacity reductions and the reductions in forced generator outages are then compared. To avoid double counting, only the highest megawatt value between the two impacts is selected for valuation. This megawatt value is priced using historical line outage data and a weighted average yearly price comprised of light-load and heavy-load hours using a suitable forward price curve. The present value is then determined. For calculation of multiple line outages, it is assumed that it takes a fixed amount of time—based on historical information—to restore affected generation. Since it is impossible to determine the exact time of day when an outage will occur, the megawatt value for multiple line outages is priced using the weighted heavy-load and light-load hour average of the entire forward price curve. This value is then multiplied by the probability of the outage and the present value is then determined.
- Reduced exposure to loss of firm customer load, based on calculation of avoided loss of retail revenue from customers during system outages.
The system is evaluated with the new segment(s) in service and compared against the existing system. If the configuration with the new segment(s) enables load service that would otherwise be lost during outage conditions, this difference is the reduction in risk to customer load loss. For multiple outages (N-1-1), the probability of such an occurrence is utilized and load is assumed to be lost for two hours for each outage occurrence. The value is developed by multiplying the loss in customer demand by the probability of the outage condition by the Company’s average Retail Energy Rate (dollars per kWh) for the state where the new transmission segment is placed in service. Based on this, the present value is determined.

The system performance criteria used by the Company are specified in the mandatory FERC, NERC and WECC Transmission System Planning Standards and Performance Criteria.

Customer and Regulatory Benefits

As growing demand depletes excess transmission capacity, the likelihood of impacting large industrial or commercial customers increases due to a need to curtail load to maintain a safe and reliable operating system under certain, abnormal conditions. Such circumstances can result in lost retail sales of energy, lost sales for retail customers, equipment damage, lost product, and potentially a negative economic development value for areas impacted by poor transmission system reliability. In addition, the regulatory costs following a significant outage and the resulting investigation and remediation costs can be quantified. The risk of such circumstances can be significantly reduced with new transmission capacity that supports customer load growth across the operating system.

Avoided Capital Cost

This metric considers capital investment that may be avoided by a transmission alternative, where the addition of a new transmission project resolves underlying issues identified by planning studies. In such a case, the transmission project avoids underlying upgrades for load service or reliability needs and SBT factors in the one-time capital investment as an avoided cost

benefit of those projects displaced or deferred. The avoided cost of replaced or deferred investments is a commonly used metric in transmission benefit analysis.

Improved Generation Dispatch (reliability driven)

Without adequate transmission capacity, the system may not be able to fully utilize generation resources in constrained areas. As a result of this congestion, the Company may be unable to dispatch the most economic resources to meet customer needs, increasing costs to customers. New transmission infrastructure can alleviate these conditions and improve overall generation dispatch to meet system load and reliability requirements. Additionally, the same generation resources that are constrained by transmission limitations can also provide capacity benefits that may be used for system reserves through the addition of transmission capability. The SBT calculates the value of generation that may be online but not at full output and could otherwise be dispatched up to full nameplate capacity for reserves purposes when new segment(s) reduce or eliminate transmission congestion. The benefits associated with increased access to existing, dispatchable generation for reserves is calculated as the difference between the minimum unit operating limit and the amount of increased transmission capacity provided by the new segment(s) up to the maximum output of each unit. The benefit value of this generation is based on the reduced need for incremental new generation at the cost of acquiring generation or market purchases, whichever is lower.

Wheeling Revenue Opportunity

Transmission services sold to system users provides a wheeling revenue benefit derived from selling new incremental transmission capacity. The SBT reviews new incremental transmission capacity for each segment or sub-segment analyzed and identifies the value of this new capacity. The present value of the benefit attributable to wheeling revenue for each of the segments or sub-segments is based on PacifiCorp's long-term point-to-point wheeling charge (Schedules 7, 1 and 2²¹) and the new transfer capability (megawatts) not otherwise captured in the Operational Cost Savings. Incremental system capacity for each segment or sub-segment is determined by comparing the initial path transfer capability with the improved path capacity after adding the new segment(s). In cases where the available capacity has not been fully subscribed by point-to-point users, this benefit is referred to as a wheeling revenue "opportunity."

Request for Acknowledgement of Sigurd to Red Butte

The Sigurd to Red Butte transmission project is required to satisfy the Company's federal regulatory obligations to its network transmission customers under its OATT and comply with the mandatory FERC, NERC and WECC reliability standards. In addition, consistent with the Company's commitment described at the beginning of this chapter, PacifiCorp has developed—in consultation with other transmission providers, transmission planning regions, and stakeholders—a SBT for evaluating the benefits of transmission projects for which the Company seeks regulatory acknowledgment. The SBT helps identify and quantify those transmission benefits not recognized using traditional IRP analysis tools, capturing the full range of benefits associated with additional transmission. Using this tool, the Company has calculated at least \$645 million in benefits associated with the Sigurd to Red Butte transmission project, and a 1.64 benefit-to-cost ratio. In March 2013, PacifiCorp obtained a certificate of public convenience and

²¹ At a minimum, these rate schedules would be applicable to purchasers of long-term point-to-point transmission service.

necessity authorizing construction of the Sigurd to Red Butte transmission line from the Utah Public Service Commission. To meet regulatory reliability requirements, with demonstration of project need and showing of project benefits, the Company requests regulatory acknowledgement of the Sigurd to Red Butte transmission project.

Factors Supporting Acknowledgement

The key drivers supporting PacifiCorp's request for acknowledgement of the Sigurd to Red Butte transmission project include meeting its obligations to its network transmission customers consistent with its OATT, complying with mandatory FERC, NERC and WECC reliability standards and the positive cost benefit analysis of this project compared to other alternatives.

Improved Transmission System Capacity

The full-rated capacity of the southwest Utah transmission system, including the existing Sigurd to Three Peaks to Red Butte No. 1 – 345 kV transmission line, cannot currently provide adequate service under all expected operating conditions and customer demands. The existing Sigurd to Red Butte transmission line represents the sole connection to a major southwest Utah load area, with customer designated generation sources to this critical load isolated during line outage events. Load growth in southwestern Utah continues, and is forecasted to continue, surpassing the capability of the existing transmission system. New facilities must be constructed to provide reliable capacity for load service. Without the Sigurd to Red Butte transmission project, peak load in southwestern Utah cannot be reliably served during transmission line outages or major equipment contingencies. The Sigurd to Red Butte transmission project also supports future electrical load growth in southwestern Utah and improves the ability of the Company's transmission system to transport energy into southwest and central Utah and to high growth areas along the Wasatch Front of Salt Lake City.

Enhanced Transfer Capability to Promote Energy Transfers

Under its OATT, the Company has transmission service contract obligations for firm transmission service into and out of southwestern Utah. Indeed, the OATT obligates the Company to provide adequate and non-discriminatory network transmission service for delivery of network generation to loads. The current system supports up to 400 MW of firm energy transfers (bi-directional) between southwestern Utah and Nevada. The Company has contractual commitments and future load service requirements that cannot reliably be delivered via the transmission system existing in the area today. To meet these transfer obligations, the Company must increase the total capacity between the existing Sigurd and Red Butte substations. Following completion of the Sigurd to Red Butte project, the transfer capacity of the existing system between Utah and Nevada will increase by an additional 200 MW. This additional transmission capacity can be purchased by the Company to make off-system sales during periods when surplus energy exists, or can be purchased for use by third parties. The Sigurd to Red Butte transmission project will enable the Company to continue to meet its OATT obligations, as well as its contractual service obligations to PacifiCorp Energy, Utah Associated Municipal Power Systems, Utah Municipal Power Association, and Deseret Generation & Transmission Cooperative, Inc. The added transfer capacity is vital to the Company's continued ability to provide reliable service to these entities in the future.

Improved Transmission System Reliability

In addition to increasing system capacity, the Sigurd to Red Butte transmission project will provide needed redundancy to the existing infrastructure and substantially improve the Company's ability to provide reliable electric service to its customers in compliance with mandatory FERC, NERC and WECC reliability standards. These standards require that transmission providers evaluate all expected customer demand levels and operating conditions, and plan for adequate redundancy in their systems in order to maintain required system reliability and performance levels. It is the responsibility of the Company as the transmission provider to utilize operational history and experience to plan, design, site and construct transmission projects as required to meet system performance requirements and manage reliability, risks, and costs. Without the Sigurd to Red Butte transmission project, peak loads in southwestern Utah will not be reliably served and transmission service contract obligations will not be met. The Sigurd to Red Butte transmission project has been designed in a manner that meets the Company's system planning criteria (developed in compliance with mandatory FERC, NERC and WECC standards and criteria, and based on the Company's operational history and experience), substantially improving the Company's ability to provide reliable electric service to its customers long term and enhancing the reliability and capacity of the existing transmission system.

Sigurd to Red Butte Cost Benefit Analysis

The SBT metrics quantify the transmission benefits that are otherwise not captured within the existing IRP analysis. As applied to the Sigurd to Red Butte transmission project, for which the Company is seeking acknowledgement in this IRP, the SBT derived the following benefits and benefit-to-cost ratio.

Table 4.1 – SBT-Derived Values for Sigurd to Red Butte

<p>***** <i>SBT-Derived values for Sigurd to Red Butte</i> *****</p> <p><u>\$645 million over 2015-2034 period, 1.64 benefit-cost ratio</u></p>	
Operational Cost Savings	
• Energy (option at 25% of total)	\$470 million
• Third-party wheeling	\$104 million
Segment Loss Savings ²²	
• Energy	\$55.5 million
• Capacity	\$14.9 million
System Reliability Benefits	
• N-1 load curtailment (load over 580 MW)	\$1 million
Customer and Regulatory Benefits	
	TBD
Wheeling Revenue Opportunity:	
• ATC firm southbound	\$57 million

TOTAL MEASURED BENEFITS	
(minus Wheeling Revenue Opportunity)	\$645 million
PROJECT CAPITAL COST	\$392 million²³
PROJECT BENEFIT-TO-COST RATIO	1.64
<i>NOTE: See excel spreadsheet for detailed Sigurd to Red Butte SBT assumptions and calculations²⁴</i>	

Gateway West – Continued Permitting

The Windstar to Populus transmission project (Energy Gateway Segment D) is the first of two planned segments of Gateway West. Given the delays experienced in the permitting process, the current project schedule for Windstar to Populus shows a delay of the in-service date to December 31, 2019. In a future IRP, the Company will support a request for acknowledgement to construct Windstar to Populus with a thorough cost-benefit analysis for the project, similar to that provided in this IRP for the Sigurd to Red Butte transmission project. While the Company is

²² All present value calculations for Sigurd to Red Butte line losses are based on a 20-year time horizon starting in 2015, using a 6.88% discount rate, which was PacifiCorp’s weighted average cost of capital at the time the analysis was undertaken.

²³ Includes fully loaded capital and related operations and maintenance costs on a 20-year time horizon starting in 2015, discounted at 6.88%.

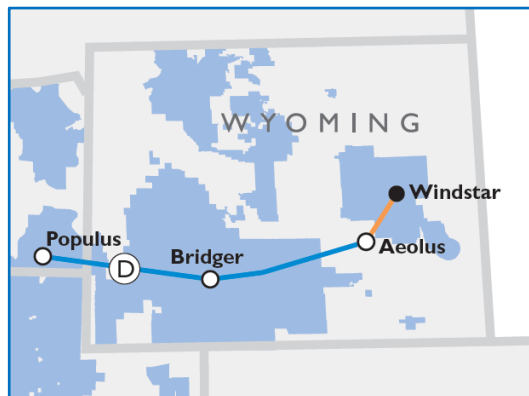
²⁴ “System Benefit Tool for Sigurd to Red Butte Transmission Line (Segment G)”
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacTras_SigurdToRedButte-SBT_4-30-13.xlsx

not requesting acknowledgement in this IRP of a plan to *construct* the Windstar to Populus project, the Company will continue to *permit* the project, and provides below a preliminary SBT analysis summary that demonstrates significant project benefits to support this plan.

Windstar to Populus

The Windstar to Populus transmission project consists of three key sections:

- A single-circuit 230 kilovolt (kV) line that will run approximately 75 miles between the existing Windstar substation in eastern Wyoming and the Aeolus substation to be constructed near Medicine Bow, Wyoming;
- A single-circuit 500 kV line running approximately 140 miles from the Aeolus substation to a new annex substation near the existing Bridger substation in western Wyoming; and
- A single-circuit 500 kV line running approximately 200 miles between the new annex substation and the recently constructed Populus substation in southeast Idaho.



The project would enable the Company to more efficiently dispatch system resources, improve performance of the transmission system (i.e. reduced line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long-term.

Preliminary SBT Analysis – Windstar to Populus (Segment D)

The SBT metrics quantify the transmission benefits that are otherwise not captured within the existing IRP analysis. The footnoted excel spreadsheet provides for a detailed view of the project benefits, including operational savings as measured by the System Optimizer model²⁵.

The following metrics were determined to apply to Segment D and were analyzed to determine possible benefits associated with each:

²⁵ “System Benefit Tool for Preferred Portfolio Case 07 Energy Gateway Scenario 2 (Segment D)” http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_System-Benefits-Tool-C07_4-23-13.xlsx

Table 4.2 – Windstar to Populus Benefits Calculation

Benefits Calculation	Case EG2-C07
System Optimizer Analysis	\$511
Avoided Transmission System Capital Cost	\$151
System Reliability Benefits	\$112
Improved Generation Dispatch	\$39
Segment Loss Savings - Energy	\$69
Segment Loss Savings - Capacity	\$18
Customer and Regulatory Benefits	\$249
Wheeling Revenue Opportunity	\$16
<i>Total Benefits (\$m)</i>	\$1,165
<i>Costs (\$m)</i>	\$ (934)
<i>Net Benefit (\$m, 2012\$)</i>	\$ 231

Plan to Continue Permitting Gateway West

The Windstar to Populus transmission project continues to offer benefits under multiple, future resource scenarios. To ensure the Company is well positioned to advance the project as required to meet customer need, PacifiCorp believes it is prudent to continue to permit the Gateway West transmission project.

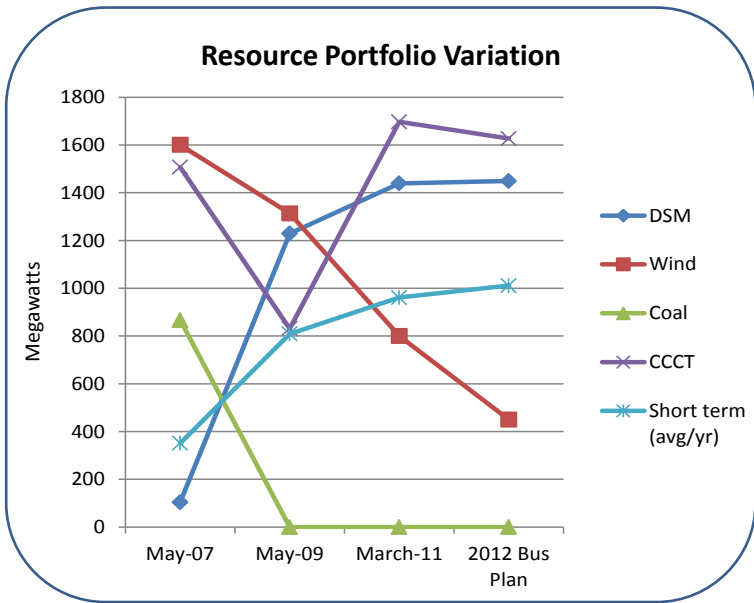
Evolution of the Energy Gateway Transmission Expansion Plan

Introduction

Given the long periods of time necessary to successfully site, permit and construct major new transmission lines, these projects need to be planned and developed in time to meet customer need. The Energy Gateway Transmission Expansion Plan is the result of several robust local and regional transmission planning efforts that are ongoing and have been conducted multiple times over a period of several years. The purpose of this section is to provide important background information on the transmission planning efforts that led to the Company's proposal of the Energy Gateway Transmission Expansion Plan.

Background

Until the Company’s announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered around the generation additions identified in the IRP. As the figure here shows, the generation resources in the Company’s preferred portfolio have historically fluctuated significantly from one IRP to the next. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proven problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable transmission resource options for meeting customer need. The existing transmission system has been at capacity for several years and new capability is necessary to enable new resource development.



The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across the Company’s multi-state service area. Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

Planning Initiatives

Energy Gateway is the result of robust local and regional transmission planning efforts. The Company has participated in numerous transmission planning initiatives, both leading up to and since Energy Gateway’s announcement. Stakeholder involvement has played an important role in each of these initiatives, including participation from state and federal regulators, government agencies, private and public energy providers, independent developers, consumer advocates, renewable energy groups, policy think tanks, environmental groups, and elected officials. These studies have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers throughout the West, and include:

- Northwest Transmission Assessment Committee (NTAC)**
 The NTAC was the sub-regional transmission planning group representing the Northwest region, preceding Northern Tier Transmission Group and ColumbiaGrid. The NTAC developed long term transmission options for resources located within the provinces of British Columbia and Alberta, and the states of Montana, Washington and Oregon to serve Northwest loads and Northern California.

- ***Rocky Mountain Area Transmission Study***²⁶

Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:

- Bridger system expansion similar to Gateway West
- Southeast Idaho to Southwest Utah expansion akin to Gateway Central and Sigurd-Red Butte
- Improved East-West connectivity similar to Energy Gateway Segment H alternatives

“The analyses presented in this Report suggest that well-considered transmission upgrades, capable of giving LSEs greater access to lower cost generation and enhancing fuel diversity, are cost-effective for consumers under a variety of reasonable assumptions about natural gas prices.”

- ***Western Governors’ Association Transmission Task Force Report***²⁷

Examined the transmission needed to deliver the largely remote generation resources contemplated by the Clean and Diversified Energy Advisory Committee. This effort built upon the transmission previously modeled by the Seams Steering Group-Western Interconnection, and included transmission necessary to support a range of resource scenarios, including high efficiency, high renewables and high coal scenarios. Again, for PacifiCorp’s system, the transmission expansion that supported these scenarios closely resembled Energy Gateway’s configuration.

“The Task Force observes that transmission investments typically continue to provide value even as network conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location.”

- ***Western Regional Transmission Expansion Partnership (WRTEP)***

The WRTEP was a group of six utilities working with four western governors' offices to evaluate the proposed Frontier Transmission Line. The Frontier Line was proposed to connect California and Nevada to Wyoming's Powder River Basin through Utah. The utilities involved were PacifiCorp, Nevada Power, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Sierra Pacific Power.

- ***Northern Tier Transmission Group Transmission Planning Reports***

- 2007 Fast Track Project Process and Annual Planning Report²⁸
- 2008-2009 Transmission Plan²⁹
- 2010-2011 Transmission Plan³⁰

Each Energy Gateway segment was included in the 2007 Fast Track Project Process and

“The Fast Track Project Process was used in 2007 to identify projects needed for reliability and to meet Transmission Service Requests.”

²⁶ <http://psc.state.wy.us/rmats/rmats.htm>

²⁷ http://www.westgov.org/index.php?option=com_joomdoc&task=doc_download&gid=97&Itemid

²⁸ http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=353&Itemid=31

²⁹ http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=1020&Itemid=31

³⁰ http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=1437&Itemid=31

has since been reevaluated as part of each Northern Tier Transmission Group biennial planning process. These are open, stakeholder processes.

- ***WECC/TEPPC Annual Reports and Western Interconnection Transmission Path Utilization Studies***³¹

These analyses measure the historical utilization of transmission paths in the West to provide insight into where congestion is occurring and assess the cost of that congestion. The Energy Gateway segments have been included in the analyses that support these studies, alleviating several points of significant congestion on the system, including Path 19 (Bridger West) and Path 20 (Path C).

“Path 19 [Bridger] is the most heavily loaded WECC path in the study... Usage on this path is currently of interest due to the high number of requests for transmission service to move renewable power to the West from the Wyoming area.”

Energy Gateway Configuration

For addressing constraints identified on PacifiCorp’s system, as well as meeting system reliability requirements discussed further below, the recommended bulk electric transmission additions took on a consistent footprint, which is now known as Energy Gateway. This expansion plan establishes a triangle over Utah, Idaho and Wyoming with paths extending into Oregon and Washington, and contemplates logical resource locations for the long-term based on environmental constraints, economic generation resources, and federal and state energy policies.

Since Energy Gateway’s announcement, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and interconnection-wide levels. In accordance with the local planning requirements in PacifiCorp’s federal OATT, Attachment K, the Company has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp’s Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of the Northern Tier Transmission Group (NTTG) and WECC’s Transmission Expansion Policy and Planning Committee



³¹ <http://www.wecc.biz/committees/BOD/TEPPC/External/Forms/external.aspx>

(TEPPC).

These groups continually evaluate PacifiCorp’s transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp’s OASIS site for information and materials related to these public processes.³²

Additionally, the Project Teams conducted an extensive 18-month stakeholder process on Gateway West and Gateway South. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to establish need, assess benefits to the region, vet alternatives and eliminate duplication of projects. Meeting materials and related reports can be found on PacifiCorp’s Energy Gateway OASIS site.

Energy Gateway’s Continued Evolution

The Energy Gateway Transmission Expansion Plan is the result of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway’s scope and scale have continued to evolve to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, the Company has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section on Efforts to Maximize Existing System Capability). The IRP process, as compared to transmission planning, is a frequently changing resource planning process that does not support the longer-term development needs of transmission, or the ability to implement transmission in time to meet customer need. Together, however, the IRP and transmission planning processes complement each other by helping the Company optimize the timing of its transmission and resource investments for meeting customer needs.

While the core principles for Energy Gateway’s design have not changed, the project configuration and timing continue to be reviewed and modified to coincide with the latest mandatory transmission system reliability standards and performance requirements, annual system reliability assessments, input from several years of federal and state permitting processes, and changes in generation resource planning and our customers’ forecasted demand for energy.

As originally announced in May 2007, Energy Gateway consisted of a combination of single- and double-circuit 230 kV, 345 kV and 500 kV lines connecting Wyoming, Idaho, Utah, Oregon and Nevada. In response to regulatory and industry input regarding potential regional benefits of “upsizing” the project capacity (e.g. maximized use of energy corridors, reduced environmental impacts and improved economies of scale), the Company included in its original plan the potential for doubling the project’s capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received in excess of 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. The Company identified the costs required for this upsized system and offered transmission service contracts to queue customers. These customers,

³² <http://www.oatioasis.com/ppw/index.html>

however, were unable to commit due to the upfront costs and lack of firm contracts with customers to take delivery of future generation, and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading the Company to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

In 2010, the Company entered into memorandums of understanding (MOU) to explore potential joint-development opportunities with Idaho Power on its Boardman to Hemingway project and with Portland General Electric (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate the Company's East and West control areas, and Gateway Segment H from western Idaho into southern Oregon was originally proposed to satisfy this need. However, recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has pursued these potential partnership opportunities as a lower cost alternative.

In 2011, the Company announced the indefinite postponement of the 500 kV Gateway South segment between the Mona substation in central Utah and Crystal substation in Nevada. This extension of Gateway South, like the double-circuit configuration discussed above, was a component of the upsized system to address regional needs if supported by queue customers or partnerships. However, despite significant third-party interest in the Gateway South segment to Nevada, there was a lack of financial commitment needed to support the upsized configuration.

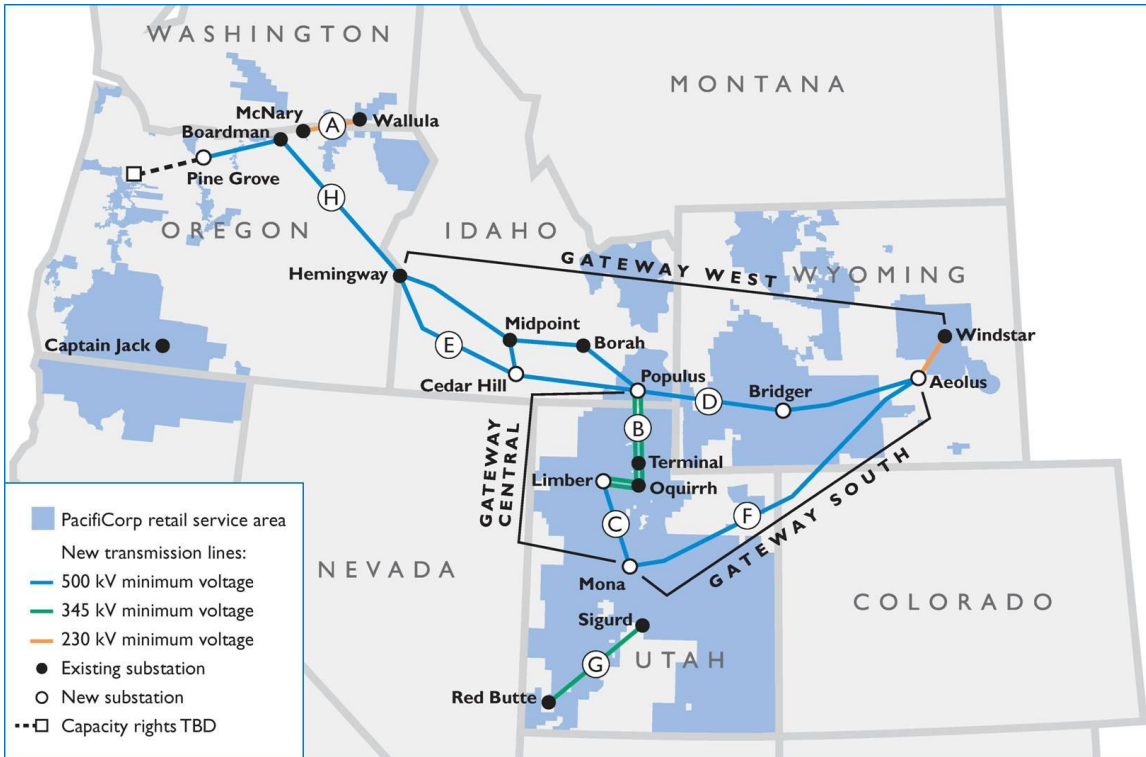
In 2012, the Company determined, due to experience with land use limitations and National Environmental Policy Act permitting requirements, that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line was feasible, and that the second new proposed 230 kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from the Company's ongoing focus on meeting customer needs, taking stakeholder feedback and land use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012 the Company signed the Boardman to Hemingway Permitting Agreement with Idaho Power and Bonneville Power Administration that provides for the Company's participation through the permitting phase of the project.

In January 2013, the Company began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint-development and/or firm capacity rights into PacifiCorp's Oregon system. PacifiCorp continues to pursue potential partnership opportunities with PGE on Cascade Crossing and with Idaho Power and Bonneville Power Administration on the Boardman to Hemingway project as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack).

Finally, the timing of segments is regularly assessed and adjusted. While permitting delays have played a significant role in the adjusted timing of some segments (e.g., Gateway West and Gateway South), the Company has been proactive in deferring in-service dates due to permitting schedules, moderated load growth, changing customer needs, and system reliability improvements discussed below (e.g., Sigurd-Red Butte and Oquirrh-Terminal).

The Company will continue to adjust the timing and configuration of its proposed transmission investments based on its ongoing assessment of the system's ability to meet customer needs and its compliance with mandatory reliability standards.

Figure 4.1 – Energy Gateway Transmission Expansion Plan



This map is for general reference only and reflects current plans. It may not reflect the final routes, construction sequence or exact line configuration.

Segment & Name	Description	Approximate Mileage	Status ³³ and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	<ul style="list-style-type: none"> • Status: local permitting completed • Scheduled in-service: 2013-2014*
(B) Populus-Terminal	345 kV, double circuit	135 mi	<ul style="list-style-type: none"> • Status: completed • Placed in-service November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	<ul style="list-style-type: none"> • Status: construction nearing completion • Scheduled in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	<ul style="list-style-type: none"> • Status: rights-of-way acquisition underway • Scheduled in-service: June 2016*
(D) Windstar-Populus	230 kV single circuit 500 kV single circuit	400 mi	<ul style="list-style-type: none"> • Status: permitting underway • Scheduled in-service: 2019-2021*
(E) Populus-Hemingway	500 kV single circuit	600 mi	<ul style="list-style-type: none"> • Status: permitting underway • Scheduled in-service: 2020-2023*
(F) Aeolus-Mona	500 kV single circuit	400 mi	<ul style="list-style-type: none"> • Status: permitting underway • Scheduled in-service: 2020-2022*
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	<ul style="list-style-type: none"> • Status: construction started April 2013 • Scheduled in-service: June 2015
(H) West of Hemingway	500 kV single circuit	500 mi	<ul style="list-style-type: none"> • Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in-service: sponsor driven

* Scheduled in-service date adjusted since last IRP Update.

³³ Status as of the filing of this IRP.

Efforts to Maximize Existing System Capability

The system analyses described above continue to confirm the need for the Energy Gateway projects, but have also been used to identify short-term improvements throughout the Company's system that have helped maximize efficient use of the existing system and defer the need for larger scale infrastructure investment. Over the past 20 to 30 years, limited new transmission capacity has been added to the system. Instead, PacifiCorp has maintained system reliability and maximized system efficiency through these smaller-scale, incremental projects.

System-wide, the Company has instituted more than 120 grid operating procedures and 17 special protection schemes to maximize the existing system capability while managing system risk. Since 2008, the Company has upgraded or rebuilt over 140 miles of existing Wyoming 230 kV transmission lines to achieve new capacity, relocated and reused more than 800 MVA of existing transformers, upgraded three major series capacitors to increase capacity, and obtained WECC approval of four major path rating upgrades. PacifiCorp recently installed equipment that will allow real time dynamic line ratings on a critical 230 kV path in Wyoming (pending WECC approval). This equipment will allow the maximum capability of the conductor, or winter rating, to be used during periods of moderate temperature in summer months, as a way to maximize capability of the existing system. Other transmission system improvements include:

- Southern Utah:
 - Installed 345 kV series capacitor at Pinto substation;
 - Installed shunt capacitors at Pinto and Red Butte substations;
 - Installed static var compensator at Red Butte substation;
 - Installed second 230/345 kV transformer at Harry Allen substation in Las Vegas, Nevada.
- ➔ These investments, together, helped maximize the existing system's capability, improved the Company's ability to serve growing customer loads, increased transfer capacity across WECC Paths TOT2B1 (Four Corners to Pinto, Glen Canyon to Sigurd) and TOT2C (Harry Allen to Red Butte), and reduced the risk of voltage collapse following the loss of one of the two 345 kV lines serving the Red Butte area. Specifically, these benefits include the upgrade of Path TOT2C by 300 MW, the simultaneous operation of Paths TOT2C and TOT2B1 to approved limits, and elimination of a Path TOT2B1 de-rate with growing load in southern Utah.
- Wyoming
 - Reconductored over 66 miles of 230 kV line between Windstar, Dave Johnston and Casper;
 - Installed shunt capacitors at Riverton, Midwest and Atlantic City substations;
 - Replaced components of the Jim Bridger transmission system Remedial Action Scheme (RAS);
 - Upgraded the series capacitor at the Borah substation and the switches in the Borah and Kinport substations;
 - Installed a dynamic line rating system on the Miners to Platte 230 kV line;
 - Installed a phase shifting transformer at the Monument substation.

- ➔ These investments improved reliability and helped maximize the transmission system’s capabilities, providing numerous system and customer benefits:
 - Maximized transfer capability between Windstar, Dave Johnston and Casper substations during all seasons;
 - Improved the Company’s ability to move Wyoming resources to PacifiCorp’s customer loads;
 - Increased transfer capacity of Paths TOT4A (south and west of Casper and Dave Johnston) and TOT4B (north and west of Casper and Dave Johnston), which otherwise would have been downgraded, requiring curtailment of generation in Wyoming;
 - Increased Bridger West path rating from 2200 MW to 2400 MW, allowing integration of new resources and improved ability to serve large-customer load growth in Wyoming;
 - Reduced risk of customer impact during peak-condition operation of Jim Bridger generator;
 - Eliminated line overload conditions and generating plant output reductions.

- Idaho
 - Installed two 230 kV capacitor banks at the Meridian substation located in Oregon which supports an increased eastbound line rating on the Summer Lake to Hemingway line from 400 MW to 550 MW.
 - ➔ This investment supports load growth and the ability to move additional resources and reserves from PacifiCorp’s western control area to its eastern control area, supporting reliability and load service.

- Oregon/Washington/California
 - Participated with BPA in a number of upgrades to the California-Oregon Intertie (COI), including two new series capacitor banks at Bakeoven substation; 500 kV capacitor banks at Captain Jack and Slatt substations; reconductoring of a section of the 500 kV line; and replacement and upgrade of the Malin substation series capacitor;
 - Reconductored the 230 kV tie line between Dixonville 500 kV and Dixonville 230 kV;
 - Installed the new Nickel Mountain 230-115 kV substation and converted Line 37 in southwest Oregon from 69 to 115 kV;
 - Converted Line 3 in the Medford, Oregon area and Line 1 in the Yreka, California area from 69 kV to 115 kV;
 - Reconductored 5 miles of the Union Gap to North Park 115 kV line in Yakima Washington.
 - ➔ These investments helped maximize the transmission system’s capabilities and provided numerous system and customer benefits, including:
 - Increased the COI operating capability by 300 MW;

- Improved the Company’s ability to move resources to customer loads;
- Enabled operation of the COI at its limits in the summer months, increasing the system capability by an average of 80 MW and supporting customer load growth;
- Improved reliability and support for customer load growth in southern Oregon and northern California;
- Complied with required NERC and WECC reliability standards and improved service to customers in the Yakima, Washington area.

These improvements have enabled more efficient use of the transmission system and, coupled with the recent economic sluggishness, have helped meet short-term needs. However, with projected long-term growth and the need for additional resources as depicted in our customers’ load and resource forecasts, PacifiCorp’s transmission system is approaching the point where no additional capacity is available, requiring additional transmission infrastructure to meet the long-term needs of our customers.

CHAPTER 5 – RESOURCE NEEDS ASSESSMENT

CHAPTER HIGHLIGHTS

- On both a capacity and energy basis, PacifiCorp calculates load and resource balances using existing resource levels, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability at the time of the coincident system peak load hour.
- For capacity expansion planning, the Company uses a 13-percent planning reserve margin applied to PacifiCorp's obligation (Loads – Interruptibles – DSM). The 13-percent planning reserve margin is supported by Stochastic Loss of Load Probability Study in Appendix I.
- The system coincident peak load is forecasted to grow at a compounded average annual growth rate of 1.2 percent for 2013 through 2022. On an energy basis, PacifiCorp expects system-wide average load growth of 1.1 percent per year from 2013 through 2022.
- The Company has updated the calculation of the Load and Resource balance in-step with the upgraded IRP models. Certain items have moved from one component category to another. Sales moved from increasing obligation to reducing existing resources. Non-Owned Reserves moved from increasing reserves to reducing existing resources. Existing DSM and Interruptible contracts moved from increasing Existing Resources to reducing obligation.
- The Company projects a summer peak resource deficit of 824 MW for the PacifiCorp system beginning in 2013. The table below shows the system capacity position forecast, indicating the widening capacity deficit, which reaches 2,308 MW by 2022.
- The near-term deficit will be met by incremental demand-side management programs, and market purchases.

System	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Resources	10,010	10,065	9,996	9,602	9,556	9,553	9,487	9,488	9,864	9,803
Obligation	9,588	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718
Reserves (Based on 13% Target)	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Obligation + 13% Planning Reserves	10,834	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)
Reserve Margin	4.4%	2.9%	0.6%	(2.0%)	(4.0%)	(5.6%)	(7.5%)	(8.8%)	(6.7%)	(8.5%)

Introduction

This chapter presents PacifiCorp’s assessment of resource need, focusing on the first ten years of the IRP’s 20-year study period, 2013 through 2022. The Company’s long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are addressed in detail in Appendix A. The summary level system coincident peak is presented 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 indicates when PacifiCorp is expected to be either deficit or surplus on both a capacity and energy basis for each year of the planning horizon.

System Coincident Peak Load Forecast

The system coincident peak load is the maximum load on the system in any hour in a one-year period. The Company’s long-term load forecasts (both energy and coincident peak) for each state and the system are addressed in detail in Appendix A.

The 2013 IRP used the Company’s July 2012 load forecast. Table 5.1 shows the annual coincident peak load stated in megawatts as reported in the capacity load and resource balance prior to any load reductions from energy efficiency (Class 2 DSM). The system peak load grows at a compounded average annual growth rate (CAAGR) of 1.2 percent for 2013 through 2022.

Table 5.1 – Forecasted System Coincidental Peak Load in Megawatts, Prior to Energy Efficiency Reductions

Region	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System	10,136	10,330	10,495	10,359	10,512	10,687	10,816	10,971	11,133	11,280

Existing Resources

For the forecasted 2013 summer peak, PacifiCorp owns, or has interest in, resources with an expected system peak capacity of 11,964 MW. Table 5.2 provides anticipated system peak capacity ratings by resource category as reflected in the IRP load and resource balance for 2013. Note that capacity ratings in the following tables are rounded to the nearest megawatt and a column shows the Load and Resource balance capacity value at the time of system coincident peak.

Table 5.2 – 2013 Capacity Contribution at System Peak for Existing Resources

Resource Type ^{1/}	L&R Balance Capacity at System Peak (MW) ^{2/}	Percent (%)
Pulverized Coal	6,168	51.6%
Gas-CCCT	1,994	16.7%
Gas-SCCT	562	4.7%
Hydroelectric	913	7.6%
DSM ^{3/}	407	3.4%
Renewables	121	1.0%
Purchase ^{4/}	1,487	12.4%
Qualifying Facilities	171	1.4%
Interruptible	141	1.2%
Total	11,964	100%

^{1/} Sales and Non-Owned Reserves are not included.

^{2/} Represents the capacity available at the time of system peak used for preparation of the capacity load and resource balance. For specific definitions by resource type see the section entitled, “Load and Resource Balance Components”, later in this chapter.

^{3/} DSM includes existing Class 1 and Class 2 programs.

^{4/} Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.

Thermal Plants

Table 5.3 lists existing PacifiCorp’s coal fired thermal plants and Table 5.4 lists existing natural gas fired plants. The assumed end of life dates are used for the 2013 IRP modeling of existing coal resources, additional information on methodology is in Chapter 7. The IRP confidential Volume III goes into additional analysis on coal plants.

Table 5.3 – Coal Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	L&R Balance Capacity at System Peak (MW)	Assumed End of Life Year
Carbon 1	100	Utah	67	2014
Carbon 2	100	Utah	105	2014
Cholla 4	100	Arizona	387	2042
Colstrip 3	10	Montana	74	2046
Colstrip 4	10	Montana	74	2046
Craig 1	19	Colorado	84	2034
Craig 2	19	Colorado	84	2034
Dave Johnston 1	100	Wyoming	106	2027
Dave Johnston 2	100	Wyoming	106	2027
Dave Johnston 3	100	Wyoming	220	2027
Dave Johnston 4	100	Wyoming	330	2027
Hayden 1	24	Colorado	45	2030

Plant	PacifiCorp Percentage Share (%)	State	L&R Balance Capacity at System Peak (MW)	Assumed End of Life Year
Hayden 2	13	Colorado	33	2030
Hunter 1	94	Utah	418	2042
Hunter 2	60	Utah	269	2042
Hunter 3	100	Utah	479	2042
Huntington 1	100	Utah	459	2036
Huntington 2	100	Utah	450	2036
Jim Bridger 1	67	Wyoming	354	2037
Jim Bridger 2	67	Wyoming	363	2037
Jim Bridger 3	67	Wyoming	349	2037
Jim Bridger 4	67	Wyoming	353	2037
Naughton 1	100	Wyoming	158	2029
Naughton 2	100	Wyoming	205	2029
Naughton 3*	100	Wyoming	330	2029
Wyodak	80	Wyoming	268	2039
TOTAL – Coal			6,168	

* Naughton 3 to repower to Natural Gas fueled generators in early 2015.

Table 5.4 – Natural Gas Plants

Natural Gas -fueled	PacifiCorp Percentage Share (%)	State	L&R Balance Capacity at System Peak (MW)
Chehalis	100	Washington	477
Currant Creek	100	Utah	506
Gadsby 1	100	Utah	57
Gadsby 2	100	Utah	69
Gadsby 3	100	Utah	105
Gadsby 4	100	Utah	39
Gadsby 5	100	Utah	39
Gadsby 6	100	Utah	39
Hermiston 1 *	50	Oregon	233
Hermiston 2 *	50	Oregon	233
Lake Side	100	Utah	545
Lake Side 2 **	100	Utah	628
James River Cogen (CHP)	100	Washington	14
West Valley – Lease	0	Utah	200
TOTAL – Gas and Combined Heat & Power			2,556

* Hermiston plant 50% owned and 50% under long-term contract.

** Lake Side 2 is currently under construction with in-service date of mid-2014.

Renewables

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

Wind

PacifiCorp either owns or purchases under contract 2,186 MW of wind resources. Since the 2011 IRP Update, the Company has entered into power purchase agreements totaling 160 MW:

- Meadow Creek
 - North Point
 - Five Pine
- Butter Creek
 - High Plateau
 - Mule Hollow
 - Lower Ridge
 - Pine City

Table 5.5 shows existing wind facilities owned by PacifiCorp, while Table 5.6 shows existing wind power purchase agreements.

Table 5.5 – PacifiCorp-owned Wind Resources

Utility-Owned Wind Projects	Capacity (MW)	L&R Balance Capacity at System Peak (MW)	In-Service Year	State
Foote Creek I *	33	2	2005	WY
Leaning Juniper	101	4	2006	OR
Goodnoe Hills East Wind	94	4	2007	WA
Marengo	140	6	2007	WA
Marengo II	70	3	2008	WA
Glenrock Wind I	99	4	2008	WY
Glenrock Wind III	39	2	2008	WY
Rolling Hills Wind	99	4	2008	WY
Seven Mile Hill Wind	99	4	2008	WY
Seven Mile Hill Wind II	20	1	2008	WY
High Plains	99	4	2009	WY
McFadden Ridge 1	29	1	2009	WY
Dunlap 1	111	4	2010	WY
TOTAL – Owned Wind	1,032	43		

*Net total capacity for Foote Creek I is 40 MW.

Table 5.6 – Wind Power Purchase Agreements and Exchanges

Power Purchase Agreements / Exchanges	Capacity (MW)	L&R Balance Capacity at System Peak (MW)	In-Service Year	State
Foote Creek II	2	0	2005	WY
Foote Creek III	25	1	2005	WY
Foote Creek IV	17	1	2005	WY
Combine Hills	41	2	2003	OR
Stateline Wind	175	17	2002	OR / WA
Wolverine Creek	65	3	2005	ID
Rock River I	50	2	2006	WY
Mountain Wind Power I	60	3	2008	WY

Power Purchase Agreements / Exchanges	Capacity (MW)	L&R Balance Capacity at System Peak (MW)	In-Service Year	State
Mountain Wind Power II	80	3	2008	WY
Spanish Fork Wind Park 2	19	1	2008	UT
Three Buttes Wind Power (Duke)	99	4	2009	WY
Oregon Wind Farms I	45	3	2009	OR
Oregon Wind Farms II	20	0	2010	OR
Casper Wind	17	0	2010	WY
Top of the World	200	8	2010	WY
Power County Wind Park North	22	1	2011	ID
Power County Wind Park South	22	1	2011	ID
Meadow Creek Project – North Point *	80	3	2012	ID
Meadow Creek Project – Five Pine *	40	2	2012	ID
Butter Creek – High Plateau *	10	0	2013	OR
Butter Creek – Lower Ridge *	10	0	2013	OR
Butter Creek – Mule Hollow *	10	0	2013	OR
Butter Creek – Pine City *	10	0	2013	OR
TOTAL – Purchased Wind	1,154	55		

*New since the 2011 IRP Update.

Geothermal

PacifiCorp owns and operates the Blundell Geothermal Plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus and is rated at 0.28 MW. The Company has also entered into a Qualifying Facility agreement for a 10 MW Oregon Geothermal plant scheduled to be online in late 2013.

Biomass / Biogas

Since the 2011 IRP Update, PacifiCorp has added more than 8 MW of Biogas resources. These types of resources are primarily Qualifying Facilities.

Renewables Net Metering

As of year-end 2012, PacifiCorp had 4,974 net metering customers throughout its six-state territory, generating more than 35,000 kW using solar, hydro, wind, and fuel cell technologies. About 95 percent of customer generators are solar-based, followed by wind-based generation at 4 percent of total generation.

Net metering has grown by more than 33 percent from last year. The Company averaged 114 new net metered customers a month in 2012, compared to 84 new customers per month in 2011.

Hydroelectric Generation

PacifiCorp owns 1,145 MW³⁴ of hydroelectric generation capacity and purchases the output from 136 MW of other hydroelectric resources. These resources account for approximately 10 percent of PacifiCorp’s total generating capability, in addition to providing operational benefits such as flexible generation, spinning reserves and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate or purchase from 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. Operational limitations of the hydroelectric facilities are impacted by varying water levels, licensing requirements for fish and aquatic habitat, and flood control; leading to load and resource balance capacity values that are different from net facility capacity ratings.

Hydroelectric purchases are categorized into two groups as shown in Table 5.7, which reports 2013 capacity included in the load and resource balance.

Table 5.7 – Hydroelectric Contracts - Load and Resource Balance Capacities

Hydroelectric Contracts by Load and Resource Balance Category	L&R Balance Capacity at System Peak (MW)
Hydroelectric	99
Qualifying Facilities - Hydroelectric	37
Total Contracted Hydroelectric Resources	136

Table 5.8 provides an operational profile for each of PacifiCorp’s owned hydroelectric generation facilities. The dates listed refer to a calendar year.

Table 5.8 – PacifiCorp Owned Hydroelectric Generation Facilities - Load and Resource Balance Capacities

Plant	State	L&R Balance Capacity at System Peak (MW)
West		
Big Fork	Montana	4
Clearwater 1	Oregon	15
Clearwater 2	Oregon	26
Copco 1 and 2	California	47
Fish Creek	Oregon	0
Iron Gate	California	11
JC Boyle	Oregon	15
Lemolo 1	Oregon	32
Lemolo 2	Oregon	16
Merwin	Washington	23
Rogue	Oregon	30
Small West Hydro ^{1/}	California / Oregon / Washington	3

³⁴ 2012 PacifiCorp 10-K filing shows 1,145 MW of Net Facility Capacity.

Plant	State	L&R Balance Capacity at System Peak (MW)
Soda Springs	Oregon	12
Swift 1	Washington	240
Swift 2 ^{2/}	Washington	72
Toketee and Slide	Oregon	26
East-Side / West-Side	Oregon	3
Yale	Washington	134
East		
Bear River	Idaho / Utah	86
Small East Hydro ^{3/}	Idaho / Utah / Wyoming	29
TOTAL – Hydroelectric before contracts		824
Hydroelectric Contracts		136
TOTAL – Hydroelectric		960

^{1/} Includes Bend, Condit, Fall Creek, and Wallowa Falls

^{2/} Cowlitz County PUD owns Swift No. 2, and is operated in coordination with the other projects by PacifiCorp

^{3/} Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock

Hydroelectric Relicensing Impacts on Generation

Table 5.9 lists the estimated impacts to average annual hydro generation from FERC orders and relicensing settlement commitments. PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned pursuant to the Klamath Hydroelectric Settlement Agreement in the year 2020 and that the Wallowa Falls project and other projects to be relicensed in future years will receive new operating licenses, but that additional operating restrictions imposed in new licenses, such as higher bypass flow requirements, will reduce generation available from these facilities.

Table 5.9 – Estimated Impact of FERC License Renewals and Relicensing Settlement Commitments on Hydroelectric Generation

Year	Lost Generation (MWh)
2013	201,228
2014	201,228
2015	201,228
2016	201,228
2017	201,228
2018	201,228
2019	201,228
2020	918,048
2021	918,048
2022	918,048
2023	918,048
2024	918,048
2025	918,048
2026	918,048
2027	918,048
2028	918,048
2029	918,048
2030	918,048

Year	Lost Generation (MWh)
2031	918,048
2032	918,048

Demand-side Management

DSM resources/products vary in their dispatchability, reliability of results, term of load reduction benefit and persistence over time. Each has its value and place in effectively managing utility investments, resource costs and system operations. Those that have greater persistence and firmness can be reasonably relied upon as a base resource for planning purposes; those that do not are more suited as system reliability resource options. 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. DSM resources/products can be divided into four general classes based on their relative characteristics, the classes are:

- Class 1 DSM: Resources from fully dispatchable or scheduled firm capacity product offerings/programs** – Class 1 DSM programs are those for which capacity savings occur as a result of active Company control or advanced scheduling. Once customers agree to participate in Class 1 DSM program, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. In most cases, loads are shifted rather than avoided. Examples include residential and small commercial central air conditioner load control programs (“Cool Keeper”) that are dispatchable in nature and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design and/or event noticing requirements).
- Class 2 DSM: Resources from non-dispatchable, firm energy and capacity product offerings/programs** – Class 2 DSM programs are those for which sustainable energy and related capacity savings are achieved through facilitation of technological advancements in equipment, appliances, lighting and structures, or repeatable and predictable voluntary actions on a customer’s part to manage the energy use at their facility or home. Class 2 DSM programs generally provide financial and/or service incentives to customers to improve the efficiency of existing or new customer-owned facilities through the installation of more efficient equipment such as lighting, motors, air conditioners, or appliances or upgrading building efficiency through improved insulation levels, windows, etc. however the category has recently been expanded to include strategic energy management efforts at business facilities and home energy reports in the residential sector. The savings endure (are considered firm) over the life of the improvement or customer action. Program examples include comprehensive commercial and industrial new and retrofit energy efficiency programs (“Energy FinAnswer” and “FinAnswer Express”), refrigerator recycling programs (“See ya later, refrigerator®”), comprehensive home improvement retrofit programs (“Home Energy Saving”), strategic energy management and home energy reports.
- Class 3 DSM: Resources from price responsive energy and capacity product offerings/programs** – Class 3 DSM programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. Savings are measured at a customer-by-customer level (via metering and/or metering data analysis against baselines), and customers are compensated or

in accordance with a program's pricing parameters. As a result of their voluntary nature, savings are less predictable, making them less suitable to incorporate into resource planning exercises, at least until such time that their size and customer behavior profile provide sufficient information for a reliable diversity result for modeling and planning purposes. Savings typically only endure for the duration of the incentive offering and in many cases 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 block tariff designs. Although the impacts of such programs may not be explicitly considered in the resource planning process however are captured naturally in long-term load growth patterns and forecasts.

- **Class 4 DSM: Non-incented behavioral based savings achieved through broad energy education and communication efforts** – Class 4 DSM programs promote reductions in energy or capacity usage through broad based energy education and communication efforts. The program objectives are to help customers better understand how to manage their energy usage through no cost actions such as conservative thermostat settings and turning off appliances, equipment and lights when not in use. The programs also are used to increase customer awareness of additional actions they might take to save energy and the service and financial tools available to assist them. Class 4 DSM programs help foster an understanding and appreciation of why utilities seek customer participation in Classes 1, 2 and 3 DSM programs. Program examples include Company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs such as "Let's turn the answers on" and "*watt*smart" campaigns. Like Class 3 resources, the impacts of such programs may not be explicitly considered in the resource planning process however are captured naturally in long-term load growth patterns and forecasts

PacifiCorp has been operating successful DSM programs since the late 1970s. While the Company's DSM focus has remained strong over this time, since the 2001 western energy crisis, the Company's DSM pursuits have been expanded in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1 through 4) and resource planning considerations. Company investments continue to increase year on year with 2012 investments of nearly \$120 million (all states). Work continues on the expansion of program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon the Company continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, and ensure adequate funding and Company support in pursuit of DSM resource targets. Washington's portfolio and programs continue to evolve under Initiative 937 requirements and the performance of Wyoming's program portfolio has shown increasing improvement since the latest round of program revisions were approved in November, 2011. Finally, significant changes to the Idaho and Utah Class 1 DSM portfolios are underway in an effort to improve program effectiveness and economics in those states and providing for a more viable delivery platforms for the expansion of Class 1 programs to the west side of the system as the need and value for new west-side capacity resources dictate.

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

Class 1 Demand-side Management

Currently there are two Class 1 DSM programs running across PacifiCorp's six-state service area; Utah's "Cool Keeper" residential and small commercial air conditioner load control program and Idaho's and Utah's dispatchable irrigation load management programs. In 2012 these programs accounted for over 350 MW of realized reduction from Class 1 DSM program resources under management helping the Company better manage demand during peak periods³⁵.

Class 2 Demand-side Management

The Company currently manages ten distinct Class 2 DSM products, many of which are offered in multiple states. In all, the combination of Class 2 DSM programs across the five states where the Company is directly responsible for delivery totals thirty-one. The cumulative historical energy and capacity savings (1992-2012) associated with Class 2 DSM program activity has accounted for over 5.4 million MWh and approximately 925 MW of non-coincident peak load reductions.

Class 3 Demand-side Management

The Company has numerous Class 3 DSM offerings currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), residential seasonal inverted block rates (Idaho, Utah and Wyoming), residential year-round inverted block rates (California, Oregon and Washington) and Energy Exchange programs (all states). System-wide, approximately 19,500 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2011.³⁶ All of the Company's residential customers not opting for a time-of-use rates are currently subject to seasonal or year-round inverted block rate plans.

Savings associated with these resources are captured within the Company's load forecast, with the exception of the more immediate call-to-action programs, and are thus captured in the integrated resource planning framework. PacifiCorp continues to evaluate Class 3 DSM programs for applicability to long-term resource planning. As part of the development of the 2013 IRP, the Company commissioned a study by The Cadmus Group to investigate the handling of Class 3 DSM by utilities in integrated resource planning. The study, titled "Treatment of Class 3 DSM Resources in Integrated Resource Planning", is provided as Appendix D and provides valuable insights into methods used to account for the impacts of Class 3 DSM resources in integrated resource planning. The study also led to a more thorough impact assessment of the Company's existing Class 3 DSM offerings in the updated "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" ("DSM Potential Study"), the study that was used in the development of the revised DSM resource supply-curves used in the 2013 IRP. Those impacts are reflected in Table 5.10 below. In addition, the update to the DSM Potential Study expanded its analysis of the interactive effects of competing DSM resources in order to allow for modeling of all classes of DSM resources at the same time without the risks of over estimating their impacts. The DSM Potential Study is provided as Appendix D.

³⁵ Realized reductions vary by event (temperature and month and time dependent), cited load reduction represents the sum of the highest event performance across the three states for the two programs and account for line losses (are "at generator" values).

³⁶ Year-end 2011 participation data were used for the analysis in the DSM Potential Study. At the end of 2012, there were approximately 19,200 customers on time-varying rates.

As discussed in Chapter 6, five Class 3 DSM programs were provided as resource options in preliminary IRP modeling scenarios.

Class 4 Demand-side Management

Educating customers regarding energy efficiency and load management opportunities is an important component of the Company’s long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts and messages, newsletters, school education programs, and personal contact. Load reductions due to Class 4 DSM activity will show up in Class 1 and Class 2 DSM program results and non-program reductions in the load forecast over time.

Table 5.10 summarizes the existing DSM programs. Note that since Class 2 DSM is determined as an outcome of resource portfolio modeling and is included in the preferred portfolio, existing Class 2 DSM is shown as having zero MW³⁷.

Table 5.10 – Existing DSM Summary, 2013-2022

Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2013-2022 Period
1	Residential/small commercial air conditioner load control	120 MW summer peak	Yes
	Irrigation load management	209 MW summer peak ³⁸	Yes
	Interruptible contracts	2013~ 324 MW, 2014~298 MW 2015-2022~310 MW	Yes.
2	Company and Energy Trust of Oregon programs	0 MW	No. Class 2 DSM programs are modeled as resource options in the portfolio development process, and included in the preferred portfolio.
3	Energy Exchange	0-19 ³⁹ MW (assumes no other Class 3 DSM competing products running)	No. Program is leveraged as economic and reliability resource dependent on market prices/system loads.
	Time-based pricing	27-143 MW summer peak, 19,500 customers	No. Historical behavior is captured in load forecast. Impacts estimated in 2013 Conservation Potential Assessment
	Inverted rate pricing	45-123 MW summer peak, 1.5 million residential customers	No. Historical behavior is captured in load forecast. Impacts estimated in 2013 Conservation Potential Assessment

³⁷ The impacts of historic acquisition rates of Class 2 DSM are backed out of the load forecast prior to modeling for new Class 2 DSM.

³⁸ Assumes realized irrigation load curtailment in Idaho and Utah of 171 MW and 38 MW, respectively.

³⁹ 2013 Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources.

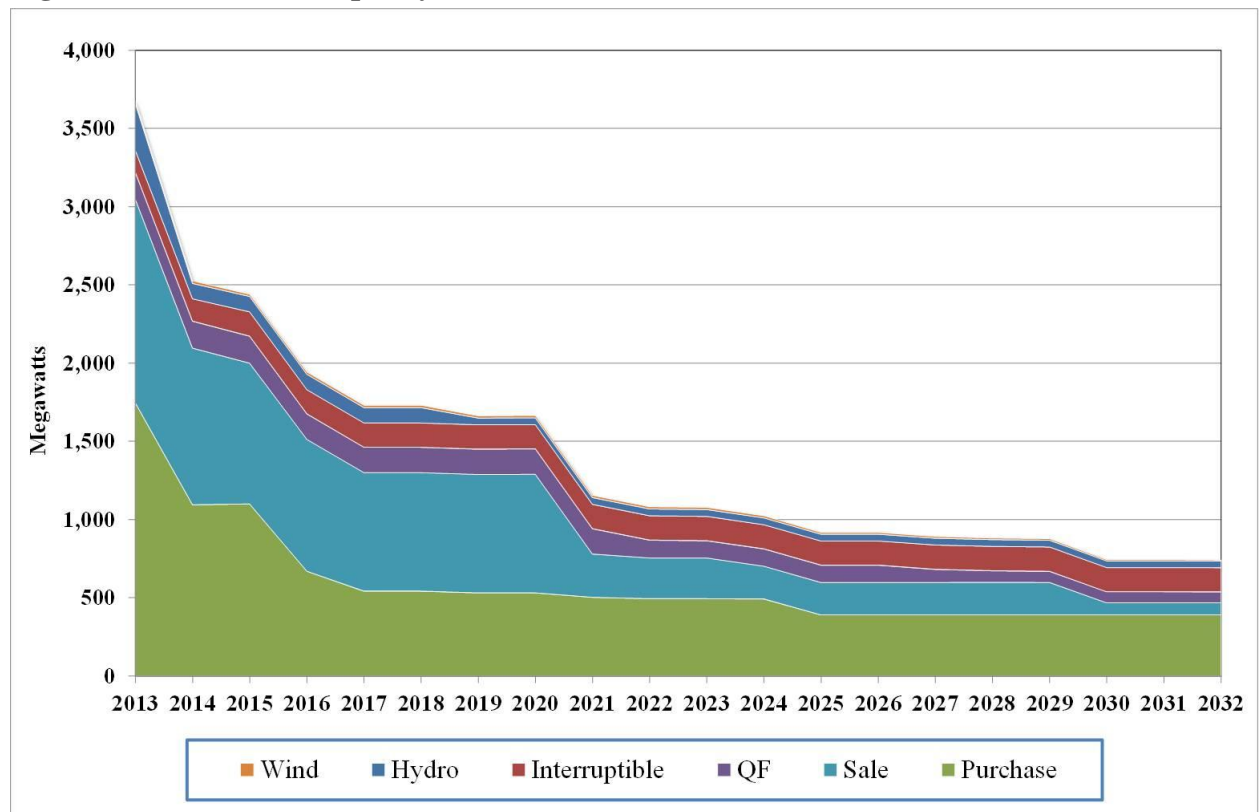
Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2013-2022 Period
4	Energy Education	MWa/MW unavailable	No. Program impacts is captured in load forecast over time and other Class 1 and 2 DSM program results.

Power Purchase Contracts

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

Figure 5.1 presents the contract capacity in place for 2013 through 2032 as of November 2012. 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 through the end of the IRP study period.) Note that renewable wind contracts are shown at their capacity contribution levels.

Figure 5.1 – Contract Capacity in the 2013 Load and Resource Balance



Listed below are the major contract expirations expiring between the summer 2013 and summer 2014:

- Expiring Front Office Transactions East – 300 MW
- Expiring Utah Capacity Purchase East – 200 MW
- Expiring Front Office Transactions West – 100 MW
- Expiring Bonneville Power Administration Spring / Summer Option – 150 MW
- Net decrease for other contracts – 18 MW

Load and Resource Balance

Capacity and Energy Balance Overview

The purpose of the load and resource balance is to compare the annual obligations 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 (2013-2022) of the planning horizon. The peak load and load interruptible programs and load reduction DSM programs were netted 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 (PRM), 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 (2013-2022). The average obligation (load less DSM programs) was computed and subtracted from the average existing resource availability for each month and time-of-day period. This was done for each side of the PacifiCorp system as well as at the system level. The energy balance complements the capacity balance in that it also indicates when resource deficits occur, but it also provides insight into what type of resource will best fill the need. The usefulness of the energy balance is limited as it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed with the portfolio studies described in Chapter 8.

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. The Company has updated the calculation of the Load and Resource balance in-step with the upgraded IRP models. Certain items have moved from one component category to another.

Under the new calculation, there are now negative values in the table for both the resources and obligation sections. This modification provides an improvement as to how resources are modeled and represented in the categories in relation to the updated models. The four resource categories are Sales, Non-Owned Reserves, Interruptibles, and Class 1 DSM. Later in the portfolio load and resource balance Class 2 DSM follows Class 1 DSM into the obligation section. Listed below are the changes for the four categories:

- Sales moved from increasing obligation to reducing Existing Resources
- Non-Owned Reserves moved from increasing Reserves to reducing Existing Resources
- Existing Class 1 DSM moved from increasing Existing Resources to reducing obligation
- Existing Interruptible contracts moved from increasing Existing Resources to reducing obligation

For comparability to prior IRP load and resource balance tables, Table 5.11 has been provided in the prior format. This next section provides a description of these various components.

Existing Resources

A description of each of the resource categories follows:

- **Thermal.** This category 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 de-rates them for forced outages and maintenance. This includes the existing fleet of 11 coal-fired plants, six natural gas-fired plants, and one cogeneration unit. These thermal resources account for roughly two-thirds of the firm capacity available in the PacifiCorp system.
- **Hydro.** This category 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 the time of system peak, an approach consistent with current WECC capacity reporting practices. The energy associated with critical level stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. The energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation, are also accounted for. Over 90 percent of the hydroelectric capacity is situated on the west side of the PacifiCorp system.
- **Renewable.** This category comprises geothermal and variable (wind and solar) renewable energy capacity. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages.

For wind and solar resources, the Company changed its method of calculating capacity contributions for wind and solar resources for this IRP. Rather than using a statistical approach to derive peak load carrying capabilities for each resource, the Company now determines aggregate peak capacity credits for each resource type by analyzing historical energy generation data for the period 2007 through 2010. For wind resources, PacifiCorp calculated the capacity credit for each year by first summing the hourly generation for all

wind resources for each hour of the year and dividing the hourly generation by the aggregate nameplate capacity to get hourly capacity factors. The average capacity factor for the 100 highest summer peak hours in the year is then calculated. Finally, the wind capacity credit is multiplied by 0.90, or 90 percent, to reflect the Company's assumption that there is a 90 percent probability that the wind resources will generate at the annual historical level in future years. The resulting annual capacity credit, averaged for the four years of historical data, is 4.2 percent. Since the Company has no historical data for solar resources, a similar set of calculations was performed based on simulated hourly solar profiles that use historic meteorological solar radiation data for five locations across the Company's service territory. The capacity credit for solar resources is 13.6 percent assuming that most installations are optimized for energy output rather than peak capacity. See Appendix O for additional information on wind and solar peak contributions.

- **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 QF 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 should be noted that three of the QF resources (Kennecott, Tesoro, and US Magnesium) are considered non-firm and thus do not contribute to capacity planning.
- **Sales.** This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system peak and the energy balance counts them by optimum model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view. Due to the way System Optimizer now handles the calculation of reserve margins, sales are now categorized as a resource modifier, and are applied as a decrease to resource capacity.
- **Non-owned reserves.** For this IRP, non-owned reserves capacity is now categorized as a decrease to resource capacity to represent the treatment of Non-owned reserve capacity in the of System Optimizer. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. The annual reserve obligation is about 9 MW and 138 MW on the west and east balancing authorities, respectively. As the balancing authority, PacifiCorp is required to hold reserves for these counterparties but is not required to serve any associated loads.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less Demand-side Management and less Interruptibles. The following are descriptions of each of these components:

- **Load.** The largest component of the obligation is the retail load. The capacity balance counts the peak load (MW) at the hour of system coincident peak load. The system coincident peak hour is determined by summing the loads for all locations (topology bubbles with loads).

Loads reported by East and West control areas thus reflect loads at the time of PacifiCorp's coincident system peak. The energy balance counts the load as an average of monthly as well as annual time-of-day energy (MWa).

- **Dispatchable Load Control (Class 1 DSM).** For this IRP, existing dispatchable load control program capacity is categorized as a decrease to the obligation rather than an increase to resource capacity as was done for prior IRPs. This change is in line with the treatment of DSM capacity in the latest version of System Optimizer. DSM capacity is now handled as a “load modifier”, which means that it reduces load in the denominator of the planning reserve margin formula used by the model (As noted below, the reserve margin is the difference between system capability and anticipated peak demand as a percentage of the peak load.) In contrast, prior capacity balances included existing Class 1 DSM as a resource increase.
- **Interruptible.** There are three east-side load curtailment contracts in this category. These agreements with Monsanto, US Magnesium, and Nucor provide about 324 MW of load interruption capability at time of system peak. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus planning reserves are not held for them. As with Class 1 DSM, this resource is now categorized as a decrease to the peak load.

Reserves

The reserves are the total megawatts of planning 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 (PRM). The planning reserve margin accounts for WECC operating reserves⁴⁰, load forecast errors, and other long-term resource adequacy planning uncertainties. The following equation expresses the planning reserve requirement.

Position

The position is the resource surplus (deficit) after subtracting obligation plus required reserves from the resource total. 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 difference between system capability and anticipated peak demand, measured either in megawatts or as a percentage of the peak load. A positive reserve margin indicates that system capabilities exceed system obligations. Conversely, a negative reserve margin indicates that system capabilities do not meet obligations. If system capabilities equal obligations, then the reserve margin is zero. It should be pointed out that the position can be negative when the corresponding reserve margin is non-negative. This is because the reserve margin is measured relative only to obligation, while the position is measured relative to obligation plus reserves. PacifiCorp adopted a 13 percent target planning reserve margin for the 2013 IRP. Note that a resource can only serve load in another topology location if there is

⁴⁰ As part of the WECC, PacifiCorp is currently required to maintain at least 5 percent and 7 percent operating reserve margins on hydro and thermal load-serving resources, respectively.

adequate transfer capacity. PacifiCorp captures transfer capacities as part of its capacity expansion planning process. The supporting loss of load probability study is included as Appendix I.

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:

$$\textit{Existing Resources} = \textit{Thermal} + \textit{Hydro} + \textit{Renewable} + \textit{Firm Purchases} + \textit{Qualifying Facilities} - \textit{Firm Sales} - \textit{Non-owned Reserves}$$

The peak load, Interruptible and Class 1 DSM are netted together for each of the annual system peak hours to compute the annual peak-hour obligation:

$$\textit{Obligation} = \textit{Load} - \textit{Class 1 DSM} - \textit{Interruptibles}$$

The amount of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the planning reserve margin of 13%. The formula for this calculation is the following:

$$\textit{Planning Reserves} = \textit{Obligation} \times \textit{PRM}$$

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

$$\textit{Capacity Position} = \textit{Existing Resources} - (\textit{Obligation} + \textit{Reserves})$$

Firm capacity transfers from PacifiCorp's west to east control areas are reported for the east capacity balance, while capacity transfers from the east to west control areas are reported for the west capacity balance. Capacity transfers represent the optimized control area interchange at the time of the system coincident peak load as determined by the System Optimizer model.⁴¹

Load and Resource Balance Assumptions

The assumptions underlying the current load and resource balance are generally the same as those from the 2011 IRP update with a few exceptions. The following is a summary of these assumption changes:

- **Wind Additions.** Since the 2011 IRP Update the following wind resource additions are included in existing portion of the Load and Resource balance:

⁴¹ West-to-east and east-to-west transfers should be identical. However, decimal precision of a transmission loss parameter internal to the System Optimizer model results in a slight discrepancy (less than 2 MW) between reported values.

New Qualifying Facility Wind Plants

- Meadow Creek Project – Five Pine – 40 MW
 - Meadow Creek Project – North Point – 80 MW
 - Lower Ridge Wind – 10 MW
 - Mule Hollow Wind – 10 MW
 - High Plateau Wind – 10 MW
 - Pine City Wind – 10 MW
- **Solar Wind.** PacifiCorp has acquired a 2 MW photovoltaic solar plant in eastern Oregon to meet the Oregon Statute ORS 757.370, which requires the Company to acquire 8.7 MW_{ac} of qualifying photovoltaic system capacity by 2020.
 - Black Cap Solar – 2 MW
 - **Coal plant turbine upgrades.** The current load and resource balance assumes 14 MW of coal plant turbine upgrades for Craig unit 2 (2 MW) and Jim Bridger Unit 2 (12 MW), completing the scheduled upgrades as noted in the 2011 IRP Update Report.
 - **Construction of Lake Side 2.** PacifiCorp has begun construction of the Lake Side 2 plant in Utah. This plant is expected to have a net capacity of 645 MW.

Capacity Balance Results

PacifiCorp has updated the format for the load and resource balance table in Table 5.12. For reference, the Company has also provided table 5.11 which shows the same underlying information but in the table format used in prior IRPs. The tables show the annual capacity balances and component line items using a target planning reserve margin of 13 percent to calculate the planning reserve amount. Balances for the system as well as PacifiCorp's east and west balancing authority 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.) Also note that the new Qualifying Facility wind projects listed above are reported under the Qualifying Facilities line item rather than the Renewables line item.

Table 5.11 provides a view of the Load and Resource balance using the old IRP's format for comparability to past IRP tables on the system level.

Table 5.11 – Old IRP Format: System Capacity Loads and Resources without Resource Additions

Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System										
Thermal	8,724	9,150	8,984	8,974	8,957	8,957	8,957	8,957	8,957	8,954
Hydroelectric	913	891	916	917	915	912	858	861	782	785
Class 1 DSM	407	407	407	407	407	407	407	407	407	407
Renewable	121	121	119	119	119	119	119	119	118	99
Purchase	1,487	836	842	411	298	298	287	287	259	259
Qualifying Facilities	171	172	172	162	162	162	161	162	162	114
Interruptible	141	143	155	155	155	155	155	155	155	155
Transfers	(2)	(1)	0	0	0	0	0	(2)	0	0
System Existing Resources	11,962	11,719	11,595	11,145	11,013	11,010	10,944	10,946	10,840	10,773
System Total Resources	11,962	11,719	11,595	11,145	11,013	11,010	10,944	10,946	10,840	10,773
Load	10,136	10,330	10,495	10,359	10,512	10,687	10,816	10,971	11,133	11,280
Sale	1,292	992	890	834	748	748	748	749	267	261
System Obligation	11,428	11,322	11,385	11,193	11,260	11,435	11,564	11,720	11,400	11,541
Planning reserves (13%)	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Non-owned reserves	112	112	147	147	147	147	147	147	147	147
System Reserves	1,358	1,383	1,438	1,421	1,441	1,463	1,480	1,500	1,521	1,540
System Obligation + Reserves	12,786	12,705	12,823	12,614	12,701	12,898	13,044	13,220	12,921	13,081
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)

Table 5.12 – Updated Format: System Capacity Loads and Resources without Resource Additions

Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
East										
Thermal	6,200	6,626	6,460	6,454	6,454	6,454	6,454	6,454	6,454	6,454
Hydroelectric	137	140	140	135	135	132	135	135	135	135
Renewable	85	85	83	83	83	83	83	83	82	80
Purchase	1,005	611	611	398	285	285	285	285	257	257
Qualifying Facilities	83	73	73	73	73	73	73	73	73	25
Sale	(1,032)	(732)	(730)	(724)	(638)	(638)	(638)	(639)	(158)	(158)
Non-Owned Reserves	(103)	(103)	(138)	(138)	(138)	(138)	(138)	(138)	(138)	(138)
Transfers	750	829	737	672	678	683	1,124	1,122	1,124	706
East Existing Resources	7,125	7,529	7,236	6,953	6,932	6,934	7,378	7,375	7,829	7,361
Load	6,920	7,061	7,188	6,994	7,105	7,217	7,337	7,455	7,584	7,697
Existing Resources:										
Interruptible	(141)	(143)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)
DSM	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
East obligation	6,400	6,539	6,654	6,460	6,571	6,683	6,803	6,921	7,050	7,163
Planning Reserves (13%)	832	850	865	840	854	869	884	900	917	931
East Reserves	832	850	865	840	854	869	884	900	917	931
East Obligation + Reserves	7,232	7,389	7,519	7,300	7,425	7,552	7,687	7,821	7,967	8,094
East Position	(107)	140	(283)	(347)	(493)	(618)	(309)	(446)	(138)	(733)
East Reserve Margin	11.3%	15.1%	8.7%	7.6%	5.5%	3.8%	8.5%	6.6%	11.0%	2.8%
West										
Thermal	2,524	2,524	2,524	2,520	2,503	2,503	2,503	2,503	2,503	2,500
Hydroelectric	776	751	776	782	780	780	723	726	647	650
Renewable	36	36	36	36	36	36	36	36	36	19
Purchase	482	225	231	13	13	13	2	2	2	2
Qualifying Facilities	88	99	99	89	89	89	88	89	89	89
Sale	(260)	(260)	(160)	(110)	(110)	(110)	(110)	(110)	(109)	(103)
Non-Owned Reserves	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Transfers	(752)	(830)	(737)	(672)	(678)	(683)	(1,124)	(1,124)	(1,124)	(706)
West Existing Resources	2,885	2,536	2,760	2,649	2,624	2,619	2,109	2,113	2,035	2,442
Load	3,216	3,269	3,307	3,365	3,407	3,470	3,479	3,516	3,549	3,583
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
West obligation	3,188	3,241	3,279	3,337	3,379	3,442	3,451	3,488	3,521	3,555
Planning Reserves (13%)	414	421	426	434	439	447	449	453	458	462
West Reserves	414	421	426	434	439	447	449	453	458	462
West Obligation + Reserves	3,602	3,662	3,705	3,771	3,818	3,889	3,900	3,941	3,979	4,017
West Position	(717)	(1,126)	(945)	(1,122)	(1,194)	(1,270)	(1,791)	(1,828)	(1,944)	(1,575)
West Reserve Margin	(9.5%)	(21.8%)	(15.8%)	(20.6%)	(22.3%)	(23.9%)	(38.9%)	(39.4%)	(42.2%)	(31.3%)
System										
Total Resources	10,010	10,065	9,996	9,602	9,556	9,553	9,487	9,488	9,864	9,803
Obligation	9,588	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718
Reserves	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Obligation + Reserves	10,834	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)
Reserve Margin	4.4%	2.9%	0.6%	(2.0%)	(4.0%)	(5.6%)	(7.5%)	(8.8%)	(6.7%)	(8.5%)

Figures 5.2 through 5.4 charts the table above for annual capacity position (resource surplus or deficits) for the system, west balancing area, and east balancing area, respectively. The east increase in 2014 is primarily due to the addition of Lake Side 2 natural gas plant.

Figure 5.2 – System Capacity Position Trend

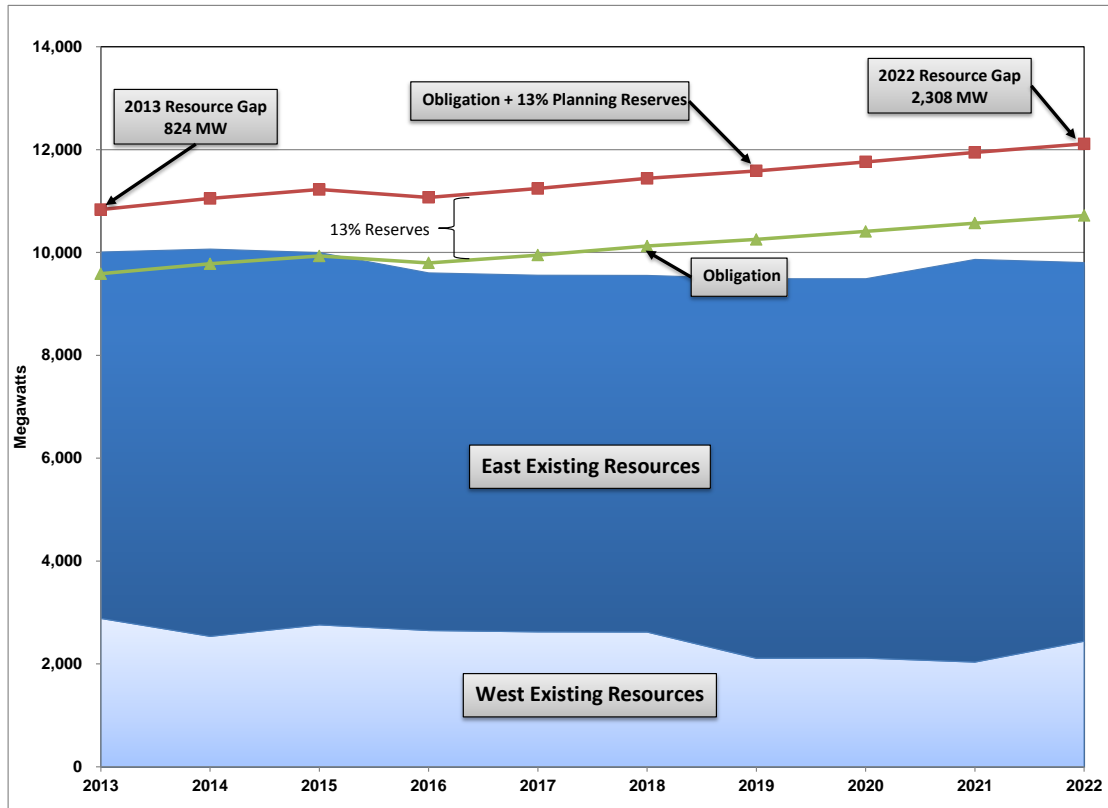


Figure 5.3 – West Capacity Position Trend

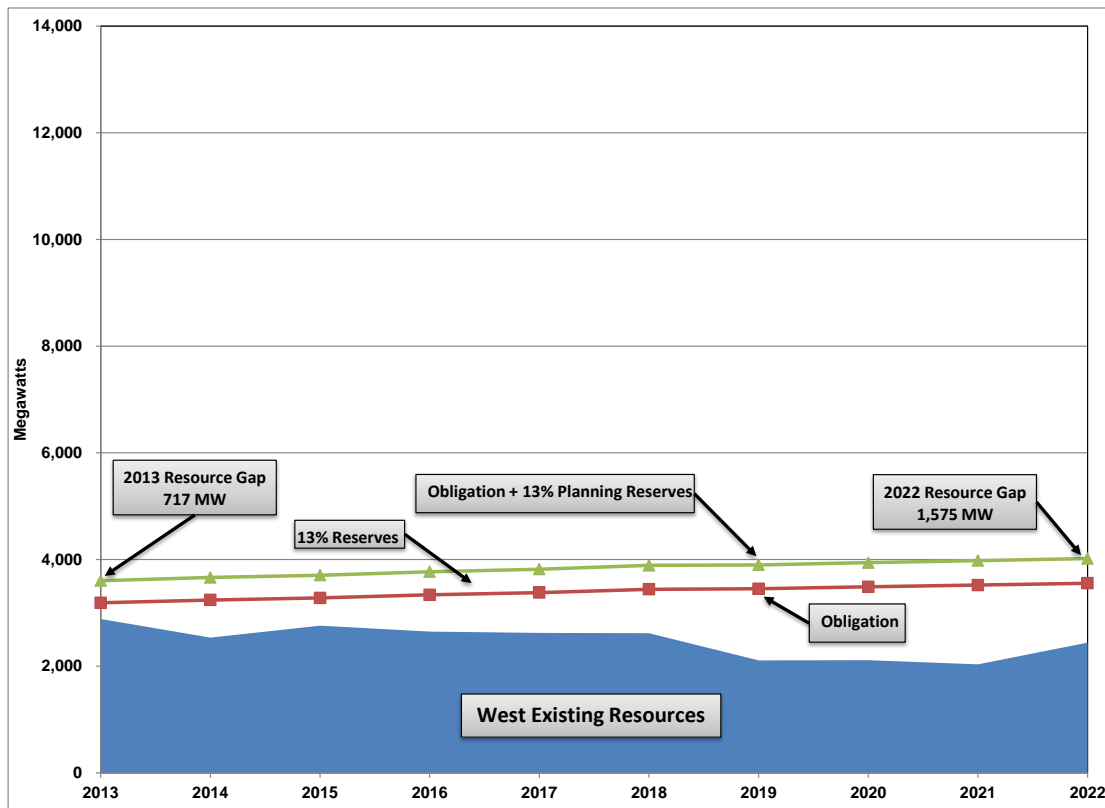
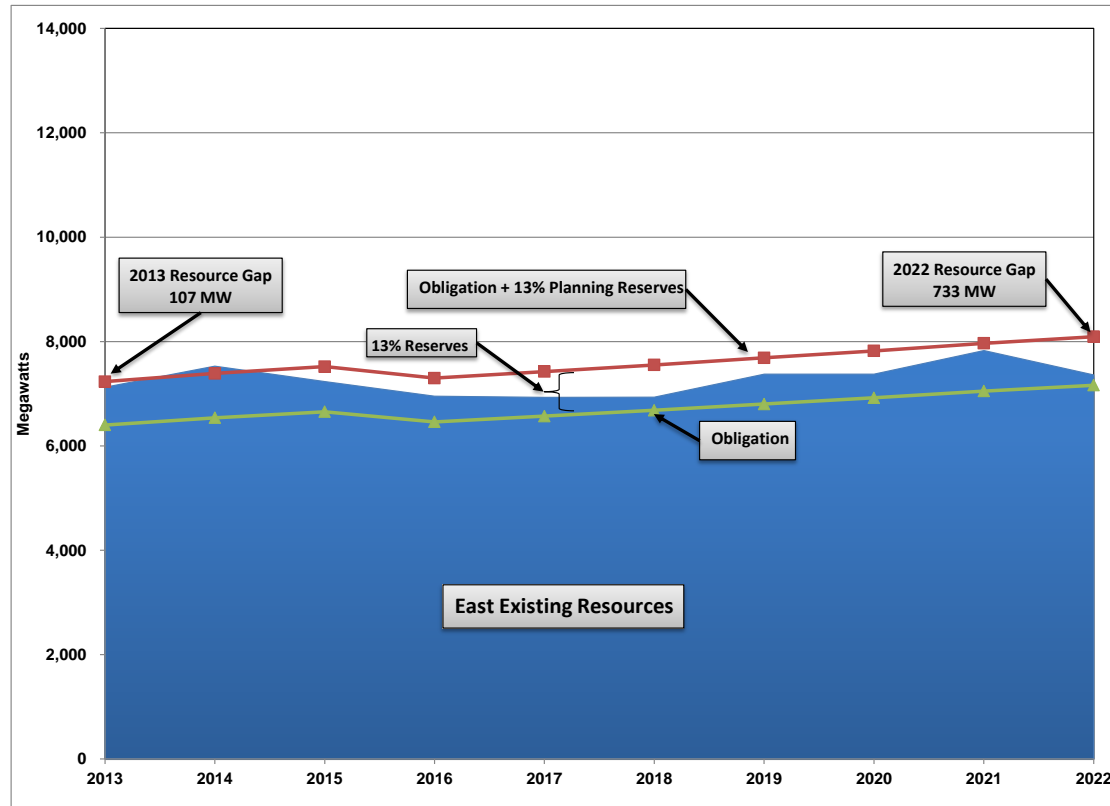


Figure 5.4 – East Capacity Position Trend



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. 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.

$$\text{Existing Resources} = \text{Thermal} + \text{Hydro} + \text{Class 1 DSM} + \text{Renewable} + \text{Firm Purchases} + \text{QF} + \text{Interruptible} - \text{Sales}$$

The average obligation is computed using the following formula:

$$\text{Obligation} = \text{Load} + \text{Sales}$$

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

$$\text{Energy Position} = \text{Existing Resources} - \text{Obligation} - \text{Reserve Requirements (13 percent PRM)}$$

Energy Balance Results

The capacity position shows how existing resources and loads balance during the coincident peak load hour of the year inclusive of a planning reserve margin. Outside of the peak hour, the Company economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, the Company can dispatch resources that in aggregate exceed then-current load obligations facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs fall below prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how the Company manages net power costs. Figures 5.5 through 5.7 provide for the system, west balancing area, and east balancing area, respectively, a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and current wholesale power and natural gas prices.⁴² The figures show expected monthly energy production from resources during on-peak and off-peak periods in relation to load assuming no additional resources are added to PacifiCorp's system. At times, resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figures 5.5 through 5.7 also show how much energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and are indicative of short energy positions absent the addition of incremental resources to the portfolio. During on-peak periods, the first energy shortfall appears in July 2018, and by 2022 available system energy falls short of monthly loads in January, July, August, and October. During off-peak periods, there are no energy shortfalls through the 2022 timeframe.

⁴² On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday, excluding NERC-observed holidays. All other hours define off-peak periods.

Figure 5.5 – System Average Monthly and Annual Energy Positions

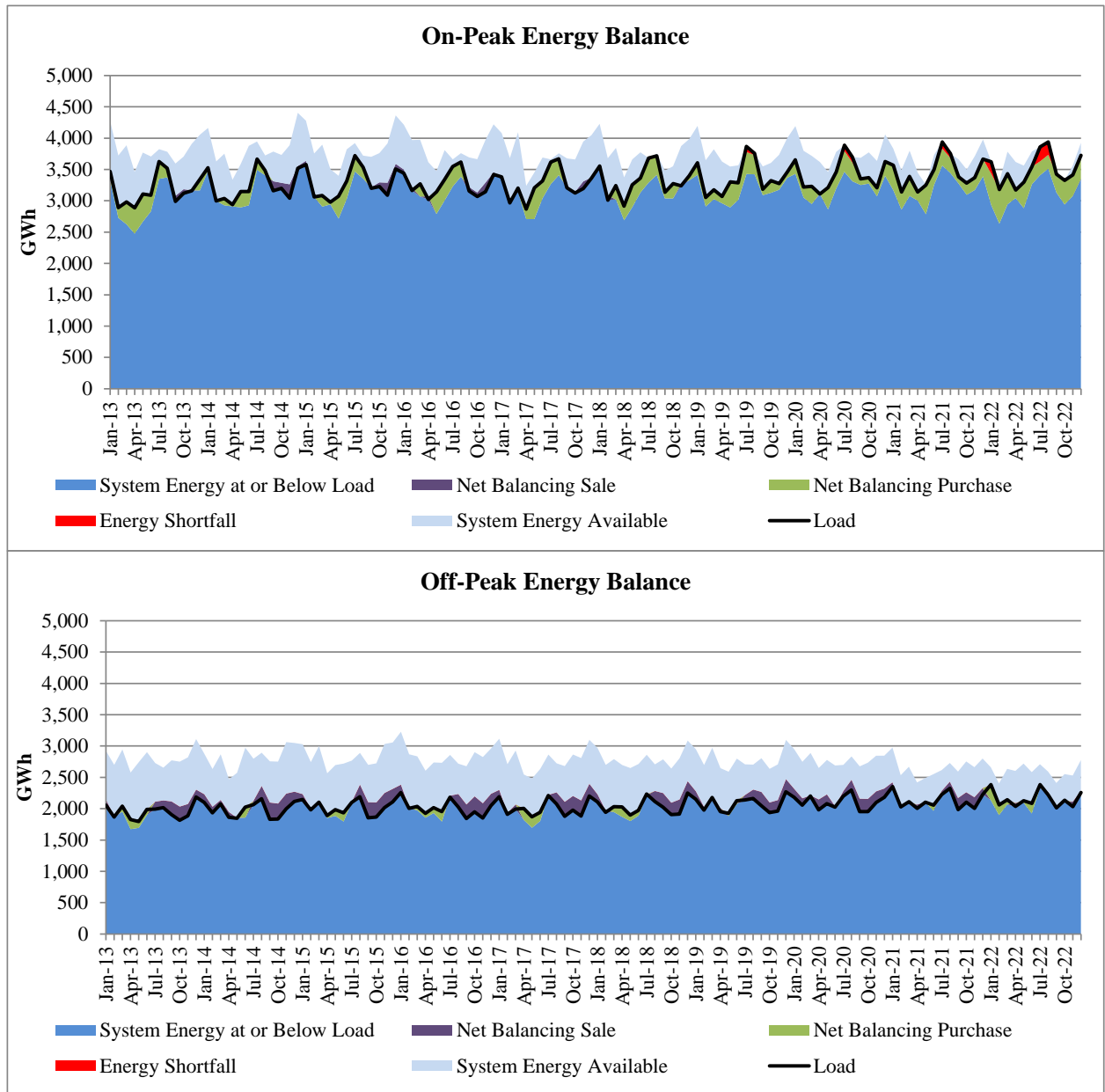


Figure 5.6 – West Average Monthly and Annual Energy Positions

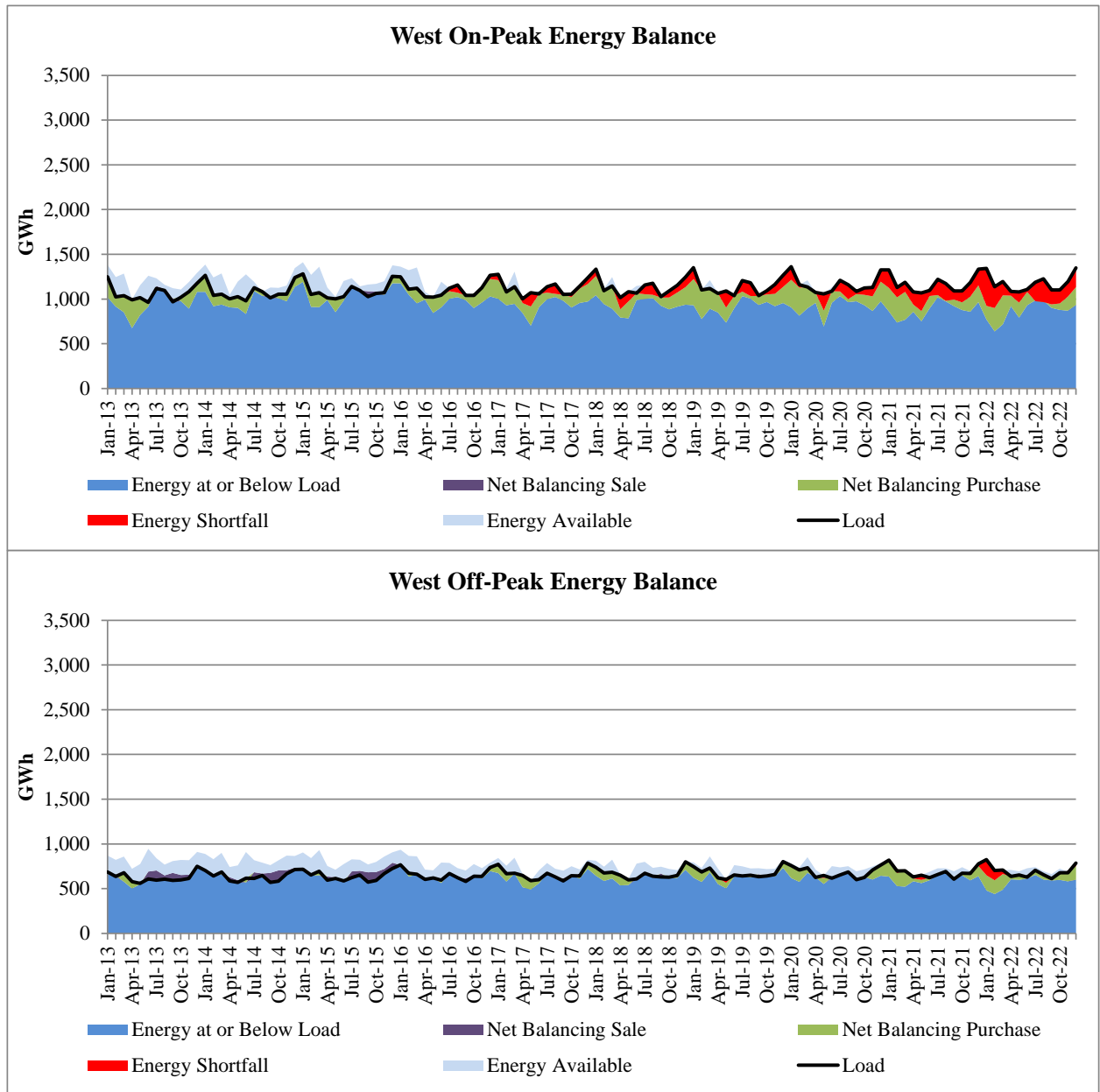
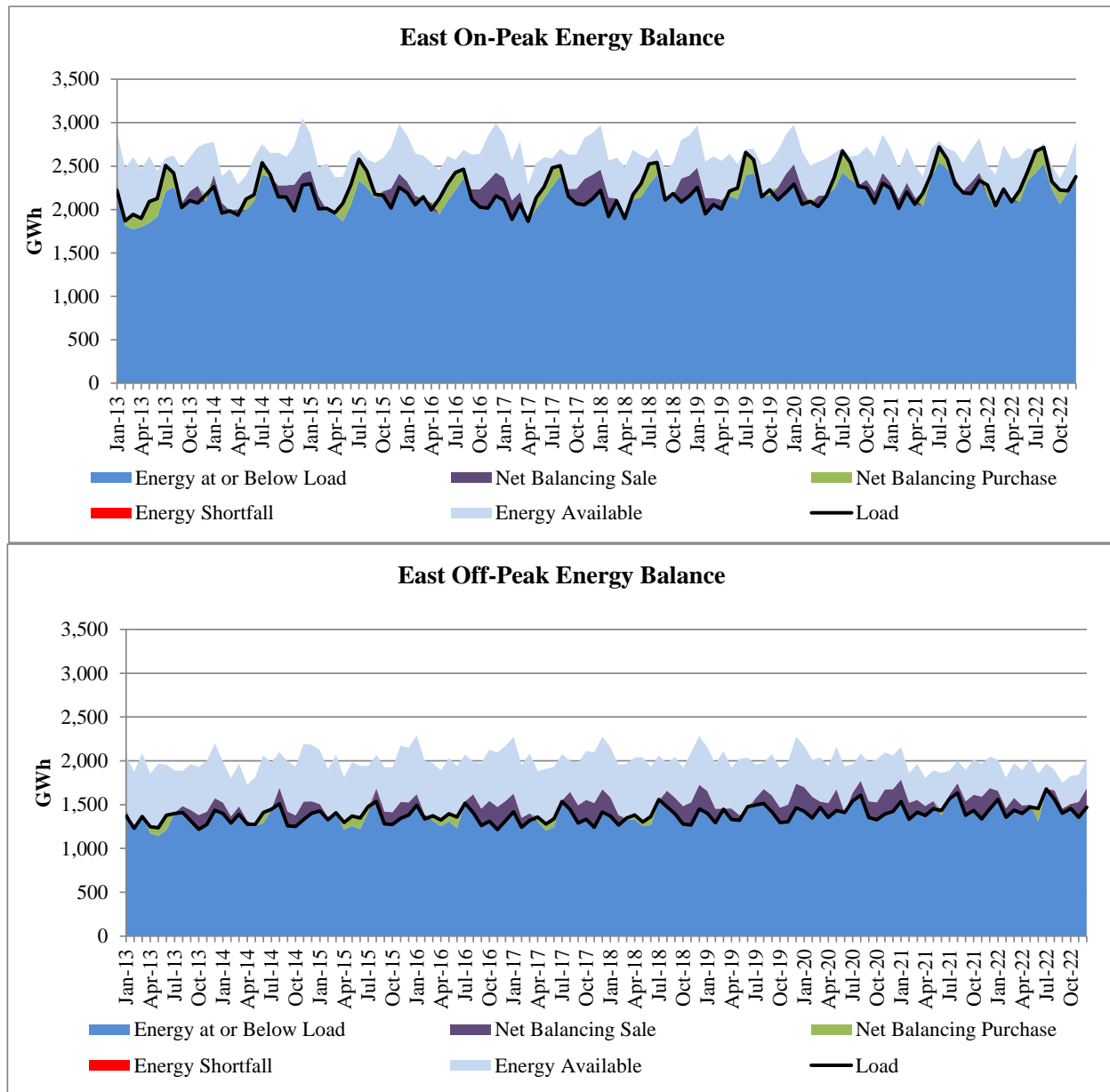


Figure 5.7 – East Average Monthly and Annual Energy Positions



Load and Resource Balance Conclusions

Without additional resources the Company projects a summer peak system resource deficit of 824 MW beginning in 2013. The near-term deficit will be filled by additional DSM programs and market purchases.

CHAPTER 6 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, public meeting comments, and studies. Current economic conditions have reduced capital cost uncertainty. Long-term resource pricing, especially for emerging technologies, remains a challenge to predict.
- Resource costs have been generally stable since the previous IRP due to the economic slow-down from 2008 through 2012.
- Large utility scale solar photovoltaic options have been included in this IRP.
- Geothermal purchase power agreements (PPA) have been included as supply-side options in this IRP.
- An expanded number of combustion turbine types and configurations are provided in the current Supply Side Resource options table.
- Energy storage systems continue to be of interest with options included for advanced large batteries (one megawatt) as well as pumped hydro and compressed air energy storage.
- A 2013 resource potential study, conducted by The Cadmus Group, served as the basis for updated resource characterizations covering demand-side management (DSM) and distributed generation. The demand-side resource information was converted into supply curves by measure or product type and competed against other resource alternatives in IRP modeling.
- PacifiCorp applied cost reduction credits for energy efficiency, reflecting risk mitigation benefits, transmission & distribution investment deferral benefits, and a 10 percent market price credit for Washington and Oregon as required by the Northwest Power Act.

Introduction

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

Supply-side Resources

The list of supply-side resource options has been updated to reflect the realities evidenced through permitting, internally-generated studies, and externally-commissioned studies undertaken to better understand the details of available generation resources. Capital costs, in general, have remained stable due to recessionary economic conditions in 2008-2009 and a very

gradual recovery experienced in 2010-2012. Natural gas-fueled plants are expected to fulfill the current and expected base-load obligations to meet customer needs and therefore natural gas-fueled resources have received a significant level of attention. A variety of gas-fueled generating resources were selected after consultation with major suppliers, large engineering-consulting firms, and primary stakeholders. New coal-fueled resources did not receive as much focus during this cycle due to ongoing environmental permitting and sociopolitical obstacles for siting new coal-fueled generation. The capital and operating costs of simple and combined-cycle gas turbine plants have remained relatively low in recent years, with a flat to slightly increasing cost trend in the past two years. Certain alternative (i.e. non-fossil-fuel) energy resources such as wind and solar received greater emphasis during this review cycle compared to prior reviews. Specifically, additional solar and wind resource options have been included in the analysis compared to the previous IRP to capture cost and performance differences across different regions within the service territory. Additional solar resources include utility-size photovoltaic systems (PV) utilizing both fixed and single axis tracking. Energy storage options of at least one megawatt continue to be of interest among the stakeholders, with options analyzed for large pumped hydro projects, as well as advanced battery, fly wheel and compressed air energy storage projects.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2011 IRP. This resource list was reviewed and modified to reflect stakeholder input, environmental factors, cost dynamics, and permitting realities. Once the basic list of resources was determined, the cost and performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the Supply Side Resource table:

- Recent (2012) third-party, cost and performance estimates;
- Prior third-party, cost and performance studies or updated earlier estimates;
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes;
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options; and
- Recent Requests for Proposals and Requests for Information.

Recent third-party engineering information from original equipment manufacturers were used to develop capital, operating and maintenance costs, performance and operating characteristics and planned outage cycle estimates. Engineering-consultants or government agencies have access to this data based on prior research studies, academia, actual installations, and direct information exchanges with original equipment manufacturers. Examples of this type of effort include the 2012 Black & Veatch estimates prepared for simple cycle and combined cycle options and the 2012 HDR Engineering (HDR) study of various storage technologies.

Prior studies include studies prepared by others but not specifically for the Integrated Resource Plan process, and include similar types of cost and performance data provided in the Supply Side Resource table. This information includes publicly available engineering and government agency

reports. Examples of this type of study include the United States Department of Energy’s 2011 Wind Technologies Market Report.

PacifiCorp or industry installations provide a solid basis for capital/maintenance costs and operating histories. Performance characteristics were adjusted to site-specific conditions identified in the Supply Side Resource Table. For instance, the capacity of combustion turbine based resources varies with elevation and ambient temperature and, to a lesser extent, relative humidity. Adjustments were made for site-specific elevations of actual plants to more generic, regional elevations for future resources. Examples of actual PacifiCorp installations that were used to develop the cost and performance information provided in the Supply Side Resource table include the Gadsby GE LM6000PC peaking units, the Lake Side 1 combined cycle plant and PacifiCorp’s recent Black Cap solar photovoltaic project in Oregon.

Potential PacifiCorp resources also provide a source for cost and performance data. As with the actual installations, performance data was adjusted to match site conditions. Examples of potential or under-construction resources that have been used in developing information in the Supply Side Resource table include the Lake Side 2 combined cycle plant, the Vogtle Nuclear Plant currently under construction in Georgia, as well as the proposed McFadden Ridge 2 Wind Plant and 12-Mile Hill Wind Plant sites.

Recent Requests for Information (RFI) and Requests for Proposals (RFP) also provide a useful source of cost and performance data. In these cases, original equipment manufacturers provided technology specific information. Examples of RFIs informing the Supply Side Resource Table include a Greenfield geothermal site data solicitation for the “Generic Geothermal PPA 90% CF” option and the Wind Capacity Factor Assumptions RFI for different state-specific wind resource options.

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for many generation options is relatively high. Various factors contribute to this uncertainty, including the relatively small number of facilities that have been built, especially for new and emerging technologies, as well as prolonged economic uncertainty. Despite this uncertainty, the cost profile between the last IRP and the current IRP has not changed significantly. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices in the last year. This same information was presented in the 2011 IRP and the end data from that chart is shown in Figure 6.1. In the last year, costs have decreased slightly from higher initial costs and are currently close to costs that existed in September 2010. This is also illustrated by the long-term historical steel pricing trend as shown in Figure 6.2. The capital cost of generation resources reflect this status quo reality.

Figure 6.1 – World Carbon Steel Pricing by Type

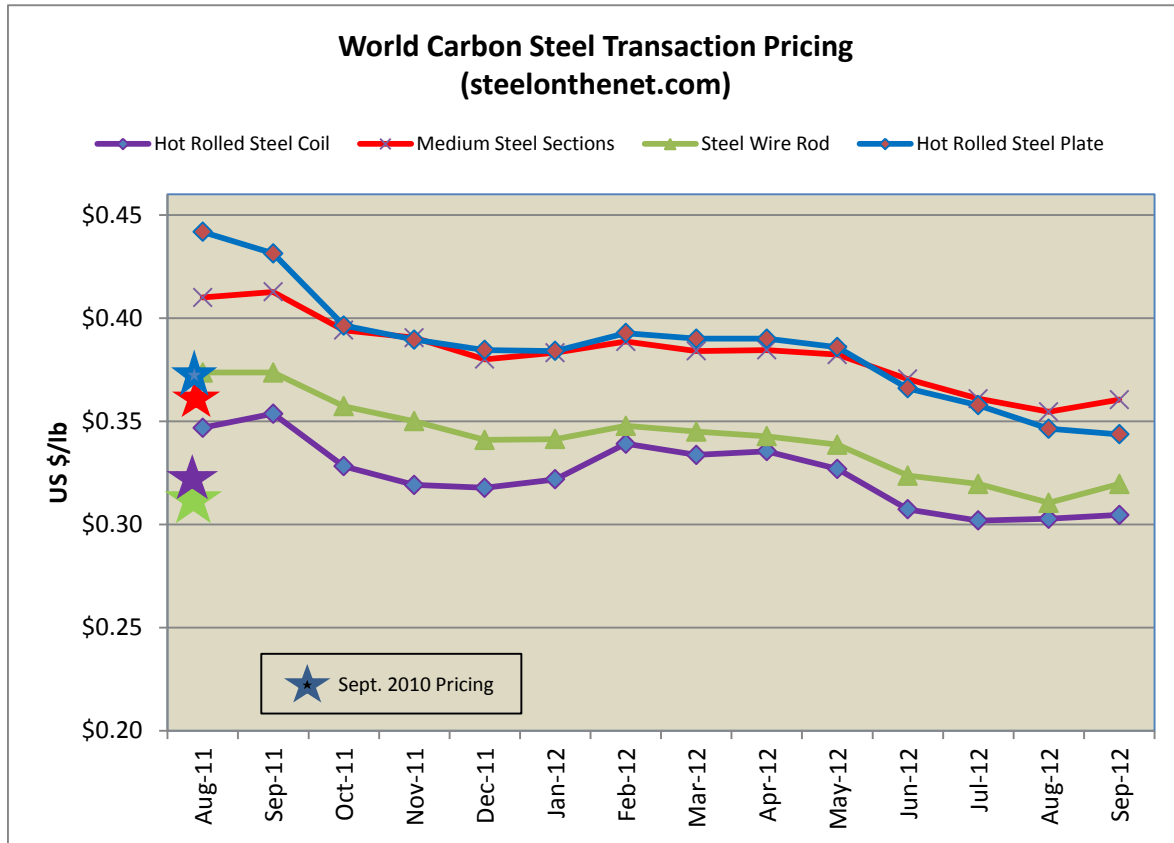
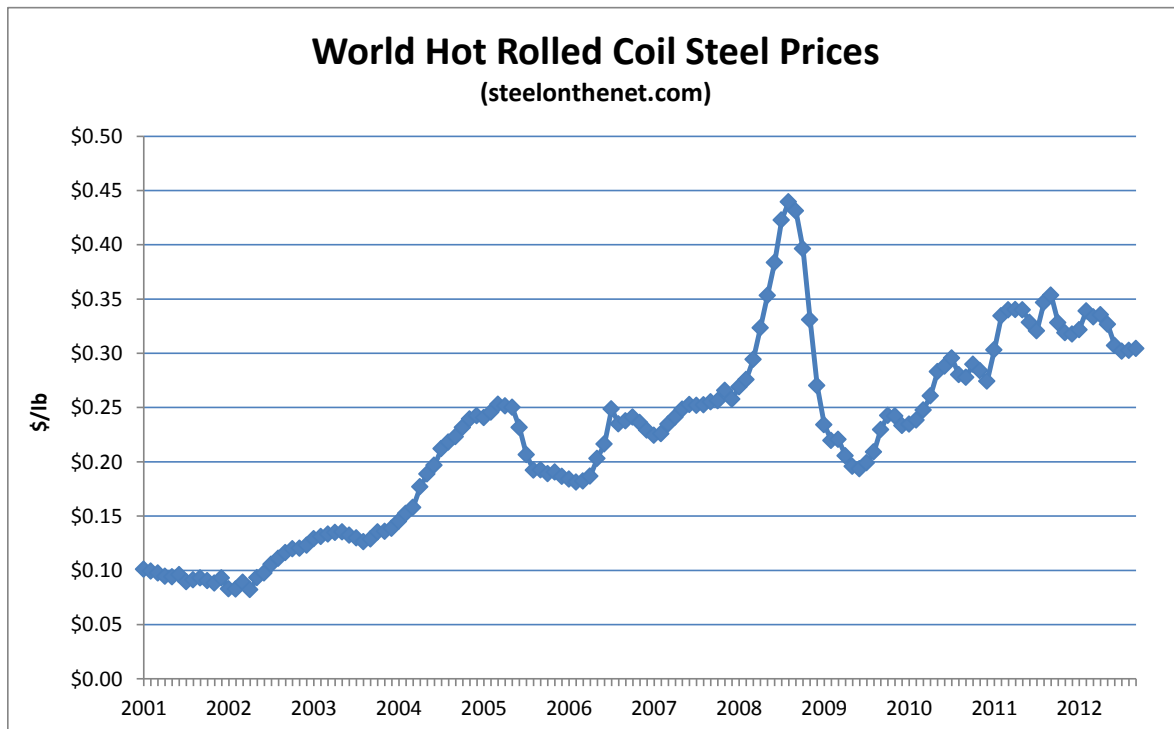


Figure 6.2 – Historic Carbon Steel Pricing



Prices for solar photovoltaic (PV) panels have fallen significantly since the 2011 IRP. Real prices are projected to continue to decline for the next several years, but uncertainty in the solar

market makes it difficult to accurately predict future prices. Other technologies, such as gas turbines, and wind turbines have seen more stable prices since the 2011 IRP. Long-term resource pricing remains challenging to forecast.

Some generation technologies, such integrated gasification combined cycle (IGCC), have shown significant cost uncertainty because only a few units have been built and operated. Recent experience with cost overruns on IGCC projects such as Duke Energy’s Edwardsport and Southern Company’s Kemper County IGCC plants are examples that illustrate the difficulty in accurately estimating capital costs of these developing resource options. As these technologies mature and more plants are constructed, the costs of such new technologies may decrease relative to more mature options such as pulverized coal and natural gas-fueled plants.

The supply-side resource options tables do not include the potential for such capital cost reductions since the benefits are not expected to be realized until the next generation of new plants are built and operated. For example, construction and operating “experience curve” benefits for IGCC plants are not expected to be available until after their commercial operation dates. As such, future IRPs will be better able to incorporate the potential benefits of future cost reductions. Given the current emphasis on construction and operating experience associated with renewable generation, the Company anticipates the cost benefits for these technologies to be available sooner. The estimated capital costs are displayed in the supply-side resource tables along with expected availability of each technology for commercial utilization.

Resource Options and Attributes

Table 6.1 presents cost and performance attributes for supply-side resource options designated by generic, elevation-specific regions where a resource could ultimately be located:

- ISO conditions: 0’ elevation (sea level and 59 degrees F); this is used as a reference only for certain modeling purposes.
- 1,500’ elevation: eastern Oregon/Washington.
- 4,500’ elevation: northern Utah, specifically Salt Lake/Utah/Davis/Box Elder counties
- 5,050’ elevation: central Utah, southern Idaho, central Wyoming.
- 6,500’ elevation: southwestern Wyoming

Tables 6.2 and 6.3 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year, real- levelized costs for resources, stated in June 2012 dollars. The resource costs are presented for both the \$0 and \$16 CO₂ tax levels in recognition of the uncertainty in characterizing emission costs.

A Glossary of Terms and a Glossary of Acronyms from the Supply Side Resource table is summarized in Table 6.4 and Table 6.5.

Table 6.1 - 2013 Supply Side Resource Table (2012\$)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation	Net	Commercial	Design	Base Capital	Var O&M	Fixed O&M	Average Full Load			Water Consumed	SO2	NOx	Hg	CO2
		(AFSL)	Capacity (MW)	Operation Year	Life (yrs)				Heat Rate (HHV Btu/KWh)/Efficiency (%)	EFOR (%)	POR (%)					
Natural Gas	SCCT Aero x3, ISO	0	163	2016	30	1,081	3.50	9.88	9,739	2.6	3.9	56	0.0006	0.018	0.255	118
Natural Gas	Intercooled SCCT Aero x1, ISO	0	102	2016	30	1,004	2.92	15.23	8,867	2.9	3.9	78	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1, ISO	0	203	2016	35	679	8.46	7.73	9,950	2.7	3.9	10	0.0006	0.018	0.255	118
Natural Gas	IC Recips x6, ISO	0	117	2016	30	1,204	7.40	15.61	8,447	2.5	5.0	5	0.0006	0.018	0.255	118
Natural Gas	CCCT Dry "F", 2x1, ISO	0	609	2017	40	995	2.11	6.13	6,738	2.5	3.8	11	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1, ISO	0	138	2017	40	522	0.08	0.00	8,482	0.8	3.8	11	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "G/H", 1x1, ISO	0	372	2017	40	971	2.53	10.70	6,866	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO	0	48	2017	40	612	0.08	0.00	8,262	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1, ISO	0	746	2017	40	959	2.44	5.61	6,743	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO	0	96	2017	40	600	0.07	0.00	8,105	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1, ISO	0	439	2018	40	931	2.20	9.13	6,495	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO	0	43	2018	40	486	0.08	0.00	8,611	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	Intercooled SCCT Aero x1	1,500	99	2016	30	1,034	2.99	15.67	8,839	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	1,500	197	2016	35	699	8.71	7.97	9,950	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x 6	1,500	112	2016	30	1,253	7.63	16.31	8,447	2.5	3.8	5	0.0006	0.030	0.255	118
Natural Gas	CCCT Dry "F", 2x1	1,500	583	2016	40	1,039	2.18	6.43	6,738	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1	1,500	138	2016	40	522	0.08	0.00	8,482	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	1,500	715	2017	40	1,000	2.54	5.86	6,773	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	1,500	96	2017	40	600	0.07	0.00	8,135	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	1,500	425	2018	40	962	2.27	9.43	6,495	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	1,500	43	2018	40	486	0.08	0.00	8,611	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	SCCT Aero x3	4,250	144	2016	30	1,225	3.89	11.11	9,739	2.6	3.9	58	0.0006	0.018	0.255	118
Natural Gas	Intercooled SCCT Aero x1	4,250	91	2016	30	1,127	3.23	16.97	8,867	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	4,250	181	2016	35	762	9.48	8.67	9,950	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x6	4,250	103	2016	30	1,368	8.15	18.39	8,447	2.5	5.0	5	0.0006	0.030	0.255	118
Natural Gas	CCCT Wet "F", 2x1	4,250	545	2017	40	1,104	2.87	8.58	6,666	2.5	3.8	200	0.0006	0.007	0.255	118
Natural Gas	CCCT Wet "F", DF, 2x1	4,250	89	2017	40	490	0.32	0.00	7,901	0.8	3.8	200	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", 1x1	5,050	255	2017	40	1,253	2.57	13.94	6,815	2.5	3.8	9	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", DF, 1x1	5,050	48	2017	40	546	0.08	0.00	8,518	0.8	3.8	9	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", 2x1	5,050	523	2017	40	1,159	2.42	7.14	6,738	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1	5,050	138	2017	40	522	0.08	0.00	8,482	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 1x1	5,050	320	2017	40	1,129	2.94	12.45	6,866	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 1x1	5,050	48	2017	40	612	0.08	0.00	8,262	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	5,050	640	2017	40	1,118	2.82	6.55	6,743	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	5,050	96	2017	40	600	0.07	0.00	8,105	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	5,050	380	2018	40	1,075	2.54	10.54	6,495	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	5,050	43	2018	40	486	0.08	0.00	8,611	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	SO Fuel Cell	4,500	5	2018	20	2,090	0.03	8.82	8,061	3	2	2	0.0006	0	0.255	118
Natural Gas	Intercooled SCCT Aero x1	6,500	86	2016	30	1,189	3.39	17.91	8,867	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	6,500	172	2016	35	804	10.00	9.13	9,950	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x6	6,500	96	2016	30	1,469	8.60	19.03	8,447	2.5	5.0	5	0.0006	0.0295	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	6,500	617	2017	40	1,159	2.92	6.80	6,743	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	6,500	96	2017	40	600	0.07	0.00	8,105	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	6,500	368	2018	40	1,110	2.62	10.88	6,495	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	6,500	43	2018	40	486	0.08	0.00	8,611	0.8	3.8	9	0.0006	0.008	0.255	118

Table 6.1 - 2013 Supply Side Resource Table (2012\$) (Continued)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
		Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital (\$/KW)	Var O&M (\$/MWh)	Fixed O&M (\$/KW-yr)	Average Full Load		Water Consumed (Gal/MWh)	SO2 (lbs /MMBtu)	NOx (lbs /MMBtu)	Hg (lbs /TBTu)	CO2 (lbs /MMBtu)	
Fuel	Resource							Heat Rate (HHV Btu/KWh)/Efficiency (%)	EFOR (%)	POR (%)						
Coal	SCPC with CCS	4,500	526	2032	40	5,410	6.71	69.22	13,087	5	5	1,004	0.009	0.070	0.022	20.5
Coal	SCPC without CCS	4,500	600	2027	40	2,992	0.96	40.65	9,106	4.6	4	600	0.005	0.070	0.022	205.4
Coal	IGCC with CCS	4,500	466	2032	40	5,238	11.28	55.78	10,823	8	7	394	0.009	0.050	0.333	20.5
Coal	IGCC without CCS	4,500	560	2027	40	3,734	8.39	42.45	8,734	8	7	361	0.013	0.059	0.333	205.4
Coal	PC CCS retrofit @ 500 MW	4,500	-139	2029	20	1,188	6.20	74.52	14,372	5	5	1,004	0.005	0.070	1.200	20.5
Coal	SCPC with CCS	6,500	692	2032	40	6,126	7.26	64.29	13,242	5	5	1,004	0.009	0.070	0.022	20.5
Coal	SCPC without CCS	6,500	790	2027	40	3,388	1.27	37.71	9,214	4.6	4	600	0.005	0.070	0.022	205.4
Coal	IGCC with CCS	6,500	456	2032	40	5,931	13.52	60.76	11,047	8	7	394	0.009	0.050	0.333	20.5
Coal	IGCC without CCS	6,500	548	2027	40	4,228	10.06	46.24	8,915	8	7	361	0.013	0.059	0.333	205.4
Coal	PC CCS retrofit @ 500 MW	6,500	-139	2029	20	1,345	6.71	69.22	14,372	5	5	1,004	0.005	0.070	1.200	20.5
Geothermal	Blundell Dual Flash 90% CF	4,500	35	2016	40	4,795	0.98	118.49	na	5	5	1453	0	0	0	0
Geothermal	Greenfield Binary 90% CF	4,500	43	2018	40	5,916	0.98	187.85	na	5	5	1453	0	0	0	0
Geothermal	Generic Geothermal PPA 90% CF	4,500	30	2016	20	n/a	110.00	n/a	na	5	5	1453	0	0	0	0
Wind	2.3 MW turbine 29% CF WA	1,500	100	2017	25	2,365	0.00	33.11	0	Included with CF	0	0	0	0	0	0
Wind	2.3 MW turbine 29% CF UT	4,500	100	2017	25	2,304	0.00	33.11	0	Included with CF	0	0	0	0	0	0
Wind	2.3 MW turbine 35% CF WY	6,500	100	2017	25	2,138	0.65	33.11	0	Included with CF	0	0	0	0	0	0
Wind	2.3 MW turbine 40% CF WY	6,500	200	2017	25	2,257	0.65	33.11	0	Included with CF	0	0	0	0	0	0
Solar	PV Thin Film 21% CF	4,500	2	2014	25	3,476	0.00	51.50	na	Included with CF	0	0	0	0	0	0
Solar	PV Poly-Si Fixed Tilt 22% CF	4,500	2	2014	25	3,153	0.00	51.50	na	Included with CF	0	0	0	0	0	0
Solar	PV Poly-Si Single Tracking 25% CF	4,500	2	2014	25	3,810	0.00	67.00	na	Included with CF	0	0	0	0	0	0
Solar	PV Poly-Si Fixed Tilt 28% CF	4,500	50	2015	25	2,952	0.00	27.81	na	Included with CF	0	0	0	0	0	0
Solar	PV Poly-Si Single Tracking 33% CF	4,500	50	2015	25	3,176	0.00	32.55	na	Included with CF	0	0	0	0	0	0
Solar	CSP Trough w Natural Gas	4,500	100	2015	30	5,072	0.00	64.00	11,750	Included with CF	725	0	0	0	0	0
Solar	CSP Tower 24% CF	4,500	100	2015	30	4,831	0.00	64.00	na	Included with CF	725	0	0	0	0	0
Solar	CSP Tower Molten Salt 30% CF	4,500	100	2015	30	5,796	0.00	64.00	na	Included with CF	750	0	0	0	0	0
Water	Hydrokinetic/Wave 40% CF	0	100	2024	20	5,539	0.00	166.17	na	na	na	0	0	0	0	0
Biomass	Forestry Byproduct	1,500	5	2017	30	3,334	0.96	40.65	10,017	5.06	4.4	660	0.1	0.2	0.4	205
Storage	Pumped Storage	4,500	1,000	2022	50	3,000	4.30	4.30	77.5%	3	1.9	0	0	0	0	0
Storage	Lithium Ion Battery	4,500	10	2015	20	8,712	0.00	27.40	91.0%	3	1.9	0	0	0	0	0
Storage	Sodium-Sulfur Battery	4,500	10	2015	20	4,400	0.00	27.40	72.5%	0.3	0	0	0	0	0	0
Storage	Vanadium RedOx Battery	4,500	10	2015	20	5,530	0.00	36.53	70.0%	2	0	0	0	0	0	0
Storage	Advanced Fly Wheel	4,500	10	2015	20	2,406	0.00	96.24	85.0%	2	0	0	0	0	0	0
Storage	CAES	4,500	557	2017	30	1,751	22.51	33.80	83.5%	3.5	3.5	0	0.001	0.011	0.255	118
Nuclear	Advanced Fission	4,500	2,236	2025	40	7,093	2.04	88.75	10,710	7.7	7.3	767	0	0	0	0
Nuclear	Modular Reactor	4,500	25	2030	40	3,390	1.02	44.38	10,710	7.7	7.3	767	0	0	0	0

Table 6.2 – Total Resource Cost for Supply-Side Resource Options, \$0 CO2 Tax

\$0 CO2 Tax		Capital Cost \$/kW			Fixed Cost					
Supply Side Resource Options Mid-Calendar Year 2012 Dollars (\$)	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment (\$/kW-Yr)	Fixed O&M \$/kW-Yr					Total Fixed (\$/kW-Yr)
					O&M	Capitalized Premium	O&M Capitalized	Gas Transporta tion	Total	
Resource Description										
SCCT Aero x3, ISO	0	\$1,081	8.428%	\$91.13	9.88	1.34%	0.13	32.51	42.52	\$133.65
Intercooled SCCT Aero x1, ISO	0	\$1,004	8.428%	\$84.61	15.23	1.40%	0.21	29.59	45.04	\$129.65
SCCT Frame "F" x1, ISO	0	\$679	7.954%	\$53.98	7.73	1.37%	0.11	33.21	41.05	\$95.02
IC Recips x6, ISO	0	\$1,204	8.428%	\$101.45	15.61	0.40%	0.06	28.19	43.87	\$145.31
CCCT Dry "F", 2x1, ISO	0	\$995	7.886%	\$78.43	6.13	1.23%	0.08	22.49	28.69	\$107.12
CCCT Dry "F", DF, 2x1, ISO	0	\$522	7.886%	\$41.13	0.00	0.00%	0.00	28.31	28.31	\$69.44
CCCT Dry "G/H", 1x1, ISO	0	\$971	7.886%	\$76.59	10.70	1.96%	0.21	22.92	33.83	\$110.42
CCCT Dry "G/H", DF, 1x1, ISO	0	\$612	7.886%	\$48.23	0.00	0.00%	0.00	27.58	27.58	\$75.81
CCCT Dry "G/H", 2x1, ISO	0	\$959	7.886%	\$75.63	5.61	1.86%	0.10	22.51	28.22	\$103.85
CCCT Dry "G/H", DF, 2x1, ISO	0	\$600	7.886%	\$47.32	0.00	0.00%	0.00	27.05	27.05	\$74.37
CCCT Dry "J", Adv 1x1, ISO	0	\$931	7.886%	\$73.39	9.13	1.95%	0.18	21.68	30.98	\$104.37
CCCT Dry "J", DF, Adv 1x1, ISO	0	\$486	7.886%	\$38.36	0.00	0.00%	0.00	28.74	28.74	\$67.10
Intercooled SCCT Aero x1	1500	\$1,034	8.428%	\$87.12	15.67	1.40%	0.22	29.50	45.39	\$132.51
SCCT Frame "F" x1	1500	\$699	7.954%	\$55.56	7.97	1.37%	0.11	33.21	41.29	\$96.85
IC Recips x 6	1500	\$1,253	8.428%	\$105.64	16.31	0.40%	0.06	28.19	44.57	\$150.21
CCCT Dry "F", 2x1	1500	\$1,039	7.886%	\$81.97	6.43	1.23%	0.08	22.49	29.00	\$110.96
CCCT Dry "F", DF, 2x1	1500	\$522	7.886%	\$41.13	0.00	0.00%	0.00	28.31	28.31	\$69.44
CCCT Dry "G/H", 2x1	1500	\$1,000	7.886%	\$78.87	5.86	1.86%	0.11	22.61	28.57	\$107.45
CCCT Dry "G/H", DF, 2x1	1500	\$600	7.886%	\$47.32	0.00	0.00%	0.00	27.15	27.15	\$74.47
CCCT Dry "J", Adv 1x1	1500	\$962	7.886%	\$75.83	9.43	1.95%	0.18	21.68	31.29	\$107.13
CCCT Dry "J", DF, Adv 1x1	1500	\$486	7.886%	\$38.36	0.00	0.00%	0.00	28.74	28.74	\$67.10
SCCT Aero x3	4250	\$1,225	8.428%	\$103.21	11.11	1.34%	0.15	21.95	33.21	\$136.42
Intercooled SCCT Aero x1	4250	\$1,127	8.428%	\$94.97	16.97	1.40%	0.24	19.99	37.19	\$132.16
SCCT Frame "F" x1	4250	\$762	7.954%	\$60.57	8.67	1.37%	0.12	22.43	31.22	\$91.79
IC Recips x6	4250	\$1,368	8.428%	\$115.31	18.39	0.40%	0.07	19.04	37.50	\$152.82
CCCT Wet "F", 2x1	4250	\$1,104	7.886%	\$87.05	8.58	0.70%	0.06	15.03	23.67	\$110.71
CCCT Wet "F", DF, 2x1	4250	\$490	7.886%	\$38.63	0.00	0.00%	0.00	17.81	17.81	\$56.44
CCCT Dry "F", 1x1	5050	\$1,253	7.886%	\$98.81	13.94	1.29%	0.18	15.36	29.49	\$128.29
CCCT Dry "F", DF, 1x1	5050	\$546	7.886%	\$43.08	0.00	0.00%	0.00	19.20	19.20	\$62.28
CCCT Dry "F", 2x1	5050	\$1,159	7.886%	\$91.37	7.14	1.23%	0.09	15.19	22.42	\$113.79
CCCT Dry "F", DF, 2x1	5050	\$522	7.886%	\$41.13	0.00	0.00%	0.00	19.12	19.12	\$60.25
CCCT Dry "G/H", 1x1	5050	\$1,129	7.886%	\$89.04	12.45	1.96%	0.24	15.48	28.17	\$117.21
CCCT Dry "G/H", DF, 1x1	5050	\$612	7.886%	\$48.23	0.00	0.00%	0.00	18.62	18.62	\$66.86
CCCT Dry "G/H", 2x1	5050	\$1,118	7.886%	\$88.16	6.55	1.86%	0.12	15.20	21.87	\$110.03
CCCT Dry "G/H", DF, 2x1	5050	\$600	7.886%	\$47.32	0.00	0.00%	0.00	18.27	18.27	\$65.59
CCCT Dry "J", Adv 1x1	5050	\$1,075	7.886%	\$84.74	10.54	1.95%	0.21	14.64	25.39	\$110.13
CCCT Dry "J", DF, Adv 1x1	5050	\$486	7.886%	\$38.36	0.00	0.00%	0.00	19.41	19.41	\$57.77

Table 6.2 – Total Resource Cost for Supply-Side Resource Options, \$0 CO2 Tax (Continued)

\$0 CO2 Tax		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)			
Supply Side Resource Options Mid-Calendar Year 2012 Dollars (\$)	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	Levelized Fuel		O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	Credits		Total Resource Cost - With PTC / ITC Credits
					e/mmBtu	Mills/kWh							Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	
SCCT Aero x3, ISO	0	21%	72.65	na	472	45.97	3.50	6.67%	0.23	-	-	122.36	-	-	122.36
Intercooled SCCT Aero x1, ISO	0	21%	70.48	na	472	41.85	2.92	6.83%	0.20	-	-	115.45	-	-	115.45
SCCT Frame "F" x1, ISO	0	21%	51.65	na	472	46.97	8.46	7.80%	0.66	-	-	107.74	-	-	107.74
IC Recips x6, ISO	0	21%	78.99	na	472	39.87	7.40	4.33%	0.32	-	-	126.59	-	-	126.59
CCCT Dry "F", 2x1, ISO	0	56%	21.84	na	472	31.80	2.11	7.69%	0.16	-	-	55.91	-	-	55.91
CCCT Dry "F", DF, 2x1, ISO	0	16%	49.54	na	472	40.04	0.08	0.00%	0.00	-	-	89.65	-	-	89.65
CCCT Dry "G/H", 1x1, ISO	0	56%	22.51	na	472	32.41	2.53	7.05%	0.18	-	-	57.63	-	-	57.63
CCCT Dry "G/H", DF, 1x1, ISO	0	16%	54.09	na	472	39.00	0.08	0.00%	0.00	-	-	93.16	-	-	93.16
CCCT Dry "G/H", 2x1, ISO	0	56%	21.17	na	472	31.83	2.44	7.30%	0.18	-	-	55.62	-	-	55.62
CCCT Dry "G/H", DF, 2x1, ISO	0	16%	53.06	na	472	38.26	0.07	0.00%	0.00	-	-	91.39	-	-	91.39
CCCT Dry "J", Adv 1x1, ISO	0	56%	21.28	na	472	30.66	2.20	7.03%	0.15	-	-	54.29	-	-	54.29
CCCT Dry "J", DF, Adv 1x1, ISO	0	16%	47.87	na	472	40.65	0.08	0.00%	0.00	-	-	88.60	-	-	88.60
Intercooled SCCT Aero x1	1500	21%	72.03	na	472	41.72	2.99	6.83%	0.20	-	-	116.95	-	-	116.95
SCCT Frame "F" x1	1500	21%	52.65	na	472	46.97	8.71	7.80%	0.68	-	-	109.00	-	-	109.00
IC Recips x 6	1500	21%	81.65	na	472	39.87	7.63	4.48%	0.34	-	-	129.50	-	-	129.50
CCCT Dry "F", 2x1	1500	56%	22.62	na	472	31.80	2.18	7.67%	0.17	-	-	56.77	-	-	56.77
CCCT Dry "F", DF, 2x1	1500	16%	49.54	na	472	40.04	0.08	0.00%	0.00	-	-	89.66	-	-	89.66
CCCT Dry "G/H", 2x1	1500	56%	21.90	na	472	31.97	2.54	7.29%	0.19	-	-	56.60	-	-	56.60
CCCT Dry "G/H", DF, 2x1	1500	16%	53.13	na	472	38.40	0.07	0.00%	0.00	-	-	91.61	-	-	91.61
CCCT Dry "J", Adv 1x1	1500	56%	21.84	na	472	30.66	2.27	7.01%	0.16	-	-	54.93	-	-	54.93
CCCT Dry "J", DF, Adv 1x1	1500	16%	47.87	na	472	40.65	0.08	0.00%	0.00	-	-	88.60	-	-	88.60
SCCT Aero x3	4250	21%	74.16	na	431	42.02	3.89	6.67%	0.26	-	-	120.33	-	-	120.33
Intercooled SCCT Aero x1	4250	21%	71.84	na	431	38.26	3.23	6.83%	0.22	-	-	113.55	-	-	113.55
SCCT Frame "F" x1	4250	21%	49.90	na	431	42.93	9.48	7.80%	0.74	-	-	103.05	-	-	103.05
IC Recips x6	4250	21%	83.07	na	431	36.45	8.15	4.48%	0.36	-	-	128.03	-	-	128.03
CCCT Wet "F", 2x1	4250	56%	22.57	na	431	28.76	2.87	6.27%	0.18	-	-	54.38	-	-	54.38
CCCT Wet "F", DF, 2x1	4250	16%	40.27	na	431	34.09	0.32	0.00%	0.00	-	-	74.68	-	-	74.68
CCCT Dry "F", 1x1	5050	56%	26.15	na	431	29.41	2.57	7.50%	0.19	-	-	58.33	-	-	58.33
CCCT Dry "F", DF, 1x1	5050	16%	44.44	na	431	36.75	0.08	0.00%	0.00	-	-	81.27	-	-	81.27
CCCT Dry "F", 2x1	5050	56%	23.20	na	431	29.07	2.42	7.67%	0.19	-	-	54.87	-	-	54.87
CCCT Dry "F", DF, 2x1	5050	16%	42.98	na	431	36.60	0.08	0.00%	0.00	-	-	79.66	-	-	79.66
CCCT Dry "G/H", 1x1	5050	56%	23.89	na	431	29.63	2.94	6.99%	0.21	-	-	56.66	-	-	56.66
CCCT Dry "G/H", DF, 1x1	5050	16%	47.70	na	431	35.65	0.08	0.00%	0.00	-	-	83.43	-	-	83.43
CCCT Dry "G/H", 2x1	5050	56%	22.43	na	431	29.10	2.82	7.27%	0.21	-	-	54.55	-	-	54.55
CCCT Dry "G/H", DF, 2x1	5050	16%	46.80	na	431	34.97	0.07	0.00%	0.00	-	-	81.84	-	-	81.84
CCCT Dry "J", Adv 1x1	5050	56%	22.45	na	431	28.02	2.54	6.98%	0.18	-	-	53.19	-	-	53.19
CCCT Dry "J", DF, Adv 1x1	5050	16%	41.22	na	431	37.15	0.08	0.00%	0.00	-	-	78.45	-	-	78.45

Table 6.2 – Total Resource Cost for Supply-Side Resource Options, \$0 CO2 Tax (Continued)

\$0 CO2 Tax		Capital Cost \$/kW			Fixed Cost					
Supply Side Resource Options Mid-Calendar Year 2012 Dollars (\$)	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment (\$/kW-Yr)	Fixed O&M \$/kW-Yr					Total Fixed (\$/kW-Yr)
					O&M	Capitalized Premium	O&M Capitalized	Gas Transporta tion	Total	
Resource Description										
Intercooled SCCT Aero x1	6500	\$1,189	8.428%	\$100.24	17.91	1.40%	0.25	17.07	35.24	\$135.47
SCCT Frame "F" x1	6500	\$804	7.954%	\$63.91	9.13	1.37%	0.13	19.16	28.42	\$92.33
IC Recips x6	6500	\$1,469	8.428%	\$123.84	19.03	0.40%	0.08	16.27	35.37	\$159.21
CCCT Dry "G/H", 2x1	6500	\$1,159	7.886%	\$91.40	6.80	1.86%	0.13	12.99	19.91	\$111.31
CCCT Dry "G/H", DF, 2x1	6500	\$600	7.886%	\$47.32	0.00	0.00%	0.00	15.61	15.61	\$62.93
CCCT Dry "J", Adv 1x1	6500	\$1,110	7.886%	\$87.54	10.88	1.95%	0.21	12.51	23.60	\$111.14
CCCT Dry "J", DF, Adv 1x1	6500	\$486	7.886%	\$38.36	0.00	0.00%	0.00	16.58	16.58	\$54.94
IGCC with CCS	6500	\$5,931	7.438%	\$441.13	60.76	0.00%	0.00	0.00	60.76	\$501.90
Generic Geothermal PPA 90% CF	4500	\$0	6.831%	\$0.00	735.46	0.00%	0.00	0.00	735.46	\$735.46
2.3 MW turbine 29% CF WA	1500	\$2,365	8.165%	\$193.12	33.11	1.14%	0.38	0.00	33.49	\$226.61
2.3 MW turbine 29% CF UT	4500	\$2,304	8.165%	\$188.12	33.11	1.14%	0.38	0.00	33.49	\$221.61
2.3 MW turbine 40% CF WY	6500	\$2,257	8.165%	\$184.30	33.11	1.14%	0.38	0.00	33.49	\$217.78
PV Poly-Si Fixed Tilt 22% CF (1.21 MWdc/MWac)	4500	\$3,153	8.165%	\$257.48	51.50	2.45%	1.26	0.00	52.76	\$310.24
PV Poly-Si Fixed Tilt 28% CF (1.37 MWdc/MWac)	4500	\$2,952	8.165%	\$241.05	27.81	2.45%	0.68	0.00	28.49	\$269.54
PV Poly-Si Single Tracking 34% CF (1.34 MWdc/MWac)	4500	\$3,176	8.165%	\$259.29	32.55	2.45%	0.80	0.00	33.35	\$292.64
Forestry Byproduct	1500	\$3,334	7.542%	\$251.45	40.65	5.07%	2.06	0.00	42.71	\$294.16
Pumped Storage	4500	\$3,000	7.459%	\$223.77	4.30	6.19%	0.27	0.00	4.57	\$228.34
Sodium-Sulfur Battery	4500	\$4,400	8.722%	\$383.77	27.40	0.00%	0.00	0.00	27.40	\$411.17
Advanced Fly Wheel	4500	\$2,406	8.722%	\$209.85	96.24	0.00%	0.00	0.00	96.24	\$306.09
CAES	4500	\$1,751	8.428%	\$147.57	33.80	0.00%	0.00	21.95	55.75	\$203.33
Advanced Fission	4500	\$7,093	7.623%	\$540.70	88.75	5.79%	5.14	0.00	93.89	\$634.59

Table 6.2 – Total Resource Cost for Supply-Side Resource Options, \$0 CO2 Tax (Continued)

\$0 CO2 Tax		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)			
Supply Side Resource Options Mid-Calendar Year 2012 Dollars (\$)	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	Levelized Fuel		O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	Credits		Total Resource Cost - With PTC / ITC Credits
					e/mmBtu	Mills/kWh							Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	
Resource Description															
Intercooled SCCT Aero x1	6500	21%	73.64	na	431	38.26	3.39	6.83%	0.23	-	-	115.52	-	-	115.52
SCCT Frame "F" x1	6500	21%	50.19	na	431	42.93	10.00	7.80%	0.78	-	-	103.90	-	-	103.90
IC Recips x6	6500	21%	86.55	na	431	36.45	8.60	4.48%	0.39	-	-	131.98	-	-	131.98
CCCT Dry "G/H", 2x1	6500	56%	22.69	na	431	29.10	2.92	7.27%	0.21	-	-	54.92	-	-	54.92
CCCT Dry "G/H", DF, 2x1	6500	16%	44.90	na	431	34.97	0.07	0.00%	0.00	-	-	79.94	-	-	79.94
CCCT Dry "J", Adv 1x1	6500	56%	22.66	na	431	28.02	2.62	6.96%	0.18	-	-	53.48	-	-	53.48
CCCT Dry "J", DF, Adv 1x1	6500	16%	39.20	na	431	37.15	0.08	0.00%	0.00	-	-	76.43	-	-	76.43
IGCC with CCS	6500	86%	66.96	na	271	29.91	13.52	12.08%	1.63	-	-	112.02	-	-	112.02
Generic Geothermal PPA 90% CF	4500	90%	93.28	na	-	-	11.00	0.00%	0.00	-	-	104.29	-	-	104.29
2.3 MW turbine 29% CF WA	1500	29%	89.20	na	-	-	0.00	0.00%	0.00	2.55	-	91.76	(19.48)	-	72.28
2.3 MW turbine 29% CF UT	4500	29%	87.23	na	-	-	0.00	0.00%	0.00	2.55	-	89.79	(19.48)	-	70.31
2.3 MW turbine 40% CF WY	6500	40%	62.15	na	-	-	0.65	0.00%	0.00	2.55	-	65.36	(19.48)	-	45.88
PV Poly-Si Fixed Tilt 22% CF (1.21 MWdc/MWac)	4500	22%	160.98	na	-	-	0.00	0.00%	0.00	0.64	-	161.62	(19.91)	-	141.70
PV Poly-Si Fixed Tilt 28% CF (1.37 MWdc/MWac)	4500	28%	108.69	na	-	-	0.00	0.00%	0.00	0.64	-	109.33	(14.49)	-	94.84
PV Poly-Si Single Tracking 34% CF (1.34 MWdc/MWac)	4500	34%	98.86	na	-	-	0.00	0.00%	0.00	0.64	-	99.50	(13.06)	-	86.45
Forestry Byproduct	1500	91%	37.00	na	512	51.29	0.96	0.00%	0.00	-	-	89.25	(17.86)	-	71.39
Pumped Storage	4500	42%	62.56	77.5%	472	59.32	4.30	0.00%	0.00	-	-	126.18	-	-	126.18
Sodium-Sulfur Battery	4500	25%	187.75	72.5%	472	63.41	0.00	0.00%	0.00	-	-	251.16	-	-	251.16
Advanced Fly Wheel	4500	5%	698.84	85.0%	472	54.09	0.00	0.00%	0.00	-	-	752.93	-	-	752.93
CAES	4500	33%	69.63	83.5%	472	55.06	22.51	10.29%	2.32	-	-	149.52	-	-	149.52
Advanced Fission	4500	86%	84.67	na	85	9.11	2.04	0.00%	0.00	-	-	95.82	-	-	95.82

Table 6.3 – Total Resource Cost for Supply-Side Resource Options, \$16 CO₂ Tax

\$16 CO ₂ Tax		Capital Cost \$/kW			Fixed Cost						
Supply Side Resource Options Mid-Calendar Year 2012 Dollars (\$)		Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment (\$/kW-Yr)	Fixed O&M \$/kW-Yr					Total Fixed (\$/kW-Yr)
Resource Description	O&M					Capitalized Premium	O&M Capitalized	Gas Transporta tion	Total		
SCCT Aero x3, ISO	0	\$1,081	8.428%	\$91.13	9.88	1.34%	0.13	32.51	42.52	\$133.65	
Intercooled SCCT Aero x1, ISO	0	\$1,004	8.428%	\$84.61	15.23	1.40%	0.21	29.59	45.04	\$129.65	
SCCT Frame "F" x1, ISO	0	\$679	7.954%	\$53.98	7.73	1.37%	0.11	33.21	41.05	\$95.02	
IC Recips x6, ISO	0	\$1,204	8.428%	\$101.45	15.61	0.40%	0.06	28.19	43.87	\$145.31	
CCCT Dry "F", 2x1, ISO	0	\$995	7.886%	\$78.43	6.13	1.23%	0.08	22.49	28.69	\$107.12	
CCCT Dry "F", DF, 2x1, ISO	0	\$522	7.886%	\$41.13	0.00	0.00%	0.00	28.31	28.31	\$69.44	
CCCT Dry "G/H", 1x1, ISO	0	\$971	7.886%	\$76.59	10.70	1.96%	0.21	22.92	33.83	\$110.42	
CCCT Dry "G/H", DF, 1x1, ISO	0	\$612	7.886%	\$48.23	0.00	0.00%	0.00	27.58	27.58	\$75.81	
CCCT Dry "G/H", 2x1, ISO	0	\$959	7.886%	\$75.63	5.61	1.86%	0.10	22.51	28.22	\$103.85	
CCCT Dry "G/H", DF, 2x1, ISO	0	\$600	7.886%	\$47.32	0.00	0.00%	0.00	27.05	27.05	\$74.37	
CCCT Dry "J", Adv 1x1, ISO	0	\$931	7.886%	\$73.39	9.13	1.95%	0.18	21.68	30.98	\$104.37	
CCCT Dry "J", DF, Adv 1x1, ISO	0	\$486	7.886%	\$38.36	0.00	0.00%	0.00	28.74	28.74	\$67.10	
Intercooled SCCT Aero x1	1500	\$1,034	8.428%	\$87.12	15.67	1.40%	0.22	29.50	45.39	\$132.51	
SCCT Frame "F" x1	1500	\$699	7.954%	\$55.56	7.97	1.37%	0.11	33.21	41.29	\$96.85	
IC Recips x 6	1500	\$1,253	8.428%	\$105.64	16.31	0.40%	0.06	28.19	44.57	\$150.21	
CCCT Dry "F", 2x1	1500	\$1,039	7.886%	\$81.97	6.43	1.23%	0.08	22.49	29.00	\$110.96	
CCCT Dry "F", DF, 2x1	1500	\$522	7.886%	\$41.13	0.00	0.00%	0.00	28.31	28.31	\$69.44	
CCCT Dry "G/H", 2x1	1500	\$1,000	7.886%	\$78.87	5.86	1.86%	0.11	22.61	28.57	\$107.45	
CCCT Dry "G/H", DF, 2x1	1500	\$600	7.886%	\$47.32	0.00	0.00%	0.00	27.15	27.15	\$74.47	
CCCT Dry "J", Adv 1x1	1500	\$962	7.886%	\$75.83	9.43	1.95%	0.18	21.68	31.29	\$107.13	
CCCT Dry "J", DF, Adv 1x1	1500	\$486	7.886%	\$38.36	0.00	0.00%	0.00	28.74	28.74	\$67.10	
SCCT Aero x3	4250	\$1,225	8.428%	\$103.21	11.11	1.34%	0.15	21.95	33.21	\$136.42	
Intercooled SCCT Aero x1	4250	\$1,127	8.428%	\$94.97	16.97	1.40%	0.24	19.99	37.19	\$132.16	
SCCT Frame "F" x1	4250	\$762	7.954%	\$60.57	8.67	1.37%	0.12	22.43	31.22	\$91.79	
IC Recips x6	4250	\$1,368	8.428%	\$115.31	18.39	0.40%	0.07	19.04	37.50	\$152.82	
CCCT Wet "F", 2x1	4250	\$1,104	7.886%	\$87.05	8.58	0.70%	0.06	15.03	23.67	\$110.71	
CCCT Wet "F", DF, 2x1	4250	\$490	7.886%	\$38.63	0.00	0.00%	0.00	17.81	17.81	\$56.44	
CCCT Dry "F", 1x1	5050	\$1,253	7.886%	\$98.81	13.94	1.29%	0.18	15.36	29.49	\$128.29	
CCCT Dry "F", DF, 1x1	5050	\$546	7.886%	\$43.08	0.00	0.00%	0.00	19.20	19.20	\$62.28	
CCCT Dry "F", 2x1	5050	\$1,159	7.886%	\$91.37	7.14	1.23%	0.09	15.19	22.42	\$113.79	
CCCT Dry "F", DF, 2x1	5050	\$522	7.886%	\$41.13	0.00	0.00%	0.00	19.12	19.12	\$60.25	
CCCT Dry "G/H", 1x1	5050	\$1,129	7.886%	\$89.04	12.45	1.96%	0.24	15.48	28.17	\$117.21	
CCCT Dry "G/H", DF, 1x1	5050	\$612	7.886%	\$48.23	0.00	0.00%	0.00	18.62	18.62	\$66.86	
CCCT Dry "G/H", 2x1	5050	\$1,118	7.886%	\$88.16	6.55	1.86%	0.12	15.20	21.87	\$110.03	
CCCT Dry "G/H", DF, 2x1	5050	\$600	7.886%	\$47.32	0.00	0.00%	0.00	18.27	18.27	\$65.59	
CCCT Dry "J", Adv 1x1	5050	\$1,075	7.886%	\$84.74	10.54	1.95%	0.21	14.64	25.39	\$110.13	
CCCT Dry "J", DF, Adv 1x1	5050	\$486	7.886%	\$38.36	0.00	0.00%	0.00	19.41	19.41	\$57.77	
Intercooled SCCT Aero x1	6500	\$1,189	8.428%	\$100.24	17.91	1.40%	0.25	17.07	35.24	\$135.47	
SCCT Frame "F" x1	6500	\$804	7.954%	\$63.91	9.13	1.37%	0.13	19.16	28.42	\$92.33	
IC Recips x6	6500	\$1,469	8.428%	\$123.84	19.03	0.40%	0.08	16.27	35.37	\$159.21	
CCCT Dry "G/H", 2x1	6500	\$1,159	7.886%	\$91.40	6.80	1.86%	0.13	12.99	19.91	\$111.31	
CCCT Dry "G/H", DF, 2x1	6500	\$600	7.886%	\$47.32	0.00	0.00%	0.00	15.61	15.61	\$62.93	
CCCT Dry "J", Adv 1x1	6500	\$1,110	7.886%	\$87.54	10.88	1.95%	0.21	12.51	23.60	\$111.14	
CCCT Dry "J", DF, Adv 1x1	6500	\$486	7.886%	\$38.36	0.00	0.00%	0.00	16.58	16.58	\$54.94	

Table 6.3 – Total Resource Cost for Supply-Side Resource Options, \$16 CO₂ Tax (Continued)

\$16 CO ₂ Tax	Supply Side Resource Options Mid-Calendar Year 2012 Dollars (\$)	Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)			
		Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	Levelized Fuel		O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	Credits	Total Resource Cost - With PTC / ITC Credits
						¢/mmBtu	Mills/kWh							PTC Tax Credits / ITC (Solar Only)	
Resource Description															
SCCT Aero x3, ISO	0	21%	72.65	na	498	48.47	3.50	6.67%	0.23	-	3.86	128.72	-	128.72	
Intercooled SCCT Aero x1, ISO	0	21%	70.48	na	498	44.13	2.92	6.83%	0.20	-	3.52	121.24	-	121.24	
SCCT Frame "F" x1, ISO	0	21%	51.65	na	498	49.52	8.46	7.80%	0.66	-	3.95	114.24	-	114.24	
IC Recips x6, ISO	0	21%	78.99	na	498	42.04	7.40	4.33%	0.32	-	3.35	132.10	-	132.10	
CCCT Dry "F", 2x1, ISO	0	56%	21.84	na	498	33.53	2.11	7.69%	0.16	-	2.67	60.31	-	60.31	
CCCT Dry "F", DF, 2x1, ISO	0	16%	49.54	na	498	42.21	0.08	0.00%	0.00	-	3.36	95.19	-	95.19	
CCCT Dry "G/H", 1x1, ISO	0	56%	22.51	na	498	34.17	2.53	7.05%	0.18	-	2.72	62.12	-	62.12	
CCCT Dry "G/H", DF, 1x1, ISO	0	16%	54.09	na	498	41.12	0.08	0.00%	0.00	-	3.28	98.56	-	98.56	
CCCT Dry "G/H", 2x1, ISO	0	56%	21.17	na	498	33.56	2.44	7.30%	0.18	-	2.67	60.02	-	60.02	
CCCT Dry "G/H", DF, 2x1, ISO	0	16%	53.06	na	498	40.34	0.07	0.00%	0.00	-	3.21	96.69	-	96.69	
CCCT Dry "J", Adv 1x1, ISO	0	56%	21.28	na	498	32.32	2.20	7.03%	0.15	-	2.58	58.53	-	58.53	
CCCT Dry "J", DF, Adv 1x1, ISO	0	16%	47.87	na	498	42.86	0.08	0.00%	0.00	-	3.41	94.22	-	94.22	
Intercooled SCCT Aero x1	1500	21%	72.03	na	498	43.99	2.99	6.83%	0.20	-	3.51	122.73	-	122.73	
SCCT Frame "F" x1	1500	21%	52.65	na	498	49.52	8.71	7.80%	0.68	-	3.95	115.50	-	115.50	
IC Recips x 6	1500	21%	81.65	na	498	42.04	7.63	4.48%	0.34	-	3.35	135.02	-	135.02	
CCCT Dry "F", 2x1	1500	56%	22.62	na	498	33.53	2.18	7.67%	0.17	-	2.67	61.17	-	61.17	
CCCT Dry "F", DF, 2x1	1500	16%	49.54	na	498	42.21	0.08	0.00%	0.00	-	3.36	95.20	-	95.20	
CCCT Dry "G/H", 2x1	1500	56%	21.90	na	498	33.71	2.54	7.29%	0.19	-	2.69	61.02	-	61.02	
CCCT Dry "G/H", DF, 2x1	1500	16%	53.13	na	498	40.49	0.07	0.00%	0.00	-	3.23	96.92	-	96.92	
CCCT Dry "J", Adv 1x1	1500	56%	21.84	na	498	32.32	2.27	7.01%	0.16	-	2.58	59.17	-	59.17	
CCCT Dry "J", DF, Adv 1x1	1500	16%	47.87	na	498	42.86	0.08	0.00%	0.00	-	3.41	94.22	-	94.22	
SCCT Aero x3	4250	21%	74.16	na	472	45.97	3.89	6.67%	0.26	-	3.86	128.15	-	128.15	
Intercooled SCCT Aero x1	4250	21%	71.84	na	472	41.85	3.23	6.83%	0.22	-	3.52	120.66	-	120.66	
SCCT Frame "F" x1	4250	21%	49.90	na	472	46.97	9.48	7.80%	0.74	-	3.95	111.03	-	111.03	
IC Recips x6	4250	21%	83.07	na	472	39.87	8.15	4.48%	0.36	-	3.35	134.81	-	134.81	
CCCT Wet "F", 2x1	4250	56%	22.57	na	472	31.46	2.87	6.27%	0.18	-	2.64	59.73	-	59.73	
CCCT Wet "F", DF, 2x1	4250	16%	40.27	na	472	37.30	0.32	0.00%	0.00	-	3.13	81.02	-	81.02	
CCCT Dry "F", 1x1	5050	56%	26.15	na	472	32.17	2.57	7.50%	0.19	-	2.70	63.79	-	63.79	
CCCT Dry "F", DF, 1x1	5050	16%	44.44	na	472	40.21	0.08	0.00%	0.00	-	3.38	88.10	-	88.10	
CCCT Dry "F", 2x1	5050	56%	23.20	na	472	31.80	2.42	7.67%	0.19	-	2.67	60.27	-	60.27	
CCCT Dry "F", DF, 2x1	5050	16%	42.98	na	472	40.04	0.08	0.00%	0.00	-	3.36	86.46	-	86.46	
CCCT Dry "G/H", 1x1	5050	56%	23.89	na	472	32.41	2.94	6.99%	0.21	-	2.72	62.17	-	62.17	
CCCT Dry "G/H", DF, 1x1	5050	16%	47.70	na	472	39.00	0.08	0.00%	0.00	-	3.28	90.05	-	90.05	
CCCT Dry "G/H", 2x1	5050	56%	22.43	na	472	31.83	2.82	7.27%	0.21	-	2.67	59.96	-	59.96	
CCCT Dry "G/H", DF, 2x1	5050	16%	46.80	na	472	38.26	0.07	0.00%	0.00	-	3.21	88.34	-	88.34	
CCCT Dry "J", Adv 1x1	5050	56%	22.45	na	472	30.66	2.54	6.98%	0.18	-	2.58	58.40	-	58.40	
CCCT Dry "J", DF, Adv 1x1	5050	16%	41.22	na	472	40.65	0.08	0.00%	0.00	-	3.41	85.36	-	85.36	
Intercooled SCCT Aero x1	6500	21%	73.64	na	472	41.85	3.39	6.83%	0.23	-	3.52	122.63	-	122.63	
SCCT Frame "F" x1	6500	21%	50.19	na	472	46.97	10.00	7.80%	0.78	-	3.95	111.88	-	111.88	
IC Recips x6	6500	21%	86.55	na	472	39.87	8.60	4.48%	0.39	-	3.35	138.76	-	138.76	
CCCT Dry "G/H", 2x1	6500	56%	22.69	na	472	31.83	2.92	7.27%	0.21	-	2.67	60.33	-	60.33	
CCCT Dry "G/H", DF, 2x1	6500	16%	44.90	na	472	38.26	0.07	0.00%	0.00	-	3.21	86.44	-	86.44	
CCCT Dry "J", Adv 1x1	6500	56%	22.66	na	472	30.66	2.62	6.96%	0.18	-	2.58	58.69	-	58.69	
CCCT Dry "J", DF, Adv 1x1	6500	16%	39.20	na	472	40.65	0.08	0.00%	0.00	-	3.41	83.34	-	83.34	

Table 6.3 – Total Resource Cost for Supply-Side Resource Options, \$16 CO₂ Tax (Continued)

\$16 CO₂ Tax		Capital Cost \$/kW			Fixed Cost						
Supply Side Resource Options Mid-Calendar Year 2012 Dollars (\$)		Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment (\$/kW-Yr)	Fixed O&M \$/kW-Yr					Total Fixed (\$/kW-Yr)
Resource Description	O&M					Capitalized Premium	O&M Capitalized	Gas Transporta tion	Total		
IGCC with CCS	6500	\$5,931	7.438%	\$441.13	60.76	0.00%	0.00	0.00	60.76	\$501.90	
Generic Geothermal PPA 90% CF	4500	\$0	6.831%	\$0.00	735.46	0.00%	0.00	0.00	735.46	\$735.46	
2.3 MW turbine 29% CF WA	1500	\$2,365	8.165%	\$193.12	33.11	1.14%	0.38	0.00	33.49	\$226.61	
2.3 MW turbine 29% CF UT	4500	\$2,304	8.165%	\$188.12	33.11	1.14%	0.38	0.00	33.49	\$221.61	
2.3 MW turbine 40% CF WY	6500	\$2,257	8.165%	\$184.30	33.11	1.14%	0.38	0.00	33.49	\$217.78	
PV Poly-Si Fixed Tilt 22% CF (1.21 MWdc/MWac)	4500	\$3,153	8.165%	\$257.48	51.50	2.45%	1.26	0.00	52.76	\$310.24	
PV Poly-Si Fixed Tilt 28% CF (1.37 MWdc/MWac)	4500	\$2,952	8.165%	\$241.05	27.81	2.45%	0.68	0.00	28.49	\$269.54	
PV Poly-Si Single Tracking 34% CF (1.34 MWdc/MWac)	4500	\$3,176	8.165%	\$259.29	32.55	2.45%	0.80	0.00	33.35	\$292.64	
Forestry Byproduct	1500	\$3,334	7.542%	\$251.45	40.65	5.07%	2.06	0.00	42.71	\$294.16	
Pumped Storage	4500	\$3,000	7.459%	\$223.77	4.30	6.19%	0.27	0.00	4.57	\$228.34	
Sodium-Sulfur Battery	4500	\$4,400	8.722%	\$383.77	27.40	0.00%	0.00	0.00	27.40	\$411.17	
Advanced Fly Wheel	4500	\$2,406	8.722%	\$209.85	96.24	0.00%	0.00	0.00	96.24	\$306.09	
CAES	4500	\$1,751	8.428%	\$147.57	33.80	0.00%	0.00	21.95	55.75	\$203.33	
Advanced Fission	4500	\$7,093	7.623%	\$540.70	88.75	5.79%	5.14	0.00	93.89	\$634.59	

\$16 CO₂ Tax		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)			
Supply Side Resource Options Mid-Calendar Year 2012 Dollars (\$)		Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	Levelized Fuel		O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	Credits	
Resource Description	¢/mmBtu					Mills/kWh	PTC Tax Credits / ITC (Solar Only)							Total Resource Cost - With PTC / ITC Credits	
IGCC with CCS	6500	86%	66.96	na	271	29.91	13.52	12.08%	1.63	-	0.76	112.79	-	112.79	
Generic Geothermal PPA 90% CF	4500	90%	93.28	na	-	-	11.00	0.00%	0.00	-	-	104.29	-	104.29	
2.3 MW turbine 29% CF WA	1500	29%	89.20	na	-	-	0.00	0.00%	0.00	2.55	-	91.76	(19.48)	72.28	
2.3 MW turbine 29% CF UT	4500	29%	87.23	na	-	-	0.00	0.00%	0.00	2.55	-	89.79	(19.48)	70.31	
2.3 MW turbine 40% CF WY	6500	40%	62.15	na	-	-	0.65	0.00%	0.00	2.55	-	65.36	(19.48)	45.88	
PV Poly-Si Fixed Tilt 22% CF (1.21 MWdc/MWac)	4500	22%	160.98	na	-	-	0.00	0.00%	0.00	0.64	-	161.62	(19.91)	141.70	
PV Poly-Si Fixed Tilt 28% CF (1.37 MWdc/MWac)	4500	28%	108.69	na	-	-	0.00	0.00%	0.00	0.64	-	109.33	(14.49)	94.84	
PV Poly-Si Single Tracking 34% CF (1.34 MWdc/MWac)	4500	34%	98.86	na	-	-	0.00	0.00%	0.00	0.64	-	99.50	(13.06)	86.45	
Forestry Byproduct	1500	91%	37.00	na	512	51.29	0.96	0.00%	0.00	-	6.90	96.15	(17.86)	78.29	
Pumped Storage	4500	42%	62.56	77.5%	472	59.32	4.30	0.00%	0.00	-	-	126.18	-	126.18	
Sodium-Sulfur Battery	4500	25%	187.75	72.5%	472	63.41	0.00	0.00%	0.00	-	-	251.16	-	251.16	
Advanced Fly Wheel	4500	5%	698.84	85.0%	472	54.09	0.00	0.00%	0.00	-	-	752.93	-	752.93	
CAES	4500	33%	69.63	83.5%	472	55.06	22.51	10.29%	2.32	-	3.86	153.38	-	153.38	
Advanced Fission	4500	86%	84.67	na	85	9.11	2.04	0.00%	0.00	-	-	95.82	-	95.82	

Table 6.4- Glossary of Terms from Supply Side Resource Table

Term	Description
Fuel:	Primary fuel used for electricity generation or storage.
Resource:	Primary technology used for electricity generation or storage.
Elevation (afsl):	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW):	Net dependable capacity is the net electrical output for a given technology at the given elevation and annual average ambient temperature in a "new and clean" condition.
Commercial Operation Year:	First year the resource could be placed in service; available for generation and dispatch.
Design Life (yrs):	Average number of years the resource is expected to be "used and useful", based on various factors such as OEM guarantees, fuel availability and environmental regulations.
Base Capital (\$/kW):	Total capital expenditure in \$/kW for the development and construction of a resource, including direct costs (equipment, buildings, installation/overnight construction, commissioning, EPC fees/profit, and contingency), owner's costs (land acquisition, water rights, air permitting, rights of way, design engineering, spare parts, project management costs, legal/financial costs, grid interconnection costs, owner's contingency), and financial costs (AFUDC, capital surcharge, property taxes, escalation.)
Var O&M (\$/MWh):	Includes real levelized variable operating costs such as combustion turbine maintenance, raw water costs, boiler water/circulating water treatment chemicals, pollution control chemicals, equipment maintenance chemicals, and fired hour fee.
Fixed O&M (\$/KW-yr):	Includes fixed operating costs: labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment, training.
Full Load Heat Rate HHV (Btu/KWh):	Efficiency of a resource to generate electricity for a given heat input in a "new and clean" condition.
EFOR (%):	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates, for a given resource at the given site.
POR (%):	Estimated Planned Outage Rate for a given resource at the given site.
Water Consumed (gal/MWh):	Average amount of water consumed by a resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO ₂ (lbs/MMBtu):	Expected permitted level of sulfur dioxide emissions in pounds of sulfur dioxide per million Btu of heat input.
NO _x (lbs/MMBtu):	Expected permitted level of nitrogen oxides (expressed as NO ₂) in pounds of NO _x per million Btu of heat input.
Hg (lbs/TBtu):	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO ₂ (lbs/MMBtu):	Pounds of carbon dioxide emitted per million Btu of heat input.

Table 6.5 – Glossary of Acronyms Used in the Supply Side Resource Table

Acronyms	Description
Adv:	Advanced (Combined Cycle Combustion Turbine)
AFSL:	Average Feet (Above) Sea Level
CAES:	Compressed Air Energy Storage
CCCT:	Combined Cycle Combustion Turbine
CCS:	Carbon Capture and Sequestration
CF:	Capacity Factor
CSP:	Concentrated Solar Power
DF:	Duct Firing
IC:	Internal Combustion
IGCC:	Integrated Gasification Combined Cycle
ISO:	International Organization for Standardization (Temp = 59 F/15 C, Pressure = 14.7 psia/1.013 bar)
PC CCS:	Pulverized Coal-Carbon Capture and Sequestration
PV Poly-Si:	Photovoltaic cells constructed from poly-crystalline silicon semiconductor wafers
Recip:	Reciprocating Engine
SCCT:	Simple Cycle Combustion Turbine
SCPC:	Super-Critical Pulverized Coal
SO:	Solid Oxide (Fuel Cell)

Some important factors that apply to the Supply Side Resource Tables are listed below:

- Capital costs are all-inclusive and include Allowance for Funds Used During Construction (AFUDC), land, EPC (Engineering, Procurement, and Construction) cost premiums, owner's costs, etc. Capital costs in Table 6.5 reflect mid-2012 dollars, and do not include escalation from mid-year to the year of commercial operation.
- Costs of energy for solar resources include investment tax credits. Hybrid solar with natural gas backup would not qualify for investment tax credits.
- Wind, hydrokinetic, biomass, and geothermal resources are assumed to qualify for Production Tax Credits (PTC), depending on the installation date.
- Capital costs include interconnection costs to the transmission system (switchyard and other upgrades needed to interconnect the resource to PacifiCorp's transmission network) but do not include transmission system network upgrades.
- For the nuclear resource, capital costs include the cost of storing spent fuel on-site during the life of the facility. Costs for ultimate off-site disposal of spent fuel are not included.
- Wind resources are representative generic resources included in the IRP models for planning purposes. Cost and performance attributes of specific resources are identified as part of the acquisition process. An estimate for wind integration costs, \$2.55/MWh, has been added to variable O&M cost.
- State specific tax benefits are excluded from the IRP supply side table but would be considered in the evaluation of a specific project.

A sensitivity analysis was prepared for three Natural Gas-fired Combined Cycle Combustion Turbine resource options at varying capacity factors. Table 6.6 shows the total resource cost results for this analysis.

Table 6.6 – Total Resource Cost, Natural Gas-fired plants at varying Capacity Factors (2012\$)

Total Resource Cost (Mills/kWh)				
Capacity Factor CCCT	Elevation (AFSL)	40%	56%	80%
Capacity Factor Duct Fire		10%	16%	22%
CCCT Wet "F", 2x1	4250	\$68.75	\$59.73	\$52.96
CCCT Wet "F", DF, 2x1	4250	\$105.18	\$81.02	\$70.04
CCCT Dry "F", 1x1	5050	\$74.25	\$63.79	\$55.95
CCCT Dry "F", DF, 1x1	5050	\$114.76	\$88.10	\$75.98
CCCT Dry "F", 2x1	5050	\$69.55	\$60.27	\$53.32
CCCT Dry "F", DF, 2x1	5050	\$112.25	\$86.46	\$74.74
CCCT Dry "G/H", 1x1	5050	\$71.73	\$62.17	\$55.00
CCCT Dry "G/H", DF, 1x1	5050	\$118.67	\$90.05	\$77.04
CCCT Dry "G/H", 2x1	5050	\$68.93	\$59.96	\$53.23
CCCT Dry "G/H", DF, 2x1	5050	\$116.42	\$88.34	\$75.58
CCCT Dry "J", Adv 1x1	5050	\$67.38	\$58.40	\$51.66
CCCT Dry "J", DF, Adv 1x1	5050	\$110.09	\$85.36	\$74.12

Distributed Generation

Table 6.7 presents cost and performance attributes for small combined heat and power and solar resource options.

Tables 6.8 and 6.9 present the total resource cost attributes for small combined heat and power and solar resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2012 dollars. The resource costs are presented for both the \$0 and \$16 CO₂ tax levels in recognition of the uncertainty in characterizing emission costs. Additional explanatory notes for the tables are as follows:

- Administrative costs, representing the estimated cost of delivering a program to end-use customers, are included for solar photovoltaic and water heating systems. Small combined heat and power are considered qualifying facilities as such do not include administrative or interconnection costs.
- As available, federal tax benefits are included for the following resources based on a percent of capital cost.

– Reciprocating Engine	10 percent
– Microturbine	10 percent
– Fuel Cell	30 percent
– Gas Turbine	10 percent
– Industrial Biomass	10 percent
– Anaerobic Digesters	10 percent
- The resource cost for Industrial Biomass is based on data from The Cadmus Group, Inc. (Cadmus). The fuel is assumed to be provided by the project owner at no cost, a conservative assumption. In reality, the cost to the Company would be each state’s filed avoided cost rate.
- Installation costs for on-site (“micro”) solar generation technologies are treated on a total resource cost basis; that is, customer installation costs are included. If available, capital costs are adjusted downward to reflect federal tax credits of 30 percent of installed system costs. Conversely, no adjustment is made for state tax incentives as these are not included in the Total Resource Cost test that sees the incentive as a benefit to customers but also as a cost to the state’s tax payers, making the net effect zero. In Utah, these resources are assessed on a Utility Cost Test basis, considering only utility incentives and program administrative

Table 6.7- Distributed Generation Resource Supply-Side Options

Supply-side Resource Options Mid-Calendar Year 2012 Dollars (\$)	Location / Timing		Plant Details				Outage Information		Costs			Emissions				
	Resource Description	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW	Fuel	Design Plant Life in Years	Annual Average Heat Rate HHV BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate	Base Capital Cost in \$/kW	Var. O&M, \$/MWh	Fixed O&M in \$/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
Small Combined Heat & Power																
Reciprocating Engine	Idaho	2013	0.40	Natural Gas	20	8,000	2%	3%	\$ 1,495	-	\$ 47.41	0.001	0.101	0.255	118.00	
Reciprocating Engine	Utah	2013	6.61	Natural Gas	20	8,000	2%	3%	\$ 1,495	-	\$ 47.41	0.001	0.101	0.255	118.00	
Reciprocating Engine	Oregon / California	2013	1.04	Natural Gas	20	8,000	2%	3%	\$ 1,495	-	\$ 47.41	0.001	0.101	0.255	118.00	
Reciprocating Engine	Washington	2013	1.28	Natural Gas	20	8,000	2%	3%	\$ 1,495	-	\$ 47.41	0.001	0.101	0.255	118.00	
Reciprocating Engine	Wyoming	2013	0.89	Natural Gas	20	8,000	2%	3%	\$ 1,495	-	\$ 47.41	0.001	0.101	0.255	118.00	
Gas Turbine	Idaho	2013	0.14	Natural Gas	20	6,300	2%	3%	\$ 1,757	-	\$ 55.42	0.001	0.050	0.255	118.00	
Gas Turbine	Utah	2013	1.90	Natural Gas	20	6,300	2%	3%	\$ 1,757	-	\$ 55.42	0.001	0.050	0.255	118.00	
Gas Turbine	Oregon	2013	0.27	Natural Gas	20	6,300	2%	3%	\$ 1,757	-	\$ 55.42	0.001	0.050	0.255	118.00	
Gas Turbine	Washington	2013	0.13	Natural Gas	20	6,300	2%	3%	\$ 1,757	-	\$ 55.42	0.001	0.050	0.255	118.00	
Gas Turbine	Wyoming	2013	0.30	Natural Gas	20	6,300	2%	3%	\$ 1,757	-	\$ 55.42	0.001	0.050	0.255	118.00	
Microturbine	Utah	2013	0.95	Natural Gas	10	8,000	2%	3%	\$ 2,168	-	\$ 63.42	0.001	0.101	0.255	118.00	
Fuel Cell	Utah	2013	0.47	Natural Gas	10	6,100	2%	3%	\$ 3,673	-	\$ 186.91	0.001	0.003	0.255	118.00	
Commercial Biomass, Anaerobic Digester	Utah	2013	0.20	Biomass	25	-	10%	10%	\$ 2,452	-	\$ 61.78	-	-	-	-	
Commercial Biomass, Anaerobic Digester	Wyoming	2013	0.16	Biomass	25	-	10%	10%	\$ 2,452	-	\$ 61.78	-	-	-	-	
Industrial Biomass, Waste	Utah	2013	0.16	Biomass	25	-	5%	5%	\$ 631	-	\$ 28.82	-	-	-	-	
Industrial Biomass, Waste	Oregon / California	2013	0.55	Biomass	25	-	5%	5%	\$ 631	-	\$ 28.82	-	-	-	-	
Solar																
Rooftop Photovoltaic (Utility Cost)	Utah	2013	13.116	Solar	30	-			\$ 902	-	-	-	-	-	-	
Rooftop Photovoltaic	Wyoming	2013	0.291	Solar	30	-			\$ 4,693	-	\$ 20.47	-	-	-	-	
Rooftop Photovoltaic	Oregon / California	2013	7.613	Solar	30	-			\$ 4,753	-	\$ 20.47	-	-	-	-	
Rooftop Photovoltaic	Idaho	2013	0.148	Solar	30	-			\$ 4,693	-	\$ 20.47	-	-	-	-	
Rooftop Photovoltaic	Washington	2013	0.154	Solar	30	-			\$ 4,693	-	\$ 20.47	-	-	-	-	
Water Heaters (Utility Cost)	Utah	2013	1.531	Solar	20	-			\$ 194	-	-	-	-	-	-	
Water Heaters	Oregon	2013	2.159	Solar	20	-			\$ 1,600	-	\$ 20.36	-	-	-	-	

Table 6.8 – Distributed Generation Total Resource Cost, \$0 CO₂ Tax

Supply-side Resource Options Mid-Calendar Year 2012 Dollars (\$)	Location	Capital Cost \$/kW					Fixed Cost		Convert to Mills				Variable Costs (mills/kWh)			Total Resource Cost with Tax Benefits (Mills/kWh)	Tax Incentive (Mills/kWh)	Total Resource Cost without Tax Benefits (Mills/kWh)
		Tax Incentive	Rebate and Administrative Costs	Net Capital Costs	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Total Fixed (\$/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	Levelized Fuel		O&M	Gas Transportation	Environmental			
											c/mmBtu	Mills/kWh						
Resource Description																		
Small Combined Heat & Power																		
Reciprocating Engine	Idaho	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	431.47	34.52	-	\$ 2.06	-	\$ 95.39	\$ 5.03	\$ 100.42
Reciprocating Engine	Utah	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	431.47	34.52	-	\$ 2.06	-	\$ 95.39	\$ 5.03	\$ 100.42
Reciprocating Engine	Oregon / California	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	472.04	37.76	-	\$ 3.05	-	\$ 99.62	\$ 5.03	\$ 104.65
Reciprocating Engine	Washington	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	472.04	37.76	-	\$ 3.05	-	\$ 99.62	\$ 5.03	\$ 104.65
Reciprocating Engine	Wyoming	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	431.47	34.52	-	\$ 1.76	-	\$ 95.09	\$ 5.03	\$ 100.12
Gas Turbine	Idaho	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	431.47	27.18	-	\$ 1.62	-	\$ 62.89	\$ 2.92	\$ 65.81
Gas Turbine	Utah	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	472.04	29.74	-	\$ 1.62	-	\$ 65.45	\$ 2.92	\$ 68.37
Gas Turbine	Oregon	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	472.04	29.74	-	\$ 1.62	-	\$ 65.45	\$ 2.92	\$ 68.37
Gas Turbine	Washington	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	431.47	27.18	-	\$ 1.62	-	\$ 62.89	\$ 2.92	\$ 65.81
Gas Turbine	Wyoming	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	431.47	27.18	-	\$ 1.62	-	\$ 62.89	\$ 2.92	\$ 65.81
Microturbine	Utah	\$ 241		\$ 2,168	14.39%	\$ 311.92	\$ 63.42	\$ 375.34	49%	87.44	431.47	34.52	-	\$ 2.06	-	\$ 124.02	\$ 8.07	\$ 132.09
Fuel Cell	Utah	\$ 1,574		\$ 3,673	14.39%	\$ 528.51	\$ 186.91	\$ 715.42	71%	115.03	431.47	26.32	-	\$ 1.57	-	\$ 142.92	\$ 36.42	\$ 179.33
Commercial Biomass, Anaerobic Digester	Utah	\$ 272		\$ 2,452	8.17%	\$ 200.23	\$ 61.78	\$ 262.00	46%	65.09	-	-	-	-	-	\$ 65.09	\$ 5.53	\$ 70.62
Commercial Biomass, Anaerobic Digester	Wyoming	\$ 272		\$ 2,452	8.17%	\$ 200.23	\$ 61.78	\$ 262.00	46%	65.09	-	-	-	-	-	\$ 65.09	\$ 5.53	\$ 70.62
Industrial Biomass, Waste	Utah	\$ 70		\$ 631	8.17%	\$ 51.50	\$ 28.82	\$ 80.32	90%	10.19	-	-	-	-	-	\$ 10.19	\$ 0.73	\$ 10.91
Industrial Biomass, Waste	Oregon / California	\$ 70		\$ 631	8.17%	\$ 51.50	\$ 28.82	\$ 80.32	90%	10.19	-	-	-	-	-	\$ 10.19	\$ 0.73	\$ 10.91
Solar																		
Rooftop Photovoltaic (Utility Cost)	Utah		\$ 902	\$ 902	7.54%	\$ 68.05	-	\$ 68.05	17%	45.70	-	-	-	-	-	\$ 45.70	-	\$ 45.70
Rooftop Photovoltaic	Wyoming	\$ 2,011	\$ 131	\$ 4,693	7.54%	\$ 353.93	\$ 20.47	\$ 374.40	19%	229.23	-	-	-	-	-	\$ 229.23	\$ 92.87	\$ 322.11
Rooftop Photovoltaic	Oregon / California	\$ 2,037	\$ 133	\$ 4,753	7.54%	\$ 358.49	\$ 20.47	\$ 378.96	16%	274.87	-	-	-	-	-	\$ 274.87	\$ 111.44	\$ 386.31
Rooftop Photovoltaic	Idaho	\$ 2,011	\$ 131	\$ 4,693	7.54%	\$ 353.93	\$ 20.47	\$ 374.40	15%	279.35	-	-	-	-	-	\$ 279.35	\$ 113.17	\$ 392.52
Rooftop Photovoltaic	Washington	\$ 2,011	\$ 131	\$ 4,693	7.54%	\$ 353.93	\$ 20.47	\$ 374.40	14%	298.88	-	-	-	-	-	\$ 298.88	\$ 121.09	\$ 419.97
Water Heaters (Utility Cost)	Utah		\$ 194	\$ 194	9.15%	\$ 17.72	-	\$ 17.72	6%	33.92	-	-	-	-	-	\$ 33.92	-	\$ 33.92
Water Heaters	Oregon	\$ 752	\$ 267	\$ 1,600	9.15%	\$ 146.45	\$ 20.36	\$ 166.81	7%	263.15	-	-	-	-	-	\$ 263.15	\$ 108.58	\$ 371.73

Table 6.9 – Distributed Generation Total Resource Cost, \$16 CO₂ Tax

Supply-side Resource Options Mid-Calendar Year 2012 Dollars (\$)	Location	Capital Cost \$/kW					Fixed Cost		Convert to Mills				Variable Costs (mills/kWh)			Total Resource Cost (Mills/kWh)	Tax Incentive (Mills/kWh)	Total Resource Cost without Tax Benefits (Mills/kWh)
		Tax Incentive	Rebate and Administrative Costs	Net Capital Costs	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Total Fixed (\$/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	Levelized Fuel		O&M	Gas Transportation or Wind Integration	Environmental			
											c/mmBtu	Mills/kWh						
Resource Description																		
Small Combined Heat & Power																		
Reciprocating Engine	Idaho	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	472.04	37.76	-	\$ 2.06	3.17	\$ 101.80	\$ 5.03	\$ 106.83
Reciprocating Engine	Utah	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	472.04	37.76	-	\$ 2.06	3.17	\$ 101.80	\$ 5.03	\$ 106.83
Reciprocating Engine	Oregon / California	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	497.71	39.82	-	\$ 3.05	3.17	\$ 104.85	\$ 5.03	\$ 109.88
Reciprocating Engine	Washington	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	497.71	39.82	-	\$ 3.05	3.17	\$ 104.85	\$ 5.03	\$ 109.88
Reciprocating Engine	Wyoming	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	472.04	37.76	-	\$ 1.76	3.17	\$ 101.50	\$ 5.03	\$ 106.53
Gas Turbine	Idaho	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	472.04	29.74	-	\$ 1.62	2.50	\$ 67.94	\$ 2.92	\$ 70.86
Gas Turbine	Utah	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	497.71	31.36	-	\$ 1.62	2.50	\$ 69.56	\$ 2.92	\$ 72.48
Gas Turbine	Oregon	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	497.71	31.36	-	\$ 1.62	2.50	\$ 69.56	\$ 2.92	\$ 72.48
Gas Turbine	Washington	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	472.04	29.74	-	\$ 1.62	2.50	\$ 67.94	\$ 2.92	\$ 70.86
Gas Turbine	Wyoming	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	472.04	29.74	-	\$ 1.62	2.50	\$ 67.94	\$ 2.92	\$ 70.86
Microturbine	Utah	\$ 241		\$ 2,168	14.39%	\$ 311.92	\$ 63.42	\$ 375.34	49%	87.44	472.04	37.76	-	\$ 2.06	3.17	\$ 130.44	\$ 8.07	\$ 138.51
Fuel Cell	Utah	\$ 1,574		\$ 3,673	14.39%	\$ 528.51	\$ 186.91	\$ 715.42	71%	115.03	472.04	28.79	-	\$ 1.57	2.42	\$ 147.81	\$ 36.42	\$ 184.23
Commercial Biomass, Anaerobic Digester	Utah	\$ 272		\$ 2,452	8.17%	\$ 200.23	\$ 61.78	\$ 262.00	46%	65.09	-	-	-	-	-	\$ 65.09	\$ 5.53	\$ 70.62
Commercial Biomass, Anaerobic Digester	Wyoming	\$ 272		\$ 2,452	8.17%	\$ 200.23	\$ 61.78	\$ 262.00	46%	65.09	-	-	-	-	-	\$ 65.09	\$ 5.53	\$ 70.62
Industrial Biomass, Waste	Utah	\$ 70		\$ 631	8.17%	\$ 51.50	\$ 28.82	\$ 80.32	90%	10.19	-	-	-	-	-	\$ 10.19	\$ 0.73	\$ 10.91
Industrial Biomass, Waste	Oregon / California	\$ 70		\$ 631	8.17%	\$ 51.50	\$ 28.82	\$ 80.32	90%	10.19	-	-	-	-	-	\$ 10.19	\$ 0.73	\$ 10.91
Solar																		
Rooftop Photovoltaic (Utility Cost)	Utah		\$ 902	\$ 902	7.54%	\$ 68.05	-	\$ 68.05	17%	45.70	-	-	-	-	-	\$ 45.70	-	\$ 45.70
Rooftop Photovoltaic	Wyoming	\$ 2,011	\$ 131	\$ 4,693	7.54%	\$ 353.93	\$ 20.47	\$ 374.40	19%	229.23	-	-	-	-	-	\$ 229.23	\$ 92.87	\$ 322.11
Rooftop Photovoltaic	Oregon / California	\$ 2,037	\$ 133	\$ 4,753	7.54%	\$ 358.49	\$ 20.47	\$ 378.96	16%	274.87	-	-	-	-	-	\$ 274.87	\$ 111.44	\$ 386.31
Rooftop Photovoltaic	Idaho	\$ 2,011	\$ 131	\$ 4,693	7.54%	\$ 353.93	\$ 20.47	\$ 374.40	15%	279.35	-	-	-	-	-	\$ 279.35	\$ 113.17	\$ 392.52
Rooftop Photovoltaic	Washington	\$ 2,011	\$ 131	\$ 4,693	7.54%	\$ 353.93	\$ 20.47	\$ 374.40	14%	298.88	-	-	-	-	-	\$ 298.88	\$ 121.09	\$ 419.97
Water Heaters (Utility Cost)	Utah		\$ 194	\$ 194	9.15%	\$ 17.72	-	\$ 17.72	6%	33.92	-	-	-	-	-	\$ 33.92	-	\$ 33.92
Water Heaters	Oregon	\$ 752	\$ 267	\$ 1,600	9.15%	\$ 146.45	\$ 20.36	\$ 166.81	7%	263.15	-	-	-	-	-	\$ 263.15	\$ 108.58	\$ 371.73

Resource Option Description

Coal

Potential coal resources are shown in the supply-side resource options table as supercritical pulverized coal boilers (PC) and IGCC, located in both Utah and Wyoming. Costs for large coal-fired boilers, since the 2007 IRP, have increased by approximately 50 to 60 percent due to many factors involving material shortages, labor shortages, and the risk of fixed price contracting. Current economic conditions have mitigated many of these concerns and changes in price for coal generation have been relatively stable since the previous IRP. The uncertainty of both proposed and future carbon regulations and difficulty in obtaining environmental permits for coal based generation requires the Company to postpone the selection of coal as a resource before 2020.

Supercritical technology was chosen over subcritical technology for pulverized coal for a number of reasons. Increasing coal costs are making the added efficiency of the supercritical technology cost-effective. Additionally, there is a greater competitive marketplace for large supercritical boilers than for large subcritical boilers. Increasingly, large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. Due to the increased efficiency of supercritical boilers, overall emission intensity rates are smaller than for similarly sized subcritical units. Compared to subcritical boilers, supercritical boilers have better load following capability, faster ramp rates, 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 PC facility reflect the cost of adding a new unit at an existing site. PacifiCorp does not expect a significant difference in cost for a multi-unit plant at a new site versus the cost of a single unit addition at an existing site.

The potential requirement for CO₂ capture and sequestration (CCS) represents a significant cost for new and, possibly, existing coal resources. Currently proposed federal New Source Performance Standards for Greenhouse Gases (NSPS-GHG) regulations would require CCS for new coal units to meet the proposed emissions limit. Research projects are underway to develop more cost-effective methods of capturing carbon dioxide from pulverized coal boilers. The costs included in the supply side resource tables utilize amine based solvent systems for carbon capture. Sequestration would store the CO₂ underground for long-term storage and monitoring.

PacifiCorp continues to monitor CO₂ capture technologies for possible retrofit application on its existing coal-fired resources, as well as their applicability for future coal plants that could serve as cost-effective alternatives to IGCC plants if CO₂ removal becomes necessary in the future. An option to capture CO₂ at an existing coal-fired unit has been included in the supply side resource tables. Currently there are only a limited number of large-scale sequestration projects in operation around the world; most of these have been installed in conjunction with enhanced oil recovery. CCS is not considered a viable option before 2025 due to risk issues associated with the availability of commercial sequestration sites and the uncertainty regarding long term liabilities for underground sequestration.

An alternative to supercritical pulverized-coal technology for coal-based generation is the application of IGCC technology. A significant advantage for IGCC when compared to pulverized coal, with amine-based carbon capture, is the reduced cost of capturing CO₂ from the process. Only a limited number of IGCC plants have been built and operated around the world.

In the United States, these facilities have been demonstration projects, resulting in capital and operating costs that are significantly greater than those costs for conventional coal plants. The majority of these projects have been constructed with significant funding from the federal government. Two large, utility-scale IGCC plants are currently in construction: Duke Energy's Edwardsport Plant that utilizes General Electric's gasification technology and Southern Company's Kemper County plant that utilizes Southern Company's Transport Integrated Gasifier (TRIG). A third IGCC project, utilizing Siemens gasification technology, the Texas Clean Energy Project, is currently in an advanced stage of development. The costs presented in the supply-side resource options tables reflect 2007 studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority (WIA) to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

PacifiCorp communicates regularly with the primary gasification technology suppliers, constructors, and other utilities. The results of all these contacts were used to help develop the coal-based generation projects in the supply side resource tables.

Coal Plant Efficiency Improvements

Fuel efficiency gains for existing coal plants, which are manifested as lower plant heat rates, are realized by: (1) continuous operations improvement, (2) monitoring the quality of the fuel supply, and (3) upgrading components if economically justified. Efficiency improvements can result in a smaller emissions footprint for a given level of plant capacity, or the same footprint when plant capacity is increased.

The efficiency of generating units, primarily measured by the heat rate (the ratio of heat input to energy output) degrades gradually as components wear over time. During operation, controllable process parameters are adjusted to optimize the unit's power output compared to its heat input. Typical overhaul work that contributes to improved efficiency includes (1) major equipment overhauls of the steam generating equipment and combustion/steam turbine generators, (2) overhauls of the cooling systems and (3) overhauls of the pollution control equipment.

When economically justified, efficiency improvements are obtained through major component upgrades of the electricity generating equipment. The most notable examples of upgrades resulting in greater generating capacity are steam turbine upgrades and generator upgrades. Turbine upgrades consist of adding additional rows of blades to the rearward section of the turbine shaft (generically known as a "dense pack" configuration), but can also include replacing existing blades, replacing end seals and enhancing seal packing media. Generator upgrades consist of cleaning and rewinding the coils in the stator, and servicing the electromagnetic core. Such upgrade opportunities are analyzed on a case-by-case basis, and are tied to a unit's major overhaul cycle, and, because they are often capital intensive, are only implemented if economically justified.

Natural Gas

A number of natural gas fueled generation options are included in the supply-side resource options table and are intended to represent technologies that are both currently commercially available and/or will be available over the next few years. Both simple and combined cycle configurations are included. Capital costs for gas-fueled generation options approximate capital costs reported in previous IRPs. In real terms, capital costs have shown a modest decline

compared to the 2011 IRP, primarily driven by limited domestic orders for new gas-fired generation due to a lack of current economic growth.

Combustion turbine options include both simple and combined cycle configurations. The simple cycle (SCCT) options include traditional frame machines as well as aero-derivative combustion turbines. Two aero-derivative options are included: the General Electric LM6000PG combustion turbine and General Electric's LMS100. These machines are flexible, high efficiency machines and can be installed with high temperature oxidation catalysts for carbon monoxide (CO) control and an SCR system for nitrogen oxides (NOx) control, which allows them to be located in areas with air emissions concerns. LM6000 gas turbines have quick-start capability (less than ten minutes to full load) and higher heating value net full load heat rates near 10,000 Btu/kWh. For the current supply side resource table, the GE LM6000PG machine was selected, which has a slightly higher output than the LM6000PC machine used in the previous IRP supply side resource table and which are installed at the Company's Gadsby Plant. As in the previous IRP, the supply-side resource table includes General Electric's LMS100 intercooled gas turbine. This combustion turbine has been successful since its debut with 28 units in service with approximately another 20 being installed as of summer 2012. It is a cross between a simple-cycle aero-derivative gas turbine and a frame machine with compressor inter-cooling to improve efficiency. The machines have higher heating value net full load heat rates of less than 9,000 Btu/kWh and similar starting capabilities as the LM6000 with significant load following capability (up to 50 MW per minute).

Frame simple cycle machines are represented by the "F" class technology and in the case of the current IRP Supply Side Resource options table the frame machine reflects a General Electric 7F 5 series (previously referred to as the 7FA.05). One combustion turbine can generate approximately 180 MW at Western U.S. elevations; they have efficiencies similar to the LM6000 family of combustion turbines when operating in simple cycle.

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 six machines at 17.2 MW each at Western elevations. The underlying technology for this category is the Wartsila 18V50SG engine; these machines are spark-ignited and have the advantages of a relatively low (when compared to simple cycle combustion turbines), low emissions profile, and a high level of availability and reliability due to the relatively high number of machines for a given target capacity block. They are capable of being brought on line up to full load in less than ten minutes and have excellent part-load efficiency which is again due to fact that there is a high number of machines for a given capacity. These types of engines also have the advantage of being relatively insensitive to elevation and do not require high-pressure natural gas, which is typical of advanced combustion turbines. In previous IRPs, the underlying technology was the Wartsila 20V34SG, a smaller engine.

At present, fuel cells hold less promise for large utility scale applications due to high capital and maintenance costs, partly attributable to the lack of production capability and limited development. Fuel cell applications are beginning to advance in small scale with some customers.

A number of combined cycle configurations have been provided in this version of the Supply Side Resource options table. Configuration options include 1x1 and 2x1 configurations based on "F" and "G/H" combustion turbines. The "G/H" frame combustion turbine, although they are

supplied by different equipment manufacturers, are combined, since the power and performance outputs are relatively similar. Also included in the current version of the Supply Side Resource options table is the new “J” class combustion turbine, which is a large advanced combustion turbine (approximately 470 megawatts in a 1x1 combined cycle configuration under ISO conditions). The “J” class combustion turbine is now commercially available in the United States, though no orders have been placed to date. The Supply Side Resource table also includes Duct Firing (“DF”), which is not a stand-alone resource option, but is considered to be an available option for any combined cycle configuration and represents a low cost option to add peaking capability at relatively high efficiency and also a mechanism to recover lost power generation capability due to high ambient temperatures. The amount of duct firing in the supply side resource options table are stated as fixed values at 50 MW for the 1x1 configuration and 100 MW for the 2x1 configuration, though in reality the amount of duct firing is a design consideration which means the incremental capacity that can be added is flexible. In most cases, all combined cycle options listed in the current supply side resource table are based on dry cooling (i.e. using an air cooled condenser), rather than wet cooling (i.e. using a forced draft cooling tower). It is assumed that the availability of water in the western United States will continue to be limited. Furthermore, during cold weather cooling towers can have plumes that are sometimes considered a visual nuisance. The assumption of dry cooling is considered to be both prudent and conservative. In certain cases and sites, sufficient water may be available for wet cooling, in which case, performance and efficiency would be improved; the overall costs of energy would be site-specific depending on the total cost of water (commodity cost, transport/storage infrastructure cost, treatment cost, discharge cost).

Wind

Resource Supply, Location, and Incremental Transmission Costs

It should be noted that the primary drivers of wind resource selection are the requirements of renewable portfolio standards and the availability of production tax credits. In the previous IRP, incremental transmission costs were expressed as dollars-per-kW values that were applied to costs of wind resources added in wind-generation-only bubbles. In the present IRP, the availability of certain wind resources is contingent upon the different Energy Gateway transmission scenarios. In the Energy Gateway scenario 1, no new Wyoming wind is available. The availability of higher capacity factor, lower cost Wyoming wind increases moving from Energy Gateway scenarios 2 through 5. In Energy Gateway scenarios 1, 2, and 4 the only available wind resource on the west side of the system delivers energy to the Willamette Valley bubble and assumes a BPA wheel from McNary to the Willamette Valley (inclusive of BPA wind integration charges). It is assumed that any potential capital required by BPA is included in the cost of the wheel. This west side wind resource further assumes an incremental PacifiCorp Transmission capital cost of \$10 million (2012\$), which equates to \$33.33/kW (2012\$). For Energy Gateway scenarios 3 and 5, a wind resource is available, which delivers energy to the Northwest via the transmission path Windstar to Hemmingway. This resource reflects additions in Gorge vial route through Boardman and then to Bethel. No BPA wheeling costs apply. No incremental transmission costs will be assigned to this resource (assumes Energy Gateway Segment H costs cover all transmission integration requirements). Table 6.10 below shows the total cumulative wind selection limits for each wind resource based upon Energy Gateway scenario.

Table 6.10 – Cumulative Wind Selection Limits by Year and Energy Gateway Scenario

Wind Resource	Capacity Factor	Total MW Available							Energy Gateway Scenario
		2016	2017	2018	2019	2020	2021	>2021	
Wyoming (Aeolius)	40%	-	-	-	-	-	-	-	EG1
Wyoming (Aeolius)	40%	-	-	-	650	650	650	650	EG2
Wyoming (Aeolius)	40%	-	-	-	650	1,200	1,200	1,200	EG3
Wyoming (Aeolius)	40%	-	-	-	650	650	1,000	1,000	EG4
Wyoming (Aeolius)	40%	-	-	-	650	650	1,500	1,500	EG5
Oregon/ Washington (Willamette Valley)	29%	-	-	-	300	300	300	300	EG 1,2,4
Oregon/ Washington (Bethel)	29%	-	-	-	600	600	600	600	EG 3,5
South Utah Wind	29%	-	200	200	200	200	200	200	All EG 1-5
Idaho (Goshen) Wind	29%	-	600	600	600	600	600	600	All EG 1-5

Capital Costs

Capital cost estimates for wind projects are based on the development and construction costs of previously built projects and 2012 market prices for the wind turbine generators. All wind resources are specified in 100 MW blocks, but the model can choose a fractional amount of a block.

Wind Resource Capacity Factors and Energy Shapes

Resource options in the topology bubbles are assigned capacity factors based upon historic or expected project performance. Wyoming resource options are assigned a capacity factor value of 40 percent, while wind resources in other states are assigned a value of 29 percent. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the System Optimizer and Planning and Risk models. The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of \$2.55/MWh (in 2012 dollars) for resource selection. The source of this value was the Company's 2012 wind integration study, which is included as Appendix H. Integration costs were incorporated into wind capital costs based on a 25-year project life expectancy and generation performance.

Other Renewable Resources

Other renewable generation resources included in the supply-side resource options table include geothermal, biomass and solar.

Geothermal

The 2010 IRP Update included information from a 2010 geothermal study (see Table 6.11) that was commissioned by PacifiCorp and performed by Black & Veatch⁴³. The 2010 study focused on geothermal projects that could demonstrate commercial viability and were in advanced phases of development.

⁴³ The 2010 geothermal study is available on PacifiCorp's IRP web page. <http://www.pacificorp.com/es/irp.html>.

Table 6.11 – 2010 Geothermal Study Results

Table 1-1. Sites Selected for In-Depth Review.							
Field Name	State	Additional Capacity Available (Gross MW)	Additional Capacity Available (Net MW)	Additional Capacity Available to PacifiCorp (Net MW)^a	Anticipated Plant Type for Additional Capacity	LCOE (Low, \$/MWh)^{b,c}	LCOE (High, \$/MWh)^{b,c}
Lake City	CA	30	24	24	Binary	\$83	\$90
Medicine Lake	CA	480	384	384	Binary	\$91	\$98
Raft River	ID	90	72	43	Binary	\$93	\$100
Neal Hot Springs	OR	30	24	0	Binary	\$80	\$87
Cove Fort	UT	100	80	60 to 63	Binary	\$68	\$75
Crystal-Madsen	UT	30	24	0	Binary	\$93	\$100
Roosevelt Hot Springs	UT	90	81 ^d	81 ^d	Flash/Binary Hybrid	\$46	\$51
Thermo Hot Springs	UT	118	94	0	Binary	\$91	\$98
Totals		968	783	592 to 595			

Source: BVG analysis for PacifiCorp.
 Note:
^a Calculated by subtracting the amount of resource under contract to or in contract negotiations with other parties from the estimated net capacity available.
^b Net basis
^c These screening level cost estimates are based on available public information. More detailed estimates based on proprietary information and calculated on a consistent basis might yield different comparisons.
^d While 81 MW net are estimated to be available, the resource should be developed in smaller increments to verify resource sustainability

In response to the 2010 IRP Update, comments from stakeholders requested additional information on geothermal projects near PacifiCorp’s service territory that are in the early stages of exploration and development. PacifiCorp issued a Geothermal Information Request (GIR) to the public in 2011 to identify geothermal projects in the early stages of exploration and development. Black & Veatch was commissioned to review the responses, categorize the development stage of each project and recommend projects to PacifiCorp. As a result of the GIR, PacifiCorp received information on 16 projects in the early stages of development from 10 respondents.

Black & Veatch reviewed the information provided and evaluated each of the 16 projects. The projects were categorized according to the Geothermal Energy Association’s definition of the four phases of energy development:

- Phase 1 – Resource Procurement and Identification
- Phase 2 – Resource Exploration and Confirmation
- Phase 3 – Permitting and Initial Development
- Phase 4 – Resource Production and Power Plant Construction

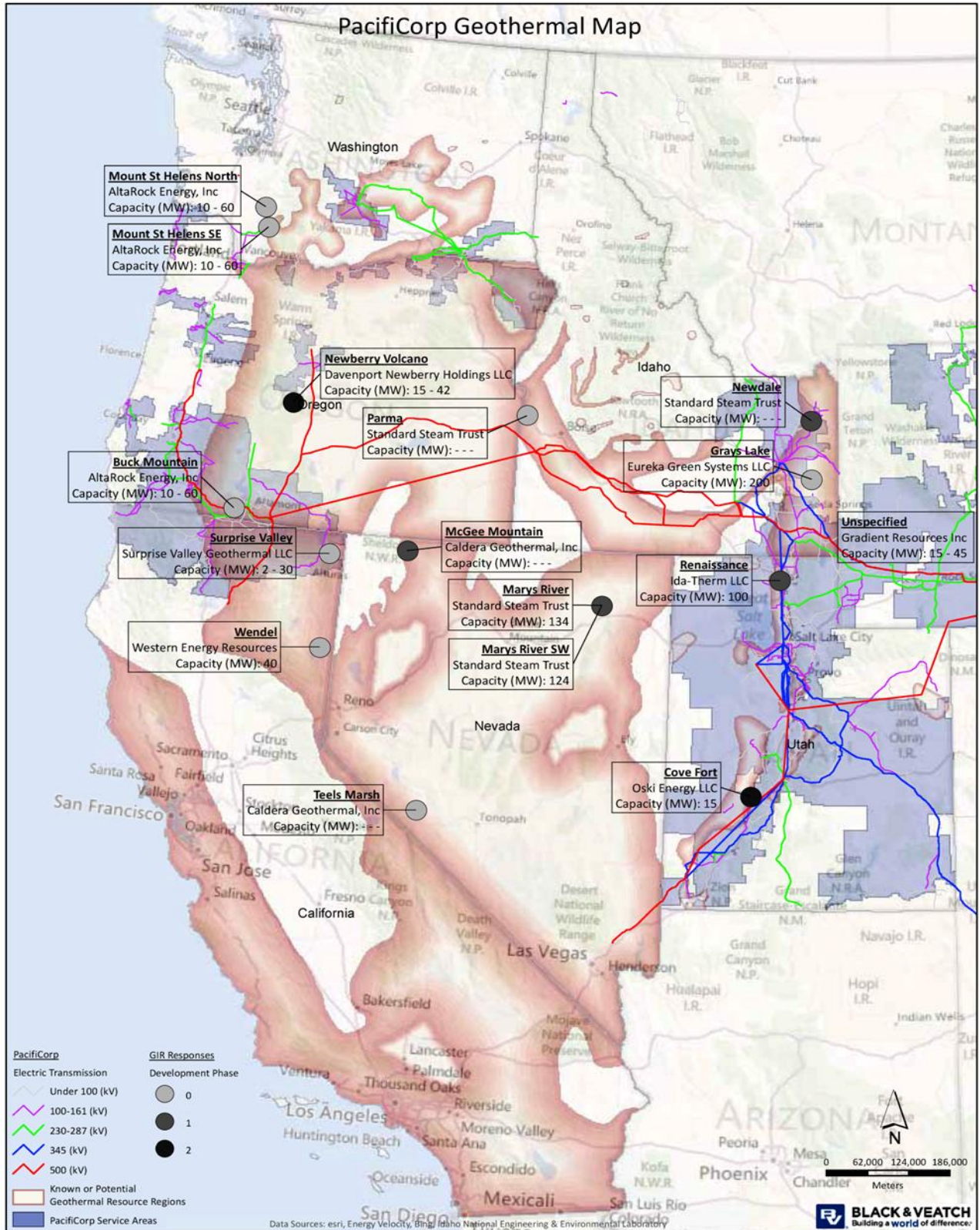
Projects that did not meet the minimum requirements to be labeled phase 1 were categorized as phase 0. All 16 projects were categorized as phase 0, phase 1, or phase 2. Black & Veatch

reviewed the experience of the project team, viability of the site, generation technology, economics, readiness and system interconnection of each project and recommended six projects. The six projects are shown below in Table 6.12 and Figure 6.3. The six recommended projects include two projects from each phase of development represented. Two of the recommended projects plan to use Enhanced Geothermal Systems (EGS), a technology that has not been commercially applied in the United States. The remaining four projects plan to use binary technology, which is inherently more costly and less efficient than the flash design suitable for projects with higher-temperature brine. The equivalent energy cost for each of the six projects ranges between \$100 and \$180/MWh. All six projects are in early stages of development and will have higher development risks than projects that have successfully completed higher phases of development.

Table 6.12 – 2012 Geothermal Study Results

PHASE	DEVELOPER	PROJECT	LOCATION	MW	TYPE
2	Oski Energy	Cove Fort	Cove Fort, UT	15	Binary (Kalina)
	Davenport Newberry	Newberry Volcano	Deschutes County, OR	15	Likely Binary /Flash EGS
1	Standard Steam Trust	Newdale	Newdale, ID	Undef.	Binary
	Ida-Therm	Renaissance	Honeyville, UT	100	Binary
0	AltaRock Energy	Buck Mountain	Klamath Falls, OR	10	Dual Flash EGS
	Surprise Valley	Surprise Valley Hot Springs	Modoc County, CA	2-5	Binary

Figure 6.3 - Commercially Viable Geothermal Resources near PacifiCorp’s Service Territory



The cost recovery mechanisms currently available to PacifiCorp as a public electric utility are not compatible with the inherent risks associated with the development of geothermal resources for the production of electricity. The primary risks of geothermal development are dry holes, insufficient temperature and insufficient pressure. These risks cannot be quantified until after wells are dug. The costs to confirm production capability of a geothermal energy resource can be as high as 35 percent of total project development costs. Test wells drilled during the exploration phase of project development are typically estimated to cost between \$500,000 and \$1.5 million per well. Full diameter wells drilled during the confirmation phase of development are estimated to cost between \$4 million and \$5 million per well. Variations in the permeability of subsurface materials can determine whether wells in close proximity are commercially viable, lacking in pressure or temperature, or completely dry with no interconnectivity to a geothermal resource. As a regulated utility subject to the public utility commissions of six states, PacifiCorp is not compensated nor incentivized to engage in risk inherent activities.

To mitigate the financial risks of geothermal development, PacifiCorp would use an RFP process to obtain market proposals for geothermal power purchase agreements or build-own-transfer project agreement structures. Geothermal developers, external to PacifiCorp, have the flexibility to structure project pricing to include all development risks. Through an RFP process, PacifiCorp could choose the geothermal project with the lowest cost offered by the market and avoid considerable risk for the Company and its customers. In the event PacifiCorp identifies a geothermal asset that appears to be economically attractive but also determines that there is a significant possibility of development risk that the market will not economically absorb, PacifiCorp may approach state regulators with estimates of resource development costs and risks associated to obtain approval for a mechanism to address risks such as dry holes. Because public utility commissions typically do not allow recovery of expenditures which do not result in a direct benefit to customers, and at least one state has a statute that precludes cost recovery of any asset that is not considered to be “used and useful,” obtaining a mechanism to recover geothermal development costs may be difficult.

Biomass

Cost and performance data for biomass based resources were obtained from third-party studies. In general, large-scale (greater than 50 MW) plants are rare, which is why the resource option shows a 5 MW plant on the supply side resource table. Nonetheless, select coal plants have been converted from burning coal to burning various types of biomass, including wood chips, cellulosic switch grass, municipal solid waste, or, in rare cases, an engineered fuel which adds processing and sorbents to the aforementioned base fuels. Certain coal plants have been identified as candidates for coal to biomass conversion, most notably Portland General Electric’s 580 MW Boardman Plant in Oregon. The greatest challenge to building large biomass plants or retrofitting a coal unit to a large biomass plant is the cost, availability, reliability, and homogeneity of a long-term fuel supply. The transport and handling logistics of large quantities of biomass fuel poses a significant challenge, depending on the size of the facility. Because of the need to be close to a large source of biomass, the Pacific Northwest or Atlantic Southeast are generally considered good regions for siting biomass resources. The climate and economy of these regions promotes growth of trees in large plantations. While PacifiCorp currently does not own any biomass plants, the company does purchase power from a number of biomass fueled installations in Oregon through power purchase agreements.

Solar

Three solar technologies are included in the supply side resource table: photovoltaic (PV) crystalline (both fixed and single axis tracking) and concentrated solar. Market prices for PV crystalline solar panels have dropped substantially during the past five plus years, giving the PV crystalline technology a cost advantage over concentrated solar and thin film. Unlike other resource options, the real capital costs for PV solar resources have been projected to decline slightly over the IRP study period. To model these decreases in real capital cost, data from PacifiCorp's 2012 market estimate and the price change curve of the nominalized 2009 NREL price forecast data were used.

Oregon passed a law in 2009 that requires electric utilities in the state to meet photovoltaic solar generation requirements with facilities in Oregon that have nameplate capacities between 500 kW and 5 MW. PacifiCorp is required to have a total of 8.7 MW of photovoltaic solar sources within its generation system in Oregon by January 1, 2020.

To meet the Oregon solar requirement, PacifiCorp issued an RFP for solar projects and commissioned a study to evaluate solar resources in 2011. The Black Cap solar facility was selected in the RFP process and was constructed in 2012. The Black Cap facility represents completion of 2 MW of PacifiCorp's 8.7 MW solar requirement in Oregon. A study to evaluate solar resources in Oregon was completed by Black & Veatch and focused on development of 2 MW projects that could be built to meet Oregon's solar generation requirement. The Oregon report evaluated PV thin film, fixed tilt PV multi-crystalline, and single axis PV multi-crystalline installations. Capital cost information in the Oregon report was updated in August 2012 to incorporate market changes in the cost of equipment. Information from this report is the basis for cost and production data for 2 MW solar resources listed in the Supply Side Resource table.

In August 2012, PacifiCorp commissioned an additional cost and performance evaluation on estimated energy production, capital and operating and maintenance costs for a nominal 50 MW solar PV resource located in southwestern Utah. The Utah estimate studied fixed-tilt and single-axis mounting systems for PV crystalline solar panels. The higher annual insolation and solar irradiance in Utah improved capacity factors and economy of scale benefits of the 50 MW resource compared to the 2 MW resource, resulting in lower total energy costs.

Distributed Supply Side Resources

As in the previous IRP, three general categories of small-scale customer-sited generation (also referred to as Distributed Generation) were included as resource options in the 2013 IRP; Combined Heat and Power (CHP), Solar Photovoltaics ("Solar PV") and Solar Water Heating ("SWH"). Traditionally, such resources fall outside the standard classification of Class 2 DSM resources for two main reasons: either they reduce utility-provided electricity consumption at the building level (rather than at an end-use level, as applies to CHP and PV), or they rely on renewable resources (solar PV, SWH, and certain CHP technologies).

CHP systems generate electricity and utilize waste heat for thermal loads, such as space or water heating. They can be used in buildings with a fairly coincident thermal and electric load, or in buildings producing combustible biomass or biogas, such as lumber mills or landfills. CHP broadly divides into subcategories based on fuels used: nonrenewable CHP typically runs on natural gas, while renewable CHP runs on a biologically derived fuel (biomass or biogas).

The IRP includes the same CHP systems as in the 2011 IRP:

- Nonrenewable
 - Reciprocating engines (RE);
 - Microturbines (MT);
 - Gas turbines (GT); and
 - Fuel cells (FC).
- Renewable
 - Industrial biomass systems are utilized in industries such as lumber mills or pulp and paper manufacturing, where site-generated waste products can be combusted in place of natural gas or other fuels.
 - Anaerobic digesters create methane gas (biogas fuel) by breaking down liquid or solid biological waste.

Solar PV systems include a collection of solar modules, generally mounted on building roofs, with an inverter to convert available sunlight into electricity compatible with a building's standard electrical infrastructure. Widely applicable in the residential and nonresidential sectors, Solar PV has been in use for several decades. In 2012, the Utah Public Service Commission approved a large expansion of the Utah Solar Incentive Program. The program is designed to encourage the development of distributed Solar PV through the payment of a rebate to customers that complete the installation of onsite Solar PV generation facilities. Based on utility experience with similar incentive programs, the 2013 IRP assumes that the program will have full participation and drive the installation of 60 MW of Solar PV resources across the Company's Utah service territory between 2013 and 2017. This has the impact of accelerating the adoption of Solar PV in Utah over the first five years of the 2013 IRP and if realized reduces the remaining potential in Utah in the later years of the plan.

SWH systems use sunlight to pre-heat domestic hot water tanks, reducing the need for electricity to heat water. Widely applicable in the residential and nonresidential sectors, SWHs have been in use for several decades.

Table 6.13 shows modeling attributes for the distributed generation resources reflected in "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" study completed in March 2013 by Cadmus ("DSM potential study").

Table 6.13 – Distributed Generation Resource Attributes⁴⁴

Technology Type	Available MW Capacity each Year by Topology Bubble 1/							Annual Fixed O&M Costs	Measure Life (Yrs)	Heat Rate (Ave. Btu/kWh)	Admin Cost (% of total program cost)	Capital Cost (\$/kW), Total	Technology Cost Change
	California	Oregon	Walla Walla, WA	Yakima, WA	Goshen, ID	Utah	Wyoming						
Reciprocating Engine	0.15	0.89	0.36	0.92	0.40	6.61	0.89	47.41	20	8,000	0%	1,495	1%
MicroTurbine	-	-	-	-	-	0.95	-	63.42	10	8,000	0%	2,168	-1%
Fuel Cell	-	-	-	-	-	0.47	-	186.91	10	6,100	0%	3,673	-3%
Gas Turbine	-	0.27	-	0.13	0.14	1.90	0.30	55.42	20	6,300	0%	1,757	1%
Industrial Biomass	-	0.55	-	-	-	0.16	-	28.82	25	N/A	0%	631	1%
Anaerobic Digesters	-	-	-	-	-	0.20	0.16	61.78	18	N/A	0%	2,452	-1%
PV	0.49	7.12	-	0.15	0.15	13.12	0.29	20.47	30	N/A	10%	4,693	-2%
Solar Water Heaters	-	2.16	-	-	-	1.53	-	20.36	20	N/A	10%	1,600	2%

⁴⁴ More details on the distributed generation resources can be found in the DSM potentials study report available for download on PacifiCorp's demand-side management Web page, <http://www.pacificorp.com/es/dsm.html>.

Nuclear

Included in the supply side resource table is a larger 2,236 MW system, which reflects the current state-of-the-art advanced nuclear plant and is modeled after the Westinghouse AP1000 technology currently being installed by Southern Company at the Vogtle Generating Station in Georgia. It is assumed that this technology would be installed at the proposed Blue Castle site near Green River, Utah. Nuclear fuel cost is assumed at \$2,770/kg in 2011 dollars but nuclear power is not considered a viable option in the PacifiCorp service territory before 2030 due to total capital cost uncertainty (including EPC and owner's costs), sociopolitical resistance, and regulatory obstacles.

Energy Storage

As in past IRPs, a number of energy storage technologies are included, such as compressed energy storage (CAES), pumped hydroelectric, and advanced batteries. There are a number of potential CAES sites—specifically solution-mined sites associated with natural gas storage in western Utah and southwest Wyoming—that could be developed in areas of existing gas transmission. CAES may be an attractive alternative for high elevation sites since the gas compression could compensate for the facility capacity derate affects associated with higher elevation.

Energy storage continues to be of interest since the variable nature of some conventional renewable generation alternatives could be enhanced if the energy produced could be stored. To model the storage options, PacifiCorp conducted an energy storage study with HDR in 2011⁴⁵.

Table 6.14 outlines the conclusions of the HDR study. The focus of this study was in defining the cost and performance characteristics of available storage technologies. The dry cell and Zinc Bromide (ZnBr) battery options were removed because these systems are similar to other options shown. Zinc-bromide batteries are similar to the VRB batteries, while the dry cells are similar to the Lithium-Ion (Li-Ion) batteries.

Table 6.14 –HDR Energy Storage Study Summary Cost and Capacity Results (2011\$)

	Flywheel	Li-Ion	NaS	VRB	Pumped Storage	CAES
System Cost (\$/kW and/or \$/kWh)	\$2,406 per kW	\$1,100 (High Energy)	\$4,000/kW	\$644/kWh	\$1,500-\$3,000/kW	\$1,400-\$1,700/kW
Rated System Size (MW)	20	89 (High Energy)	1	1	1,000	500
Rated Capacity (hrs)	0.25	4 (High Energy)	7.2	1	8 to 10	8

Numerous examples of pumped hydro systems are included in the HDR study and a composite case is presented in the resource table representing both the large size capable with this technology (1,000 MW) but at the high end of the cost range to reflect the permitting difficulties present with this geologic intense generation option. O&M is presented in both variable and fixed components. A larger variable component has been used to mirror the different potential capacity factors available with this flexible resource.

⁴⁵ The 2011 energy storage study is available on PacifiCorp's IRP web page. <http://www.pacificorp.com/es/irp.html>.

CAES has been shown at the specific size case illustrated in the HDR study. A 557 net MW capacity case is shown in the resource table at the 6,000 foot elevation example. Capital costs include the solution mining component of the technology. O&M costs are broken out into fixed and variable components.

Battery energy storage is unique in that capital costs are defined in terms of energy storage capability and not necessarily in terms of how much energy can be delivered instantaneously. In order to properly compare different battery systems it is necessary to compare the battery systems on a common denominator basis. The common denominator basis is defined by the sodium-sulfur (NaS) battery and all systems were compared on storing 7.2 hours of energy as shown in Table 6.15. All O&M in Table 6.15 is assumed fixed for ease of comparison.

Table 6.15 –HDR Storage Study, Normalized Battery Cost Comparison (2011\$)

Battery	\$/kW - Capacity	\$/kWh Energy Storage	Replacement – 10 yr life	\$ Millions	kWh – Energy Storage	\$/kWh for Energy Storage	\$/kW – Capacity & Energy	O&M \$/kW-yr
Li-Ion		\$1,100	\$1,100	\$8.71	7,200	\$1,210	\$8,712	\$27.4
NaS	\$4,000		\$4,000	\$4.40	7,200	\$0.611	\$4,400	\$27.4
Vanadium Redox (VRB)	\$400	\$644	\$644	\$5.53	7,200	\$0.768	\$5,530	\$36.5

Notes to Table 6-15:

Capacity Factor equal to 3 hours per day – 6 months per year = 6.25%

Battery size normalized at 1 MW

Normalize energy storage capability to 7.2 hours equal to the standard NaS system

Demand-side Resources

Resource Options and Attributes

Source of Demand-side Management Resource Data

Demand-side management (DSM) resource opportunity estimates used in the development of the 2013 IRP were derived from the DSM potential study. The DSM potential study, conducted by Cadmus, provided a broad estimate of the size, type, location and cost of demand-side resources.⁴⁶ For the purpose of integrated resource planning, the demand-side resource information from the DSM potential study was converted into supply curves by type of DSM (e.g. capacity-based Classes 1 and 3 DSM and energy-based Class 2 DSM) for modeling against competing supply-side alternatives.

Demand-side Management Supply Curves

Resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources. Supply curves provide a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling

⁴⁶ The 2013 DSM potential study is available on PacifiCorp's demand-side management web page. <http://www.pacificorp.com/es/dsm.html>.

utilizing supply curves allows utilities to select least-cost resources (products and quantities) based on each resource's competitiveness against alternative resource options.

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

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

Once developed, DSM supply curves are treated like discrete supply-side resources in the IRP modeling environment.

Class 1 DSM Capacity Supply Curves

Supply curves were created for three distinct Class 1 DSM products:

- 1) Direct load control (DLC) of residential and small commercial central air conditioning and water heating;
- 2) Irrigation load curtailment; and
- 3) Commercial/industrial curtailment

The potentials and costs for each product were provided at the state level resulting in three products across six states or the development of eighteen Class 1 DSM supply curves for the 2013 IRP modeling process.

Class 1 DSM resource price differences between West and East control areas for similar resources were driven by resource differences in each market, such as irrigation pump size and hours of operation as well as product performance differences. For instance, residential air conditioning load control in the West is more expensive on a unitized or dollar per kilowatt-year basis due to climatic differences that result in a lower load impact per installed switch.

The assessment of potential for distributed standby generation⁴⁷ was combined with an assessment of commercial/industrial energy management system controls in the development of the resource opportunity and costs of the commercial/industrial curtailment product. The costs for this product are constant across all jurisdictions assuming a pay-for-performance delivery model.

Recognizing that some Class 1 and 3 DSM products compete for the management of the same customer end-use loads, and to avoid overstating available impacts, the supply curves accounted for interactions within and between Class 1 and Class 3 DSM resources. Resources were prioritized within each customer sector by the firmness of the resource and then by cost. The following are examples of the logic that was applied to account for these interactions:

- Participation in the Class 1 DSM DLC air conditioning and water heating programs or DLC irrigation programs would take precedence over participation in Class 3 DSM Time-of-Use (TOU) rates/programs. Customers already enrolled in the DLC air conditioning and water heating and DLC irrigation programs would not opt out to participate in the TOU programs.
- Participation in the Class 1 DSM commercial/industrial curtailment programs would take precedent over Class 3 DSM Demand Buyback and/or Critical Peak Pricing programs where load curtailment is offered.

Tables 6.16 and 6.17 show the summary level Class 1 DSM resource information, by control area, used in the development of the Class 1 DSM resource supply curves. Potential shown is incremental to the existing Class 1 DSM resources identified in Table 5.10. For existing program offerings, it is assumed the Company could begin acquiring incremental potential in 2013. For resources representing new product offerings, it is assumed the Company could begin acquiring

⁴⁷ In February 2010 the Environmental Protection Agency made the Reciprocating Internal Combustion Engines National Emission Standards for Hazardous Air Pollutants ruling. The ruling puts restrictions on the use of standby generation after May, 2014 unless the generators meet the rulings required emission standards.

potential in 2014, accounting for the time required for program design, regulatory approval, vendor selection, etc.

Table 6.16 – Class 1 DSM Program Attributes West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost (\$/kW-yr)	First Year(s) Available
Residential and Small Commercial Air Conditioning and Water Heating	Residential time-of-use	50 hours, average of 4 hours per event	Summer	42	\$83 - \$103	2014
Irrigation Direct Load Control	Irrigation time-of-use	50 hours, average of 4 hours per event	Summer	11	\$61 - \$64	2014
Commercial/Industrial Curtailment (includes distributed standby generation)	Demand buyback and Critical peak pricing	30 hours, average of 4 hours per event	Summer and Winter	64	\$65	2014

Table 6.17 – Class 1 DSM Program Attributes East Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost (\$/kW-yr)	First Year(s) Available
Residential and Small Commercial Air Conditioning and Water Heating	Residential time-of-use	50 hours, average of 4 hours per event	Summer	31	\$70 - \$133	2013-2014
Irrigation Direct Load Control	Irrigation time-of-use	50 hours, average of 4 hours per event	Summer	1	\$51 - \$64	2013-2014
Commercial/Industrial Curtailment (includes distributed standby generation)	Demand buyback and Critical peak pricing	30 hours, average of 4 hours per event	Summer and Winter	125	\$65	2014

A number of data conversions and resource attributes are required to configure the supply curves for use in the System Optimizer model. All programs are defined to operate within a 5x8 hourly window and are priced in \$/kW-month. The following are the primary model attributes required by the model:

- **The Capacity Planning Factor (CPF):** This is the percentage of the program size (capacity) that is expected to be available at the time of system peak. For Classes 1 and 3 DSM programs, this parameter is set to 1 (100 percent)
- **Additional reserves:** This parameter indicates whether additional reserves are required for the resource. Firm resources, such as dispatchable load control, do not require additional reserves.

- **Daily and annual energy limits:** These parameters, expressed in Gigawatt-hours, are used to implement hourly limits on the programs. They are obtained by multiplying the hours available by the program size.
- **Nameplate capacity (MW) and service life (years)**
- **Maximum Annual Units:** This parameter, specified as a pointer to a vector of values, indicates the maximum number of resource units available in the year for which the resource is designated.
- **First year and month available / last year available**

Class 3 DSM Capacity Supply Curves

Supply curves were created for four discrete Class 3 DSM products, which are capacity-based resources like Class 1 DSM products:

- 1) Residential time-of-use rates;
- 2) Commercial critical peak pricing;
- 3) Commercial and industrial demand buyback; and
- 4) Voluntary irrigation time-of-use⁴⁸

The potentials and costs for each product were provided at the state level resulting in four products across six states or the development of twenty-four Class 3 DSM supply curves for the 2013 IRP modeling process.

As discussed above with regard to Class 1 DSM resources, the potential for each Class 3 DSM product was adjusted for expected interactions with competing Class 1 and 3 DSM resource options.

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

Tables 6.18 and 6.19 show the summary level Class 3 DSM resource information, by control area, used in the development of the Class 3 DSM resource supply curves. Potential shown is incremental to the existing Class 3 DSM resources identified in Table 5.10. For existing program offerings, it is assumed the Company could begin acquiring incremental potential in 2013. For resources representing new product offerings, it is assumed the Company could begin acquiring potential in 2014, accounting for the time required for program design, regulatory approval, vendor selection, etc. System Optimizer data formats and parameters for Class 3 DSM programs are similar to those defined for the Class 1 DSM programs.

Table 6.18 – Class 3 DSM Program Attributes, West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost (\$/kW-yr)	First Year(s) Available
Residential Time-of-Use	Residential A/C and Water	528 hours	Summer	3	\$117 - \$347	2013 - 2014

⁴⁸ The 2011 IRP included significantly more potential for irrigation load control driven by the assumption of mandatory participation.

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost (\$/kW-yr)	First Year(s) Available
	Heating DLC					
Commercial Critical Peak Pricing	C&I Curtailment, Demand Buyback	40 hours	Summer and Winter	0*	\$9 - \$96	2014
Commercial/Industrial Demand Buyback	C&I Curtailment, Critical Peak Pricing	50 hours	Summer and Winter	0*	\$26	2014
Voluntary Irrigation Time-of-Use	Irrigation DLC	120 hours	Summer	5	\$40 - \$97	2013 - 2014

* Although standalone potential was identified in the DSM potential study, there is assumed to be no potential available after accounting for competition with other Class 1 and 3 DSM resources.

Table 6.19 – Class 3 DSM Program Attributes, East Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost (\$/kW-yr)	First Year(s) Available
Residential Time-of-Use	Residential A/C and Water Heating DLC	480/600 hours	Summer	8	\$124 - \$195	2013 - 2014
Commercial Critical Peak Pricing	C&I Curtailment, Demand Buyback	40 hours	Summer and Winter	0*	\$9 - \$38	2014
Commercial/Industrial Demand Buyback	C&I Curtailment, Critical Peak Pricing	50 hours	Summer and Winter	0*	\$26	2014
Voluntary Irrigation Time-of-Use	Irrigation DLC	120 hours	Summer	0.2	\$20 - \$97	2013 - 2014

* Although standalone potential was identified in the DSM potential study, there is assumed to be no potential available after accounting for competition with other Class 1 and 3 DSM resources.

Class 2 DSM, Energy Supply Curves

The 2013 IRP represents the third time the Company has utilized the DSM supply curve methodology in the evaluation and selection of Class 2 DSM resources. The 2013 DSM potential study provided the information to fully assess the potential contribution from Class 2 DSM resources over the IRP planning horizon and adjusted resource potentials and costs to account for changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, and state specific resource evaluation considerations (e.g., cost-effectiveness criteria). Class 2 DSM resource potential was assessed by state down to the individual measure and facility levels; e.g., specific appliances, motors, lighting configurations for residential buildings, small offices, etc. The 2013 DSM potential study provided Class 2 DSM resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming⁴⁹
- **Measure:**

⁴⁹ Oregon’s Class 2 DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.

- 131 residential measures
 - 145 commercial measures
 - 93 industrial measures
 - Three irrigation measures
 - Four street lighting measures
- **Facility type⁵⁰:**
 - Six residential facility types
 - 24 commercial facility types
 - 14 industrial facility types
 - One irrigation facility type
 - Four street lighting types

The 2013 DSM potential study levelized total resource costs (including measure costs and a 20 percent adder for program administrative costs) over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Consistent with regulatory mandates, Utah Class 2 DSM resource costs were levelized using utility costs (incentive and non-incentive program costs) instead of total resource costs.

The technical potential for all Class 2 DSM resources across five states over the twenty-year DSM potential study horizon totaled 7.2 million MWh.⁵¹ The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (achievable). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 5.7 million MWh. The achievable technical potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of Class 2 DSM resource information available, it was impractical to model the Class 2 DSM resource supply curves at this level of detail. The combination of measures by facility type and state generated over 19,000 separate permutations or distinct measures that could be modeled using the supply curve methodology.⁵² To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs to reduce the number of combinations to a more manageable number. The granularity or range of measure costs in a particular bundle were narrowed in the development of the Class 2 DSM supply curves in the 2013 IRP relative to the 2011 IRP to address concerns regarding using too broad of

⁵⁰ Facility type includes such attributes as existing or new construction, single or multi-family, etc. Facility types are more fully described in the 2013 DSM potential study.

⁵¹ The identified technical potential represents the cumulative impact of Class 2 DSM measure installations in the 20th year of the study period. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period.

⁵² Not all energy efficiency measures analyzed are applicable to all market segments. The two most common reasons for this are (1) differences in existing and new construction and (2) some end-uses do not exist in all building types. For example, a measure may look at the savings associated with increasing an existing home's insulation up to current code levels. However, this level of insulation would already be required in new construction, and thus, would not be analyzed for the new construction segment. Similarly, certain measures, such as those affecting commercial refrigeration would not be applicable to all commercial building types, depending on the building's primary business function; for example, office buildings would not typically have commercial refrigeration.

measure costs within a bundle and its possible impact on the selection of bundled resources at or near the IRP model's economic selection point. The result was the creation of twenty-seven cost bundles; eighteen more than were developed for the 2011 IRP.

Bundle development began with the Class 2 DSM technical potential identified by the 2013 DSM potential study. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 20-year planning horizon. Consistent with the Northwest's aggressive⁵³ regional planning assumptions, it was assumed that 85 percent of the technical potential for discretionary (retrofit) resources and 72 percent of lost-opportunity (new construction or equipment upgrade on failure) could be achievable over the 20-year planning period. Over the planning period, the aggregate (both discretionary and lost opportunity) achievable technical potential is 79 percent of the technical potential.

Consistent with the 2011 IRP, the technical achievable potential for each measure by state is assigned a measure and market ramp rate, reflecting the relative state of technology and program state specific delivery infrastructure/maturity, respectively. New technologies and states with newer programs were assumed to take more time to ramp up than those with more extensive track records.

The Energy Trust of Oregon (ETO) applies achievability assumptions and ramp rates in a similar manner in its resource assessment. For a more detailed description of the methods used in PacifiCorp's 2013 DSM Potential Study and the ETO's resource assessment, see Appendix D in Volume II of this document. In contrast to the 2011 IRP, the ETO did not perform an economic pre-screening of measures in the development of the Oregon DSM supply curves allowing resource opportunities in Oregon to be economically screened in the IRP model in a comparable way as is done across PacifiCorp's other five states.

Twenty-seven cost bundles were available across six states (including Oregon), which equates to 189 Class 2 DSM supply curves. Table 6.20 shows the MWh potential for Class 2 DSM cost bundles, designated by ranges of \$/MWh. Table 6.21 shows the associated bundle price after applying cost credits afforded to Class 2 DSM resources within the model. These cost credits include the following:

- A transmission and distribution investment deferral credit of \$54/kW-year;
- Stochastic risk reduction credit of \$7.05/MWh⁵⁴;
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)⁵⁵

⁵³ The Northwest's achievability assumptions include savings realized through improved codes and standards and market transformation, and thus, applying them to identified technical potential represents an aggressive view of what could be achieved through utility DSM programs.

⁵⁴ PacifiCorp developed this credit by taking the difference between a comparison of deterministic PaR runs for the 2011 IRP preferred portfolio with and without DSM and a comparison of stochastic PaR runs for the 2011 IRP preferred portfolio with and without DSM and then dividing that difference by the MWh of DSM in the 2011 IRP preferred portfolio.

⁵⁵ The formula for calculating the \$/MWh credit is: $(\text{Bundle price} - ((\text{First year MWh savings} \times \text{market value} \times 10\%) + (\text{First year MWh savings} \times \text{T\&D deferral} \times 10\%))) / \text{First year MWh savings}$. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

The bundle price is the average levelized cost for the group of measures in the cost range, weighted by potential. In specifying the bundle cost breakpoints, narrower cost ranges were defined for the lower-cost resources to improve the cost accuracy for the bundles considered more likely to be selected by the System Optimizer model. The highest-cost bundles were specified with wider cost breakpoints that are more granular than the cost ranges used in the development of the 2011 IRP⁵⁶.

Table 6.20 – Class 2 DSM MWh Potential by Cost Bundle

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	12,499	47,610	386,701	1,158,187	149,999	260,077
10 - 20	20,796	33,861	266,687	561,726	55,791	368,790
20 - 30	8,122	16,448	415,912	259,141	61,938	89,097
30 - 40	6,731	15,149	319,680	147,314	39,224	73,359
40 - 50	6,057	22,737	230,316	114,005	52,318	41,511
50 - 60	6,221	12,542	187,293	296,558	21,271	46,368
60 - 70	3,092	42,507	30,576	169,084	30,652	35,426
70 - 80	10,223	3,952	130,529	42,672	11,993	34,507
80 - 90	6,236	26,341	27,734	59,885	21,866	8,132
90 - 100	2,545	4,690	163,658	123,069	11,629	24,313
100 - 110	13,516	5,116	26,496	143,361	13,967	52,805
110 - 120	2,049	32,070	80,433	120,914	14,856	9,397
120 - 130	3,657	942	136,215	52,796	36,833	7,200
130 - 140	465	2,040	159,330	7,810	2,631	8,554
140 - 150	1,056	8,866	9,889	20,569	9,489	9,930
150 - 160	10,928	5,589	699	9,366	37,975	16,832
160 - 170	536	2,610	15,893	34,191	11,759	2,208
170 - 180	3,330	780	1,380	37,774	12,784	1,923
180 - 190	1,701	3,055	40,912	9,847	2,945	9,364
190 - 200	3,009	1,597	16,093	32,717	2,926	11,293
200 - 250	4,691	10,981	22,796	199,384	38,157	12,118
250 - 300	2,333	5,849	33,267	103,864	14,683	18,227
300 - 400	8,166	12,931	14,581	72,193	18,759	52,596
400 - 500	3,020	2,336	11,141	62,203	19,659	23,462
500 - 750	2,077	5,753	11,028	29,966	9,048	14,670
750 - 1,000	2,213	13,313	6,853	15,890	26,499	8,578
> 1,000	5,176	6,541	6,543	133,702	25,666	22,650

⁵⁶ Increasing the granularity of the cost bundles between the 2011 IRP and 2013 IRP increased the number of total bundles within each state and load bubble from 9 to 27, respectively.

Table 6.21 – Class 2 DSM Adjusted Prices by Cost Bundle

Bundle	Levelized Cost after Adjustments (\$/MWh)					
	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	-	-	-	-	-	-
10 - 20	-	-	-	-	-	0.74
20 - 30	8.51	3.55	-	3.57	1.00	7.23
30 - 40	17.37	4.13	9.46	13.26	5.64	13.25
40 - 50	26.86	27.26	17.56	23.78	11.15	25.76
50 - 60	31.84	30.41	32.82	35.81	22.65	38.16
60 - 70	34.19	37.68	35.17	45.22	36.98	47.20
70 - 80	52.23	54.64	48.43	52.69	50.94	57.00
80 - 90	62.51	67.31	56.88	68.38	58.82	59.73
90 - 100	81.20	74.33	71.77	78.11	60.15	76.73
100 - 110	86.79	81.74	80.39	81.02	69.50	88.13
110 - 120	96.96	89.80	87.42	78.39	73.89	100.24
120 - 130	106.58	100.81	91.07	107.36	93.44	104.28
130 - 140	98.03	107.05	105.26	112.48	107.35	116.42
140 - 150	119.39	127.24	113.15	122.43	121.51	122.24
150 - 160	131.33	136.23	103.06	133.11	129.27	136.85
160 - 170	147.79	147.73	141.29	136.84	139.10	142.66
170 - 180	150.00	147.84	101.76	156.05	106.49	154.47
180 - 190	164.92	168.18	156.50	157.52	154.22	169.48
190 - 200	174.69	168.42	160.34	173.06	168.43	172.27
200 - 250	211.04	198.24	202.41	210.35	204.53	198.20
250 - 300	255.99	250.90	244.55	233.09	239.56	258.98
300 - 400	329.67	334.22	306.16	316.09	316.61	342.23
400 - 500	408.29	419.68	403.00	430.59	420.65	442.96
500 - 750	601.51	592.73	557.54	513.73	603.17	578.06
750 - 1,000	827.70	895.12	772.20	863.26	798.91	802.18
> 1,000	3,620.28	2,315.69	2,548.01	3,841.62	2,672.86	3,614.73

To capture the time-varying impacts of Class 2 DSM resources, each bundle has an annual 8,760 hourly load shape specifying the portion of the maximum capacity available in any hour of the year. These shapes are created by spreading measure-level annual energy savings over 8,760 load shapes, differentiated by state, sector, market segment, and end use accounting for the hourly variance of Class 2 DSM impacts by measure. These hourly impacts are then aggregated for all measures in a given bundle to create a single weighted average load shape for that bundle.

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

To plan for DSM, a planning capacity factor is input into the System Optimizer model for each bundle and year. To determine the planning capacity factor, an average of the capacity for hours 14 through 19 during the average July day is divided by the overall maximum capacity value during the year for each bundle and year.

An accelerated Class 2 DSM acquisition scenario was created for inclusion in three of the IRP core cases. Although the total available potential over the 20-year planning period did not change for this scenario, discretionary resource acquisition was accelerated and market ramp rates were removed⁵⁷ to allow the System Optimizer model to select up to two percent of retail sales annually in each state until discretionary resources were exhausted. In this scenario, the costs for accelerated measures were increased to acknowledge that such a scenario would likely require higher incentive and non-incentive program expenditures to expand participation and delivery infrastructure⁵⁸.

Distribution Energy Efficiency

In 2012, the Company conducted a pilot to assess the feasibility of distribution energy efficiency for four circuits in Washington. Of the 0.09 aMW predicted to be acquired through the pilot, less than 0.01 aMW was actually achieved. The pilot was not cost effective. Less than half of the anticipated reduction in average voltage was achieved, and the estimated cost of energy savings was \$112.49/MWh. Following the pilot, the Company screened all active distribution circuits in Oregon, Idaho, Wyoming, and Utah and found that between 0 and 0.2 aMW of conservation voltage reduction energy savings might exist within the Company's service territory in those four states. However, it is likely that pursuing measures in those states would not be cost effective. Two key lessons from the pilot and subsequent screening effort are:

- 1) Most of the Company's circuits are already operating at a relatively low voltage and improvements necessary to allow an even lower voltage are not usually justified by the value of the energy saved.
- 2) Small amounts of saved energy on the utility system cannot be accurately and repeatably measured due to the dynamic interplay between the system and the customers' requirements.

Distribution energy efficiency measures were not modeled as potential resources in this IRP, since the Company found through its pilot that savings from such measures are unreliable and generally not cost-effective. Further details on this pilot and its conclusions are provided in Appendix E.

⁵⁷ Hypothetical adjustments to real world constraints were made in order to provide sufficient Class 2 DSM resources to allow the model to select up to 2 percent of retail sales in each state.

⁵⁸ The resource cost adjustments in the accelerated DSM scenario may not represent the actual costs of such a scenario; there was limited information available to inform the Company what costs would be required to facilitate this level of customer participation in markets with low retail rates and limited capital.

Transmission Resources

For this IRP, PacifiCorp investigated five Energy Gateway scenarios, consisting of various combinations of transmission segments. Detailed information on the scenarios and associated modeling approach and findings are provided in Chapter 4.

In this IRP, adjustments to fixed O&M costs were developed to model the additional costs of transmission upgrades to interconnect certain supply-side resources to the Company's system. Table 6.22 below shows fixed O&M cost associated with these transmission upgrades by resource and location.

Table 6.22 – Transmission Upgrades by Supply-Side Resource and Location

Fuel	Resource	Location	Elevation (AFSL)	Transmission Cost Stated in 2012 \$/kw-year
Natural Gas	SCCT Aero x3, ISO	Portland / North Coast	0	\$37.92
Natural Gas	Intercooled SCCT Aero x1, ISO		0	\$37.92
Natural Gas	SCCT Frame "F" x1, ISO		0	\$37.92
Natural Gas	IC Recips x6, ISO		0	\$37.92
Natural Gas	CCCT Dry "F", 2x1, ISO		0	\$37.92
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		0	\$37.92
Natural Gas	CCCT Dry "G/H", 1x1, ISO		0	\$37.92
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		0	\$37.92
Natural Gas	CCCT Dry "G/H", 2x1, ISO		0	\$37.92
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		0	\$37.92
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		0	\$37.92
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		0	\$37.92
Natural Gas	SCCT Aero x3, ISO	Willamette Valley	0	\$55.12
Natural Gas	Intercooled SCCT Aero x1, ISO		0	\$55.12
Natural Gas	SCCT Frame "F" x1, ISO		0	\$55.12
Natural Gas	SCCT Aero x3, ISO	Walla Walla	1,500	\$3.51
Natural Gas	Intercooled SCCT Aero x1, ISO		1,500	\$3.51
Natural Gas	SCCT Frame "F" x1, ISO		1,500	\$3.51
Natural Gas	IC Recips x6, ISO		1,500	\$3.51
Natural Gas	CCCT Dry "F", 2x1, ISO		1,500	\$3.51
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		1,500	\$3.51
Natural Gas	CCCT Dry "G/H", 1x1, ISO		1,500	\$3.51
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		1,500	\$3.51
Natural Gas	CCCT Dry "G/H", 2x1, ISO		1,500	\$3.51
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		1,500	\$3.51
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		1,500	\$3.51
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		1,500	\$3.51
Natural Gas	CCCT Dry "G/H", 1x1, ISO	Yakima	1,500	\$3.51
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		1,500	\$3.51
Natural Gas	SCCT Frame "F" x1, ISO		1,500	\$3.51
Natural Gas	Intercooled SCCT Aero x1, ISO		1,500	\$3.51
Natural Gas	SCCT Aero x3, ISO	Salt Lake Valley	4,250	\$12.80
Natural Gas	Intercooled SCCT Aero x1, ISO		4,250	\$12.80
Natural Gas	SCCT Frame "F" x1, ISO		4,250	\$12.80
Natural Gas	IC Recips x6, ISO		4,250	\$12.80
Natural Gas	CCCT Dry "F", 2x1, ISO		4,250	\$12.80
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		4,250	\$12.80
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	\$12.80
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	\$12.80
Natural Gas	CCCT Dry "G/H", 2x1, ISO		5,050	\$12.80
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		5,050	\$12.80
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		5,050	\$12.80
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		5,050	\$12.80
Natural Gas	SCCT Aero x3, ISO	Eastern Wyoming	4,250	\$29.32
Natural Gas	Intercooled SCCT Aero x1, ISO		4,250	\$29.32
Natural Gas	SCCT Frame "F" x1, ISO		4,250	\$29.32
Natural Gas	IC Recips x6, ISO		4,250	\$29.32
Natural Gas	CCCT Dry "F", 2x1, ISO		5,050	\$29.32
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		5,050	\$29.32
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	\$29.32
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	\$29.32
Natural Gas	CCCT Dry "G/H", 2x1, ISO		5,050	\$29.32
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		5,050	\$29.32
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		5,050	\$29.32
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		5,050	\$29.32

Table 6.22 – Transmission Upgrades by Supply-Side Resource and Location (Continued)

Fuel	Resource	Location	Elevation (AFSL)	Transmission Cost Stated in 2012 \$/kw-year
Natural Gas	SCCT Aero x3, ISO	Idaho	4,250	\$3.44
Natural Gas	Intercooled SCCT Aero x1, ISO		4,250	\$3.44
Natural Gas	SCCT Frame "F" x1, ISO		4,250	\$3.44
Natural Gas	IC Recips x6, ISO		4,250	\$3.44
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	\$3.44
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	\$3.44
Natural Gas	SCCT Aero x3, ISO	Southern Oregon	4,250	\$18.96
Natural Gas	Intercooled SCCT Aero x1, ISO		4,250	\$18.96
Natural Gas	SCCT Frame "F" x1, ISO		4,250	\$18.96
Natural Gas	IC Recips x6, ISO		4,250	\$18.96
Natural Gas	CCCT Dry "F", 2x1, ISO		4,250	\$18.96
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		4,250	\$18.96
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	\$18.96
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	\$18.96
Natural Gas	CCCT Dry "G/H", 2x1, ISO		5,050	\$18.96
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		5,050	\$18.96
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		5,050	\$18.96
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		5,050	\$18.96
Natural Gas	SCCT Aero x3, ISO		Utah South	4,250
Natural Gas	Intercooled SCCT Aero x1, ISO	4,250		\$7.94
Natural Gas	SCCT Frame "F" x1, ISO	4,250		\$7.94
Natural Gas	IC Recips x6, ISO	4,250		\$7.94
Natural Gas	CCCT Dry "F", 2x1, ISO	5,050		\$7.94
Natural Gas	CCCT Dry "F", DF, 2x1, ISO	5,050		\$7.94
Natural Gas	CCCT Dry "G/H", 1x1, ISO	5,050		\$7.94
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO	5,050		\$7.94
Natural Gas	CCCT Dry "G/H", 2x1, ISO	5,050		\$7.94
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO	5,050		\$7.94
Natural Gas	CCCT Dry "J", Adv 1x1, ISO	5,050		\$7.94
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO	5,050		\$7.94
Natural Gas	Intercooled SCCT Aero x1, ISO	SW Wyoming		6,500
Natural Gas	SCCT Frame "F" x1, ISO		6,500	\$12.27
Natural Gas	IC Recips x6, ISO		6,500	\$12.27
Natural Gas	CCCT Dry "F", 2x1, ISO		5,050	\$12.27
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		5,050	\$12.27
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	\$12.27
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	\$12.27
Natural Gas	CCCT Dry "G/H", 2x1, ISO		6,500	\$12.27
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		6,500	\$12.27
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		6,500	\$12.27
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO	6,500	\$12.27	
Coal	IGCC with CCS	Wyoming	6,500	\$29.32
Geothermal	Generic Geothermal PPA 90% CF	OT/UT	4,500	\$0.00
Wind	2.3 MW turbine 29% CF (EG 1, 2 and 4)	WA/OR	1,500	\$35.07
Wind	2.3 MW turbine 29% CF (EG 3 and 5)	WA/OR	1,500	\$0.00
Wind	2.3 MW turbine 29% CF	Utah	4,500	\$7.94
Wind	2.3 MW turbine 29% CF	Idaho	4,500	\$3.44
Wind	2.3 MW turbine 40% CF	Wyoming	6,500	\$0.00
Solar	PV Poly-Si Fixed Tilt 22% CF	Various	4,500	\$0.00
Solar	PV Poly-Si Fixed Tilt 28% CF	Utah	4,500	\$6.99
Solar	PV Poly-Si Single Tracking 33% CF	Utah	4,500	\$6.99
Biomass	Forestry Byproduct	Various	1,500	\$0.00
Storage	Pumped Storage	Utah South	4,500	\$17.83
Storage	Sodium-Sulfur Battery	Various	4,500	0
Storage	Advanced Fly Wheel	Various	4,500	0
Storage	CAES	SW Wyoming	4,500	\$8.57
Nuclear	Advanced Fission	Utah	4,500	\$25.12

Market Purchases

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). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an annual forward basis to help the Company cover short positions.

As proxy resources, FOTs 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. FOT 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 of volumes and terms for these transactions.

Solicitations for FOTs 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.

Two FOT types were included for portfolio analysis: an annual flat product, and a HLH third quarter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. Third-quarter HLH transactions represent purchases received 16 hours per day, six days per week from July through September. Because these are firm products the counterparties supply the reserves; and back the supply. For example, a 100 MW front office purchase requires the seller to deliver 100 MW to PacifiCorp regardless of circumstance.⁵⁹ Thus, to insure delivery, the seller must hold the required level of reserves as warranted by its system to insure supply. For this reason, PacifiCorp does not need to hold additional reserves on its 100 MW firm front office purchase. Table 6.23 shows the FOT resources included in the IRP models, identifying the market hub, product type, annual megawatt capacity limit, and availability.

Table 6.23 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
<i>Mid-Columbia</i> Flat Annual (“7x24”) and 3 rd Quarter Heavy Load Hour (“6x16”)	400 MW + 375 MW with 10% price premium, 2013-2032
<i>California Oregon Border (COB)</i> Flat Annual (“7x24”) and 3 rd Quarter Heavy Load Hour (“6x16”)	400 MW, 2013-2032
<i>Southern Oregon / Northern California (NOB)</i> 3 rd Quarter Heavy Load Hour (“6x16”)	100 MW, 2013-2032

⁵⁹ Typically, the only exception would be under force majeure. Otherwise, the seller is required to deliver the full amount even if the seller has to acquire it at an exorbitant price.

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
<i>Mead</i> 3 rd Quarter, Heavy Load Hour (6x16)	190 MW, 2013-2014 0 MW, 2015+
<i>Mona</i> 3 rd Quarter, Heavy Load Hour (6x16)	300 MW, 2013+

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.

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

CHAPTER 7 – MODELING AND PORTFOLIO EVALUATION APPROACH

CHAPTER HIGHLIGHTS

- The IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. The 2013 IRP modeling approach consists of eight phases, from defining scenarios for portfolio development—referred to as “cases,” to final selection of preferred portfolio based on costs and risk measures.
- PacifiCorp worked closely with stakeholders to define 19 core cases that were applied uniformly across five Energy Gateway transmission scenarios and developed an additional 12 sensitivity cases reflecting alternative assumptions for load forecasts, availability of renewable resource federal tax incentives, renewable portfolio standard modeling, Class 3 demand-side management (DSM) resource availability, and coal unit environmental investments. In total 106 portfolios, each analyzing unit-by-unit environmental investments in existing coal resources, were developed and risk assessment studies were completed for 37 portfolios among three carbon dioxide (CO₂) tax levels.
- Three underlying natural gas price forecasts (low, medium, and high) were used to develop gas price projections consistent with a range of CO₂ price assumptions: zero, medium, and high, plus U.S. hard cap prices required for the power sector to achieve an 80% reduction in emission by 2050 using both medium and high natural gas price assumptions.
- Top-performing portfolios were selected on the basis of system costs using Monte Carlo simulations over a twenty year planning horizon. The Monte Carlo runs capture stochastic behavior of electricity prices, natural gas prices, loads, thermal unit availability, and hydro availability across 100 iterations.
- Final preferred portfolio selection considers additional criteria such as risk-adjusted portfolio cost, CO₂ emissions, supply reliability, resource diversity, and attainability of DSM program and renewable portfolio standard (RPS) requirements.

Introduction

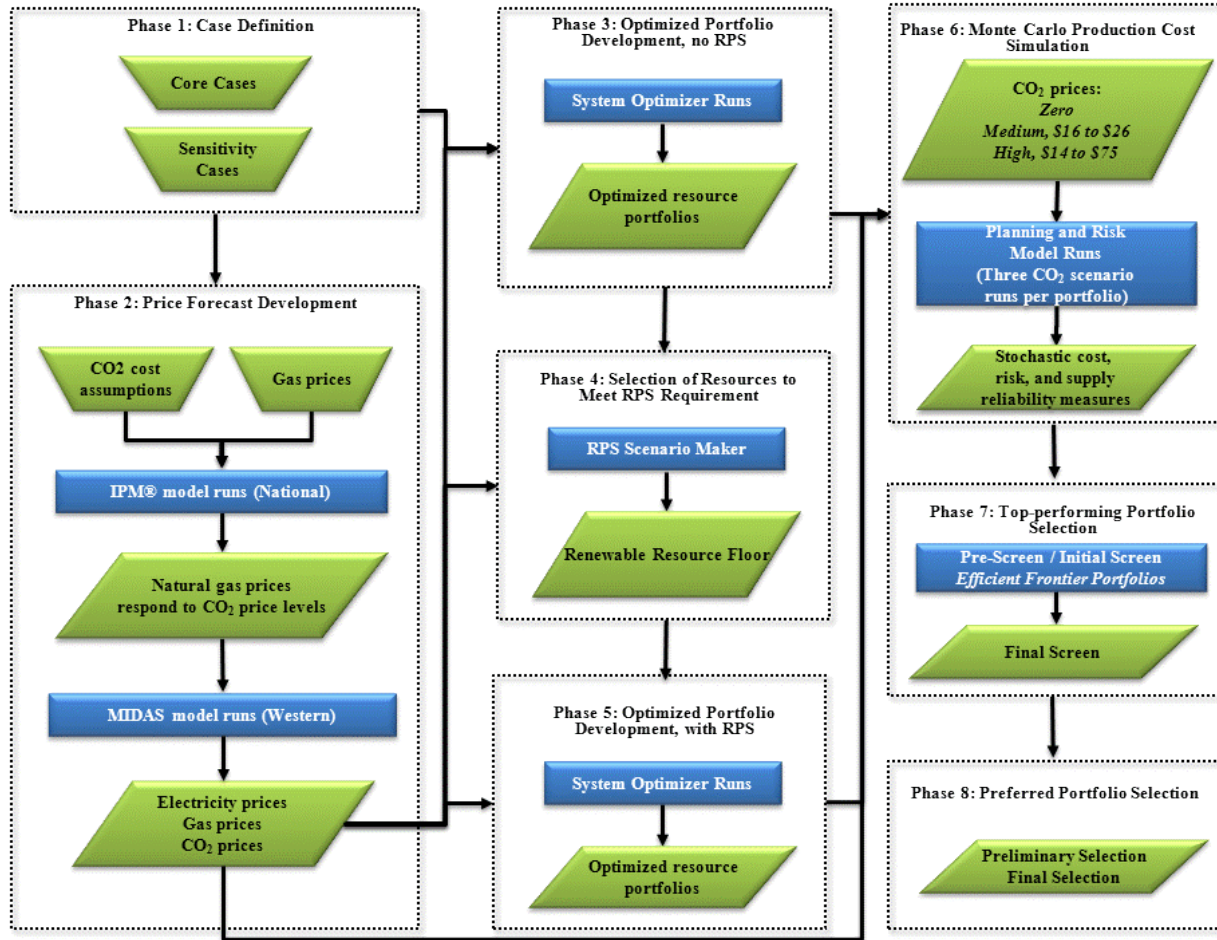
The IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation. This chapter describes the modeling and risk analysis process that supported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

The 2013 IRP modeling approach consists of eight phases, depicted as a flow chart in Figure 7.1. The eight phases are as follows:

- (1) Define input scenarios, referred to as cases, characterized by varying assumptions for CO₂ prices, commodity gas prices, wholesale electricity prices, coal prices, environmental policy and other cost drivers.
- (2) Case-specific price forecast development, where natural gas and power price assumptions are developed consistent with the definitions for each case.
- (3) Optimized portfolio development for each case that excludes RPS assumptions using PacifiCorp's System Optimizer capacity expansion model.
- (4) Development of a renewable resource floor, reflecting renewable resource additions chosen in optimized portfolios, developed in Phase 3 of the modeling approach, that meet RPS requirements in cases that include RPS assumptions. This is a new step in the modeling process for the 2013 IRP that relies upon the RPS Scenario Maker model.
- (5) Optimized portfolio development for each case that includes RPS assumptions using PacifiCorp's System Optimizer capacity expansion model requiring renewable resource additions that include at least those renewable resources developed in Phase 4 of the modeling approach.
- (6) Monte Carlo production cost simulation of optimized portfolios using PacifiCorp's Planning and Risk (PaR) model to support stochastic risk analysis.
- (7) Selection of top-performing portfolios using a three-phase screening process (preliminary screening, initial screening, and final screening) that incorporates stochastic portfolio cost and risk assessment measures, and
- (8) Preliminary preferred portfolio selection followed by final selection of the preferred portfolio.

This chapter describes the overall modeling approach, including a discussion of modeling and price assumptions, and provides a profile of each modeling phase described above.

Figure 7.1 – Modeling and Risk Analysis Process



Portfolio Modeling: System Optimizer

The System Optimizer model operates by minimizing for each year the operating costs for existing resources, taking into consideration potential compliance alternatives to coal unit environmental investments, subject to system load balance, reliability and other constraints. Over the 20-year study period, it optimizes resource additions subject to resource investment and capacity constraints (monthly peak loads plus a planning reserve margin for each load area represented in the model). In the event that early retirement of a coal unit is a lower cost alternative to installation of coal unit environmental investments, the System Optimizer model will select additional resources as required to meet monthly peak loads inclusive of a planning reserve margin.

To accomplish these optimization objectives, the model performs a time-of-day least-cost dispatch for existing and potential planned generation, contract, DSM, 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.

Modeling Capital Costs and Addressing “End-Effects”

For capital cost derivation, System Optimizer uses annual capital recovery factors to convert capital dollars into real levelized revenue requirement costs to address end-effects issues associated with capital-intensive investments that have different lives and in-service dates. All capital costs evaluated in the IRP are converted to real levelized revenue requirement costs. Use of real levelized revenue requirement costs is an established and preferred methodology to account for analysis of capital investment decisions that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given investment decision. To achieve this, the real levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that grows at inflation such that the PVRR is identical to the PVRR of the nominal annual requirement when using the same nominal discount rate. For the 2013 IRP, the PVRR is calculated inclusive of real levelized capital revenue requirement through the end of the 2032 planning period. PacifiCorp uses the real-levelized capital costs produced by System Optimizer for portfolio cost reporting by the PaR model.

In prior IRPs, growth station resources were included as generic resource alternatives in the out years of the IRP planning horizon. Historically, this resource option was used to balance capacity in each load area as a means to manage simulation run times by simplifying resource selection beyond the first 10 years of the planning period. Growth stations were ascribed costs derived from the forward power price curve. Upon expanding the scope of the 2013 IRP to evaluate coal unit environmental investments in all System Optimizer simulations, the use of growth resources was eliminated, allowing selection of supply and demand side resource alternatives in meeting loads over the entire 20 year planning horizon. This approach is required to ensure that the economics of potential early coal unit retirements capture the full cost of replacement resources over the long-term.

Modeling Front Office Transactions

Front office transactions (FOTs) 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, System Optimizer engages in market transactions. FOT transactions are firm forward power purchases that contribute capacity and energy to the system. System balancing transactions are short-term purchases and sales used to balance energy supply with demand in all hours across the system. System balancing purchases are energy transactions and do not contribute in meeting system capacity and planning reserve margin needs.

The FOTs modeled in the PaR model generally have the same characteristics as those modeled in the System Optimizer, except that transaction prices reflect wholesale forward electric market

prices that are “shocked” according to a stochastic modeling process prior to simulation execution.

Modeling Wind and Solar Resources

Wind and solar resources are modeled as non-dispatchable, must-run resources in both the System Optimizer and PaR models using fixed energy profiles that vary by month and time of day. The total energy generation for wind and solar resources represents the expected generation levels in which half of the time actual generation would fall below expected levels, and half of the time actual generation would be above expected levels.

In this IRP, the peak contribution of the wind resources is set at 4.2 percent, which was determined based upon review of actual wind generation data interconnected to PacifiCorp’s system. The peak contribution of solar resources is set at 13.6 percent, which is based on third party information due to the lack of sufficient actual solar resource generation data within the Company’s system. Volume II, Appendix O of this report discusses the details of the methodology that determined the peak contribution assumptions for wind and solar resources.

Modeling Coal Unit Environmental Investments

Building upon modeling techniques developed in the 2011 IRP and 2011 IRP Update, environmental investments required to achieve compliance with known and prospective regulations at existing coal resources have been integrated into the portfolio modeling process for the 2013 IRP. Potential alternatives to environmental investments associated with known and prospective compliance obligations are considered in the development of all resource portfolios. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. This advancement in analytical approach marks a significant evolution of the IRP process as it requires consideration of potential resource *contraction* while simultaneously analyzing alternative resource expansion plans.

Integrating coal unit environmental investment decisions in the development of resource portfolios identifies whether investments are cost effective in relation to other compliance alternatives. However, additional analysis is required to numerically quantify the economic benefit of investment decisions required on any given unit as compared to the next best alternative. Confidential Volume III summarizes additional analysis of coal unit environmental investments that are used to quantify the economic benefits of specific investment decisions that have been analyzed in the development of resource portfolios for the 2013 IRP.

Table 7.1 outlines the type of costs that are assigned to existing coal units configured with early retirement and gas conversion alternatives.

Table 7.1 – Resource Costs, Existing and Associated Gas Conversion Alternatives

Existing Coal Unit Costs	Coal Unit Early Retirement Alternative	Gas Conversion Alternative
<ul style="list-style-type: none"> • Incremental capital for environmental investments • Variable reagent costs for incremental environmental investments • Run-rate operations & maintenance (O&M) and capital • Incremental mine capital (as applicable) • Cash coal fuel costs • End-of-life decommissioning 	<ul style="list-style-type: none"> • Decommissioning costs • Recovery of incremental environmental capital and run-rate capital spent prior to early retirement date • Coal contract liquidated damages (as applicable) 	<ul style="list-style-type: none"> • Up-front capital cost • Run-rate operations & maintenance (O&M) • Fixed and variable natural gas transportation • Natural gas fuel cost • Recovery of incremental environmental capital and run-rate capital spent prior to gas conversion • Coal contract liquidated damages (as applicable)

Reserve Margin Requirement

In the System Optimizer model, PacifiCorp continues to apply a 13 percent planning reserve margin. The planning reserve margin is used to ensure that the Company has sufficient resources to meet peak loads recognizing that there is a possibility for load fluctuation and extreme weather conditions, a possibility for unplanned resource outages, and a requirement to carry contingency and regulating reserves.

In the PaR model, explicit categories of operational reserve requirements are modeled. The contingency reserves are approximately 7 percent of the system load. The amount of regulating reserves includes ramping of load, as well as requirement to integrate variable energy resources, such as wind. The reserve requirements to integrate wind resources are the results of PacifiCorp’s 2012 Wind Integration Study, which is presented in Volume II, Appendix H of this report. The forced outages and fluctuation in load due to temperature are reflected in the modeling of resource availability and simulated in the stochastic runs.

Modeling Energy Gateway Transmission Scenarios

The Energy Gateway transmission project is modeled in this IRP under five scenarios. The scenarios for Energy Gateway transmission paths are modeled as fixed inputs to both the System Optimizer and PaR models, which cannot endogenously add additional transmission resources as

can be done for supply and demand side resources. The costs of Energy Gateway segments are modeled as a real levelized revenue requirement, as discussed above, based on a real levelized capital recovery factor of 7.069 percent, which intends to recover the investment cost of the assets, return on and of capital, income taxes and property taxes. Fixed operating and maintenance costs are also included in the model as 1.07 percent of the investment.

Modeling Energy Storage Technologies

Energy storage resources in both System Optimizer and PaR models are distinguished from other resources by the following three attributes:

- Energy “take” – generation or extraction of energy from a reservoir on-peak;
- Energy “return” – energy used to fill (or charge) a reservoir off-peak; and
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

The models require specification of a reservoir size. For System Optimizer and PaR models, reservoir size is defined in gigawatt-hours. System Optimizer dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage cycle efficiency, the daily balance of take and return energy, and fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders). To determine the least-cost resource expansion plan, the model accounts for conventional generation system performance and cost characteristics of the storage resource, including investment cost, capacity factor, heat rate (if fuel is used), operating and maintenance cost, minimum capacity, and maximum capacity.

In the PaR model, simulations are conducted on a week-ahead basis. The model operates the storage plant to balance generation and charging, accounting for cycle efficiency losses, in order to end the week in the same net energy position as it began. The model chooses periods to generate and return energy to minimize system cost. It does this by calculating an hourly *value of energy* for charging. This value of energy, a form of marginal cost, is used as the cost of generation for dispatch purposes, and is derived from calculations of system cost and unit commitment effects. For compressed air energy storage (CAES) plants, a heat rate is included as a parameter to capture fuel conversion efficiency. The heat rates entered in both models represent the use of PacifiCorp’s off-peak coal-fired plants.

General Assumptions and Price Inputs

Study Period and Date Conventions

PacifiCorp executes its IRP models for a 20-year period beginning January 1, 2013 and ending December 31, 2032. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, with the exception of natural gas conversion alternatives to incremental environmental investments required at existing coal units, which are given an in-service date of June 1st for the year gas conversion is completed.

Escalation Rates and Other Financial Parameters

Inflation Rates

The IRP model simulations and price forecasts reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. For the System Optimizer model, a single escalation rate value is used. This value, 1.9 percent, is estimated as the average of the annual corporate inflation rates for the period 2013 to 2032, using PacifiCorp's March 2012 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for Gross Domestic Product (GDP) inflator and Consumer Price Index (CPI).

Discount Factor

The rate used for discounting in financial calculations is PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2013 IRP is 6.882 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.⁶⁰

Federal Renewable Resource Tax Incentives

In the current IRP, it is assumed that federal production tax credits (PTC) for qualifying renewable resources are expired and that the federal investment tax credits (ITC) for qualifying renewable resources will expire at the end of 2016, consistent with the Emergency Economic Stabilization Act of 2008 (P.L. 110-343), which allows utilities to claim the 30 percent ITC for solar facilities placed in service by January 1, 2017. This tax credit is factored into the capital cost for solar resource options in the System Optimizer model. Select cases evaluated for the 2013 IRP assume federal PTCs and ITCs are extended through 2019.

Asset Lives

Table 7.2 lists the generation resource asset book lives assumed for levelized fixed charge calculations.

⁶⁰ Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

Table 7.2 – Resource Book Lives

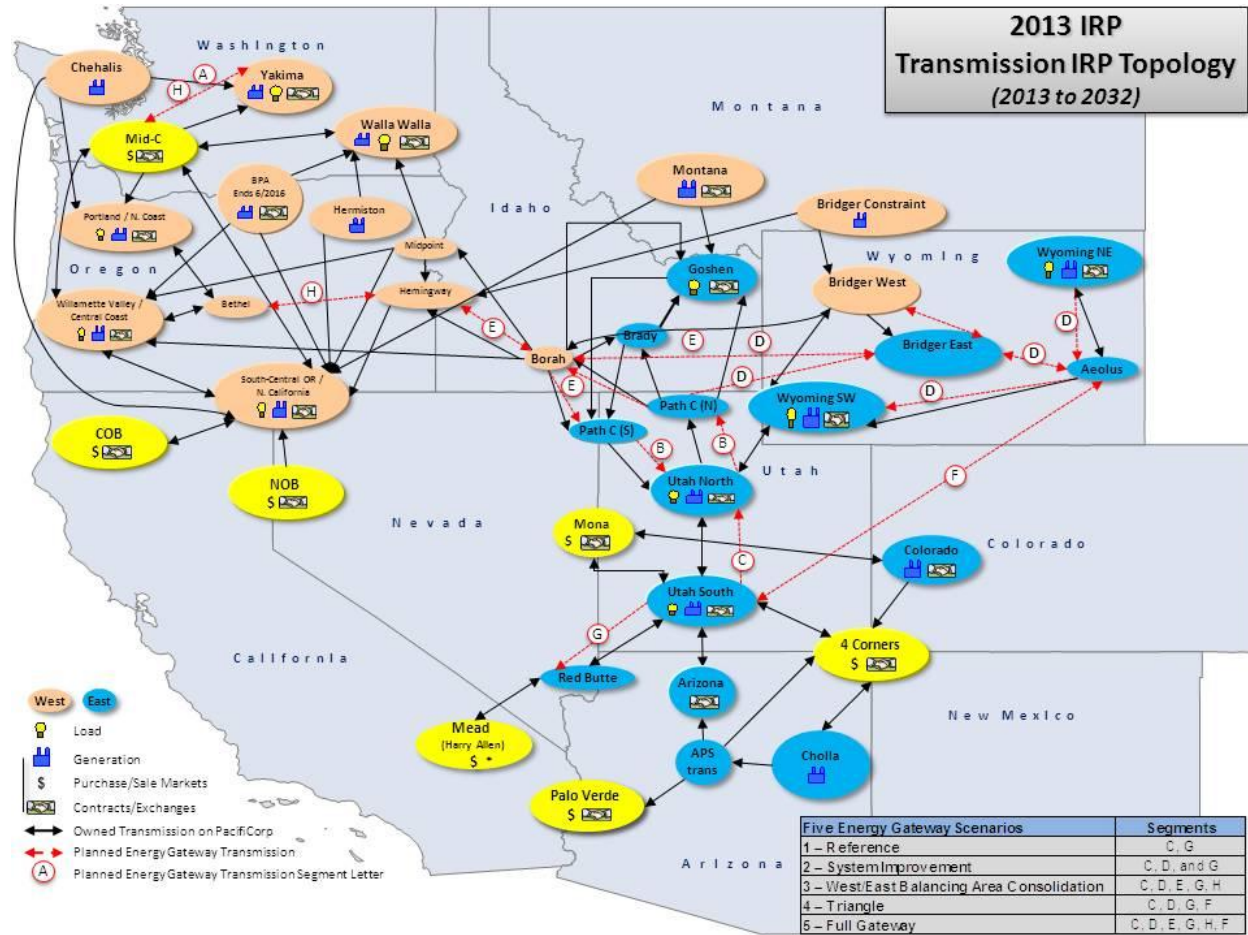
Resource	Book Life (Years)
Integrated Gasification Combined-Cycle with carbon capture and sequestration	40
Combined Cycle Combustion Turbine (CCCT)	40
Pumped Storage	50
Simple Cycle Combustion Turbine (SCCT) Frame	35
Solar Photovoltaic	25
Solar Thermal	30
Compressed Air Energy Storage	30
Single Cycle Combustion Turbine (SCCT) Aero	30
Intercooled Aeroderivative SCCT	30
Internal Combustion Engine	20
Fuel Cells	20
Wind	25
Battery Storage	30
Biomass	30
Nuclear Plant	40
CHP - Reciprocating Engine	20
CHP - Gas Turbine	20
CHP - Microturbine	10
CHP - Fuel Cell	10
CHP - Commercial Biomass, Anaerobic Digester	17
CHP - Industrial Biomass Waste	17
Solar - Rooftop Photovoltaic	30
Solar - Water Heaters	20

Transmission System Representation

PacifiCorp uses a transmission topology consisting of 19 bubbles (electrically connected areas) in its eastern balancing authority area and 18 bubbles in its western balancing authority area designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Firm transmission paths link the bubbles. The transfer capabilities for these links represent PacifiCorp Merchant's current firm rights on the transmission lines. This topology is defined for both the System Optimizer and PaR models.

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

Figure 7.2 – Transmission System Model Topology



The most significant change to the model topology from the 2011 IRP is the addition of four new bubbles and the identification of the Energy Gateway line segments.

- The Hemingway bubble addition was essential for modeling the Energy Gateway path “H” of Hemingway-Boardman-Bethel with bi-directional capabilities, and to improve the ability to model the separate transfer capability through the Idaho Power system.
- The Midpoint-Meridian bubble addition is an improved representation of existing east to west transfer capability. This modeling of the legacy contract is needed since it contains provisions limiting what energy may be transferred on the west side of the Idaho Power system.
- The Bridger Constraint bubble addition is included to model a reliability constraint consistent with operations that limits the transfer from Jim Bridger to the east balancing authority area to three of the four generating units.
- The Nevada Oregon Border (NOB) bubble addition is to provide existing access to the California ISO market via PacifiCorp’s DC Intertie rights in the model. Without this addition the benefits of the existing rights would not be apparent.

The 2011 IRP utilized separate wind bubbles in order to assign incremental transmission interconnection investment costs to the wind resources. However, in the current IRP, the

incremental transmission costs are assigned directly to the wind resources and, therefore, eliminated the need to model separate wind bubbles.

Carbon Dioxide Regulatory Compliance Scenarios

Carbon Dioxide Scenarios

Table 7.3 shows five different sets of CO₂ price assumptions used in the 2013 IRP. Each CO₂ price scenario is accompanied by a consistent set of natural gas and wholesale power price assumptions. For modeling purposes, the cost of CO₂ emissions are applied as a tax in which there is a cost imputed on each ton of CO₂ emissions generated by system resources. This approach is used in recognition that there are a wide range of policy mechanisms that might be used to regulate CO₂ emissions in the power sector at some point in the future. Application of CO₂ prices as a tax is a means to assign costs to CO₂ emissions as a surrogate for a wide range of potential future policy tools, whether implemented as a tax, cap-and-trade program, emission performance standards, or some other policy mechanism. Each of the CO₂ price scenarios used in the 2013 IRP is discussed in turn below:

Zero CO₂ Price Scenario

Given that there is currently no specific legislative proposal that has been passed by Congress for the President's consideration and no current federal regulation that would impose a direct cost on CO₂ emissions, the 2013 IRP includes a zero CO₂ price scenario. Under this scenario, there is no direct cost applied to CO₂ emissions from generation sources throughout the IRP 20-year planning horizon.

Medium CO₂ Price Scenario

The medium CO₂ price scenario ascribes a cost to CO₂ emissions within ten years of 2013, and as such, prices are assumed beginning in 2022. Price levels in this scenario are consistent with recent projections from third party forecasters. Price levels in the medium CO₂ price scenario are generally aligned with a price signal that would be required to induce switching from coal to natural gas-fired generation sources with an assumed annual real escalation rate of 3 percent.

High CO₂ Price Scenario

Under the high CO₂ price scenario, a cost is ascribed to CO₂ emissions beginning 2020, which is two years earlier than in the medium CO₂ price scenario. Under the high scenario, it is assumed that regulation would ramp into more stringent requirements over the first two years (in 2020 and 2021). The high scenario reflects how prospective CO₂ prices might respond to a future with new regulations that would impose costs on fossil fuel sources and new regulations that could increase natural gas prices (i.e. regulations that would increase the cost of natural gas supply). Under such a scenario, the CO₂ price signal required to induce switching from coal to natural gas-fired generation sources would be higher as compared to the medium CO₂ price scenario, and the resulting price trajectory is similar to the price ceiling that was included in a climate and energy bill proposed by Senator John Kerry and Senator Joe Lieberman in the American Power Act of 2010.

U.S. Hard Cap, Medium Natural Gas CO₂ Price Scenario

This scenario reflects a CO₂ price trajectory produced using the Integrated Planning Model (IPM®) assuming a generic cap-and-trade program is imposed upon the power sector of the U.S.

economy beginning in 2020 with declining annual emission limits that reach 80 percent below 2005 levels by 2050. In this simplified analysis, it was assumed that domestic and international CO₂ offsets could not be used to mitigate power sector emissions, and the resulting CO₂ price projection was developed off of medium natural gas price assumptions.

U.S. Hard Cap, High Natural Gas CO₂ Price Scenario

As in the U.S. hard cap scenario described above, this scenario reflects a CO₂ price trajectory resulting from a cap-and-trade program imposed upon the power sector of the U.S. economy beginning in 2020 with declining annual emission limits that reach 80 percent below 2005 levels by 2050. Similarly, it is assumed that domestic and international offsets cannot be used to mitigate power sector emissions. In this variant of the U.S. hard cap CO₂ price scenario, the CO₂ price projection was developed off of high natural gas price assumptions. With higher natural gas price assumptions, the resulting CO₂ price level is higher than those developed for the U.S. Hard Cap, Medium Natural Gas CO₂ Price Scenario.

Table 7.3 – CO₂ Price Scenarios

Year	CO ₂ Price, Nominal \$/short ton				
	None	Base	High	Hard Cap, Base Gas	Hard Cap, High Gas
2020	\$0.00	\$0.00	\$13.53	\$47.47	\$57.08
2021	\$0.00	\$0.00	\$19.68	\$50.86	\$61.17
2022	\$0.00	\$16.00	\$26.05	\$54.49	\$65.53
2023	\$0.00	\$16.78	\$32.67	\$58.38	\$70.21
2024	\$0.00	\$17.61	\$39.52	\$62.55	\$75.22
2025	\$0.00	\$18.47	\$46.62	\$67.01	\$80.59
2026	\$0.00	\$19.37	\$49.88	\$71.80	\$86.34
2027	\$0.00	\$20.32	\$53.37	\$76.94	\$92.52
2028	\$0.00	\$21.32	\$57.11	\$82.44	\$99.14
2029	\$0.00	\$22.36	\$61.10	\$88.35	\$106.24
2030	\$0.00	\$23.46	\$65.38	\$94.67	\$113.84
2031	\$0.00	\$24.63	\$70.02	\$101.55	\$122.12
2032	\$0.00	\$25.86	\$74.99	\$108.88	\$132.25

Figure 7.3 compares the five CO₂ price scenarios graphically, and Table 7.4 shows the U.S. power sector projected carbon emissions through 2050 under the U.S. Hard Cap Scenario.

Figure 7.3 – Carbon Dioxide Price Scenario Comparison

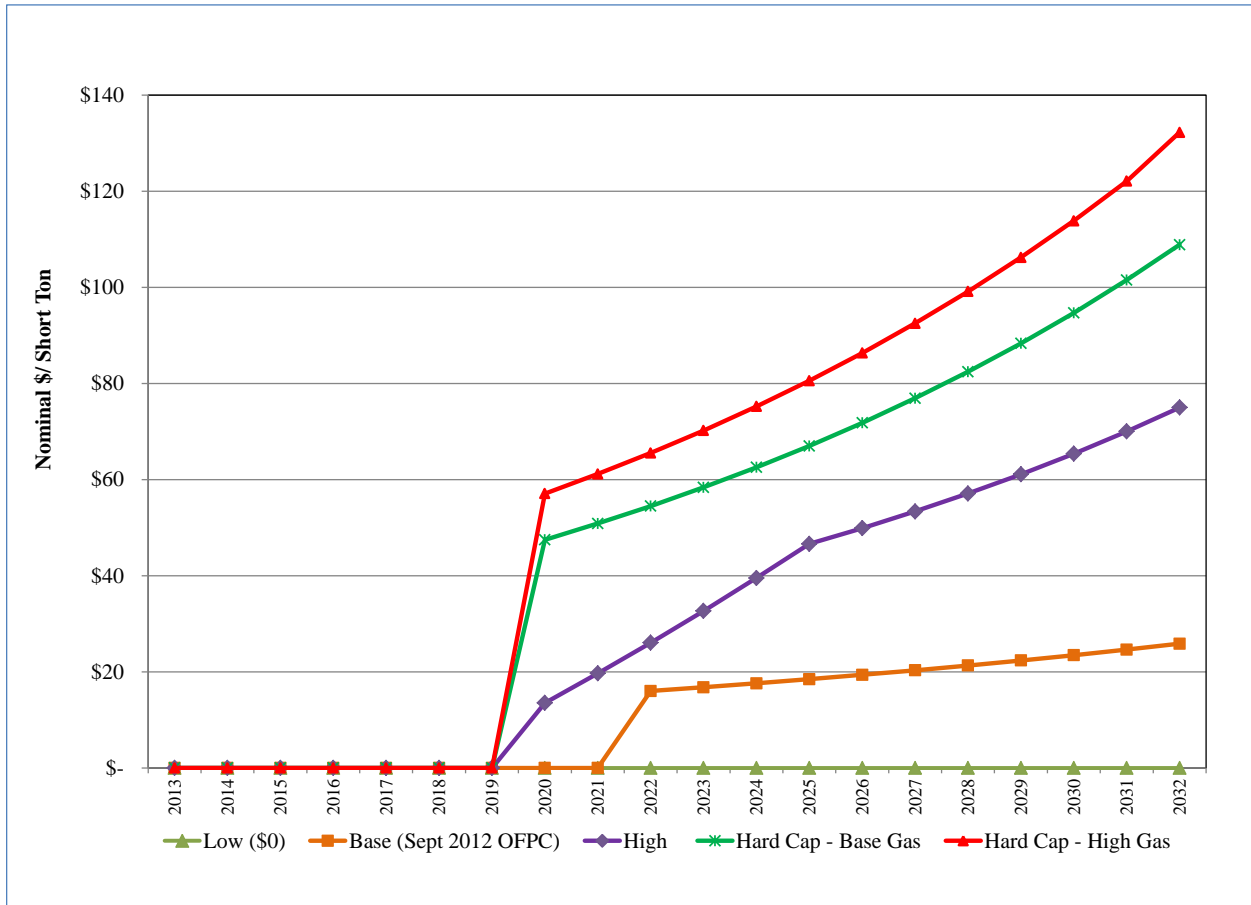


Table 7.4 – Carbon Reduction under U.S. Hard Cap Scenarios

Year	Potential Hard Cap Reduction Scenario: 80% reduction from 2005 CO ₂ power sector emission levels by 2050 (short tons)
2005	2,617,960 ⁶¹
2020	2,200,511
2021	2,144,614
2022	2,088,716
2023	2,032,819
2024	1,976,922
2025	1,921,024
2026	1,865,127
2027	1,809,230
2028	1,753,333
2029	1,697,435
2030	1,641,538
2031	1,585,641
2032	1,529,743
2033	1,473,846
2034	1,417,949
2035	1,362,052
2050	523,593

Oregon Environmental Cost Guideline Compliance

The Oregon Public Utility Commission (OPUC), in their IRP guidelines, directs utilities to construct a base-case scenario that reflects what it considers to be the most likely regulatory compliance future for CO₂, as well as alternative scenarios “ranging from the present CO₂ regulatory level to the upper reaches of credible proposals by governing entities.” Modeling portfolios with no CO₂ cost represents the current regulatory level. The base scenario was considered the most likely regulatory compliance scenario at the time that IRP CO₂ scenarios were being prepared and vetted by public stakeholders (early fall of 2012). Given the late-2010 collapse of comprehensive federal energy legislation and loss of momentum for implementing federal carbon pricing schemes, it is not likely Congress will pass federal climate change legislation for consideration by the President over the near-term. At this time, it is likely that federal CO₂ regulations will come in the form of new source performance standards, applicable to both new and existing electric generating units.

PacifiCorp believes that its CO₂ tax and hard cap scenarios reflect a reasonable range of compliance futures for meeting the OPUC scenario development guideline. As discussed in the preceding section, the Company’s CO₂ prices are indicative of varying levels of CO₂ price signals that might arise from a wide range of future policy outcomes at the federal level. Moreover, the System Optimizer model runs using the above CO₂ assumptions yielded varied composition of portfolios, with some portfolios showing nearly all of PacifiCorp’s coal units shutting down or converting to natural gas within the 20-year planning horizon.

⁶¹ Energy Information Administration / Emissions of Greenhouse Gases in the United States 2005, November 2006.

Phase (1) Case Definition

The first phase of the IRP modeling process was to define the cases (input scenarios) that the System Optimizer model uses to derive optimal resource expansion plans. The cases consist of variations to inputs representing the predominant sources of portfolio cost variability and uncertainty. PacifiCorp generally specified low, medium, and high values for key assumptions to ensure that a reasonably wide range in potential outcomes is captured. For the 2013 IRP, PacifiCorp worked closely with stakeholders to develop 19 core case definitions applied uniformly across five different Energy Gateway scenarios with an additional 12 sensitivity cases that in total sum to 106 different resource portfolios. Each of the five Energy Gateway scenarios were defined to explore how different combinations of Energy Gateway segments influence resource selection and system costs.

Core cases focus on broad comparability of portfolio performance results for five key variables. These variables include (1) timing of and level of CO₂ prices, (2) natural gas and wholesale electricity prices, (3) policy assumptions pertaining to federal tax incentives and RPS requirements, (4) policy assumptions pertaining to coal unit compliance requirements driven by Regional Haze regulations, and (5) acquisition ramp rates for Class 2 DSM energy efficiency resources.

In contrast, sensitivity cases focus on changes to resource-specific assumptions and alternative load growth forecasts. The resulting portfolios from the sensitivity cases are typically compared to one of the core case portfolios. PacifiCorp developed 12 sensitivity cases reflecting alternative assumptions for load forecasts, availability of renewable resource federal tax incentives, renewable portfolio standard modeling, Class 3 DSM resource availability, and coal unit environmental investments.

In developing these cases, PacifiCorp worked collaboratively with stakeholders to develop case definitions meeting the following objectives: (1) case definitions expected to yield resource diversity and comparative consistency among cases, (2) portfolio development structure that isolates the how individual Energy Gateway segments affect resource selection, (3) provides for an understanding of how RPS requirements affect renewable resource needs, and (4) is responsive to stakeholder requests targeting specific resource technologies.

With these objectives in mind, the Company initiated the portfolio case development process and sample case definitions at the June 20, 2012 public input meeting. In response to stakeholder comments, the Company produced draft core case definitions at the July 13, 2012 public meeting. Additional stakeholder comments were reviewed and significantly influenced updated draft core case definitions reviewed with stakeholders at the September 14, 2012 meeting. Detailed “fact sheets”, describing high level assumptions for each core case in a consistent format, was shared with stakeholders at the October 24, 2012 meeting and updated at the December 18, 2012 meeting. Sensitivity case fact sheets were shared with stakeholders at the February 27, 2013 public meeting.

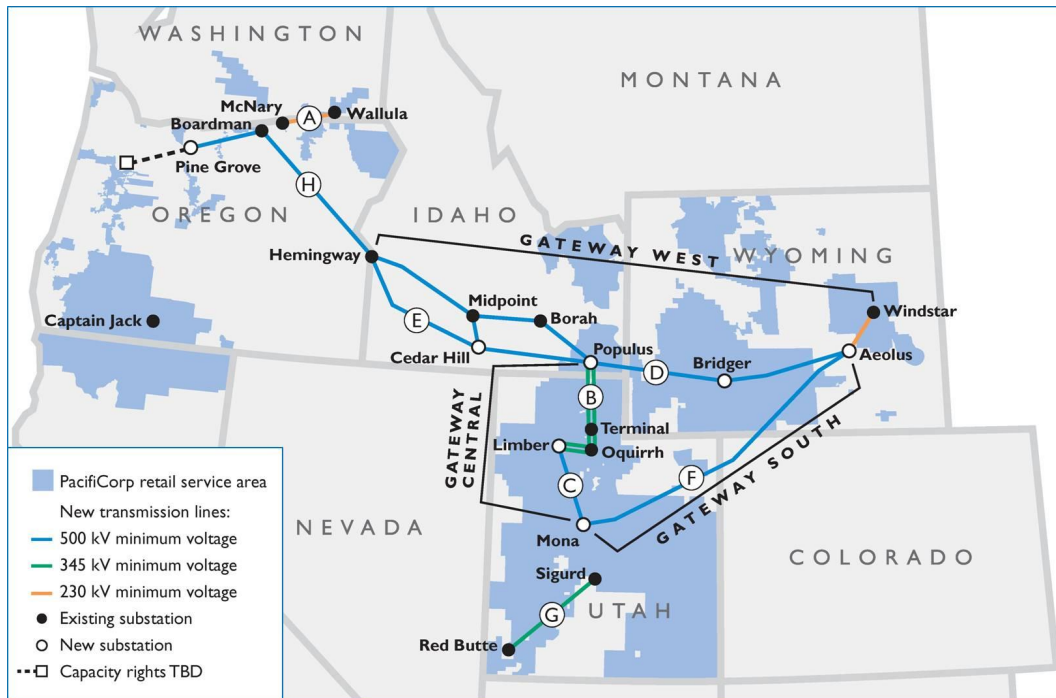
Case Specifications

Table 7.5 defines the five Energy Gateway scenarios, and Figure 7.4 shows the generation location of specific Energy Gateway Segments.

Table 7.5 – Energy Gateway Scenario Definitions

Scenario	Segments	Description
EG1	C and G	Reference – Mona-Oquirrh-Terminal, Sigurd-Red Butte
EG2	C, D, and G	System Improvement – 2013 Business Plan
EG3	C, D, E, G, and H	West/East Consolidation – Increase interchange between PACE and PACW
EG4	C, D, G, and F	Triangle – East side wind and improved reliability
EG5	C, D, E, G, H, and F	Full Gateway – All Energy Gateway segments

Figure 7.4 – Future Energy Gateway Transmission Expansion Plan



This map is for general reference only and reflects current plans. It may not reflect the final routes, construction sequence or exact line configuration.

Portfolio development cases developed for the 2013 IRP were categorized into four different themes, each described in turn below:

- (5) Reference: There are three different core cases developed for the Reference Theme. Each case relied upon base case assumptions for market prices, environmental policy

inputs, energy efficiency assumptions, and load projections. RPS assumptions differentiate the three cases in the Reference Theme, with one case assuming no state or federal RPS requirements, one case assuming only state RPS requirements, and one case assuming both state and federal RPS requirements must be met.

- (6) Environmental Policy: There are 11 different core cases and two types of sensitivity cases developed for the Environmental Policy Theme. Five of the 11 core cases reflect base case assumptions for Regional Haze requirements on existing coal units, and six of the 11 cases assume more stringent Regional Haze requirements. Differentiating the sets of cases with different Regional Haze compliance requirements are varying assumptions for market prices (low, medium, and high), CO₂ prices (zero, medium, and high), RPS requirements (with and without state and federal RPS), and energy efficiency. The two types of sensitivity cases developed for the Environmental Policy Theme describe additional analysis performed to evaluate near-term coal unit environmental investments that are summarized in Confidential Volume III.
- (7) Targeted Resources: There are four different core cases and five different sensitivity cases developed for the Targeted Resource Theme. Each of the cases is characterized by alternative assumptions for specific resource types to understand how these assumptions influence resource portfolios, costs, and risk. One of the four core cases prevents combined cycle resources from being added to the resource portfolio and assumes energy efficiency resources can be acquired at an accelerated rate. The second of the four core cases in this theme assumes that geothermal power purchase agreement resources will be used to meet RPS requirements. The third of four core cases in this theme assumes a spike in power prices over the period 2017 through 2022 and assumes natural gas prices will rise above base case levels over the entirety of the planning horizon. The fourth core case in this theme targets clean energy resources and assumes CO₂ prices rise consistent with a federal hard cap scenario, that natural gas prices rise above those assumed in the base case, that federal tax incentives for renewable resources are extended through 2019, and that energy efficiency resources can be acquired at an accelerated rate.
- (8) Transmission: The Transmission Theme included one core case, which assumes that third party transmission can be purchased from a newly built line as an alternative to the Company's Gateway Segment D project. This case was only analyzed in four of the five Energy Gateway scenarios that include the Gateway Segment D project.

Tables 7.6 and 7.7 provide the definitions of the core cases and sensitivity cases. In addition, detailed descriptions of all cases are provided in case fact sheets that are available in Volume II, Appendix M of this report.

Table 7.6 – Core Case Definitions

Theme	Case	Gas Price	CO2 Price	Coal Price	RPS	Class 2 DSM	Other
Reference	C01	Medium	Medium	Medium	None	Base	n/a
	C02	Medium	Medium	Medium	State	Base	n/a
	C03	Medium	Medium	Medium	State & Federal	Base	n/a
Environmental Policy	C04	Low	High	High	None	Base	n/a
	C05	Low	High	High	State & Federal	Base	n/a
	C06	High	Zero	Low	None	Base	n/a
	C07	High	Zero	Low	State & Federal	Base	n/a
	C08	Low	High	High	None	Base	n/a
	C09	Low	High	High	State & Federal	Base	n/a
	C10	Medium	Medium	Medium	None	Base	n/a
	C11	Medium	Medium	Medium	State & Federal	Base	n/a
	C12	High	Zero	Low	None	Base	n/a
	C13	High	Zero	Low	State & Federal	Base	n/a
	C14	Medium	Hard Cap (Medium Gas)	Medium	State & Federal	Accelerated	n/a
	Targeted Resources	C15	Medium	Medium	Medium	State & Federal	Accelerated
C16		Medium	Medium	Medium	State & Federal	Base	Geothermal/RPS
C17		High	Medium	Medium	State & Federal	Base	Market Spike
C18		Medium	Hard Cap (High Gas)	Medium	None	Accelerated	Clean Energy
Transmission	C19	Medium	Medium	Medium	State & Federal	Base	Alt. to Segment D

Table 7.7 – Sensitivity Case Definitions

Theme	Case #	Load	Gas Price	CO2 Price	RPS	PTC/ITC	Coal Investments
Load Sensitivity	S-01	Low	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
	S-02	High	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
	S-03	1 in 20	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
Targeted Resource	S-05	Base	Medium	Medium	None	2019/2019	Optimized
	S-06	Base	Medium	Medium	State & Federal (RPS Floor)	2019/2019	Optimized
	S-07	Base	Medium	Medium	State & Federal (Optimized)	2012/2016	Optimized
	S-09	Base	High	High	State & Federal (RPS Floor)	2019/2019	Optimized
	S-10	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
Environmental Policy	S-04 (Volume III)	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Hypothetical Regional Haze
	S-X (Volume III)	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Next Best Alternative

Notes

1. All sensitivity cases are based on Energy Gateway Scenario 2, consistent with the scenario in the 2013 IRP preferred portfolio.
2. Sensitivity Case S-07 applies state RPS targets as system targets in the System Optimizer model. All other sensitivities either use the RPS Scenario Maker to establish a renewable resource floor or exclude RPS requirements altogether.
3. Case S-08 (simulating PacifiCorp’s 2013 Business Plan portfolio in the current input setup) was removed due to incompatibilities in how Class 2 DSM resources are modeled in the 2013 IRP.
4. Sensitivity cases S-04 (Hypothetical Regional Haze Compliance Alternative) and S-X (Emission Control PVRR(d) Analysis) are confidential and summarized in confidential Volume III of the 2013 IRP report.

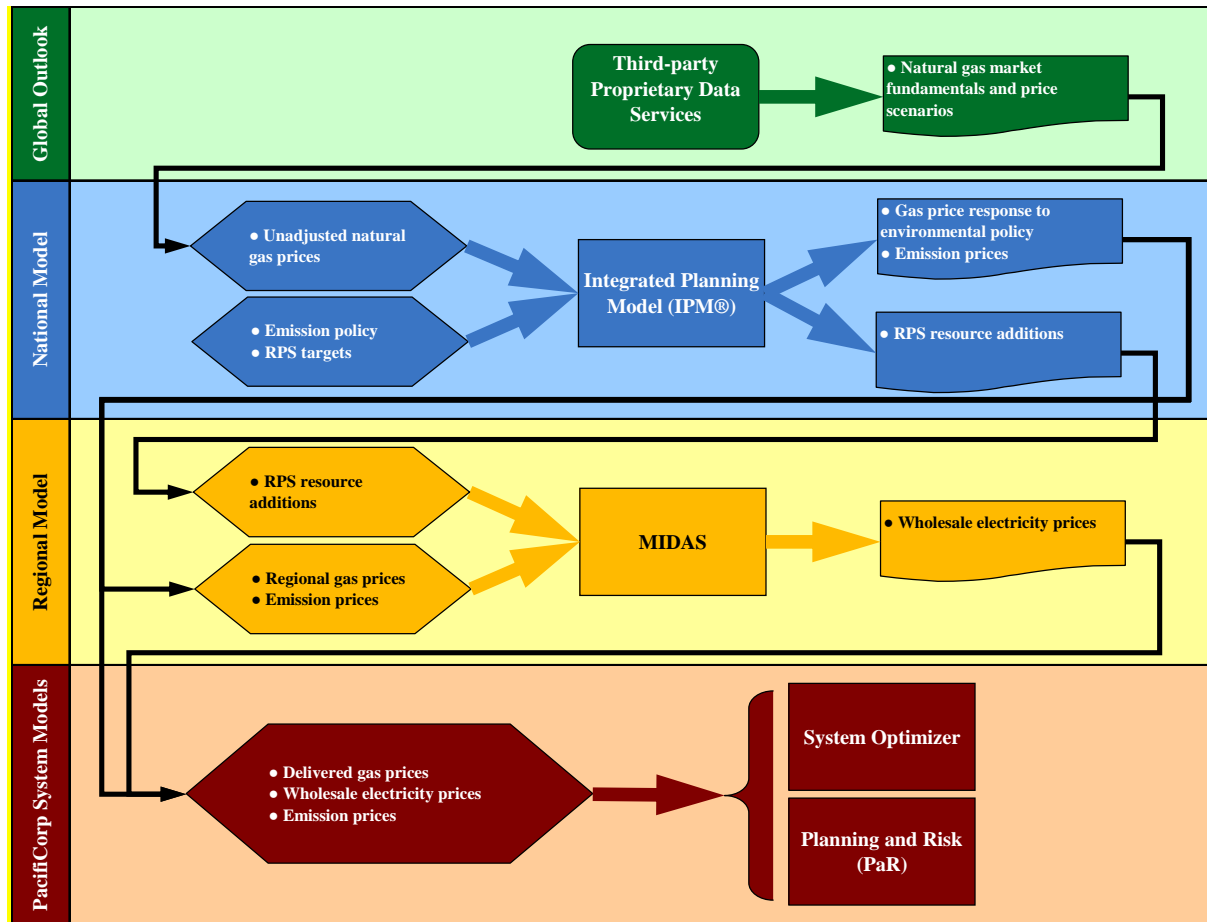
Phase (2) Scenario Price Forecast Development

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

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

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

Figure 7.5 – Modeling Framework for Commodity Price Forecasts



The process begins with an assessment of global gas market fundamentals and an associated forecast of North American natural gas prices. In this step, PacifiCorp relies upon a number of expert third-party proprietary data and forecasting services to establish a range of gas price scenarios. Each price scenario reflects a specific view of how the North American natural gas market will balance supply and demand.

Once a natural gas price forecast is established, the Integrated Planning Model (IPM®) is used to simulate the entire North American power system. IPM®, a linear program, determines the least cost means of meeting electric energy and capacity requirements over time, and in its quest to lower costs, ensures that all assumed emission policies and RPS policies are met. Concurrently, IPM® can be configured with a dynamic natural gas price supply curve that allows natural gas prices to respond to changes in demand triggered by environmental compliance. Additional outputs from IPM® include a forecast of resource additions consistent with all specified RPS

targets, electric energy and capacity prices, coal prices⁶², electric sector fuel consumption, and emission prices for policies that limit emissions or emission rates.⁶³

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

Gas and Electricity Price Forecasts

PacifiCorp's official forward price curve (OFPC) for natural gas prices is composed of market forwards for the first 72 months, followed by 12 months of blended prices which transition into a third-party fundamentals forecast, starting in month 85.

The first 72 months of the official forward price curve represents market forwards, the value that market participants will buy and sell today for a commodity that delivers sometime in the future. There is a constant consideration for what happens between today and the time of delivery and all days in between as demonstrated by dynamic (constant) changes in bids and offers. A forward curve is not a forecast; it is simply a representation of where one believes they can transact today for forward settlements/deliveries.

In contrast to market forwards, starting in month 85, PacifiCorp's OFPC is based on a third-party fundamentals forecast. This forecast is a single description of what one expects the value a commodity to be at the time it is delivered and consumed. A forecast contains no consideration for what happens between today and the forecast's scope of time.

The underlying base natural gas price forecasts used in this IRP are significantly lower than those produced for the Company's 2011 IRP and the subsequent 2011 IRP Update filed with state commissions March 2011 and March 2012, respectively. Figures 7.6, 7.7, and 7.8 compare base natural gas (Henry Hub) and electricity (Palo Verde and Mid C) price forecasts for the 2013 IRP, 2011 IRP Update, and 2011 IRP.

⁶² IPM® contains over 75 coal supply curves, with reserve estimates, by rank and quality. Coal supply curves are matched to coal demand areas, including transportation costs, and optimized. As such, IPM® is able to capture coal price response from incremental (decremental) demand, which ultimately affects the natural gas and emission prices that feed into System Optimizer and Planning and Risk.

⁶³ Emission modeling capabilities of IPM® were also used in this IRP to develop CO₂ prices for the two U.S. Hard Cap CO₂ price scenarios.

Figure 7.6 – Comparison of Base Henry Hub Gas Price Forecasts used for Recent IRPs

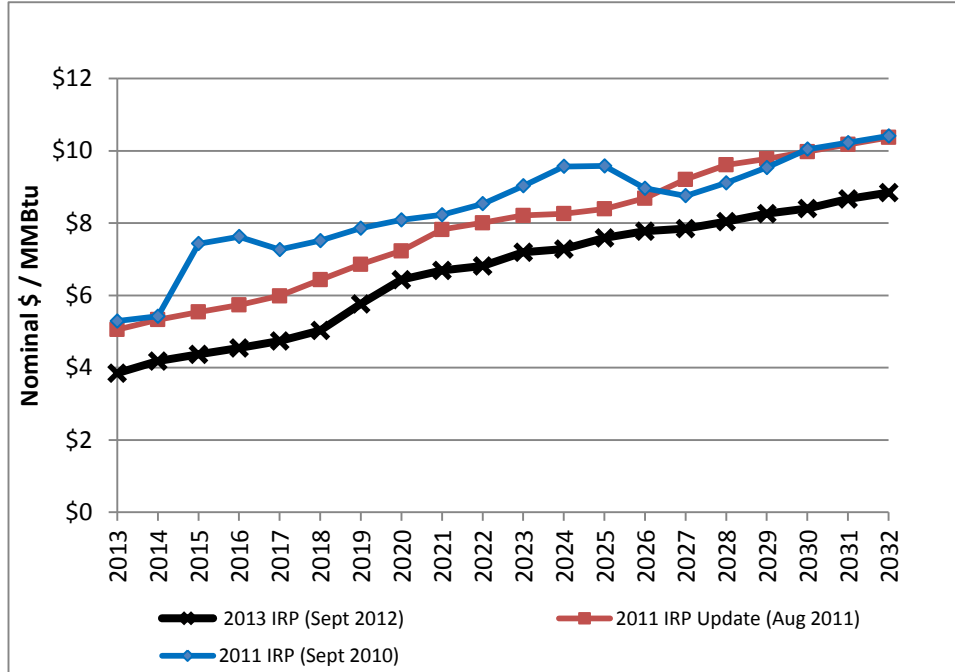


Figure 7.7 –Palo Verde Electricity Price Forecasts used in Recent IRPs

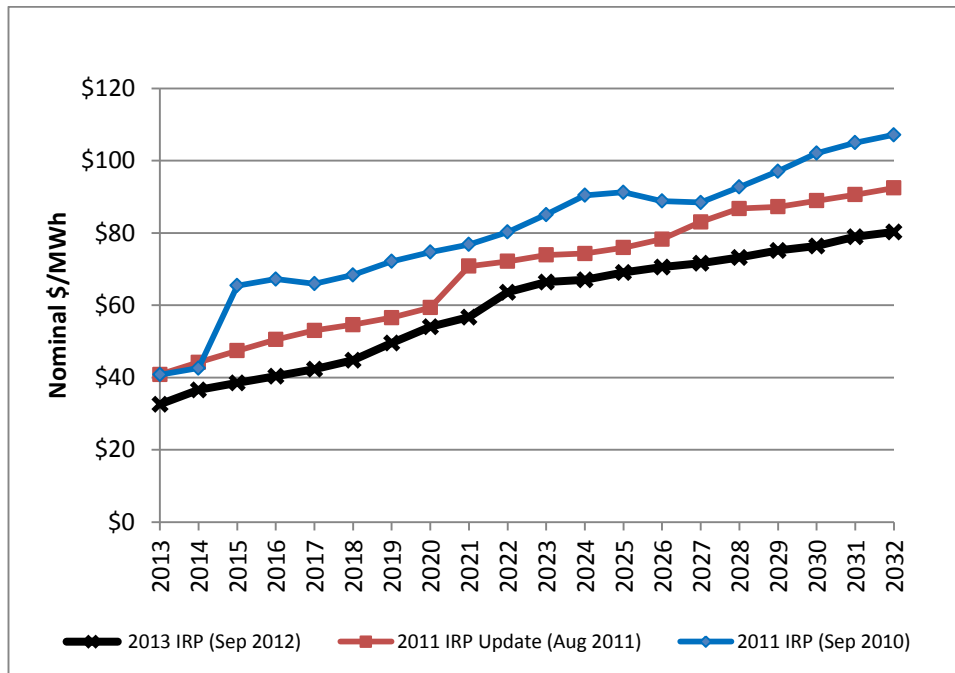
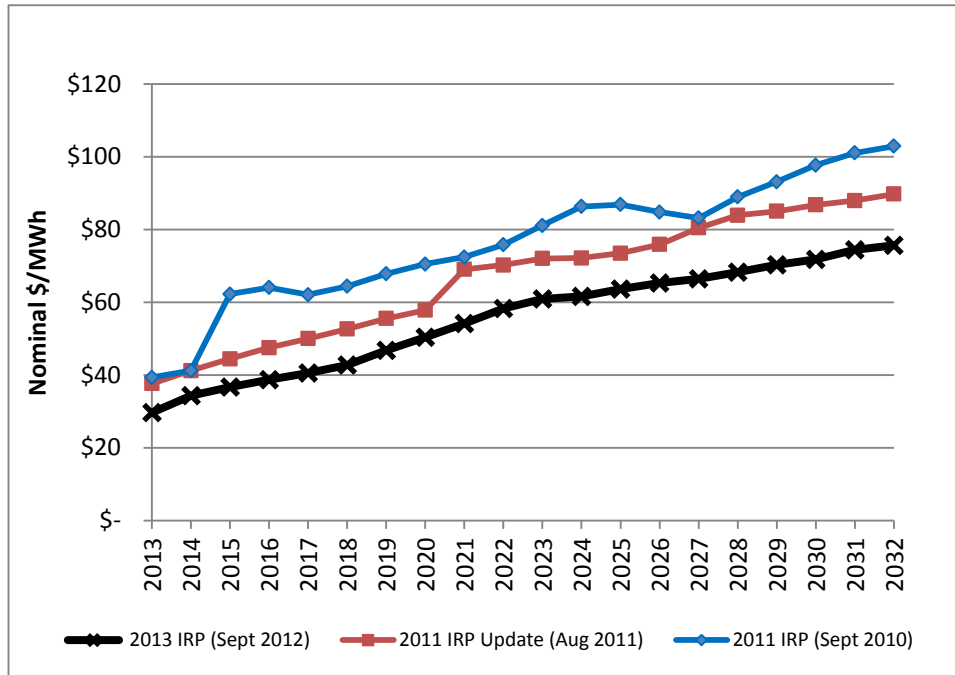


Figure 7.8 – Mid Columbia Electricity Price Forecasts used in Recent IRPs



Five natural gas price forecasts were used to derive the gas price projections for the 19 core cases analyzed in this IRP. A range of fundamental assumptions affecting how the North American market will balance supply and demand defines the underlying price forecasts.

The hard cap studies were developed June 2012. The supporting expert third-party high natural gas price scenario was issued May 2012 while the base price forecast reflects PacifiCorp’s June 29, 2012 OFPC. The OFPC is composed of market forwards for the first 72 months, followed by 12 months of blended prices which transition into an expert third-party fundamentals forecast, starting in month 85.

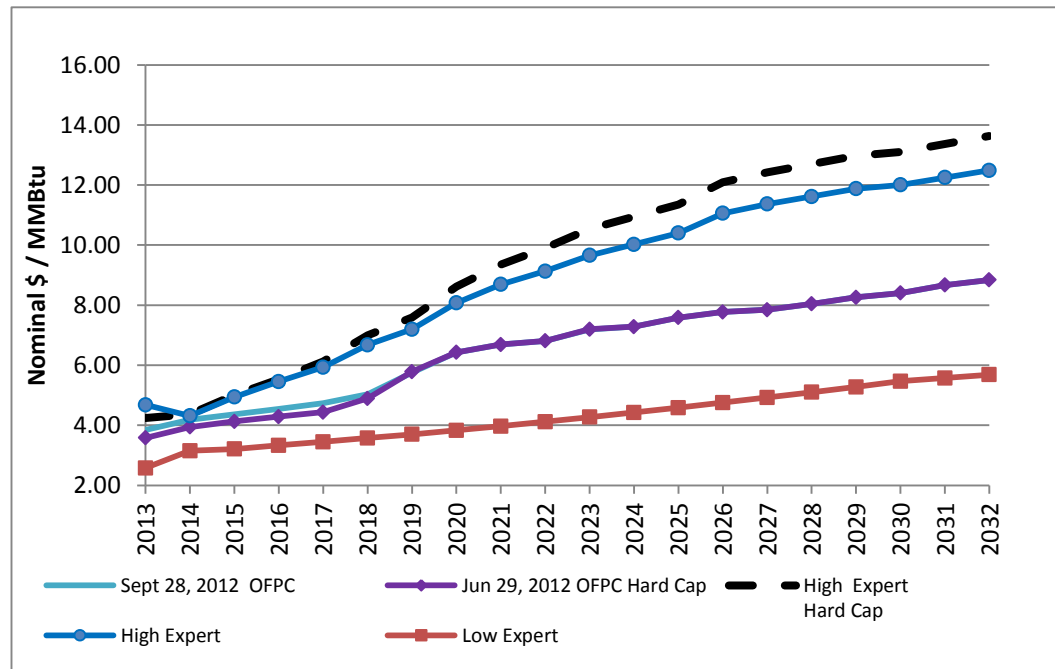
The CO₂ tax studies were developed September 2012. The supporting expert third-party high and low natural gas price scenarios were issued August 2012 while the base price forecast reflects PacifiCorp’s September 2012 OFPC. Again, the OFPC is composed of market forwards for the first 72 months, followed by 12 months of blended prices which transition into an expert third-party fundamentals forecast, starting in month 85.

Table 7.8 shows prices at the Henry Hub benchmark for the five underlying natural gas price forecasts. The forecasts serve as a point of reference and are adjusted to account for changes in natural gas demand driven by a range of environmental policy and technology assumptions specific to each IRP case. Figure 7.9 compares the five underlying Henry Hub price forecasts used in the 2013 IRP.

Table 7.8 – Underlying Henry Hub Natural Gas Price Forecast Summary (Nominal \$/MMBtu)

Forecast Name	2013	2015	2020	2025	2032
High (Tax Scenario)	\$4.68	\$4.94	\$8.07	\$10.40	\$12.49
Base (Tax Scenario)	\$3.84	\$4.37	\$6.43	\$7.59	\$8.84
Low (Tax Scenario)	\$2.58	\$3.21	\$3.83	\$4.59	\$5.68
High (Hard Cap Scenario)	\$4.24	\$5.01	\$8.61	\$11.35	\$13.63
Base (Hard Cap Scenario)	\$3.58	\$4.13	\$6.43	\$7.59	\$8.84

Figure 7.9 – Underlying Henry Hub Natural Gas Price Forecast Summary (Nominal \$/MMBtu)



Price Projections Tied to the High Forecast

The driving assumption of the underlying high-price scenario is that of high oil prices. Outside of power generation, which was quick to respond to lower gas prices in 2012, the bulk of new demands will come later in the decade as liquefied natural gas (LNG) export facilities come online. Currently, the Cheniere Sabin Pass LNG export terminal is expected to be online in 2015 with other export terminals awaiting approval from the Federal Energy Regulatory Commission (FERC). Asian buyers are particularly attracted to Gulf Coast and East Coast export facilities since the LNG is more likely to be indexed to the price of Henry Hub (versus oil). Increased industrial demands are also expected to materialize later in the decade from the petrochemical, fertilizer, steel, and transportation sectors. Volumes expected to move into the transportation sector are particularly significant and will exert upward price pressure in the early 2020’s. Moreover, the underlying high price scenarios assume that global shale development will be lagging. The lagging of global shale development helps keep natural gas pegged to oil prices (abroad) which, in turn, provides support to the US LNG export industry. Figure 7.10 summarizes prices at the Henry Hub benchmark and Figure 7.11 summarizes the accompanying electricity prices for the forecasts developed around the high gas price projection.

Figure 7.10 – Henry Hub Natural Gas Prices Derived from the High Underlying Forecast

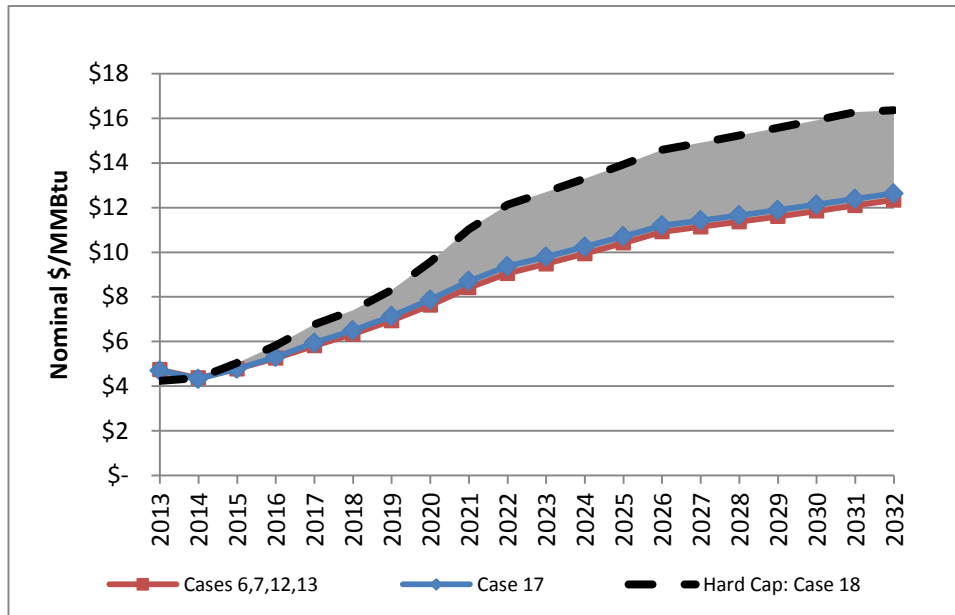
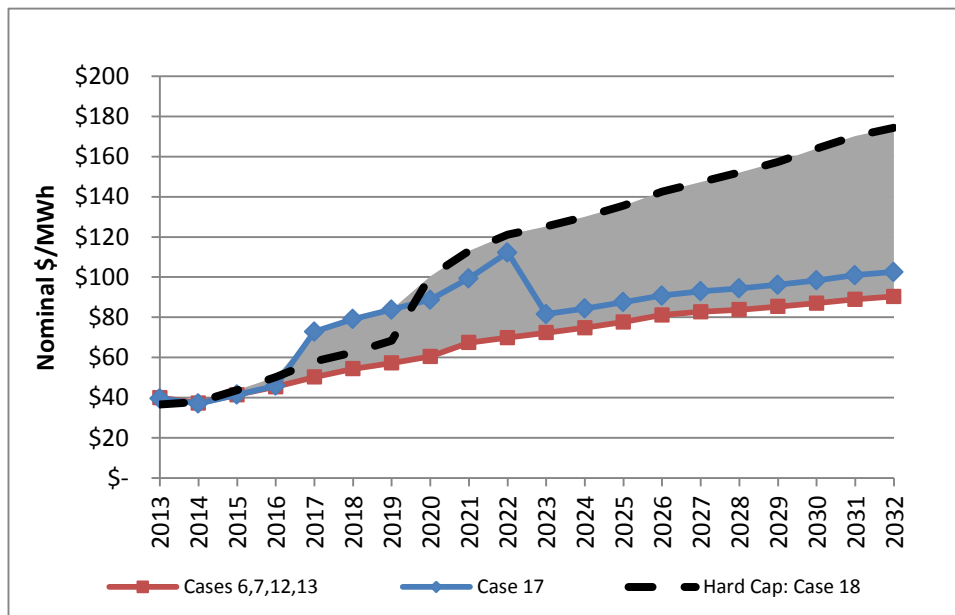


Figure 7.11 – Western Electricity Prices from the High Underlying Gas Price Forecast



Price Projections Tied to the Medium Forecast

The underlying September 2012 medium gas price forecast is also PacifiCorp’s OFPC and, as such, is composed of market forwards for the first 72 months, followed by 12 months of blended prices which transition into an expert third-party fundamentals forecast, starting in month 85. The expert third-party fundamentals forecast component was issued May 2012. The market portion of the forecast is based upon forwards as of market close September 28, 2012.

The medium gas scenario reflects a strong, but tempered, long-term demand for natural gas partially offset by increasing supply volumes resulting from new shale plays, increased well

productivity, and rig efficiencies. While associated gas, from wet plays, has filled a large part of the void left by re-directed dry gas drilling, volumes are beginning to decline. To incent new dry gas drilling, prices will need to rise.

On the demand side, increased industrial loads are expected to materialize later in the decade from the petrochemical, fertilizer, steel, and transportation sectors. Like the high case, long-term demand increases are expected from the LNG export and transportation sectors however at a slower pace due to the lengthy approval process. Environmental restrictions on shale plays are expected to increase costs but not to the point of disrupting or adversely impacting supply. In short, the medium scenario assumes the continuance of prolific liquids plays producing significant amounts of price insensitive associated gas. However, going forward, quantities of associated gas cannot fully compensate for the lack of dry gas production. Thus, upward price pressure is forthcoming as decreased associated gas supply, coupled with increasing demands from the industrial, export, and transportation sectors, take hold later this decade. Figure 7.12 shows Henry Hub benchmark prices and Figure 7.13 includes the accompanying electricity prices for the forecasts developed around the medium gas price projection.

Figure 7.12– Henry Hub Natural Gas Prices Derived from the Medium Underlying Forecast

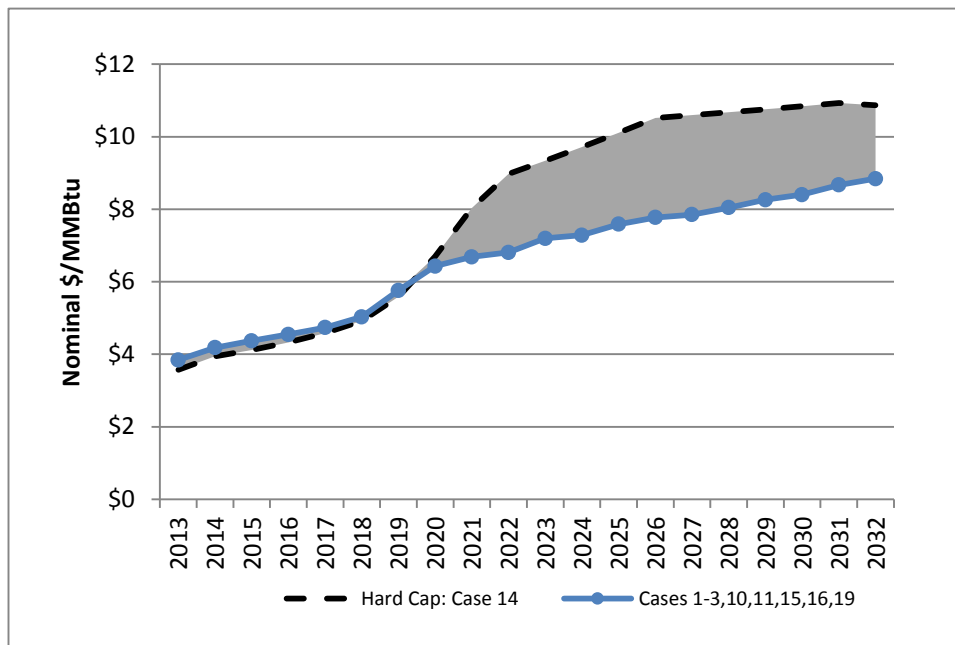
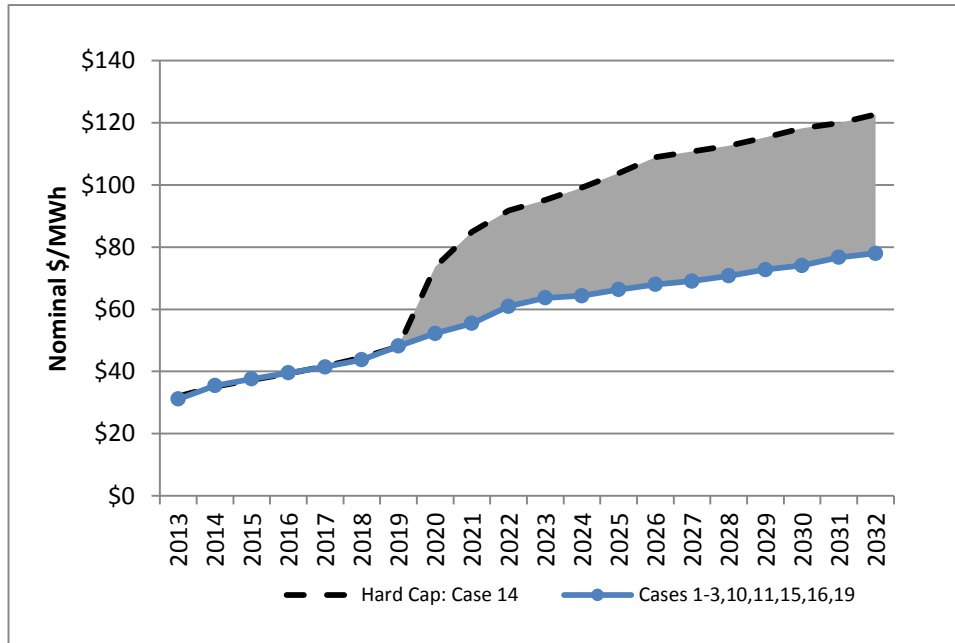


Figure 7.13 – Western Electricity Prices from the Medium Underlying Gas Price Forecast



Price Projections Tied to the Low Forecast

The low price is driven by excess gas supply and dampened demand (arising from moderated oil prices). On the supply side, increasing well productivity, technological innovations, and large volumes of price-insensitive associated gas create a flattened supply curve. Third party providers have reduced low price projections as base case forecasts have fallen to reflect continued improvements in well productivity and the large amount of price insensitive dry gas being produced as a byproduct in wet gas and shale oil plays. Even today, one-third of associated dry gas is being flared in the Bakken oil shale fields.

Under the low price assumptions, demand is tempered by limited natural gas use in both the transportation and LNG export sectors; no LNG export growth is assumed post 2020. Under this scenario, there is little incentive to invest in LNG export facilities or in gas-for-oil substitution in the transportation sector due to moderated oil prices. Moderate oil prices are attributed to the surge of U.S. shale liquids coming online. This is in keeping with expectations from both Exxon Mobile and the Energy Information Administration (EIA). Exxon Mobile’s latest outlook expects the U.S. to be a net energy exporter by 2025 while the EIA expects U.S. gas production to outpace demand by 2020⁶⁴. By 2030, the low price scenario assumes that over 19 million barrels per day (MMB/D) will be forthcoming from U. S. shale liquids, more than double that assumed in the high price scenario. Figure 7.14 shows Henry Hub benchmark prices and Figure 7.15 includes the accompanying electricity prices for cases built on the low price forecast in the 2013 IRP.⁶⁵

⁶⁴ Wall Street Journal, *Exxon Find: America as Net Energy Exporter*, December 11, 2012, page B1.

⁶⁵ All case definitions that assume low natural gas prices also assume high CO₂ price assumptions.

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

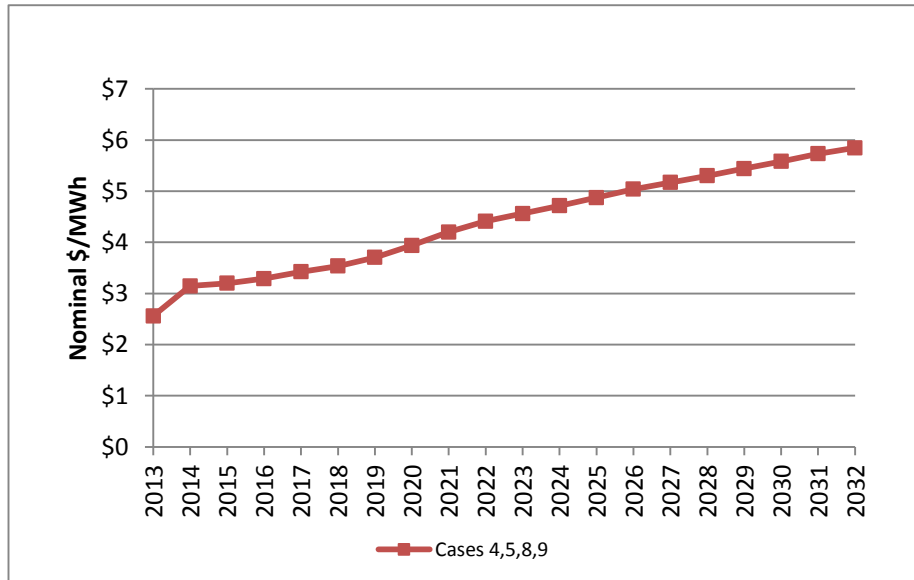
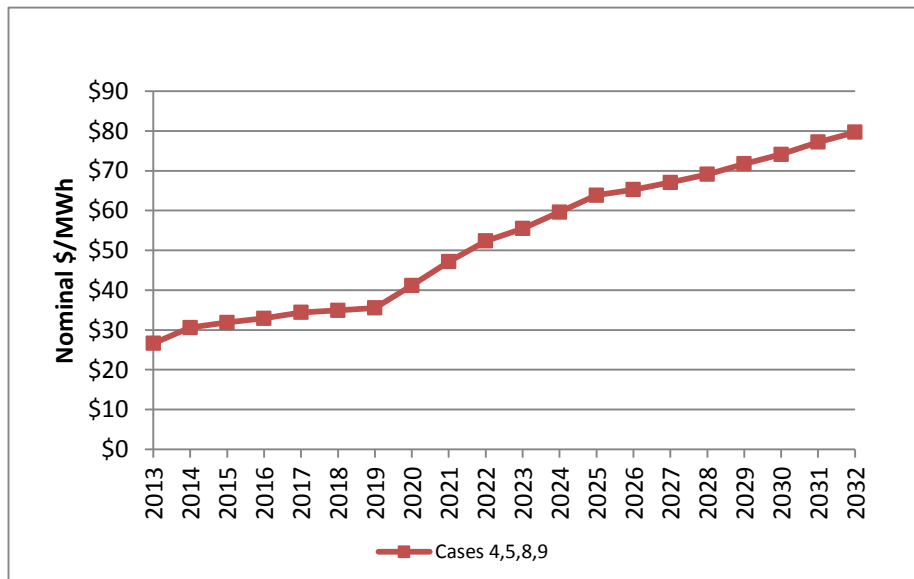


Figure 7.15 – Western Electricity Prices Derived from the Low Underlying Gas Price Forecast



Phase (3) Optimized Portfolio Development: No RPS Cases

For Phase 3 of the IRP modeling, System Optimizer is executed for each set of cases that exclude RPS requirements. These cases are completed for each of the five Energy Gateway scenarios, generating an optimized investment plan and associated real levelized PVRR for 2013 through 2032. System Optimizer simulations were first completed for these cases to identify potential renewable resources that are cost effective on a system basis. Cost effective renewable resource selections are then used to inform the next two phases of the IRP modeling process, as discussed in more detail in the following sections of this chapter.

Phase (4) Establishing a Renewable Resource Floor

For case definitions that include RPS assumptions, a minimum level of new renewable resources are needed to ensure that compliance can be achieved with specific state and/or assumed federal RPS requirements. This is achieved using an RPS compliance tool called the RPS Scenario Maker model. The RPS Scenario Maker model was introduced to the 2013 IRP modeling process in response to changing policy and market drivers that have effectively lowered the cost effectiveness of new renewable resource alternatives. These policy and market drivers are summarized below:

- Policy makers continue to debate Federal budget deficits, and deep philosophical differences have thus far proven to be a barrier to budgetary compromise making the long-term outlook for federal tax incentives that have traditionally benefited new renewable resources uncertain. Absent tax incentives, the cost for renewable resources per unit of energy output increases.
- Policy makers have not succeeded in passing federal greenhouse gas legislation for consideration by the President. While the U.S. Environmental Protection Agency (EPA) has proposed new source performance standards to regulate greenhouse gas emissions from new sources, it has not established a definitive schedule to propose rules applicable to existing sources. With continued uncertainty in federal greenhouse gas policy, the advantages of zero emission generation resources are diminished as compared to other resource alternatives.
- Over the past two years, reduced regional loads and low natural gas prices have contributed to reduced wholesale power prices. Reduced wholesale power prices lowers the energy value of generation from new renewable resources.

Given the drivers outlined above, the economic benefits of new renewable resources have deteriorated since the 2011 IRP was produced. In response, case definitions for the 2013 IRP were strategically designed to include cases that assume there are no RPS requirements to clearly identify whether new renewable resources are cost effective system resources or whether new renewable resources are needed for the sole purpose of meeting RPS requirements. To ensure that RPS compliance obligations are satisfied among those cases with RPS assumptions, the RPS Scenario Maker model was used to develop a renewable resource floor.

The RPS Scenario Maker model uses retail sales forecast inputs, state-specific targets, state-specific banked renewable energy credit (REC) balances, forecasted generation from existing RPS-eligible renewable resources, and cost and performance assumptions for potential new resources to optimize the type, timing, and location of additional renewable resources needed to meet future RPS compliance obligations. The RPS Scenario Maker model considers compliance flexibility mechanisms specific to any given RPS program including unbundled REC rules and banking rules that cannot be configured in the System Optimizer model to establish a least cost renewable resource mix that meets RPS requirements.

There are two steps in establishing the least cost RPS resource portfolio for each case that includes RPS assumptions. First, any renewable resources selected by the System Optimizer model among those cases that do not assume RPS requirements are automatically included in the RPS renewable resource portfolio for the accompanying case that does include RPS assumptions. These resources are treated as system resources for purposes of meeting state or assumed federal

RPS requirements, whereby each state is assumed to receive their proportionate share of energy that can be used for state-specific RPS compliance obligations. Second, the RPS Scenario Maker tool, configured with constraints to meet RPS targets and to accommodate state-specific RPS banking provisions, is used to provide an optimized low cost renewable resource portfolio that achieves any remaining state or federal RPS compliance shortfall with situs assigned renewable generation.⁶⁶

Phase (5) Optimized Portfolio Development: RPS Cases

For Phase 5 of the IRP modeling, System Optimizer is executed for each set of cases that assume RPS requirements must be achieved. Each of these cases is completed for each of the five Energy Gateway scenarios, generating an optimized investment plan and associated real levelized PVRR for 2013 through 2032. The System Optimizer modeling process used in this phase of IRP modeling is identical to the System Optimizer modeling performed in Phase 3 (cases that exclude RPS assumptions) with the exception that a renewable resource floor that meets RPS compliance obligations is forced into the resource portfolio. Forcing the renewable resource floor into the System Optimizer resource expansion plan does not preclude the selection of additional renewable resources above and beyond the minimum threshold that is required to achieve RPS compliance.

Phase (6) Monte Carlo Production Cost Simulation

Phase 6 of the IRP modeling entails simulation of each optimized portfolio from Phases 3 and 5 using the PaR model in stochastic mode. The stochastic simulation produces a dispatch solution that accounts for chronological commitment and dispatch constraints. Three stochastic simulations were executed for three CO₂ tax levels: zero, medium (starting at \$16/ton in 2022 and escalating to approximately \$26/ton in 2032), and high (starting at approximately \$14/ton and escalating to approximately \$75/ton by 2032). All simulations used medium natural gas and wholesale power prices from the September 2012 OFPC as the expected gas and electricity price forecast values.

The PaR simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability for new resources. Availability of wind generation is not modeled with stochastic parameters in the PaR model; however, the incremental reserve requirements associated with uncertainty and variability in wind generation are captured in the stochastic simulation. PacifiCorp's wind integration study is included in Appendix H in Volume II of this report.

For stochastic analysis, PacifiCorp completed simulation of 37 portfolios produced by 18 core cases under Energy Gateway Scenario 1 and 19 core cases produced under Energy Gateway Scenario 2 using the PaR production cost model among three CO₂ price levels to yield 111 portfolio risk studies. The sensitivity cases developed for the 2013 IRP are informative in reporting the impact of isolated changes of inputs on the portfolio selection itself, and therefore, these cases were not studied in the PaR model.

⁶⁶ Given the relatively small size of the California RPS compliance need and no restrictions that limit the use of unbundled RECs, it is assumed that California RPS compliance obligations are met with unbundled REC purchases.

The Stochastic Model

The stochastic model used in the PaR model is a two-factor (short-run and long-run) short-run mean reverting model. Variable processes assume normality or log-normality as appropriate. Since prices and loads are bounded on the low side by zero they tend to take on a lognormal shape. Thus, prices, especially, are described as having a lognormal distribution (i.e. having a positively skewed distribution while their \log_e has more of a normal distribution). Load growth is inherently more bounded on the upside than prices, and can therefore be modeled as having a normal or lognormal distribution. As such, prices and loads were treated as having a lognormal and normal distribution, respectively.

Separate volatility and correlation parameters are used for modeling the short-run and long-run factors. The short-run process defines seasonal effects on forward variables, while the long-run factor defines random structural effects on electricity and natural gas markets and retail load regions. The short-run process is designed to capture the seasonal patterns inherent in electricity and natural gas markets and seasonal pressures on electricity demand.

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

Stochastic Model Parameter Estimation

Stochastic model parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. Loads and commodity prices are mean-reverting in the short term. For instance, natural gas prices are expected to “hover” around a moving average within a given month and loads are expected to hover near seasonal norms. These built-in responses are the essence of mean reversion. The mean reversion rate tells how fast a forecast will revert to its expected mean following a shock. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. Consistent with the last IRP, PacifiCorp did not apply the long run load volatility parameter in this IRP.

Long-term volatility of natural gas and electricity prices is estimated using the standard error of a random walk regression of historic price data, by market. The resulting parameters are then used in the PaR model to develop alternative price scenarios around the Company’s official forward price curves, by market, over the twenty-year IRP study period. The long-run regression errors are correlated to capture inter-variable effects from changes to expected market equilibrium for natural gas and electricity markets, as well as the impacts from changes in expected regional electricity loads.

PacifiCorp’s econometric analysis was performed for the following stochastic variables:

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

Table 7.9 summarizes the 2013 IRP short-term load parameters, which were adopted from the 2008 IRP, as compared to the parameters used in the 2011 IRP. The 2008 IRP parameters were adopted having observed unreasonably large swings in loads using the 2011 IRP data. The Company anticipates re-estimating its short-term load parameters for its 2015 IRP. Natural gas and electricity price correlations by delivery point, as shown in Table 7.10, are the same as those developed for the 2007 IRP.

Table 7.9 – Short Term Load Stochastic Parameter Comparison, 2013 IRP vs. 2011 IRP

Short-term Volatility	Idaho	Utah	Washington	Oregon	Wyoming
Winter 2013 IRP	0.041	0.026	0.051	0.041	0.025
Spring 2013 IRP	0.051	0.028	0.038	0.032	0.022
Summer 2013 IRP	0.054	0.045	0.053	0.038	0.019
Fall 2013 IRP	0.046	0.036	0.040	0.043	0.019
Winter 2011 IRP	0.045	0.028	0.044	0.043	0.021
Spring 2011 IRP	0.038	0.037	0.043	0.044	0.017
Summer 2011 IRP	0.040	0.040	0.051	0.041	0.017
Fall 2011 IRP	0.040	0.036	0.046	0.042	0.019
Short-term Mean Reversion	Idaho	Utah	Washington	Oregon	Wyoming
Winter 2013 IRP	0.27	0.23	0.24	0.26	0.13
Spring 2013 IRP	0.05	0.09	0.19	0.16	0.10
Summer 2013 IRP	0.08	0.14	0.23	0.28	0.08
Fall 2013 IRP	0.23	0.17	0.20	0.18	0.10
Winter 2011 IRP	0.19	0.10	0.18	0.16	0.07
Spring 2011 IRP	0.02	0.16	0.24	0.21	0.10
Summer 2011 IRP	0.02	0.10	0.24	0.20	0.07
Fall 2011 IRP	0.03	0.08	0.11	0.11	0.05

Table 7.10 – Price Correlations

Winter						
	Nat Gas - East	Four Corners	COB	Mid-Columbia	Palo Verde	Nat Gas - West
Nat Gas - East	1.000	0.304	0.386	0.277	0.371	0.835
Four Corners	0.304	1.000	0.592	0.784	0.817	0.299
COB	0.386	0.592	1.000	0.634	0.564	0.492
Mid-Columbia	0.277	0.784	0.634	1.000	0.811	0.312
Palo Verde	0.371	0.817	0.564	0.811	1.000	0.364
Nat Gas - West	0.835	0.299	0.492	0.312	0.364	1.000

Spring						
	Nat Gas - East	Four Corners	COB	Mid-Columbia	Palo Verde	Nat Gas - West
Nat Gas - East	1.000	0.085	0.034	(0.131)	0.105	0.281
Four Corners	0.085	1.000	0.559	0.459	0.787	0.025
COB	0.034	0.559	1.000	0.770	0.468	0.067
Mid-Columbia	(0.131)	0.459	0.770	1.000	0.540	(0.059)
Palo Verde	0.105	0.787	0.468	0.540	1.000	(0.035)
Nat Gas - West	0.281	0.025	0.067	(0.059)	(0.035)	1.000

Summer						
	Nat Gas - East	Four Corners	COB	Mid-Columbia	Palo Verde	Nat Gas - West
Nat Gas - East	1.000	0.115	0.074	0.002	0.101	0.908
Four Corners	0.115	1.000	0.705	0.699	0.917	0.132
COB	0.074	0.705	1.000	0.809	0.734	0.117
Mid-Columbia	0.002	0.699	0.809	1.000	0.696	0.013
Palo Verde	0.101	0.917	0.734	0.696	1.000	0.126
Nat Gas - West	0.908	0.132	0.117	0.013	0.126	1.000

Fall						
	Nat Gas - East	Four Corners	COB	Mid-Columbia	Palo Verde	Nat Gas - West
Nat Gas - East	1.000	0.156	0.233	0.142	0.182	0.795
Four Corners	0.156	1.000	0.458	0.719	0.921	0.244
COB	0.233	0.458	1.000	0.446	0.467	0.299
Mid-Columbia	0.142	0.719	0.446	1.000	0.740	0.160
Palo Verde	0.182	0.921	0.467	0.740	1.000	0.281
Nat Gas - West	0.795	0.244	0.299	0.160	0.281	1.000

Table 7.11 lists short term volatility and mean reversion parameters for hydro generation that were re-estimated for the 2013 IRP based on updated historical hydro generation data, which covered calendar years 2003 through 2012.

Table 7.11 - Hydro Short Term Stochastic Parameter Comparison, 2011 IRP vs. 2013 IRP

	Short-term Volatility	Short-term Mean Reversion
2013 IRP	0.130	0.100
Winter 2011 IRP	0.0826	0.2901
Spring 2011 IRP	0.0739	0.2072
Summer 2011 IRP	0.0744	0.2263
Fall 2011 IRP	0.0901	0.2931

For outage modeling, PacifiCorp relies on the PaR model’s Monte Carlo simulation method to create a distributed outage pattern for thermal resources. PacifiCorp does not estimate stochastic parameters for plant outages. Due to the true randomness of forced outages the Monte Carlo is the preferred mode of operation for obtaining results of multi-iteration Monte Carlo quality. While average historical and/or technology-specific outage rates are specified by the user the timing and duration of outages is random.

Monte Carlo Simulation

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

The PaR model is configured to conduct 100 Monte Carlo iterations for the 20-year study period. For each of the 100 Monte Carlo iterations, the PaR model generates a set of natural gas prices, electricity prices, loads, hydroelectric generation and thermal outages. Then, the model optimizes the dispatch of resources to minimize costs to serve load and wholesale sales obligations subject to operating and physical constraints, one of which is a fixed capacity expansion plan. The end result of the Monte Carlo simulation is 100 production cost iterations reflecting a wide range of portfolio cost outcomes.

For the 37 portfolios produced by the core case assumptions analyzed in Planning and Risk, the stochastic simulation utilizes medium electricity and natural gas price forecasts, regardless of the inputs used in the System Optimizer model to produce a given portfolio. Figures 7.16 through 7.19 show the 100-iteration frequencies for market prices resulting from the Monte Carlo draws for two representative years, 2013 and 2022, and by the east and west side of PacifiCorp’s system. Figures 7.20 through 7.25 show annual loads by load areas and the system for the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles. Figure 7.26 shows the 25th, 50th, and 75th percentiles for hydroelectric generation.

Figure 7.16 – Frequency of Western (Mid-Columbia) Electricity Market Prices for 2013 and 2022

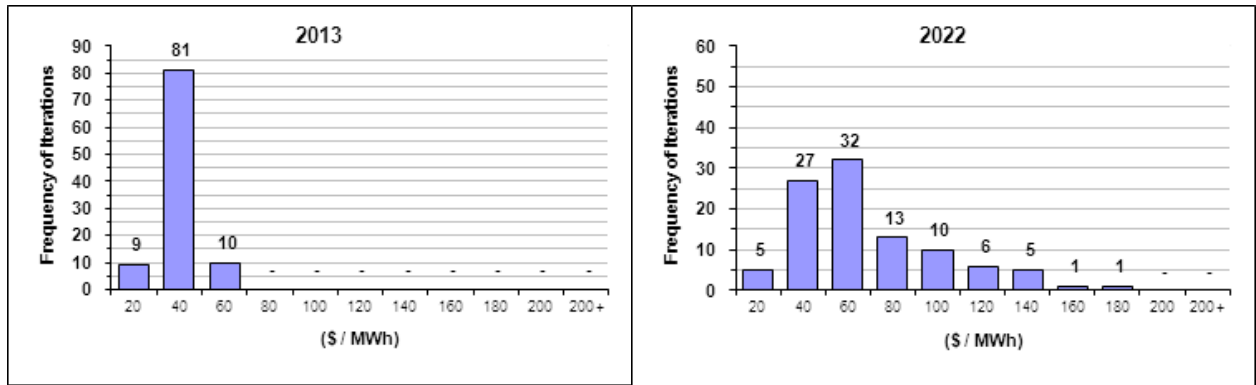


Figure 7.17 – Frequency of Eastern (Palo Verde) Electricity Market Prices, 2013 and 2022

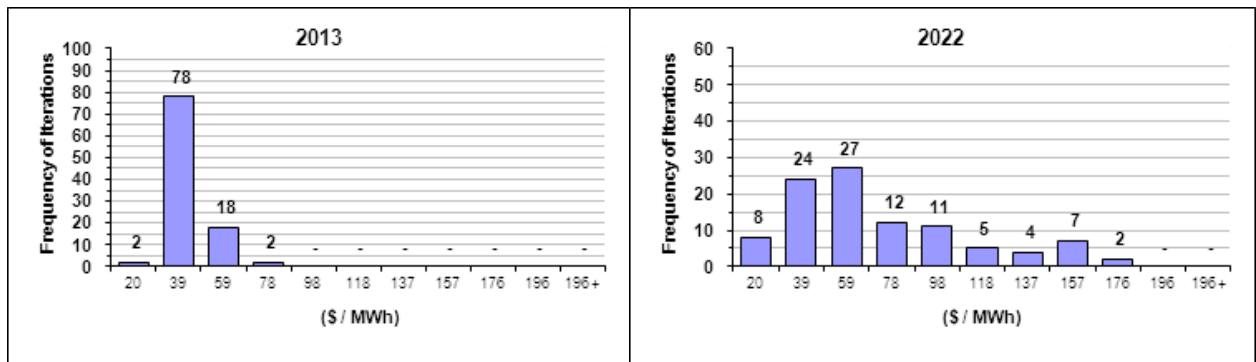


Figure 7.18 – Frequency of Western Natural Gas Market Prices, 2013 and 2022

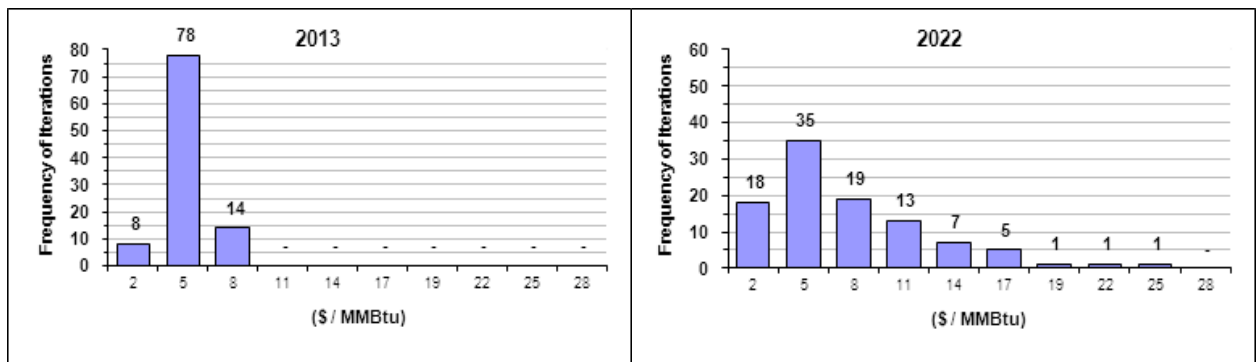


Figure 7.19 – Frequency of Eastern Natural Gas Market Prices, 2013 and 2022

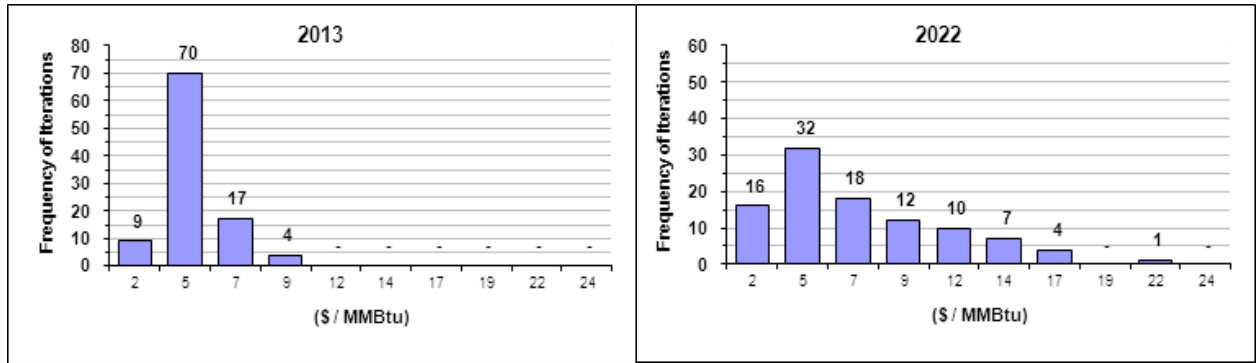
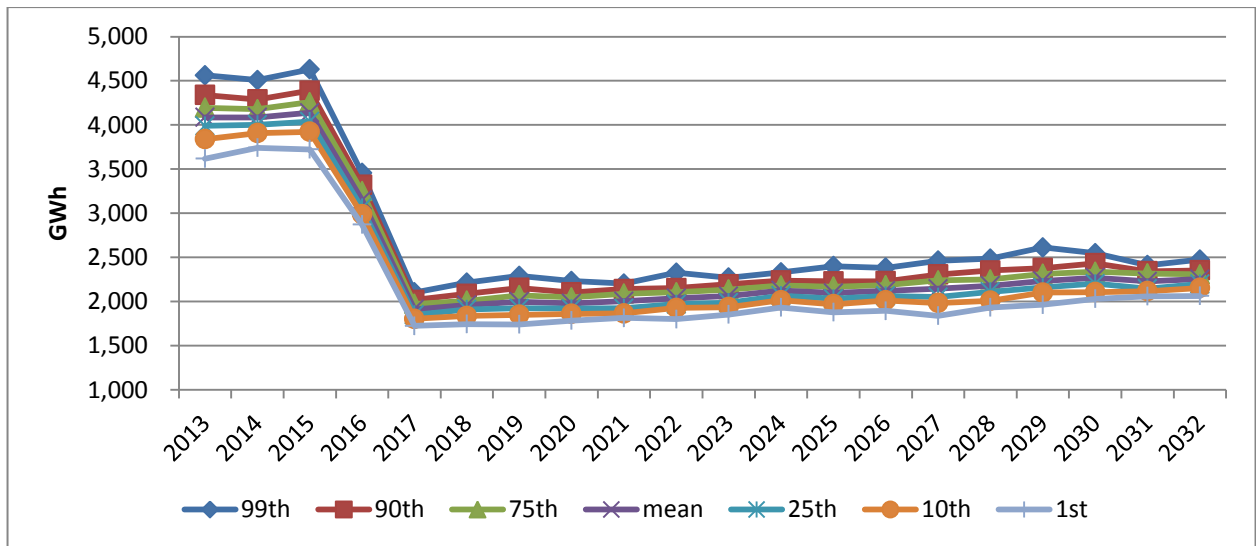


Figure 7.20 – Frequencies for Idaho (Goshen) Loads



Note: the drop in Idaho (Goshen) load from 2015 to 2017 is due to the expiration of a wholesale contract, under which PacifiCorp serves the retail load of the third party.

Figure 7.21 – Frequencies for Utah Loads

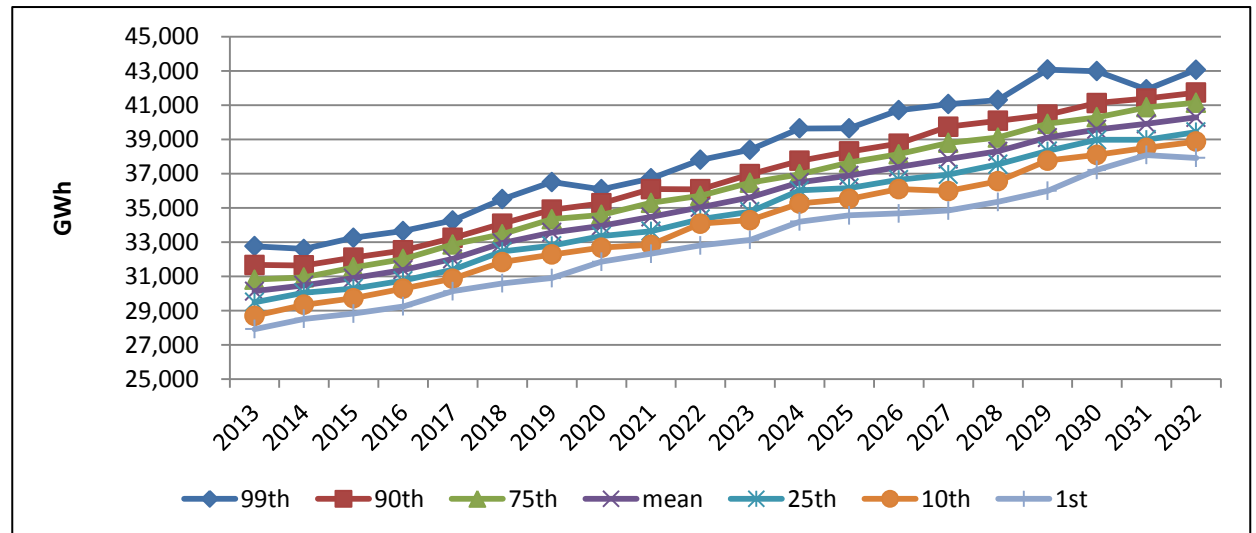


Figure 7.22 – Frequencies for Washington Loads

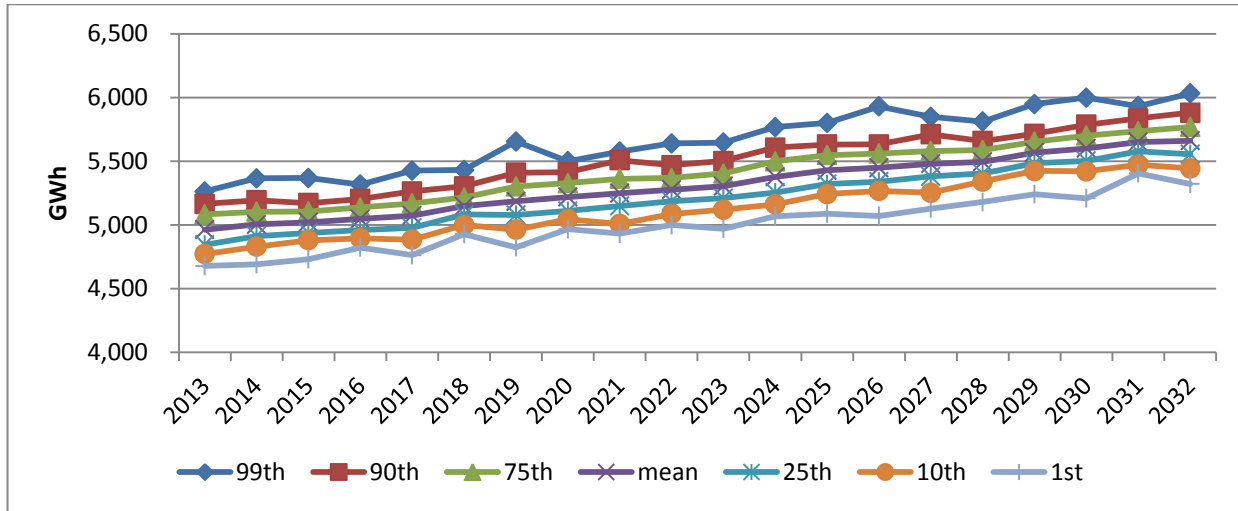


Figure 7.23 – Frequencies for California and Oregon Loads

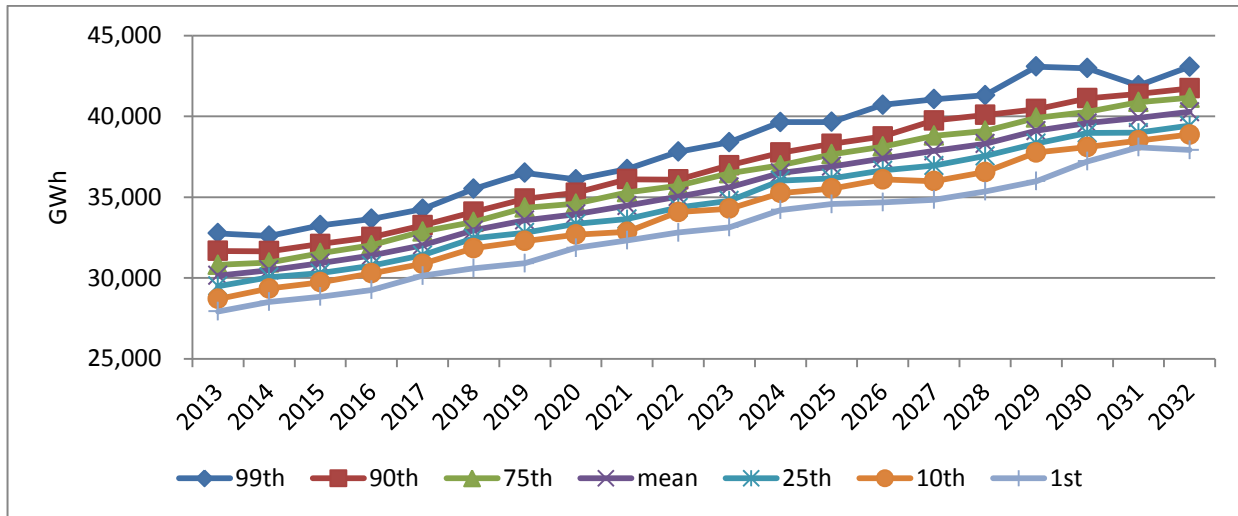


Figure 7.24 – Frequencies for Wyoming Loads

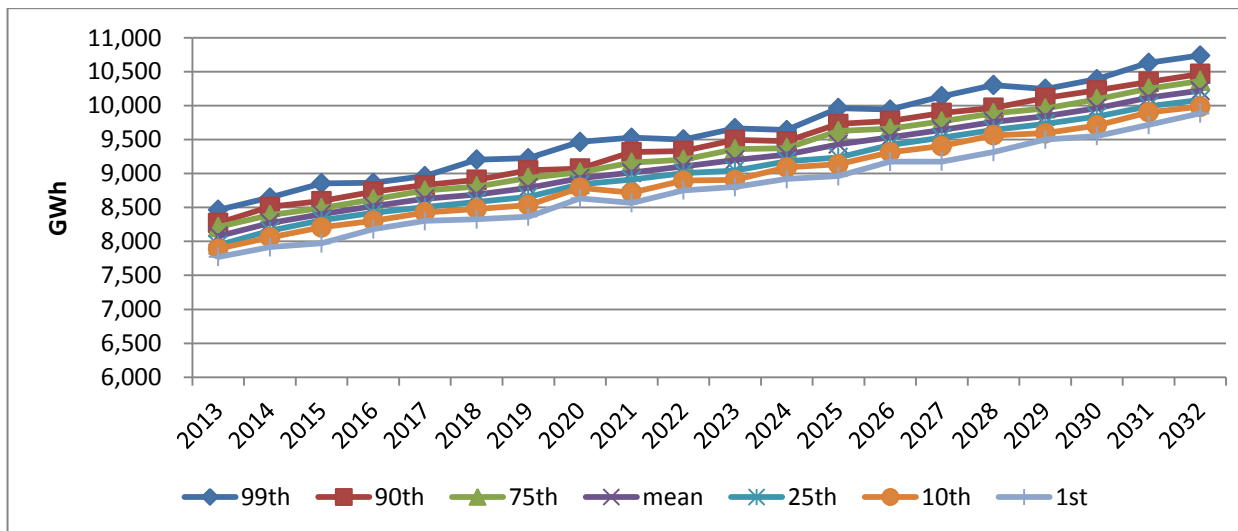


Figure 7.25 – Frequencies for System Loads

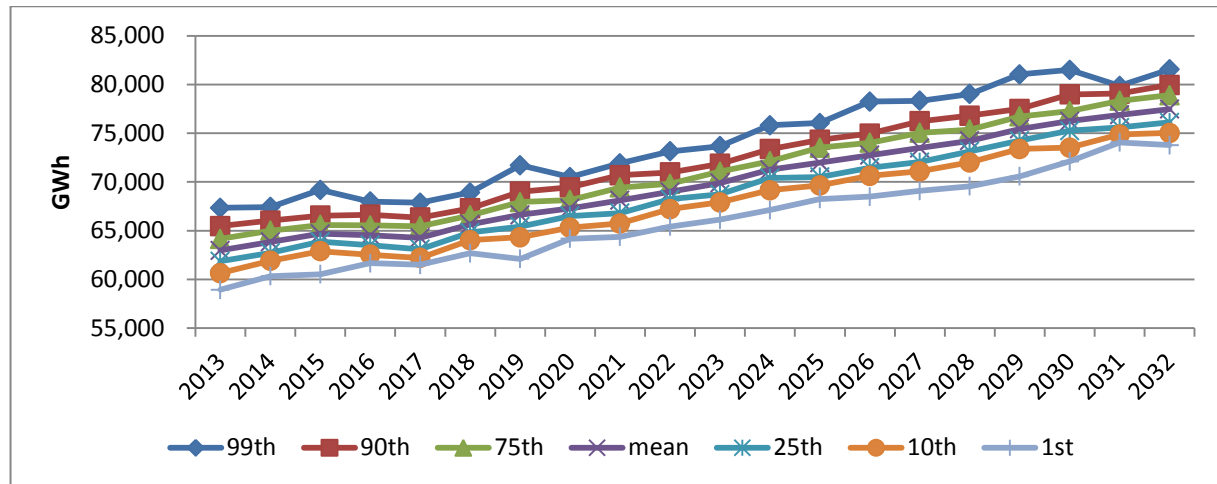
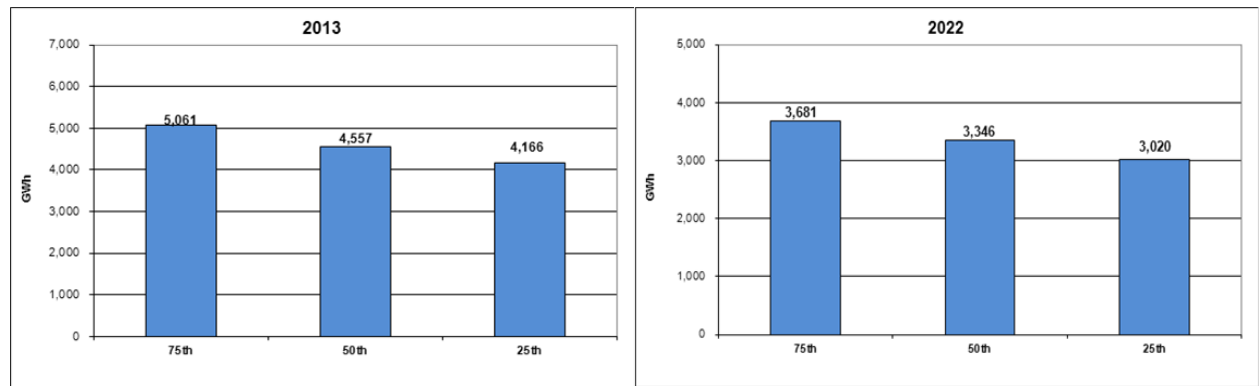


Figure 7.26 – Hydroelectric Generation Frequency, 2013 and 2022



The expected values of the Monte Carlo simulation are the average results of all 100 iterations. Results from subsets of the 100 iterations are also summarized to signify particularly adverse cost conditions, and to derive associated cost measures as indicators of high-end portfolio risk. These cost measures, and others are used to assess portfolio performance, and are described in the next section.

Stochastic Portfolio Performance Measures

Stochastic simulation results for the optimized portfolios are 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 PVRR (Present Value of Revenue Requirement)
- Risk-adjusted mean PVRR
- 20-year customer rate impact

Risk

- Upper-tail Mean PVRR less stochastic mean PVRR
- 5th and 95th Percentile PVRR

Supply Reliability

- Average annual Energy Not Served (ENS)
- Upper-tail ENS

In addition to these stochastic measures, PacifiCorp also considers resource diversity and the CO₂ emissions when comparing portfolios.

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

Stochastic Mean PVRR

The stochastic mean PVRR for each portfolio is the average of the portfolio's net variable operating costs for 100 iterations of the PaR model in stochastic mode, combined with the real levelized capital costs and fixed costs determined by the System Optimizer model. The PVRR is reported in 2012 dollars.

The net variable cost from the stochastic simulations, expressed as a net present value, includes system costs for fuel, variable plant O&M, unit start-up, market contracts, spot market purchases and sales, and costs associated with making up for generation deficiencies, referred to as energy not served. The capital additions for new resources (both generation and transmission) are calculated on an escalated "real-levelized" basis to appropriately handle investment end effects. Other components in the stochastic mean PVRR include renewable PTCs, where applicable, and emission externality costs, such as costs associated with CO₂ emissions.

The PVRR measure captures the total resource cost for each portfolio, including externality costs in the form of CO₂ costs. Total resource cost includes all the costs to the utility and customer for the variable portion of total system operations, capital requirements and fixed costs as evaluated in this IRP.

Risk-adjusted Mean PVRR

Unlike a simple mean PVRR, the risk-adjusted PVRR also incorporates the expected-value cost of low-probability, expensive outcomes.⁶⁷ This measure – risk-adjusted PVRR, for short – is calculated as the stochastic mean PVRR plus five percent of the 95th percentile of the variable production cost PVRR, excluding fixed costs. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on the 100 Monte Carlo simulations conducted for each production cost run.

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

⁶⁷ Prices are assumed to take on a lognormal distribution for stochastic Monte Carlo sampling, since they are bounded on the low side by zero and are theoretically unbounded on the up side, exhibiting a skewed distribution.

Ten-year Customer Rate Impact

To derive the rate impact measures, the Company computes the percentage revenue requirement increase (annual and cumulative 10-year basis) attributable to the resource portfolio relative to a baseline full revenue requirements forecast. The year-on-year percentage change in revenue requirement is then calculated for each of the portfolios.

The IRP portfolio revenue requirement is based on the stochastic production cost results and capital costs reported for the portfolio by the System Optimizer model on real levelized basis and adjusted to nominal dollars based on the timing when new resources are selected and added to the portfolio, including investment in transmission resources.

While this approach provides a reasonable representation of projected total system revenue requirements for IRP portfolio comparison purposes, it is not intended as an accurate depiction of such revenue requirements for rate-making purposes. For example, the IRP revenue impacts assume immediate ratemaking treatment and make no distinction between current or proposed multi-jurisdictional allocation methodologies.

Upper-Tail Mean PVRR

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

95th and 5th Percentile PVRR

The 5th and 95th percentile stochastic PVRRs are also reported. These PVRR values correspond to the iteration out of the 100 that represents the 5th and 95th percentiles on the basis PVRR of production costs, respectively. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted PVRR measure. The 5th percentile PVRR is for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost for the 100 Monte Carlo simulation iterations. The production cost is expressed as a net present value for the annual costs for 2013 through 2032. This measure is included because Oregon IRP guidelines require a stochastic measure that addresses the variability of costs in addition to one that measures the severity of bad outcomes.

Average and Upper-Tail Energy Not Served

Certain iterations of a stochastic simulation will have “energy not served” or ENS.⁶⁸ Energy Not Served is a condition where there are insufficient resources available to meet load because of physical constraints or market conditions. This occurs when the iteration has one or more stochastic variables with large random shocks that prevent the model from fully balancing the system for the simulated hour, such as large load shocks and simultaneous unplanned plant outages occur in the same iteration. Consequently, ENS, when averaged across all 100 iterations, serves as a measure of the stochastic reliability risk for a portfolio's resources.

⁶⁸ Also referred to as Expected Unserved Energy, or EUE.

For reporting of the ENS statistics, PacifiCorp calculates an average annual value for 2013 through 2032 in gigawatt-hours, as well as the upper-tail ENS (average of the five iterations with the highest ENS). Only the results using the medium CO₂ tax scenario are reported, as the tax level does not have a material influence on ENS amounts. In the current IRP, ENS is priced at \$1,000/MWh consistent with a FERC imposed price cap.

Loss of Load Probability (LOLP)

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 peak load during a given interval of time.

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

Fuel Source Diversity

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

- Thermal
- Renewables
- Demand-side management

Phase (7) Top-Performing Portfolio Selection

Initial Screening

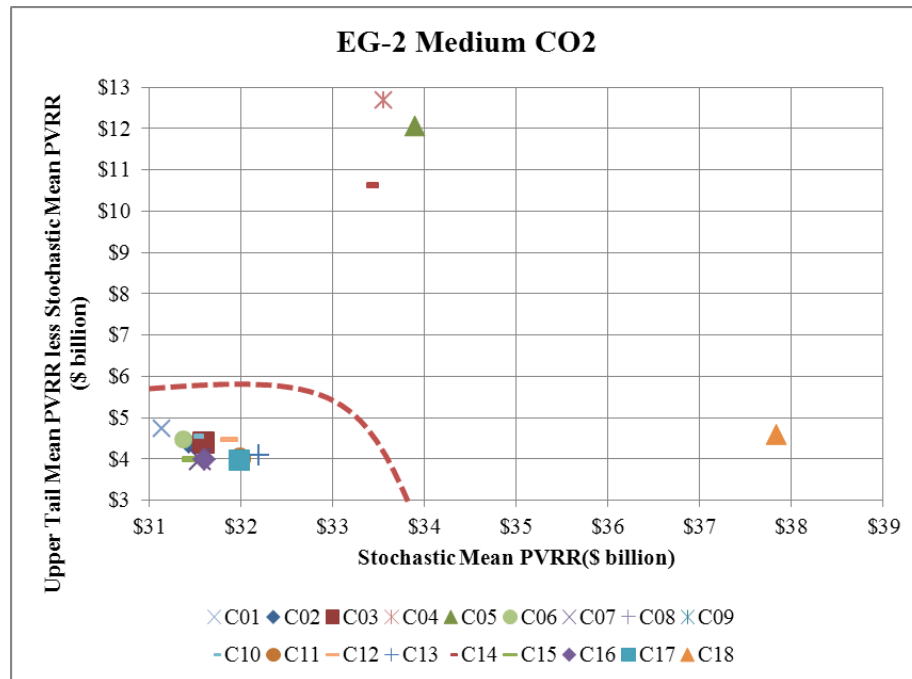
As noted earlier, PacifiCorp conducted stochastic simulations of all core cases across two Energy Gateway scenarios and three CO₂ tax levels. For preferred portfolio selection, the Company reviewed stochastic performance metrics among those core cases developed under Energy Gateway Scenarios 1 and 2. Transmission lines in Energy Gateway Scenario 1 have either already been constructed or are currently under construction. Energy Gateway Scenario 2 includes preliminary analysis using the System Operational and Reliability Benefits Tool (SBT), described in Chapter 4, supports continued pursuit of Gateway Segment D. Portfolios developed under Energy Gateway Scenarios 3 through 5 were not analyzed as candidates for the preferred portfolio. Stochastic risk analysis of Energy Gateway segments included in these scenarios will be studied in future IRPs as the SBT, described in Chapter 4, is developed for each segment.

One of the cost measures in the screening of portfolios is the system PVRR. In order for the portfolios from different Energy Gateway scenarios to be comparable, the costs of the portfolios

from Energy Gateway Scenario 2 are adjusted to reflect the benefits of Segment D as determined by the SBT that is discussed in Chapter 4.

Prior to the initial screening process, for each of the CO₂ price levels, a pre-screening was performed to remove outlier portfolios among the 36 portfolios whose mean PVRR and upper tail mean PVRR were clear cost and/or risk outliers in relation to other portfolios. Figure 7.27, which plots the upper tail risk and stochastic mean PVRR cost of candidate portfolios, illustrates how a clear delineation of cost and risk variance among portfolios can be used to exclude extreme outliers.

Figure 7.27 – Illustrative Pre-Screening to Remove Outliers



For the initial screening, PacifiCorp applied the following decision rule for identifying portfolios with the best combination of lowest mean PVRR and lowest upper-tail mean PVRR.

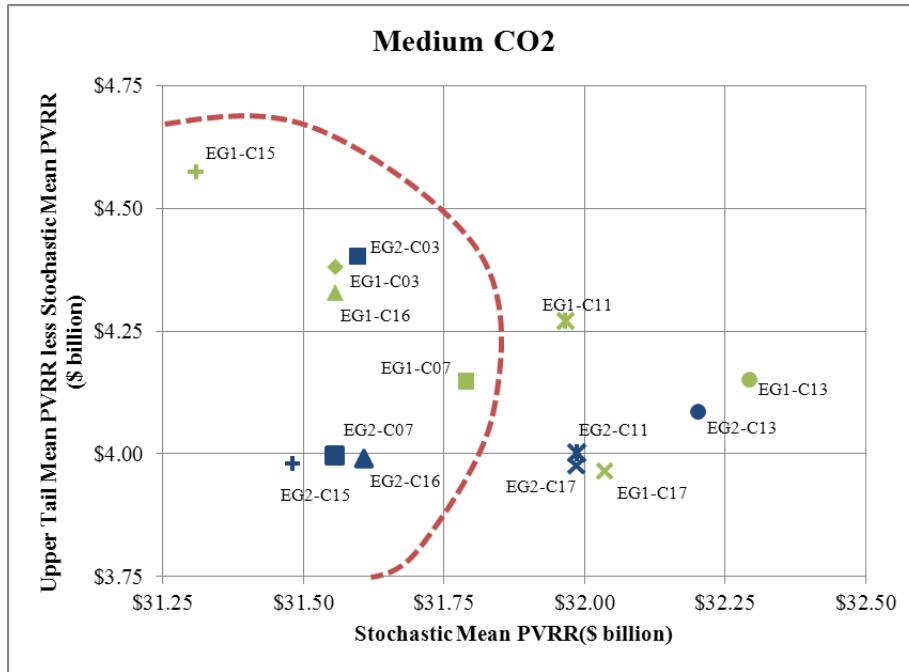
For each CO₂ tax scenario:

- Identify the portfolio with the lowest mean PVRR to establish a cost and risk threshold calculated as two percent of the least-cost portfolio;
- Identify portfolios that fall within the threshold amount as compared to the least cost portfolio;
- Identify portfolios that fall within the threshold amount as compared to the least risk portfolio, using the upper tail mean PVRR less the stochastic mean PVRR as the risk metric; then
- Select portfolios that fall within the least cost *and* least risk thresholds among any CO₂ price scenario as top performing portfolios.

The mean and upper-tail portfolio cost comparisons, as well as the top-performing portfolios, are shown graphically with the use of scatter-plot graphs. Figure 7.28 illustrates the application of

the decision rule for the medium CO₂ tax scenario results, where the dashed red curve shows the demarcation separating the lowest cost least risk portfolios.

Figure 7.28 – Illustrative Stochastic Mean vs. Upper-tail Mean PVRR Scatter-plot



Final Screening

The optimal portfolios for the three CO₂ cost scenarios plus the cost averaging view are evaluated based on the following primary criteria and measures:

- Risk-adjusted PVRR
- Carbon dioxide emissions
- Supply reliability – average annual Energy Not Served and upper-tail mean (ENS)

Phase (8): Preliminary and Final Preferred Portfolio Selection

Selection of a preliminary preferred portfolio is based upon the Company’s assessment of the criteria and measures used to summarize and rank candidate portfolios in the final screening analysis. In this phase, portfolio rankings are reviewed while considering deliverability and the core case definitions used to develop candidate portfolios. The Company also evaluates resource diversity among candidate portfolios, looking at both capacity and energy measures.

Final selection is made after performing additional analysis, as required, on the preliminary preferred portfolio taking into consideration conclusions drawn from analyses performed throughout the modeling process. For the 2013 IRP, the Company completed additional analysis on an alternative RPS compliance strategy that informed final section of the preferred portfolio

CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Top performing portfolios developed from a range of core case definitions have consistently utilize front office transactions (FOTs) and demand side management programs to meet system capacity requirements in the first ten years of the planning periods.
- Portfolios with extensive coal retirements and coal unit gas conversions, occurring in cases defined by low natural gas prices and/or high carbon dioxide prices (CO₂), rely heavily on incremental gas resources, and are high cost and high risk as compared to portfolios that have no or limited coal retirements and coal unit gas conversions.
- In cases that do not have extensive coal retirements and coal unit gas conversions, most portfolios do not include incremental natural gas fired generation within the first ten years of the planning period. Beyond the Lake Side 2 project, which is currently under construction, the preferred portfolio does not show a need for a natural gas thermal resource until 2024.
- Cases defined without renewable portfolio standard (RPS) requirements produce portfolios that have limited utility-scale renewable resources, and cases defined with RPS requirements generally do not include incremental renewable resources beyond the minimum levels required achieve compliance with RPS targets.
- Inclusive of benefits calculated using the System Operational and Reliability Benefits Tool (SBT), top performing portfolios containing renewable resources that achieve compliance with RPS requirements perform better under Energy Gateway Scenario 2, which includes the Windstar-Populus project, when compared to portfolios developed under Energy Gateway Scenario 1.
- PacifiCorp’s preferred portfolio includes the resources identified in the following table:

Resource	Installed Capacity, MW																				Total
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Expansion Options																					
Gas - CCT	-	645	-	-	-	-	-	-	-	-	-	423	-	-	-	661	-	1,084	-	-	2,813
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181	362
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	70	67	67	69	66	63	54	57	56	1,593
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	19	88	-	-	193
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	650
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	15	15	15	15	15	15	15	15	15	293
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	21
Front Office Transactions	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246	n/a
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(502)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	(1,535)
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14
Total	791	1,486	802	1,102	1,218	1,315	1,427	1,515	1,287	1,431	1,511	2,054	1,606	1,509	1,640	1,648	1,639	1,685	1,281	1,500	

Introduction

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

Discussion of the portfolio evaluation results falls into the following two main sections.

- Preferred Portfolio Selection – This section covers: (1) core case portfolio results, (2) stochastic production cost modeling results for these portfolios, (3) portfolio screening results, (4) evaluation of the top-performing portfolios, and (5) preferred portfolio selection.
- Portfolio Sensitivity Analysis – This section covers development and a comparative analysis of sensitivity case portfolios to core case portfolios.

Preferred Portfolio Selection

Core Case Portfolio Results

The preferred portfolio selection process began with the development of resource portfolios using the System Optimizer model. There are 19 core cases under each of the Energy Gateway scenarios.⁶⁹ Figures 8.1 to 8.5 represent the cumulative capacity additions by resource type for each of the core case portfolios and under the five Energy Gateway scenarios during the study period of 2013 to 2032. The detailed resource portfolio tables are included in Appendix K, along with present value of revenue requirement (PVRR) results. Comparison of the resource portfolios supports the following observations:

- Through the 20 year planning period, resource portfolios have stable levels of front office transactions (FOTs) and demand side management (DSM) resources, indicating selection of these resource types are cost effective among a wide range of scenarios.
- Except for those scenarios with core case assumptions that yield extensive coal unit retirements and gas conversions, natural gas resource additions are stable and not required until the latter years of the planning horizon.
- Core case definitions with low natural gas prices and/or high CO₂ prices produced portfolios with large scale early coal unit retirements and natural gas conversions that create an increased capacity need largely satisfied with incremental gas resource additions.
- Over the 20-year planning horizon, resource selections, while not identical, are similar among the different Energy Gateway scenarios. The type and timing of new renewable resources among cases with renewable portfolio standard (RPS) assumptions are influenced by inclusion of Energy Gateway transmission, and are largely driven by increased access to high capacity

⁶⁹ Core case C-19, which assumes an alternative to Energy Gateway Segment D, was not analyzed under Energy Gateway Scenario 1, which does not include the Segment D project.

factor wind resources in Wyoming with the addition of the Windstar-Populus project, which is included in Energy Gateway Scenarios 2 through 5.

Figure 8.1 – Total Cumulative Capacity under Energy Gateway Scenario 1, 2013 through 2032

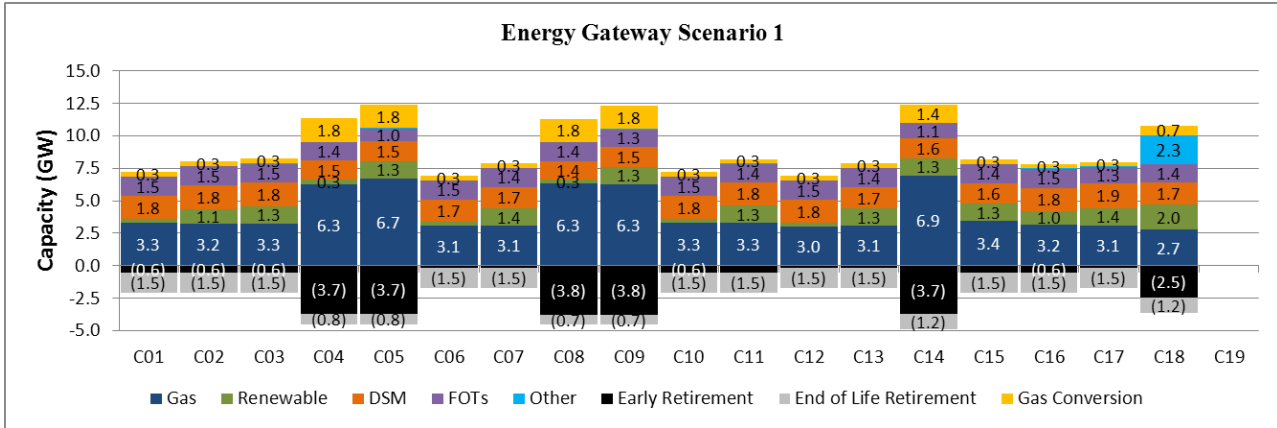


Figure 8.2 – Total Cumulative Capacity under Energy Gateway Scenario 2, 2013 through 2032

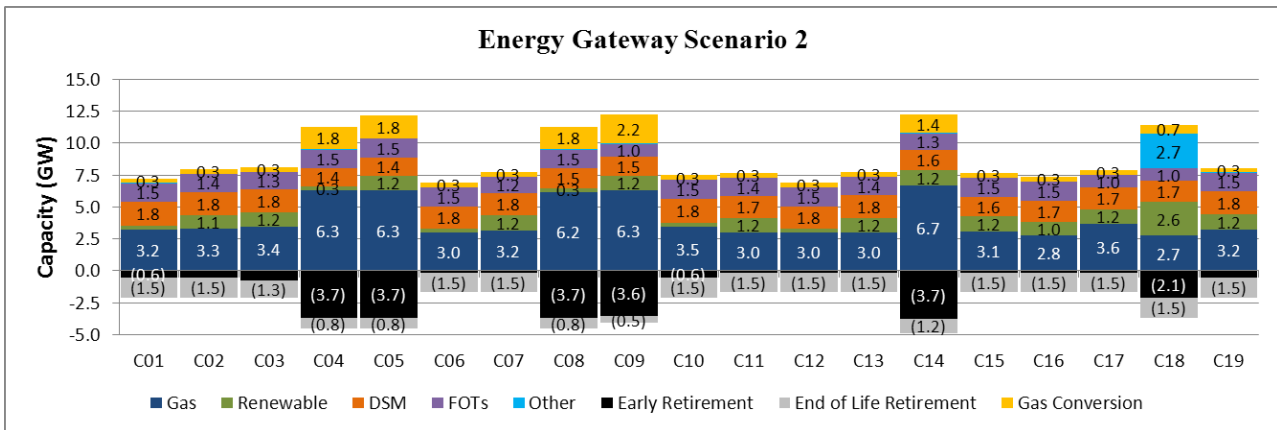


Figure 8.3 – Total Cumulative Capacity under Energy Gateway Scenario 3, 2013 through 2032

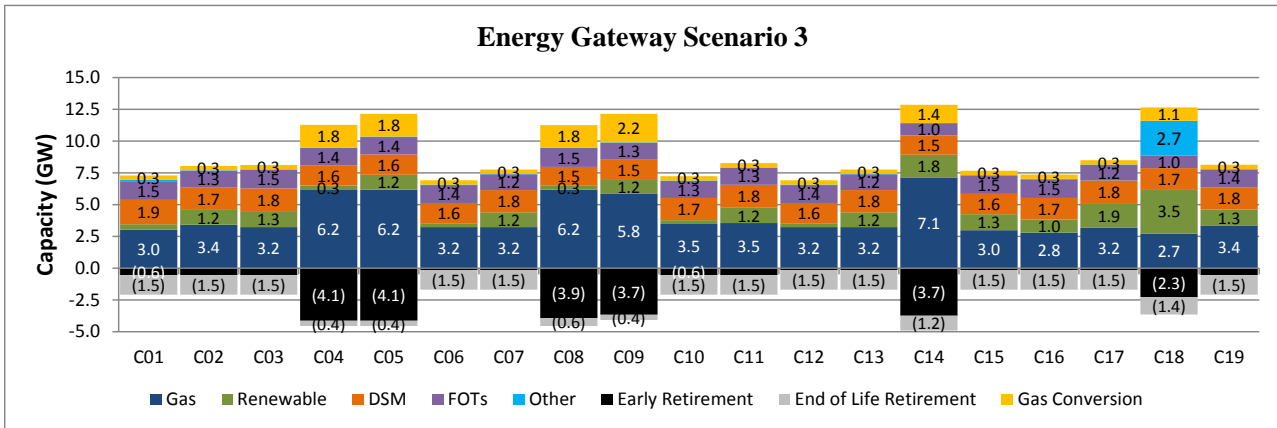


Figure 8.4 – Total Cumulative Capacity under Energy Gateway Scenario 4, 2013 through 2032

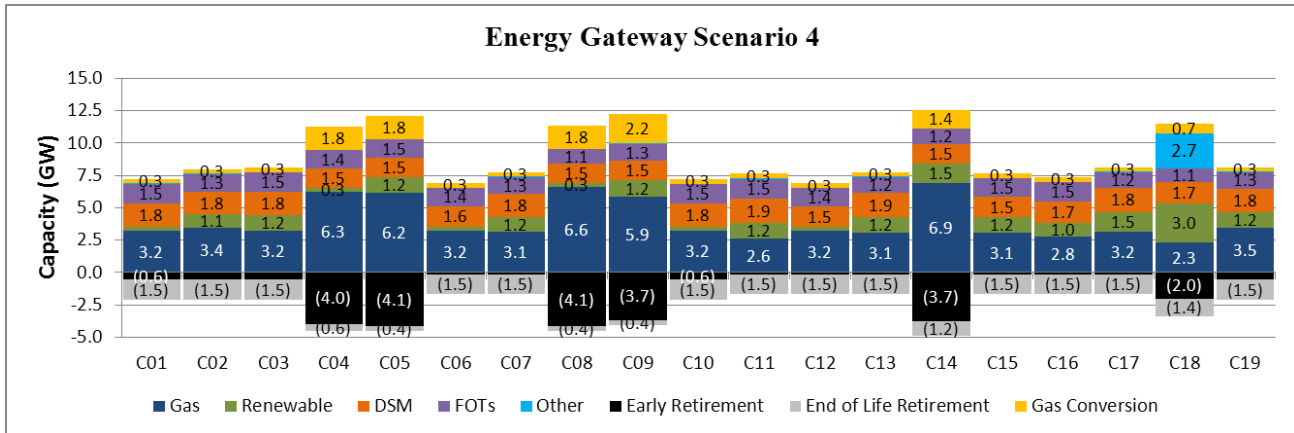
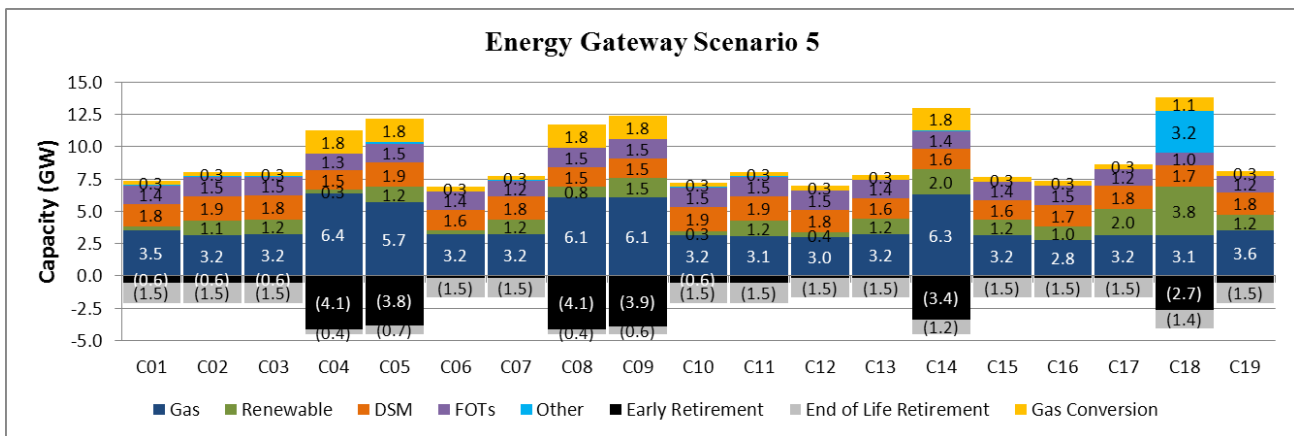


Figure 8.5 – Total Cumulative Capacity under Energy Gateway Scenarios 5, 2013 through 2032



Resource Selection by Resource Type

Gas Resources

- All portfolios include the Lake Side 2 combined cycle combustion turbine (CCCT) generating plant, which is currently under construction with a 2014 in-service date.
- There are no near-term gas-fired resources in cases defined with medium or high natural gas prices paired with medium or zero CO₂ price assumptions.
- Near-term natural gas resources are included in those portfolios where extensive coal unit retirements and natural gas conversions take place. This includes those cases with a combination of low natural gas prices, high CO₂ prices, and high coal costs (cases C04, C05, C08, and C09) and cases with U.S. hard cap CO₂ price assumptions (cases C14 and C18).
- A 2017 CCCT is included in case C17, driven by an assumed market price spike that makes FOTs more expensive.
- Gas-fired resources, added primarily in the latter half of the planning horizon among most cases, include both CCCTs in both 2x1 and 1x1 configurations with duct firing capability, and simple cycle combustion turbines (SCCTs).

Renewable Resources

- Cases that do not assume RPS assumptions are generally devoid of incremental wind resources, indicating that new wind resource additions are not cost effective given deteriorating policy and market conditions.
- Cases defined with RPS requirements generally do not include incremental renewable resources beyond the minimum levels required to achieve compliance with RPS targets. An exception to this outcome is case C14, which assumed U.S. hard cap CO₂ prices that improve the cost effectiveness of new wind generation.
- Case C18, which assumes policy and market drivers favorable to renewable resource additions (high natural gas prices, high power prices, U.S. hard cap CO₂ prices, and extension of federal tax credits through 2019) includes between 1,100 and 2,900 megawatts (MW) of new wind resources, depending upon the Energy Gateway scenarios, 450 MW of large utility scale solar photovoltaic (PV) resources, and 135 MW of capacity through a geothermal PPA by the end of the planning horizon.
- Large scale utility solar PV resources located in Utah are added in cases with RPS requirements under Energy Gateway Scenario 1 and in all 18 cases. With the exception of case C18, wind resource additions displace large utility scale solar PV resources in meeting RPS obligations when the Windstar-Populus transmission project is included among Energy Gateway Scenarios 2 through 5.
- Geothermal resources were modeled as a power purchase agreement (PPA) in the 2013 IRP and are forced into C16 portfolios.
- All portfolios include approximately 15 MW of distributed solar resource additions each year totaling 290 MW over the 20 year planning horizon. These resources are largely driven by a Utah solar incentive program, currently scheduled to conclude in 2017. Through the 2017 period, it is assumed the program will achieve approved installation levels, and beyond 2017, these resources are selected by the System Optimizer model.

Demand-side Management

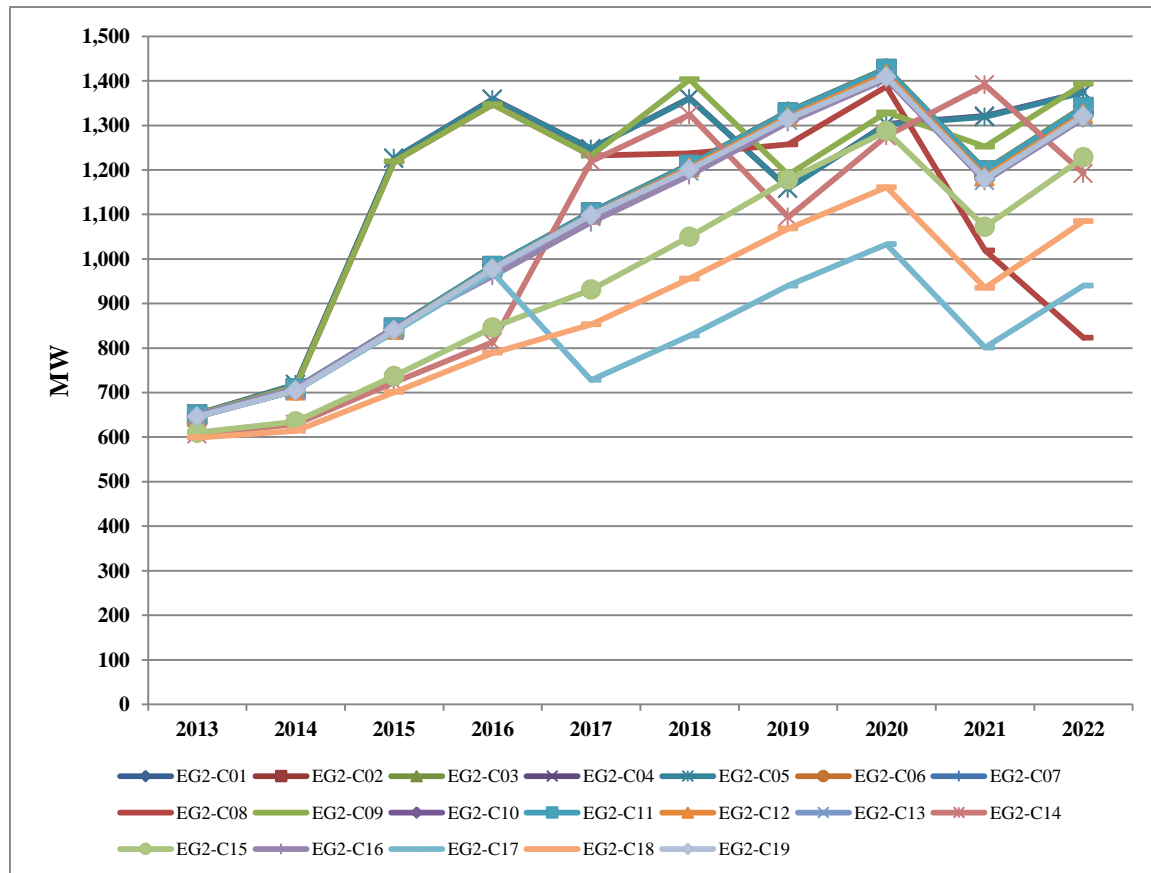
- Energy efficiency (Class 2 DSM) resource additions are prevalent among all portfolios and play a significant role in meeting projected capacity and energy needs through the planning horizon.
- Energy efficiency additions occur steadily throughout the simulation period, and by 2032 range between approximately 1,400 MW and 1,900 MW among portfolios in each Energy Gateway Scenario.⁷⁰
- In cases where accelerated acquisition of energy efficiency resources is assumed to be achievable (cases C14, C15, and C18), energy efficiency resources displace FOT resources in the near-term; however, over the long-term, these cases do not yield incremental energy efficiency resources as compared to other portfolios.
- Dispatchable load control programs (Class 1 DSM) are not added to resource portfolios in Energy Gateway Scenario 1 until 2020 and not until 2023 in Energy Gateway Scenarios 2 through 5. In cases with extensive coal unit retirements and natural gas conversions, little to no Class 1 DSM resources are included in the resource mix. On average, among all core case portfolios, System Optimizer selected between 123 MW of Class 1 DSM resources by 2032.

⁷⁰ These figures are analogous to a “nameplate” rating for thermal resources, and represent the maximum amount of load reduction savings expected for a given year.

Front Office Transactions

- All portfolios utilized front office transactions to fill both near-term and long-term system capacity needs, a consistent trend among all Energy Gateway scenarios. Figure 8.6 shows the annual front office transactions selected among core case portfolios under Energy Gateway Scenario 2. Over the first 10 years of the planning period, FOTs range between 599 MW and 1,428 MW. In the latter half of the planning horizon, annual FOT resource selections range between 710 MW and 1,472 MW. Beyond 2016, selection of FOTs is highest in case C17, which assumes a market price spike through 2022. Prior to 2016, FOTs are highest in cases with near-term coal unit retirements (cases C04, C05, C08 and C09).

Figure 8.6 – Front Office Transaction Addition Trends by Portfolio, EG-2



Retirements/Gas Conversion of Existing Coal-Fired Resources

- All portfolios reflected the end of life retirement of Carbon Unit 1 and Unit 2 in 2015.
- In addition to Carbon Unit 1 and Unit 2, asset lives of nine coal-fired facilities are assume to end prior to the end of this IRP’s study period.
- All portfolios reflect the conversion of Naughton Unit 3 to natural gas.
- Portfolio selections show that in the cases defined with medium or high natural gas prices and medium or low CO₂ prices, there are very few occurrences of coal unit early retirements or natural gas conversions. This is observed whether base case or stringent case Regional Haze investments are assumed.
- In the cases defined with high CO₂ price, low gas price and high coal cost assumptions (cases C04, C05, C08, and C09), the majority of the existing coal-fired facilities retire early and in the

first 10 years of the planning horizon. Among these cases, early retirement outcomes are not significantly different whether base case or stringent Regional Haze investments are assumed. In cases where U.S. hard cap CO₂ price assumptions are made (cases C14 and C18) coal units retire early, but latter in the planning period as compared to cases C04, C05, C08, and C09.

Impact of Energy Gateway Segments

- Additional segments of the Energy Gateway reduce system costs, especially for cases assuming RPS requirements. In these cases, access to high capacity factor Wyoming wind resources made possible by the addition of the Windstar-Populus transmission line in Energy Gateway Scenarios 2 through 5, lower RPS compliance costs.
- Figures 8.7 through 8.10 show the increase in Energy Gateway transmission costs between different Energy Gateway Scenarios as compared to Energy Gateway Scenario 1 (red line) alongside changes in system PVRR costs, as calculated by System Optimizer, between like portfolios in different Energy Gateway Scenarios as compared to Energy Gateway Scenario 1 (bars). Differences in portfolio costs among like cases do not include the benefits of Segment D as determined by the System Operational and Reliability Benefits Tool (SBT) described in Volume I, Chapter 4. Bars that fall below the red line indicate portfolios observed system cost benefits when incremental Energy Gateway transmission is added. Core cases that include RPS assumptions show system cost benefits with incremental transmission investment. Core case C19 assumes there an alternative to Energy Gateway Segment D, and is not included under Energy Gateway Scenario 1. Consequently, case C19 is not shown in the figures below.

Figure 8.7 – PVRR Difference in System Costs between Like Portfolios in Energy Gateway Scenario 2 and Energy Gateway Scenario 1 (System Optimizer)

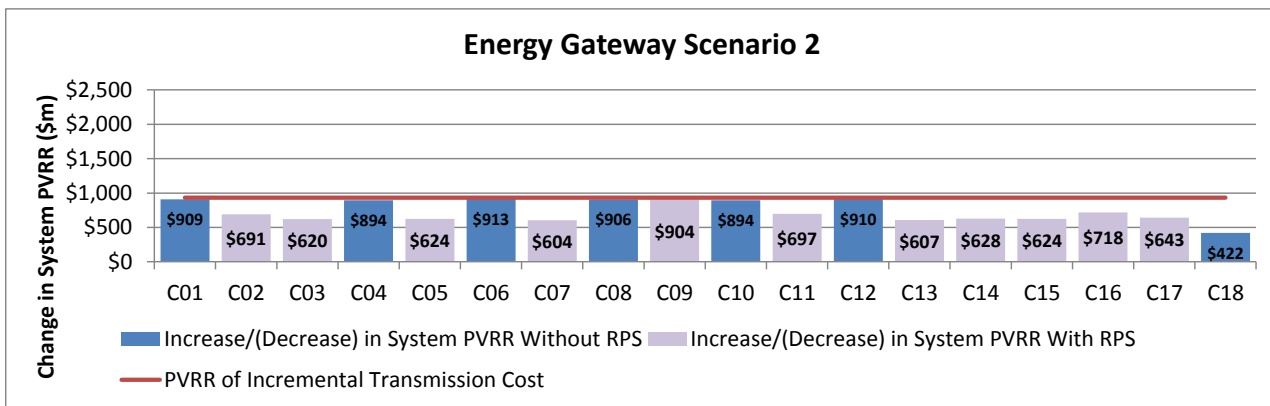


Figure 8.8– PVRR Difference in System Costs between Like Portfolios in Energy Gateway Scenario 3 and Energy Gateway Scenario 1 (System Optimizer)

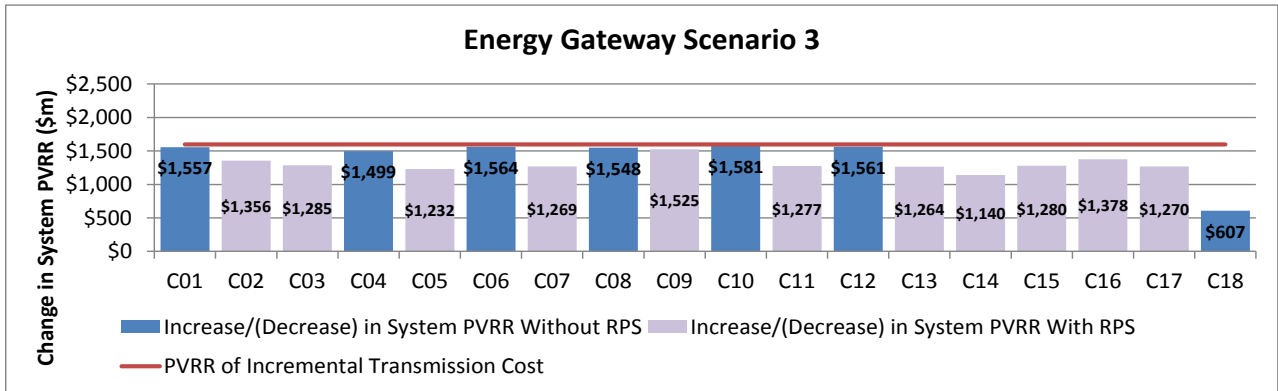


Figure 8.9 – PVRR Difference in System Costs between Like Portfolios in Energy Gateway Scenario 4 and Energy Gateway Scenario 1

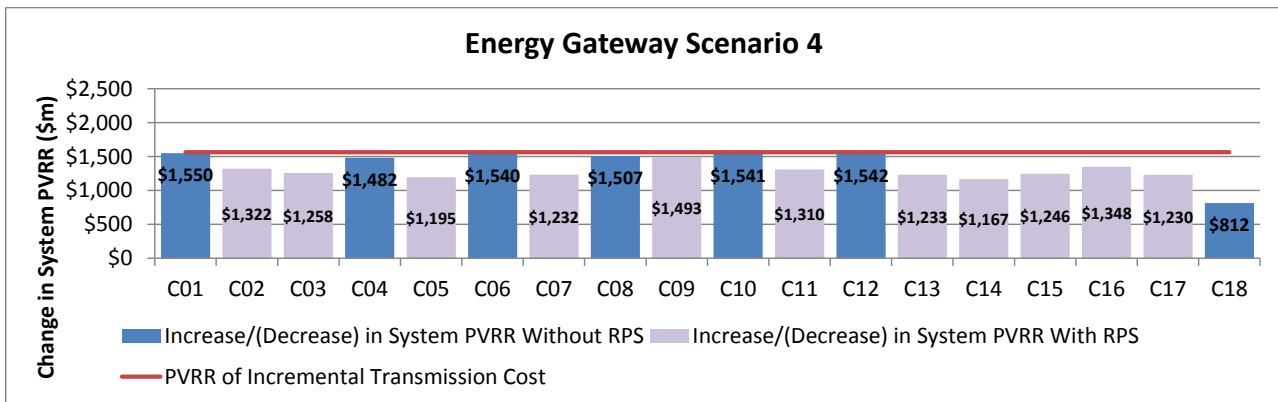
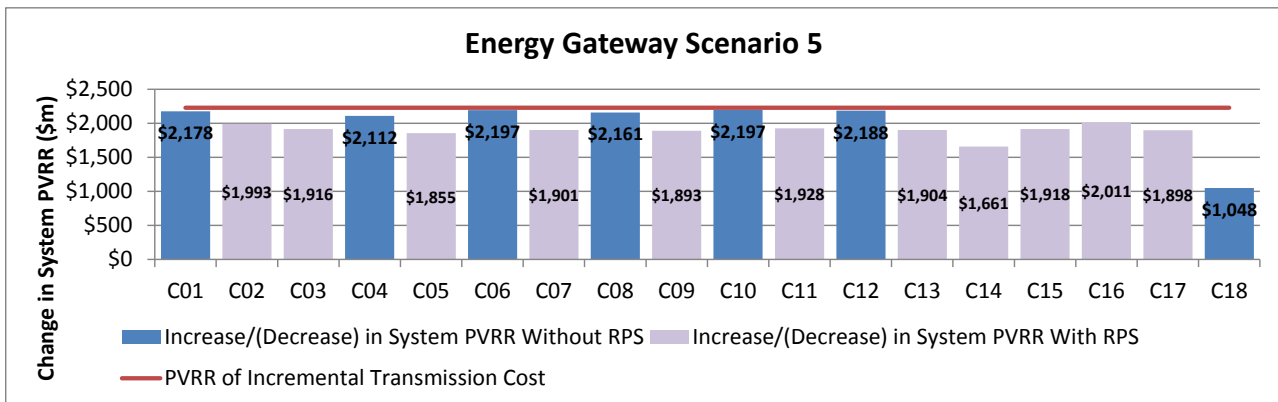


Figure 8.10 – PVRR Difference in System Costs between Like Portfolios in Energy Gateway Scenario 5 and Energy Gateway Scenario 1



Summary of Portfolios among Core Case Themes

- Reference Cases: Cases in the Reference Case Theme are characterized by base/medium assumptions with varying types of RPS assumptions.
 - Differences among portfolios in this theme are driven by RPS policy assumptions.

- When no RPS assumptions are made, there are very small quantities of large utility-scale renewable resources selected. In these cases, wind resource additions range between zero and 78 MW through 2032.
 - When state RPS assumptions are applied, renewable resources are added at levels required to achieve compliance. In Energy Gateway Scenario 1, wind additions total 600 MW and “large scale” solar photovoltaic (PV) additions total 28 MW by 2032. Among Energy Gateway Scenarios 2 through five, wind resource additions range between 759 MW and 829 MW by 2032.
 - With both state and federal RPS assumptions, renewable resources are added at levels to achieve compliance with targets. In Energy Gateway Scenario 1, incremental wind resources total 803 MW and a 227 MW large scale solar PV resource is added in 2026. Among Energy Gateway Scenarios 2 through 5, wind resource additions range between 858 MW and 928 MW by 2032.
- Environmental Policy Cases: Cases in the Environmental Policy Theme are characterized by varying combinations of commodity market prices, CO₂ prices, RPS requirements, and Regional Haze requirements.
 - The impact of RPS assumptions on renewable resource additions is similar to those observed among cases in the Reference Theme, whereby no to limited amounts of incremental renewable resources are added to the resource portfolio when RPS compliance obligations are removed.
 - Alternative Regional Haze assumptions did not drive changes in coal unit early retirement and natural gas conversions.
 - Incremental environmental investments in coal units are made in favor of early retirement and gas conversion alternatives for nearly all units and in nearly all cases where where medium natural gas prices are combined with medium CO₂ price and medium coal cost assumptions, and in cases where high natural gas prices are combined with zero CO₂ prices and low coal costs.
 - Under cases defined by low natural gas prices combined with high CO₂ prices and high coal costs (cases C04, C05, C08, and C09), nearly all of PacifiCorp’s existing coal-fired resources are retired or converted to natural gas prior to 2032.
 - When U.S. hard cap CO₂ prices are assumed, the resulting portfolios reflect coal retirements and gas conversions similar to the levels seen in cases C04, C05, C08, and C09.
 - Targeted Resource Cases: Cases in the Targeted Resource Theme are characterized by alternative assumptions for specific resource types to understand how they influence resource portfolio costs and risk.
 - Case C15 assumes energy efficiency resources (Class 2 DSM) can be acquired at an accelerated rate and disallows selection of new CCCT generation assets. High level adjustments were applied to the 2012 DSM Potential study measures and ramp rates to allow selection of up to two percent of 2011 actual sales in each state. After discretionary resources are exhausted, annual Class 2 DSM opportunities decrease, with remaining resources from equipment upgrades and new construction. As compared to core cases with base Class 2 DSM resource availability, System Optimizer model selected additional Class 2 DSM resources earlier in the planning horizon, and as intended, this portfolio does not include any new CCCT resources through the 20 year planning period.

- Case C16 assumes that state and federal RPS obligations must first be met with available geothermal power purchase agreement (PPA) resources among five sites located in PacifiCorp’s service territory. In this case, 145 MW of geothermal PPA resource is added and supplemented with additional wind resources as required to meet RPS requirements. With the addition of the geothermal PPA resources, the 227 MW large utility-scale solar PV resources added in 2026 in reference case C03 under Energy Gateway Scenario 1 is displaced.
 - Case C17 assumes forward power prices under a high natural gas price scenario increase by 50 percent during on-peak hours and by 30 percent in off-peak hours. In this case, FOT resources are reduced, but not eliminated, and a CCCT natural gas resource is added to the portfolio in 2017.
 - Case C18 targets a “Clean Energy Bookend” portfolio and is defined with high natural gas prices, high power prices, and U.S hard cap CO₂ price assumptions along with extension of federal tax incentives for renewable resources through 2019. The resulting portfolio includes incremental renewable resources beyond 2019, early coal unit retirements and gas conversions beginning 2023, a nuclear resource in 2025, and an integrated gasification combined cycle unit (IGCC) with carbon capture and sequestration (CCS) in 2032.
- Transmission Case: The Transmission Theme includes one core case assuming that transmission can be purchased from a new line built by a third party as an alternative to the Company’s Energy Gateway Segment D project. Resource selections in this case do not vary significantly from those observed in reference case C03.

Carbon Dioxide Emissions

Figures 8.11 through 8.13 show annual CO₂ emissions from resource portfolios under Energy Gateway Scenario 2 grouped by core case theme.⁷¹ All cases show emission reductions over the 20 year planning horizon with the assumed end-of-life retirement of existing coal units. Longer-term addition of renewable resources among those cases with RPS assumptions and longer-term addition of natural gas resources, required to meet load growth and assumed end-of-life coal unit retirements, also contribute to lower emission levels. Portfolios showing the most dramatic CO₂ emission reductions include those cases in the Environmental Policy and Targeted Resource Themes producing portfolios with extensive early coal unit retirements and gas conversions (cases C04, C05, C08, C09, C15, and C18).

⁷¹ Similar emission trends are observed among other Energy Gateway Scenarios.

Figure 8.11 – Annual CO₂ Emissions: Reference Cases

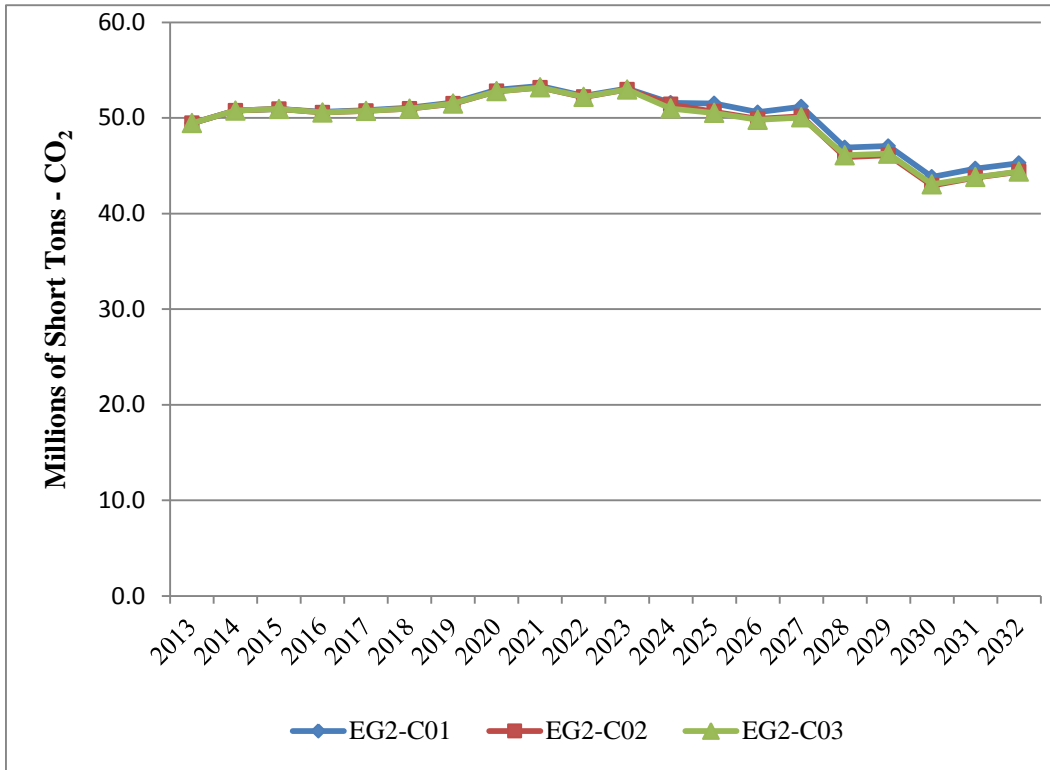


Figure 8.12 – Annual CO₂ Emissions: Environmental Policy

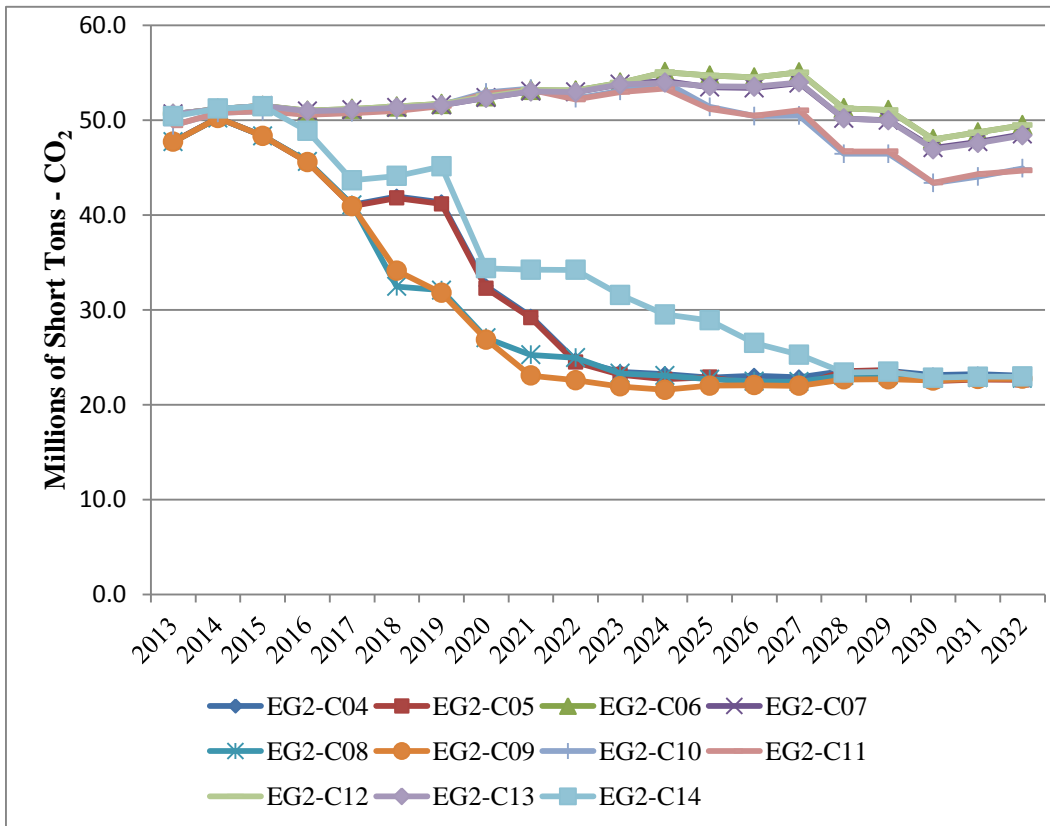
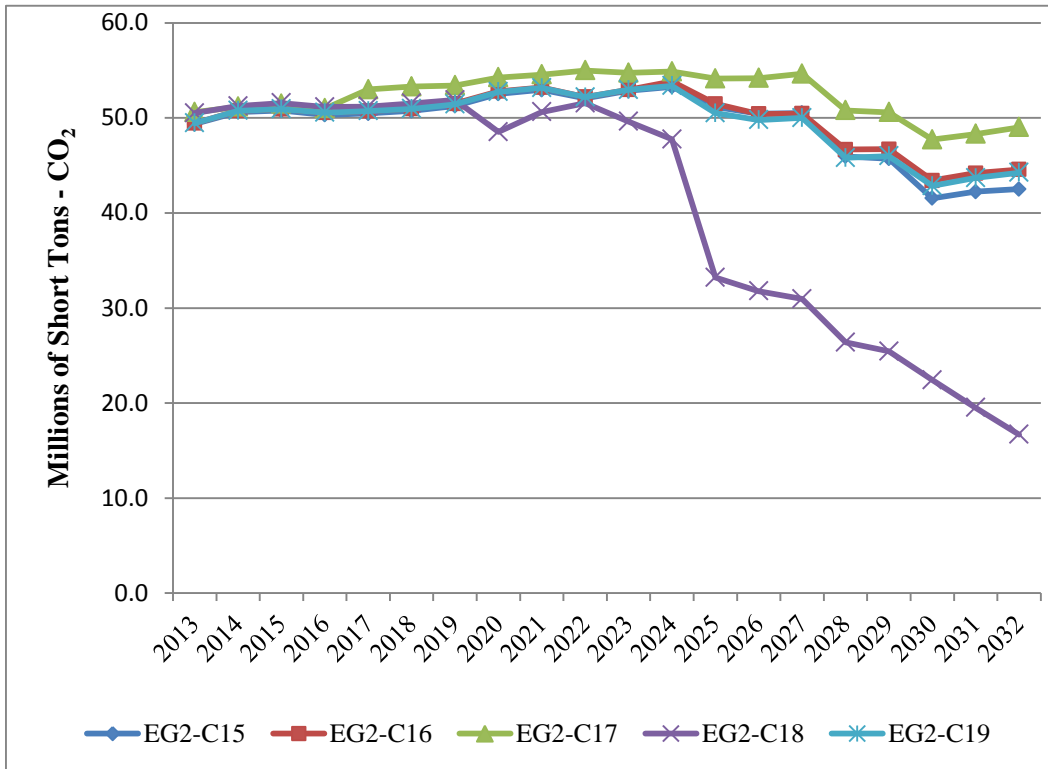


Figure 8.13 – Annual CO₂ Emissions: Targeted Resources



Pre-Screening Results

As described in Chapter 7, the Company tested in the Planning and Risk model (PaR) 36 core case portfolios from Energy Gateway Scenarios 1 and 2 with the application of stochastic Monte Carlo simulation of market prices, loads, thermal outages and hydro generation, across three CO₂ price levels (zero, medium, and high). Pre-screening of portfolios was performed by producing scatter plots of stochastic mean and upper tail mean *less* stochastic mean PVRR results using data from the PaR simulations among each CO₂ price scenario.⁷² The resulting scatter plots, shown in Figures 8.14 through 8.19, were used to identify portfolios that are extreme cost and or risk outliers relative to other portfolios. The red dashed line depicted on each of the following figures demarcates the threshold used to identify outlier portfolios. Portfolios to the left and below the dashed red line are lower cost and lower risk and were designated as superior relative to those portfolios to the right and above the red dashed line.

⁷² Netting the stochastic mean PVRR from the upper tail mean PVRR is done to isolate fixed costs common to both metrics.

Figure 8.14 – Remove Outliers, Energy Gateway Scenario 1 with Zero CO2 Prices

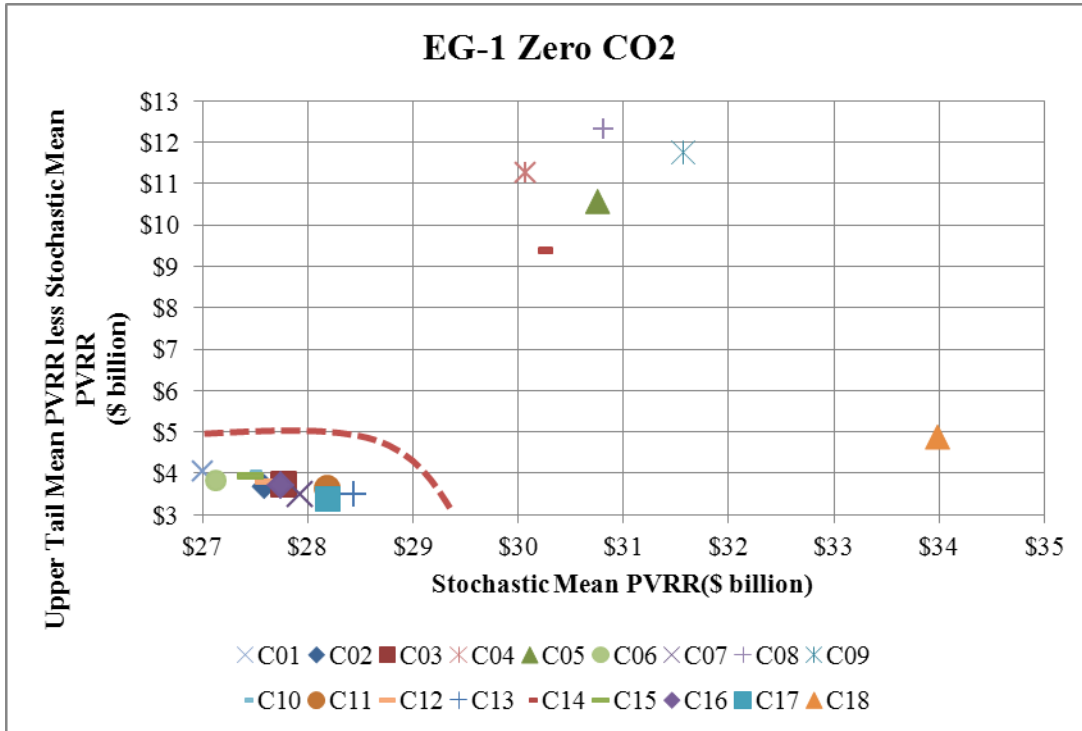


Figure 8.15 – Remove Outliers, Energy Gateway Scenario 1 with Medium CO2 Prices

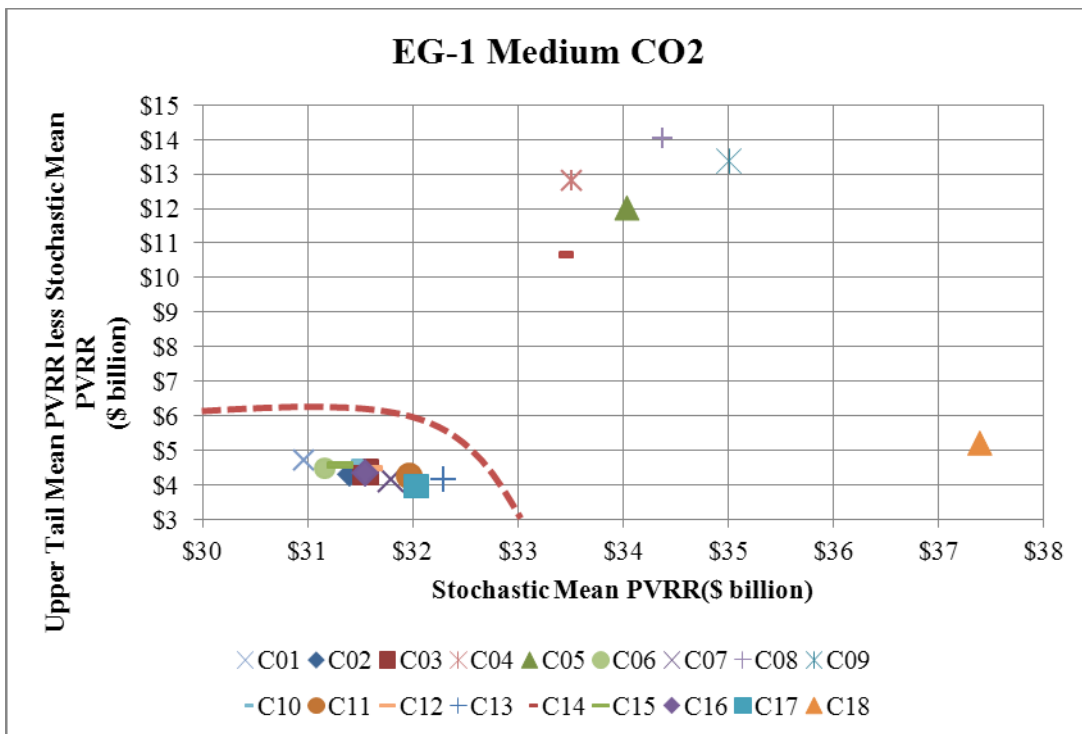


Figure 8.16 – Remove Outliers, Energy Gateway Scenario 1 with High CO₂ Prices

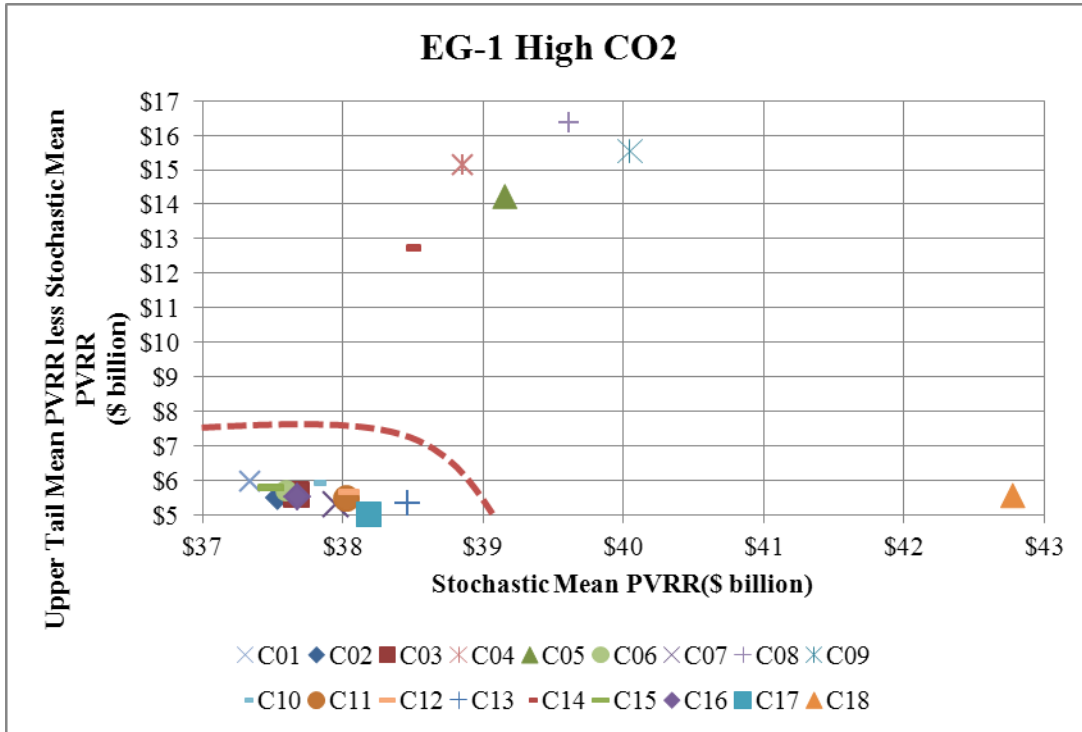


Figure 8.17 – Remove Outliers, Energy Gateway Scenario 2 with Zero CO₂ Prices

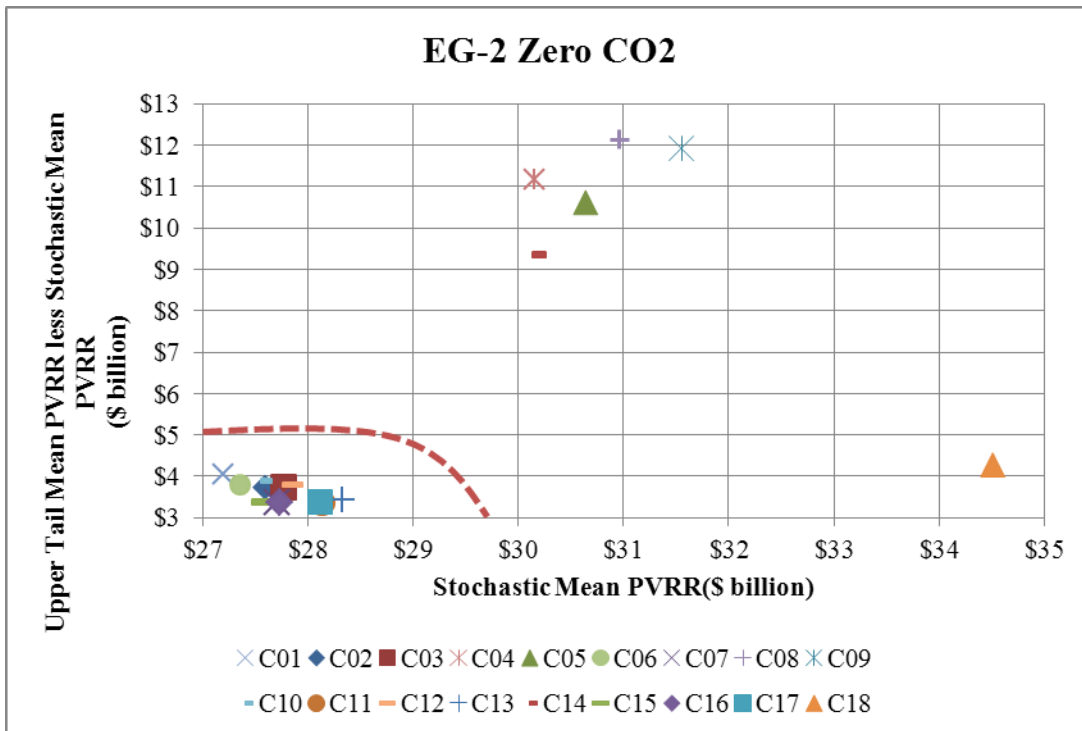


Figure 8.18 – Remove Outliers, Energy Gateway Scenario 2 with Medium CO₂ Prices

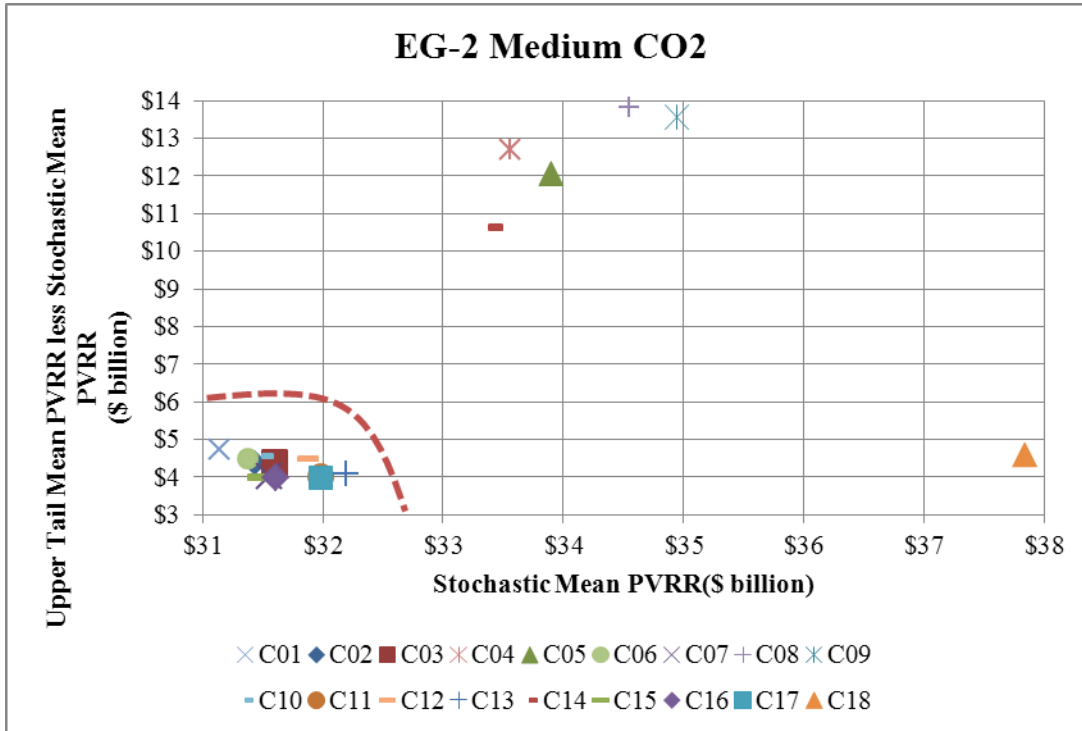
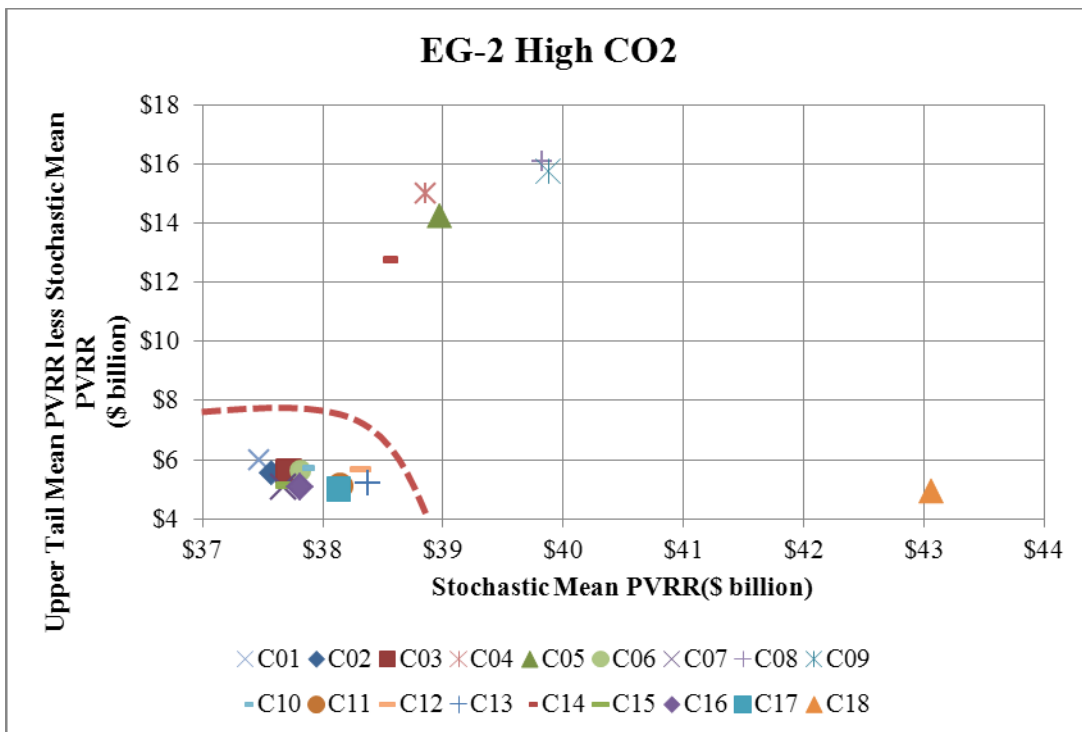


Figure 8.19 – Remove Outliers, Energy Gateway Scenario 2 with High CO₂ Prices



A consistent set of portfolios among each CO₂ price scenario and for each Energy Gateway scenario are outliers in relation to other portfolios included on the above plots. These portfolios, each

characterized by extensive early coal unit retirements and gas conversions (cases C04, C05, C08, C09, C14, and C18), were removed from consideration as candidates for the preferred portfolio. As an additional pre-screening step, the case C19 portfolio was removed from consideration because the case is predicated on completion of a third party transmission project (the Zephyr DC line), which is not currently far enough into the development process for it to be considered for the preferred portfolio.⁷³ Similarly, portfolios that cannot meet compliance with state and assumed federal RPS requirements were also removed from consideration. As a result, the portfolios identified in the pre-screening analysis as potential preferred portfolio candidates include portfolios from cases C03, C07, C11, C13, C15, C16 and C17 under Energy Gateway Scenarios 1 and 2 (14 portfolios).

Initial Screening Results

With the removal of pre-screened portfolios, scatter plots of the stochastic mean PVRR and the stochastic mean PVRR less the upper tail mean PVRR can be viewed with finer resolution. Figures 8.20 to 8.22 show these scatter plots for the 14 portfolios identified in the pre-screening analysis under zero, medium and high CO₂ price levels. The red line demarcates the group of portfolios designated as superior with respect to the combination of the cost and risk metrics. The red demarcation line is established by calculating a cost/risk variance threshold using two percent of the stochastic mean PVRR of the least cost portfolio under each CO₂ price scenario and applying this threshold to the least cost and least risk portfolios on each scatter plot. For example, under medium CO₂ price scenario, the least cost portfolio has a stochastic mean PVRR of \$31.3 billion. Two percent of this figure is \$630 million, which is the threshold used for the medium CO₂ price scenario. Any portfolio that is within \$630 million of the lowest cost portfolio *and* within \$630 million of the least risk portfolio in the medium CO₂ price scenario is to the left and below the red dashed line. The cost /risk threshold used in the zero and high CO₂ scenarios is \$550 million and \$750 million, respectively.

⁷³ The Zephyr DC line would provide no reliability benefits to PacifiCorp's existing transmission system and may require additional infrastructure additions to meet reliability for the existing system. The line does not provide interconnection for of new resources except at the termination points established if the project were constructed and does not allow for multiple interconnection points with the existing PacifiCorp transmission system. The proposed line with PacifiCorp transmission is more expensive than Energy Gateway Segment D.

Figure 8.20 – Stochastic mean PVRR versus Upper-tail Risk with Zero CO₂ Prices

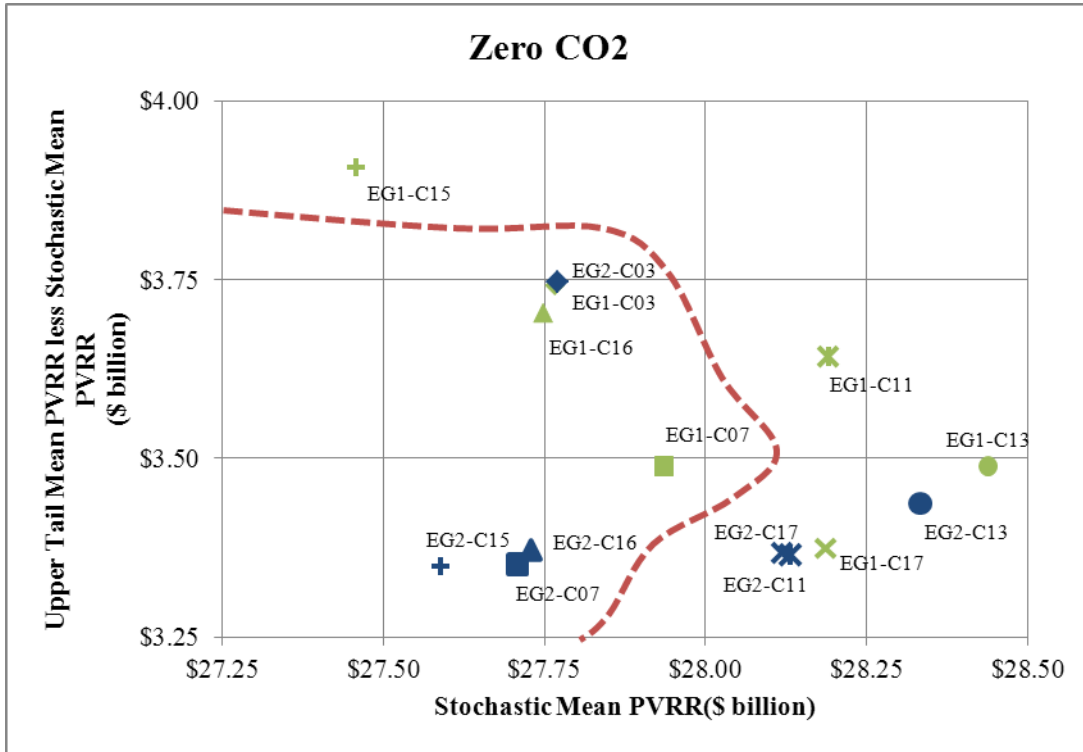


Figure 8.21 – Stochastic mean PVRR versus Upper-tail Risk with Medium CO₂ Prices

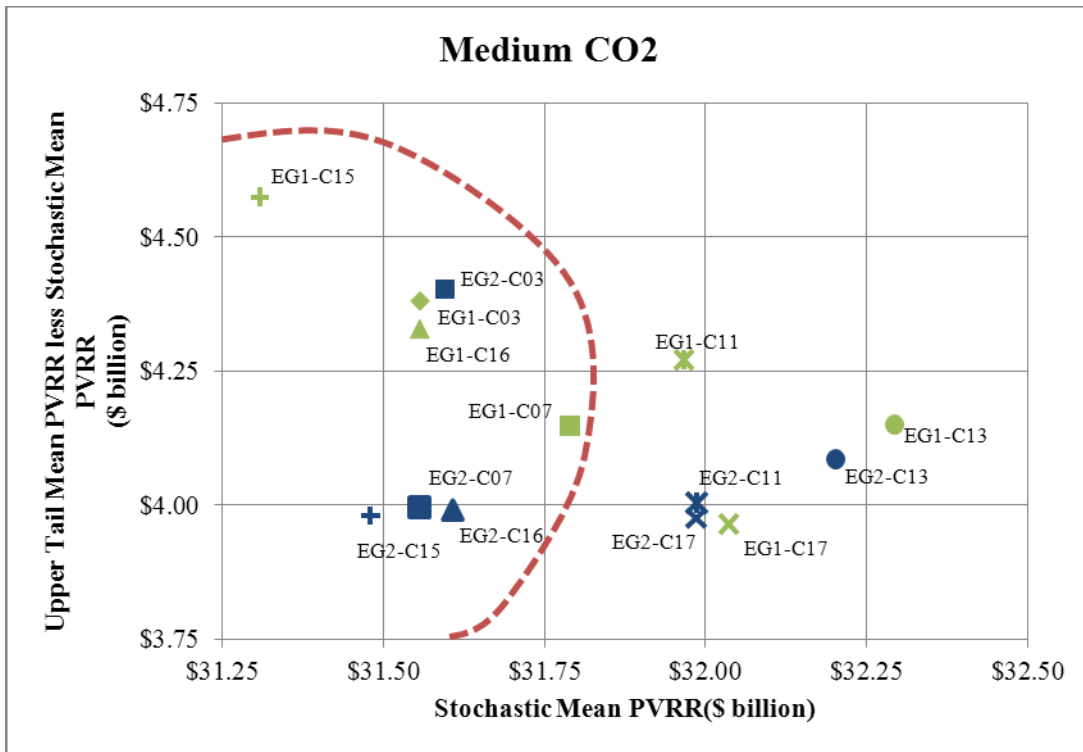
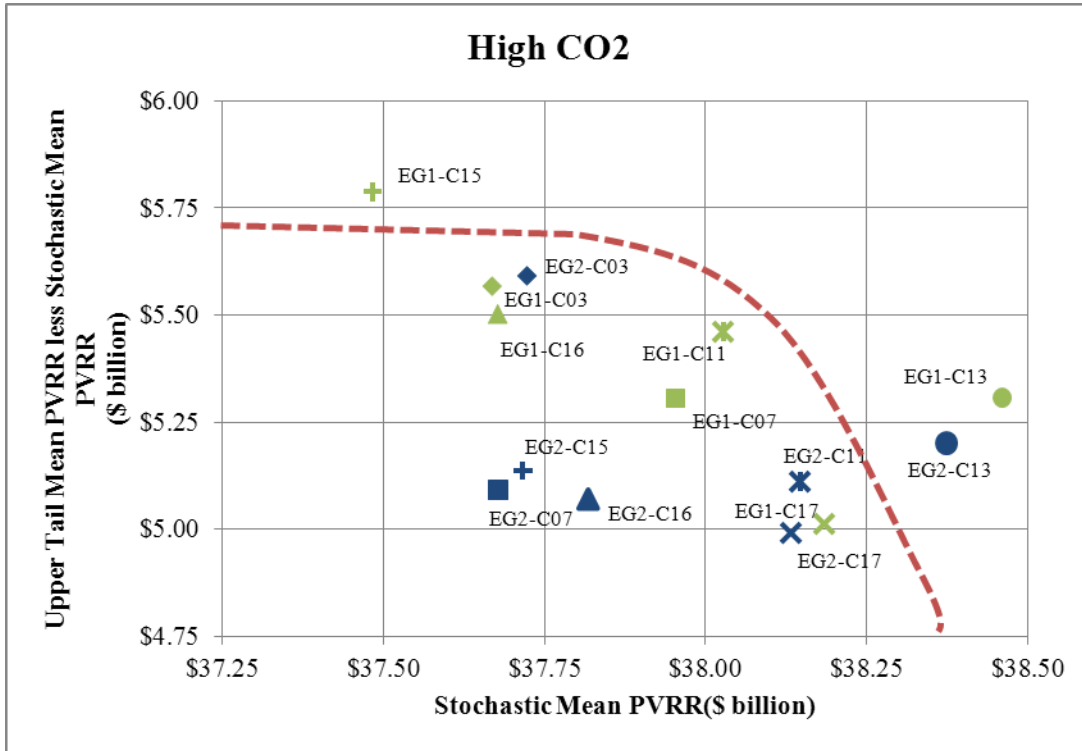


Figure 8.22 – Stochastic mean PVRR versus Upper-tail Risk with High CO₂ Prices



Portfolios that fall within the threshold identified by the red dashed line in the figures above under *any* CO₂ price scenario are considered as candidates for the preferred portfolio and passed along for final screening. Based upon the initial screening scatter plot analysis, which shows there is very little separation between portfolios, the top performing portfolios using least cost/least risk metrics include portfolios from cases C03, C07, C11, C15, C16 and C17 under Energy Gateway Scenarios 1 and 2 (12 portfolios).

Final Screening Results

Risk-adjusted PVRR

The risk adjusted PVRR is one of the primary metrics used to rank and inform selection of the preferred portfolio. As described in Chapter 7, this metric combines cost and risk attributes from the PaR model by expressing a low probability portfolio cost outcome as a risk premium to the expected PVRR.⁷⁴ Table 8.1 reports the risk-adjusted PVRR values and relative ranking among the 12 portfolios identified in the initial screening analysis by CO₂ price scenario. Portfolios developed under core case C15 under Energy Gateway Scenarios 1 and 2 (EG1-C15 and EG2-C15, as depicted in the table below), which eliminates the possibility of new CCCT resources and assumes accelerated acquisition of Class 2 DSM resources, rank high on a risk adjusted PVRR basis. The portfolio developed under core case C07 under Energy Gateway Scenario 2 also ranks high, ranking just below the C15 cases in the zero and medium CO₂ scenarios and ranking second, above the portfolio developed under case C15 from Energy Gateway Scenario 2, when high CO₂ prices are assumed.

⁷⁴ This risk adjusted PVRR is calculated as the stochastic mean PVRR plus five percent of the 95th percentile of the variable production cost PVRR, excluding fixed costs.

Table 8.1 – Portfolio Comparison, Risk-adjusted PVRR

Case	Zero CO2			Medium CO2			High CO2			CO2 Scenario Average		
	Risk Adjusted PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Risk Adjusted PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Risk Adjusted PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Risk Adjusted PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank
EG1-C03	\$28,719	\$306	7	\$32,717	\$245	4	\$39,175	\$179	3	\$33,537	\$244	5
EG1-C07	\$28,894	\$481	8	\$32,956	\$485	8	\$39,476	\$480	8	\$33,775	\$482	8
EG1-C11	\$29,140	\$727	11	\$33,123	\$651	11	\$39,529	\$534	9	\$33,931	\$637	11
EG1-C15	\$28,413	\$0	1	\$32,471	\$0	1	\$38,996	\$0	1	\$33,293	\$0	1
EG1-C16	\$28,703	\$290	6	\$32,718	\$247	5	\$39,186	\$191	5	\$33,536	\$243	4
EG1-C17	\$29,146	\$733	12	\$33,203	\$732	12	\$39,694	\$699	12	\$34,014	\$721	12
EG2-C03	\$28,695	\$282	5	\$32,729	\$257	6	\$39,203	\$208	6	\$33,542	\$249	6
EG2-C07	\$28,621	\$208	3	\$32,679	\$208	3	\$39,149	\$153	2	\$33,483	\$190	3
EG2-C11	\$29,045	\$632	10	\$33,108	\$636	9	\$39,618	\$622	11	\$33,924	\$630	9
EG2-C15	\$28,494	\$81	2	\$32,595	\$123	2	\$39,186	\$191	4	\$33,425	\$131	2
EG2-C16	\$28,646	\$233	4	\$32,735	\$263	7	\$39,295	\$299	7	\$33,558	\$265	7
EG2-C17	\$29,044	\$631	9	\$33,120	\$648	10	\$39,607	\$612	10	\$33,924	\$630	10

Cumulative Carbon Dioxide Emissions

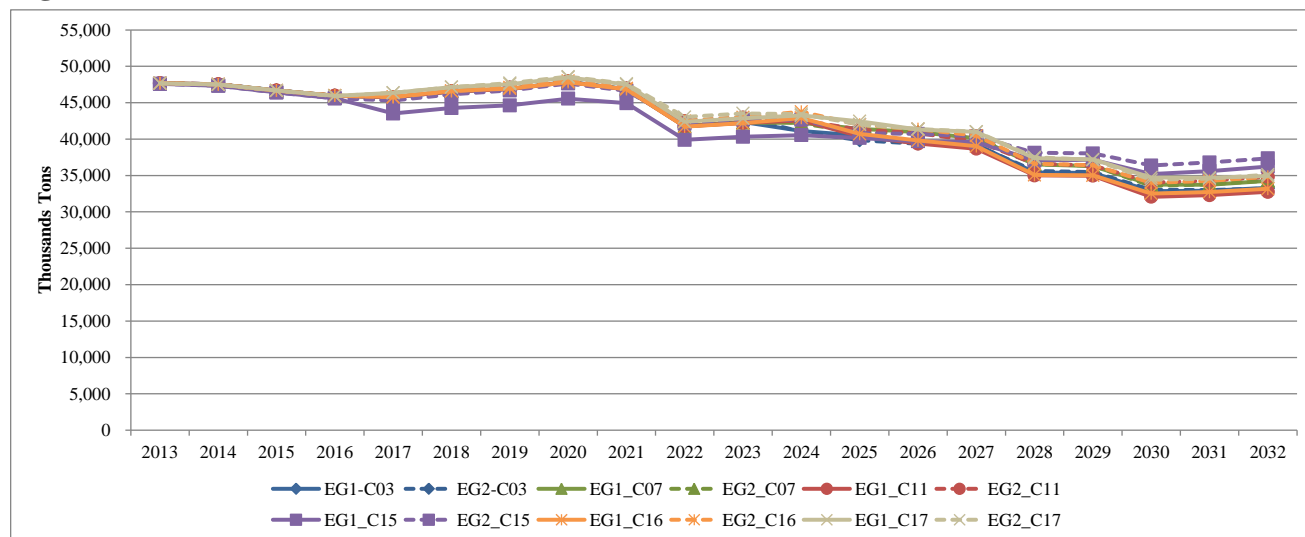
Table 8.2 reports the average cumulative 20-year CO₂ emissions (average of the 100 Monte Carlo iterations) for each of the 12 portfolios identified in the initial screening analysis. The EG1-C15 portfolio has slightly lower CO₂ emissions beginning 2017, but emissions are higher in longer-term given the absence of base load combined cycle combustion turbine resources. The difference between the average annual emissions in the highest ranking portfolio and the lowest ranking portfolio in the medium CO₂ scenario is 1.3 million tons, or 3% of annual system CO₂ emissions among all portfolios.

Table 8.2 –Portfolio Comparison, Cumulative CO₂ Emissions for 2013-2032

Case	Zero CO2			Medium CO2			High CO2			CO2 Scenario Average		
	Total CO2 Emissions, 2013-2032 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank	Total CO2 Emissions, 2013-2032 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank	Total CO2 Emissions, 2013-2032 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank	Total CO2 Emissions, 2013-2032 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
EG1-C03	871,984	9,220	3	836,154	4,773	3	803,958	2,917	3	837,365	4,990	3
EG1-C07	884,725	21,962	6	845,061	13,680	6	811,879	10,838	6	847,222	14,847	6
EG1-C11	871,047	8,283	2	833,753	2,372	2	801,042	0	1	835,280	2,905	2
EG1-C15	862,764	0	1	831,381	0	1	802,982	1,940	2	832,375	0	1
EG1-C16	873,506	10,743	4	836,778	5,397	4	804,491	3,449	5	838,258	5,883	4
EG1-C17	896,136	33,372	11	857,056	25,675	11	824,668	23,626	10	859,286	26,911	11
EG2-C03	873,964	11,200	5	837,300	5,919	5	804,480	3,439	4	838,581	6,206	5
EG2-C07	884,841	22,077	7	845,998	14,616	7	813,184	12,143	7	848,008	15,632	7
EG2-C11	886,356	23,593	8	848,108	16,727	8	815,771	14,730	8	850,079	17,703	8
EG2-C15	889,384	26,621	10	855,418	24,037	10	824,930	23,889	11	856,578	24,202	10
EG2-C16	888,635	25,871	9	851,427	20,046	9	820,124	19,083	9	853,395	21,020	9
EG2-C17	897,356	34,592	12	858,353	26,972	12	825,533	24,492	12	860,414	28,039	12

While there are differences in cumulative CO₂ emissions among each of the portfolios that are used to rank the portfolios under each of the CO₂ price scenarios, as shown in Figure 8.23, the expected emission levels among the 12 portfolios identified in the initial screening analysis are very similar over the 20 year planning period.

Figure 8.23 – Stochastic Mean Annual CO₂ Emissions with Medium CO₂ Prices



Supply Reliability

Table 8.3 and Table 8.4 report two measures of stochastic supply reliability, average annual energy not served (ENS) and upper-tail mean ENS, for each of the 12 portfolios identified in the initial screening analysis. The portfolios developed under case EG1-C15 and EG2-C11 perform the best on these two measures, and differences among portfolios are not material between CO₂ price scenarios. The high ranking of the portfolio developed under case EG1-C15 is largely influenced by west side Class 1 DSM resources that were added over the period from 2020 to 2025.

Table 8.3 – Portfolio Comparison, Stochastic Mean Energy Not Served

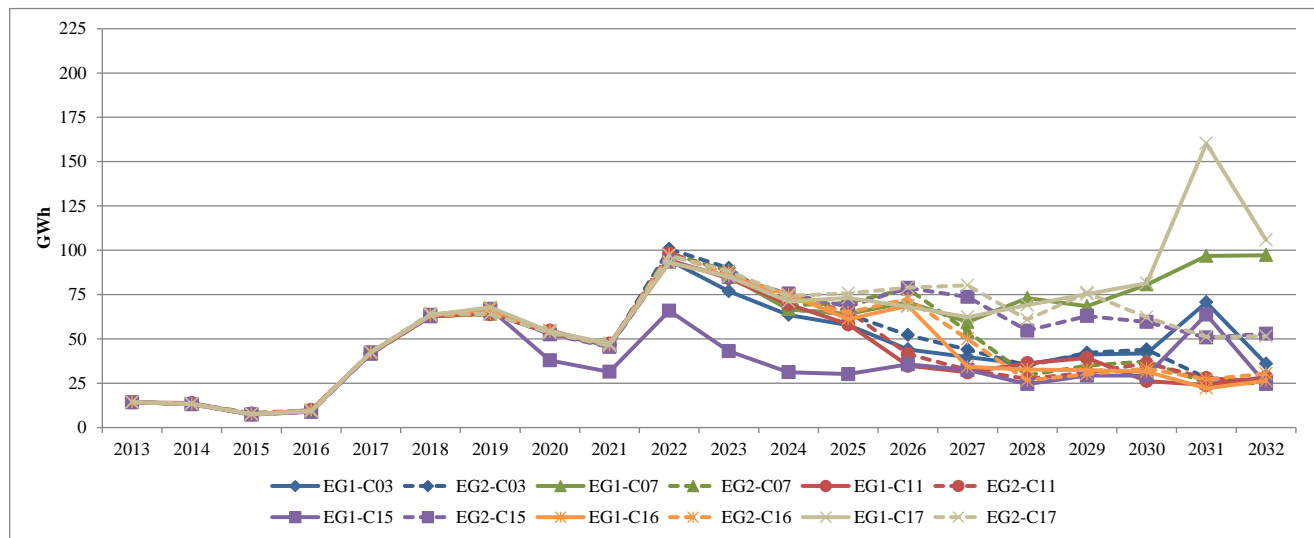
Case	Zero CO2			Medium CO2			High CO2			CO2 Scenario Average		
	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank
EG1-C03	44.9	10.5	8	46.0	11.1	7	47.1	11.3	5	46.0	11.0	7
EG1-C07	56.8	22.4	11	58.8	23.8	11	61.6	25.7	11	59.0	24.0	11
EG1-C11	40.9	6.5	3	42.3	7.3	2	44.2	8.3	2	42.5	7.4	2
EG1-C15	34.4	0.0	1	35.0	0.0	1	35.8	0.0	1	35.1	0.0	1
EG1-C16	42.4	8.0	4	44.3	9.3	4	46.5	10.7	3	44.4	9.4	4
EG1-C17	61.5	27.0	12	63.6	28.6	12	66.0	30.2	12	63.7	28.6	12
EG2-C03	42.7	8.3	6	45.6	10.7	6	49.0	13.2	7	45.8	10.7	6
EG2-C07	43.2	8.8	7	46.6	11.6	8	50.7	14.9	8	46.8	11.8	8
EG2-C11	40.6	6.2	2	43.3	8.3	3	46.8	11.0	4	43.6	8.5	3
EG2-C15	51.5	17.0	9	53.6	18.7	9	55.6	19.7	9	53.5	18.5	9
EG2-C16	42.7	8.3	5	45.6	10.6	5	48.9	13.1	6	45.8	10.7	5
EG2-C17	51.7	17.3	10	55.8	20.9	10	60.8	25.0	10	56.1	21.1	10

Table 8.4 – Portfolio Comparison, Energy Not Served - Upper Tail

Case	Zero CO2			Medium CO2			High CO2			CO2 Scenario Average		
	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank
EG1-C03	69.2	10.7	4	70.9	14.8	2	75.7	15.2	2	71.9	13.6	2
EG1-C07	97.9	39.4	11	104.2	48.2	11	115.6	55.1	10	105.9	47.5	11
EG1-C11	71.2	12.7	5	73.0	17.0	3	86.8	26.3	3	77.0	18.7	3
EG1-C15	58.5	0.0	1	56.1	0.0	1	60.5	0.0	1	58.4	0.0	1
EG1-C16	73.3	14.8	7	77.3	21.2	6	91.9	31.4	4	80.8	22.5	5
EG1-C17	106.0	47.5	12	105.1	49.0	12	113.8	53.3	9	108.3	49.9	12
EG2-C03	68.6	10.1	3	75.4	19.3	5	99.3	38.8	6	81.1	22.7	6
EG2-C07	77.1	18.6	8	89.3	33.3	9	118.4	57.9	11	94.9	36.6	9
EG2-C11	66.9	8.4	2	74.5	18.5	4	95.1	34.6	5	78.8	20.5	4
EG2-C15	82.3	23.8	9	86.3	30.2	8	102.4	41.9	8	90.3	32.0	8
EG2-C16	71.7	13.2	6	84.3	28.2	7	102.0	41.5	7	86.0	27.6	7
EG2-C17	82.6	24.1	10	99.2	43.1	10	133.4	72.9	12	105.1	46.7	10

Most of the differences in ENS ranking of stochastic mean are largely driven by changes in portfolios beyond the first ten years of the IRP planning horizon. Figure 8.24 shows the annual stochastic mean ENS among the 12 portfolios identified in the initial screening analysis under the medium CO₂ price scenario.

Figure 8.24 – Stochastic Mean Annual ENS with Medium CO₂ Prices



Preferred Portfolio Selection

Based upon the metrics reviewed in the final screening analysis, and given similarities among portfolios, particularly in the near-term, with regard to CO₂ emissions and ENS as reported by the PaR model, PacifiCorp has primarily relied upon the risk adjusted net PVRR results and the associated portfolio rankings to inform preliminary selection of a preferred portfolio.

Deliverability of Accelerated Class 2 DSM and Resource Constraints

Portfolios developed under case C15 for Energy Gateway Scenarios 1 and 2 have the highest risk adjusted net PVRR ranking among candidate portfolios across different CO₂ price scenarios.⁷⁵ Portfolios developed under case C15 assume that acquisition of Class 2 DSM resources can be accelerated and was developed absent the opportunity for cost effective selection of CCCT resources. High level adjustments were applied to base case measure costs and ramp rates to develop the input assumptions required to develop this portfolio using the System Optimizer model. While the risk adjusted net PVRR results for the two C15 portfolios rank high in relation to other candidate portfolios, the Company has *not* chosen the C15 portfolios as the preferred portfolio for the following reasons:

- The high level cost assumptions underlying selection of the accelerated Class 2 DSM resources are uncertain. The Company does not have strong evidence in support of the true acquisition costs.
- Ramp rate assumptions underlying selection of the accelerated Class 2 DSM resources are untested ramp rate modifications. The Company does not have strong evidence that the revised ramp rate assumptions are achievable given regulatory and market factors.
- The Company is reluctant to select a portfolio that was developed with the exclusion of an entire class of proven resource technology. It is not reasonable to consider a portfolio that on the outset precludes consideration of CCCT resources throughout the entire 20 year planning horizon.

Nonetheless, the potential benefits of acquiring Class 2 DSM early is highlighted in the C15 portfolio results, and specific action items have been included in the 2013 IRP Action Plan (Chapter 9) targeting accelerated acquisition of cost-effective Class 2 DSM resources.

Resource Diversity

Figure 8.25 summarizes the nameplate capacity of cumulative resource selection through 2022 among the six portfolios beyond the C15 cases that rank highest on a risk adjusted net PVRR basis. This figure illustrates the similarity among the top performing portfolios, identified using cost and risk metrics, through the first 10 years of the planning period – the timeframe most critical to influencing the 2013 IRP Action Plan. With reduced loads and market prices, each portfolio is dominated by Class 2 DSM resources and FOT resources.⁷⁶ None of the portfolios include a CCCT resource over this period. Among these portfolios, renewable resources are added in different quantities and at different times for the sole purpose of meeting west side state RPS requirements. The variability in quantity, type, and timing of new renewable resources is dependent on whether the Windstar-Populus transmission project is built under the Energy Gateway Scenario 2.

⁷⁵ The C07 portfolio under Energy Gateway Scenario 2 outranks the C15 portfolio under Energy Gateway Scenario 2 when high CO₂ prices are assumed.

⁷⁶ Among the top ranking portfolios, no Class 1 DSM resources are added in the first 10 years of the planning period.

Figure 8.25 – Resource Types among Top Performing Portfolios

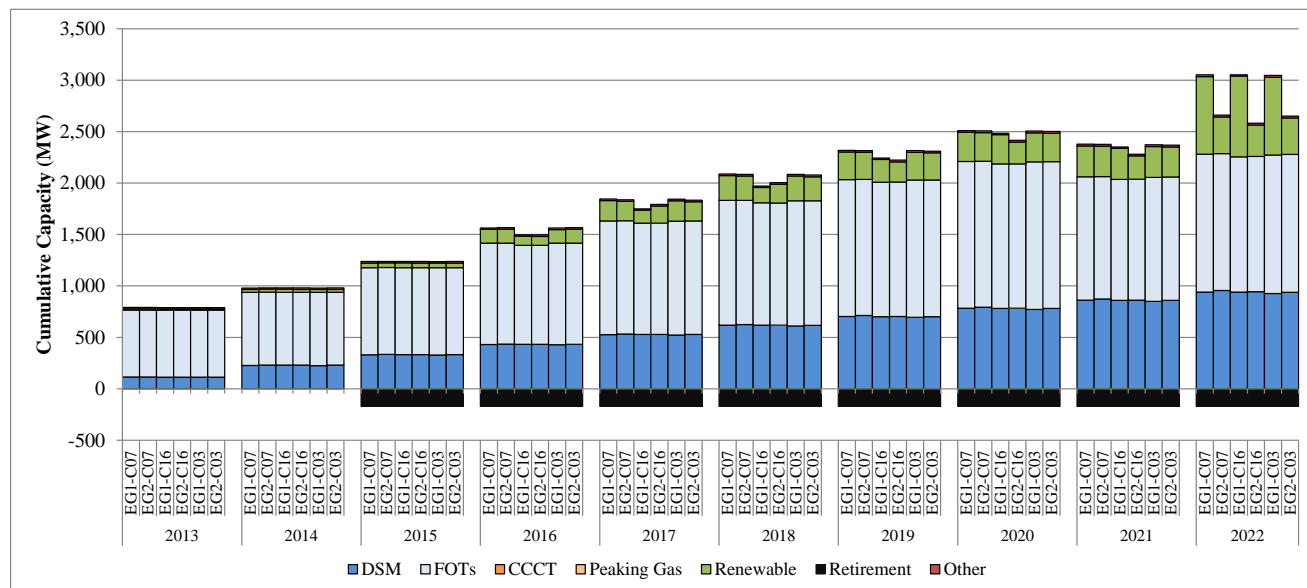


Table 8.5 reports the generation share in each portfolio among new resources by resource category for 2022 and 2032 for the six portfolios beyond the C15 cases that rank highest on a risk adjusted net PVRR basis. The resource categories reported include: thermal (including Lake Side 2), FOTs, renewable, and DSM programs.

Table 8.5 – Percentage Share of Generation of New Resources by Category

2022					
	Thermal	FOTs	Renewable	DSM	Combined Renewables/DSM
EG1-C03	24%	21%	15%	39%	54%
EG1-C07	24%	21%	15%	39%	54%
EG1-C16	24%	20%	16%	38%	55%
EG2-C03	27%	23%	6%	42%	49%
EG2-C07	27%	23%	6%	43%	49%
EG2-C16	27%	23%	7%	43%	49%
2032					
	Thermal	FOTs	Renewable	DSM	Combined Renewables/DSM
EG1-C03	26%	13%	15%	46%	60%
EG1-C07	38%	11%	14%	36%	50%
EG1-C16	26%	13%	15%	46%	61%
EG2-C03	27%	11%	16%	45%	61%
EG2-C07	35%	10%	14%	41%	55%
EG2-C16	28%	13%	17%	42%	59%

Preliminary Selection

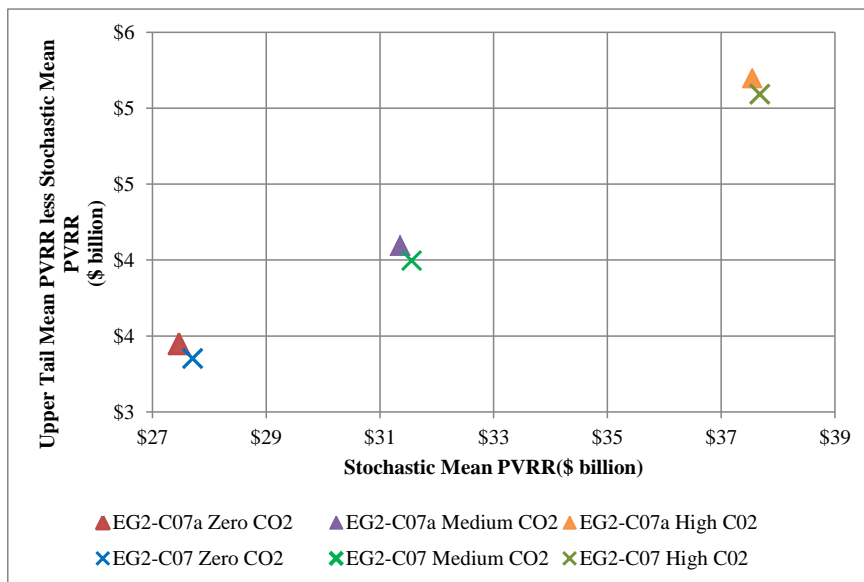
With consideration of the concerns around deliverability of Class 2 DSM resources in portfolios developed under case C15, portfolio C07 under Energy Gateway Scenario 2 ranks highest among the remaining portfolios on a risk-adjusted PVRR basis, and was selected as the preliminary preferred portfolio for the 2013 IRP. Selection of the portfolio developed under case C07 under Energy Gateway Scenario 2 is further supported by preliminary analysis using the SBT, showing net benefits with the addition of the Windstar-Populus project. These benefits would improve in the event the policy and market drivers affecting the addition of cost effective new renewables improve. The current SBT analysis of the Windstar-Populus project would further improve with prospective future additions of other Energy Gateway segments, which would increase the incremental capacity on the new line without any incremental cost.

Final Selection

Incremental wind resources included in the preliminary preferred portfolio prior to 2024 are included solely to meet the RPS compliance requirement in the state of Washington. However, there are potentially lower cost alternatives to meeting the Washington RPS requirement through the use of unbundled renewable energy credits. For this IRP, PacifiCorp performed an analysis that evaluated the use of unbundled renewable energy credits in meeting Washington RPS compliance requirements.

This alternative Washington RPS compliance strategy was performed by first developing an alternative to the EG2-C07 portfolio (EG2-C07a) using the System Optimizer model that excludes 208 MW of wind resources added to the system prior to 2024 that are used entirely for Washington RPS compliance.⁷⁷ In developing this portfolio, the System Optimizer model replaced the Washington situs assigned wind generation with alternative resources. The EG2-C07a portfolio was then analyzed in the PaR model under the same three CO₂ price assumptions used in the portfolio screening process described above. Figure 8.26 shows a scatter plot comparing the EG2-C07a portfolio to the EG2-C07 portfolio among the three different CO₂ price assumptions. As shown in the figure, under each CO₂ price scenario, EG2-C07a portfolio costs are lower and the upper tail risk metric is slightly higher.

Figure 8.26 – Stochastic Mean PVRR versus Upper-tail Risk with Zero CO₂ Prices



⁷⁷ The 208 MW of wind that was removed spans the period 2016 through 2023.

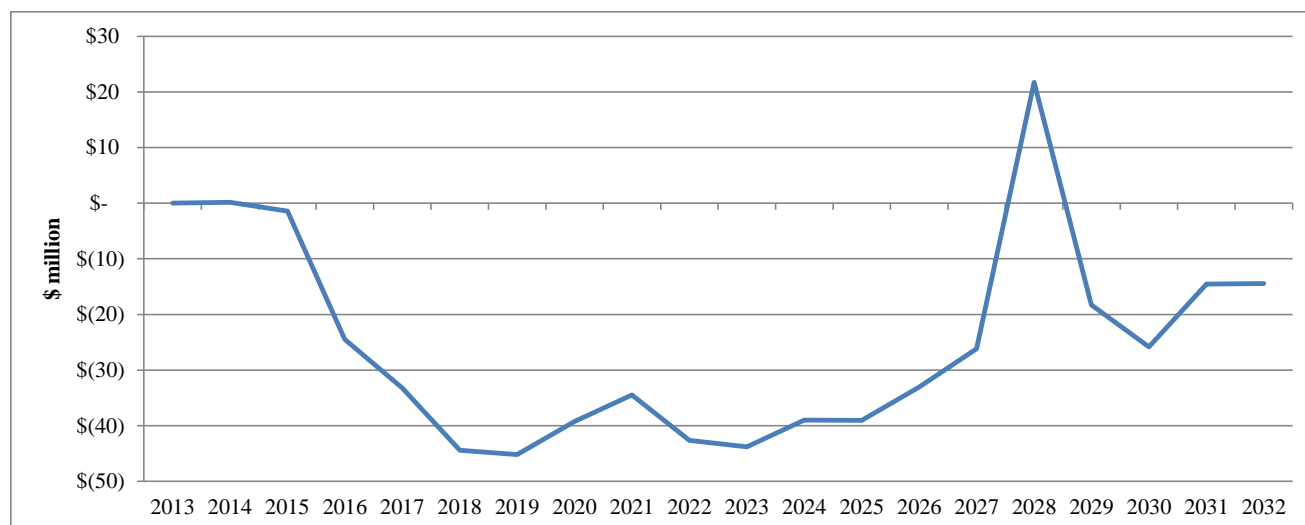
Using the PaR simulation results, the Company calculated the difference in the stochastic mean PVRR and the difference in the risk-adjusted PVRR per megawatt-hour (MWh) of wind generation removed from the EG2-C07 portfolio. Table 8.6 shows the change in the stochastic mean PVRR between the two portfolios, the change in the risk-adjusted net PVRR between the two portfolios, and the associated first year real levelized change in system costs per megawatt-hour of wind removed. Results are provided for each CO₂ price scenario.

Table 8.6 – Impact of Washington Situs Assigned Wind Generation Resources

	Stochastic Mean PVRR		Risk-Adjusted PVRR	
	Reduction in System PVRR with Removal of Wind (\$m)	Real Levelized Reduction System PVRR per MWh of Wind Removed (\$/MWh)	Reduction in System PVRR with Removal of Wind (\$m)	Real Levelized Reduction System PVRR per MWh of Wind Removed (\$/MWh)
Zero CO₂	243	61	232	59
Medium CO₂	200	51	189	48
High CO₂	132	33	116	29

The stochastic mean results above demonstrate that use of unbundled renewable energy credits (REC) at prices at or below the range of \$33/MWh to \$61/MWh, depending upon the CO₂ price scenario, is a lower cost compliance alternative to adding wind resources to the system as a means to achieve compliance with Washington RPS requirements. When accounting for risk, using the risk-adjusted PVRR metric, the range in unbundled REC prices required to achieve a lower cost compliance alternative to meeting Washington RPS requirements is slightly lower than the stochastic mean results, but still significantly higher than currently observed unbundled REC prices. The results above also suggest that REC prices would need to be in the range of \$29/MWh to \$61/MWh, depending upon CO₂ price assumptions and risk profile, for wind resources to be cost-effective given current policy and market conditions. With current unbundled REC prices trading at approximately \$1/MWh, the Company has selected portfolio EG2-C07a as the 2013 IRP preferred portfolio. Figure 8.27 compares the change in nominal revenue requirement between the EG2-C07a and EG2-C07 portfolios. The spike observed in 2028 is driven by the acceleration of Class 1 DSM resources by one year in the case where wind is removed from the EG2-C07 portfolio.

Figure 8.27 – Increase/(Decrease) in Annual Nominal Revenue Requirement with Wind Removed from the EG2-C07 Portfolio



The 2013 IRP Preferred Portfolio

Summary Reports

The following tables and figures summarize the 2013 IRP preferred portfolio:

- Table 8.7 shows the nameplate capacity of resources in the preferred portfolio over the 2013 through 2032 planning period.
- Table 8.8 shows the load and resource balance inclusive of preferred portfolio resources for the first 10 years of the planning horizon.
- Figures 8.28 and 8.29 present the capacity and energy resource mix, respectively, for representative years 2013 and 2022.
 - In the case where the resource type for a purchased power contract is identifiable, the contract is included with the corresponding resource group.
 - Energy mix figures are based upon medium natural gas, power, and CO2 price assumptions.
 - As noted in Chapter 3, the renewable energy capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.
- Figure 8.30 graphically shows how PacifiCorp’s capacity deficit is met through existing and IRP preferred portfolio resources.
- Figure 8.31 shows the contribution of energy from preferred portfolio resources to load growth projections from 2013 levels.
- Table 8.9 shows the amount of energy from Class 2 DSM resources by state.

Table 8.7 – PacifiCorp’s 2013 IRP Preferred Portfolio

Best	Preferred Portfolio (EG-2 Case-07a)	Capacity(MW)																				Resource Totals 1/				
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year			
Best	Existing Plant Retirements/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	(43)			
	Hyden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	(30)			
	Hyden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)		
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)	
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	(106)	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret. WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CCCTFD 2nd	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	1,322
	CCCTJ 1st	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	-	423	-	-	846
	Late Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	-	-	650
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	9
DSM Class 1, ID-Increase	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1	
DSM Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	-	-	-	-	-	-	88	
DSM Class 1, UT-Increase	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0	
DSM Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	19	-	-	-	-	-	-	-	22	
DSM Class 1, WY-Increase	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0	
DSM Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	19	88	-	-	-	-	-	-	121	
DSM Class 2, ID	3	3	3	3	3	3	4	3	4	3	4	3	3	3	3	3	3	3	3	3	3	3	3	31	59	
DSM Class 2, UT	63	61	54	52	50	48	48	43	42	40	30	33	30	28	27	26	24	22	21	20	500	760	-	760		
DSM Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	7	7	7	7	56	127	
DSM Class 2 Total	69	67	61	60	59	57	58	52	52	51	39	42	39	38	37	36	34	32	31	30	587	946	-	946		
Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262	
Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6	
FOT, Iowa Q3	-	-	-	-	-	37	151	248	19	161	255	-	132	253	297	292	300	59	109	74	62	119	-	119		
Expansion Resources	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12	
CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0	
DSM Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	15	
DSM Class 1, WA-DLC-RR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4	
DSM Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	-	44	
DSM Class 1, OR-DLC-RR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	3	
DSM Class 1, CA-DLC-RR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4	
DSM Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	2	
DSM Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-	-	-	72	
DSM Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	
DSM Class 2, OR	37	41	33	32	29	28	24	21	20	23	23	22	22	23	26	24	19	22	22	22	288	517	-	517		
DSM Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	3	3	3	71	112	
DSM Class 2 Total	45	49	42	41	38	35	32	28	27	30	28	28	28	29	32	30	29	23	26	26	368	647	-	647		
OR Solar (Util Cap Standard & Cost Incentive Grant)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	
FOT COB Q3	131	130	247	262	297	297	297	297	297	297	297	237	297	297	297	297	297	297	297	297	297	297	297	255	273	
FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	
FOT AdGobanra Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	
FOT AdGobanra Q3 - 2	19	79	98	221	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	317	
Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(760)	-	(760)	
Annual Additions, Long Term Resources	141	777	121	119	116	106	104	95	96	98	84	942	302	84	171	944	167	1,155	73	254	-	-	-	254		
Annual Additions, Short Term Resources	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246	-	-	-	1,246		
Total Annual Additions	791	1,486	966	1,102	1,218	1,315	1,427	1,515	1,287	1,431	1,511	2,054	1,606	1,509	1,640	2,408	1,639	2,386	1,354	1,500	-	-	-	1,500		

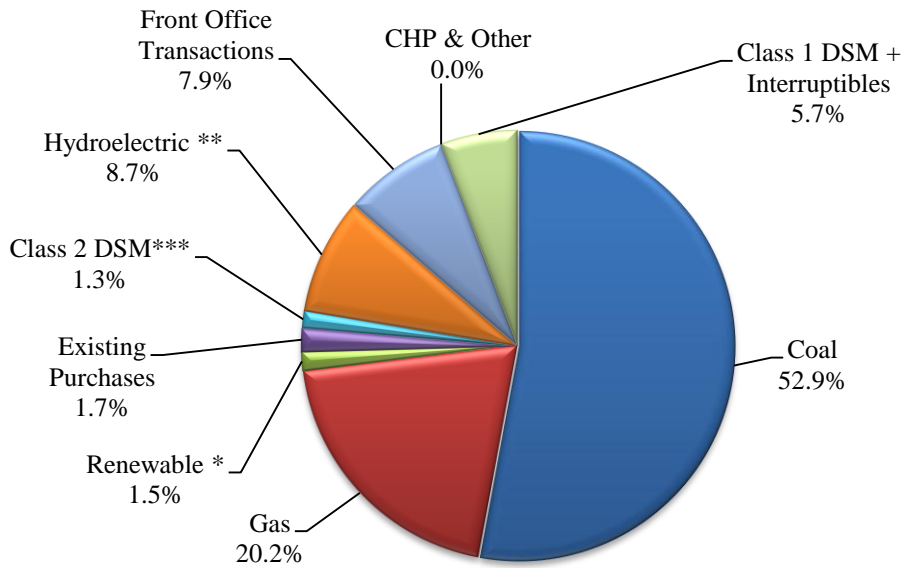
1. Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10-20-year annual average.

Table 8.8 – Preferred Portfolio Capacity Load and Resource Balance (2013-2022)

Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
East										
Thermal	6,200	6,626	6,460	6,454	6,454	6,454	6,454	6,454	6,454	6,454
Hydroelectric	137	140	140	135	135	132	135	135	135	135
Renewable	85	85	83	83	83	83	83	83	82	80
Purchase	1,005	611	611	398	285	285	285	285	257	257
Qualifying Facilities	83	73	73	73	73	73	73	73	73	25
Sale	(1,032)	(732)	(730)	(724)	(638)	(638)	(638)	(639)	(158)	(158)
Non-Owned Reserves	(103)	(103)	(138)	(138)	(138)	(138)	(138)	(138)	(138)	(138)
Transfers	804	574	847	791	890	924	871	850	754	726
East Existing Resources	7,179	7,274	7,346	7,072	7,144	7,175	7,125	7,103	7,459	7,381
Combined heat and Power	0	0	1	3	3	3	3	4	4	6
Front Office Transactions	0	0	0	0	0	41	170	280	22	181
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	1	2	3	4	5	5	6	7	8
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	0	1	3	6	7	49	178	290	33	195
East Total Resources	7,179	7,275	7,349	7,078	7,151	7,224	7,303	7,393	7,492	7,576
Load	6,920	7,061	7,188	6,994	7,105	7,217	7,337	7,455	7,584	7,697
Existing Resources:										
Interruptible	(141)	(143)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)
DSM	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
New Resources:										
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(55)	(109)	(160)	(208)	(255)	(302)	(350)	(389)	(430)	(466)
East obligation	6,345	6,430	6,494	6,252	6,316	6,381	6,453	6,532	6,620	6,697
Planning Reserves (13%)	825	836	844	813	821	830	839	849	861	871
East Reserves	825	836	844	813	821	830	839	849	861	871
East Obligation + Reserves	7,170	7,266	7,338	7,065	7,137	7,211	7,292	7,381	7,481	7,568
East Position	9	9	11	13	14	13	11	12	11	8
East Reserve Margin	13.1%	13.1%	13.2%	13.2%	13.2%	13.2%	13.2%	13.2%	13.2%	13.1%
West										
Thermal	2,524	2,524	2,524	2,520	2,503	2,503	2,503	2,503	2,503	2,500
Hydroelectric	776	751	776	782	780	780	723	726	647	650
Renewable	36	36	36	36	36	36	36	36	36	19
Purchase	482	225	231	13	13	13	2	2	2	2
Qualifying Facilities	88	99	99	89	89	89	88	89	89	89
Sale	(260)	(260)	(160)	(110)	(110)	(110)	(110)	(110)	(109)	(103)
Non-Owned Reserves	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Transfers	(804)	(574)	(848)	(792)	(890)	(924)	(872)	(851)	(754)	(727)
West Existing Resources	2,833	2,792	2,649	2,529	2,412	2,378	2,361	2,386	2,405	2,421
Combined heat and Power	1	1	2	2	3	3	4	4	5	6
Front Office Transactions	734	800	954	1,110	1,246	1,325	1,325	1,325	1,325	1,325
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	735	801	956	1,112	1,249	1,328	1,329	1,329	1,330	1,331
West Total Resources	3,568	3,593	3,605	3,641	3,661	3,706	3,690	3,715	3,735	3,752
Load	3,216	3,269	3,307	3,365	3,407	3,470	3,479	3,516	3,549	3,583
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:										
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(26)	(62)	(86)	(113)	(139)	(161)	(183)	(197)	(217)	(235)
West obligation	3,162	3,179	3,193	3,224	3,240	3,281	3,268	3,291	3,304	3,320
Planning Reserves (13%)	411	413	415	419	421	427	425	428	430	432
West Reserves	411	413	415	419	421	427	425	428	430	432
West Obligation + Reserves	3,573	3,592	3,608	3,643	3,661	3,708	3,693	3,719	3,734	3,752
West Position	(5)	1	(3)	(2)	(0)	(2)	(3)	(4)	1	0
West Reserve Margin	12.8%	13.0%	12.9%	12.9%	13.0%	13.0%	12.9%	12.9%	13.0%	13.0%
System										
Total Resources	10,747	10,868	10,954	10,719	10,812	10,930	10,993	11,108	11,227	11,328
Obligation	9,507	9,609	9,687	9,476	9,556	9,662	9,721	9,823	9,924	10,017
Reserves	1,236	1,249	1,259	1,232	1,242	1,256	1,264	1,277	1,290	1,302
Obligation + Reserves	10,743	10,858	10,946	10,708	10,798	10,918	10,985	11,100	11,214	11,319
System Position	4	10	8	11	14	12	8	8	13	9
Reserve Margin	13.0%	13.1%	13.1%	13.1%	13.1%	13.1%	13.1%	13.1%	13.1%	13.1%

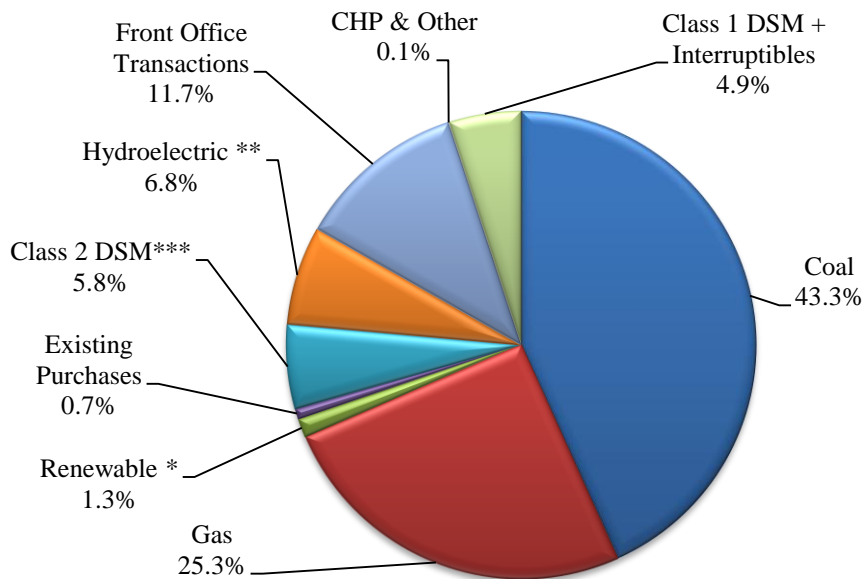
Figure 8.28 – Current and Projected PacifiCorp Resource Capacity Mix for 2013 and 2022

2013 Resource Capacity Mix with Preferred Portfolio Resources



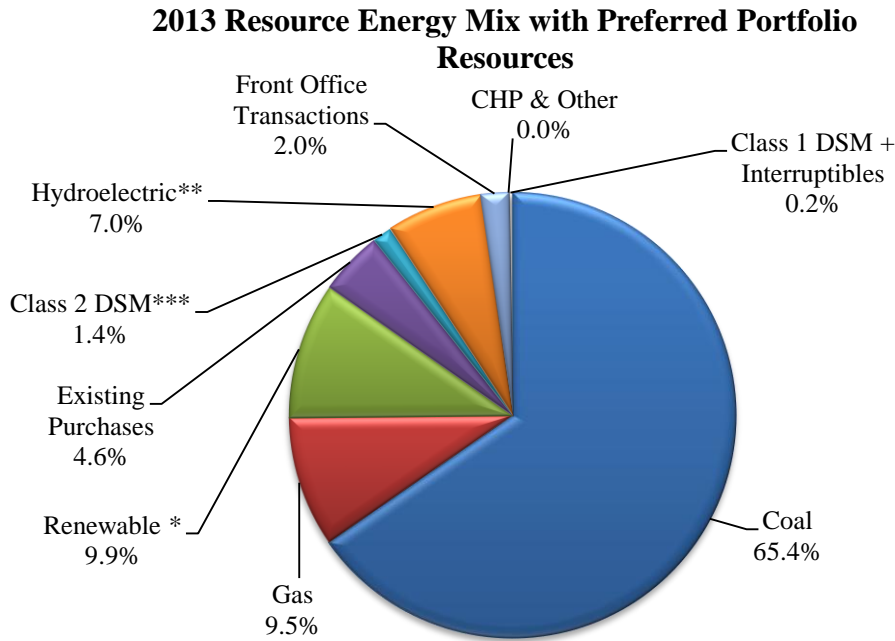
* Renewable resources include wind, solar and geothermal. Wind capacity is reported as the peak load contribution.
 ** Hydroelectric resources include owned, qualifying facilities and contract purchases.
 *** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.

2022 Resource Capacity Mix with Preferred Portfolio Resources



* Renewable resources include wind, solar and geothermal. Wind capacity is reported as the peak load contribution.
 ** Hydroelectric resources include owned, qualifying facilities and contract purchases.
 *** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.

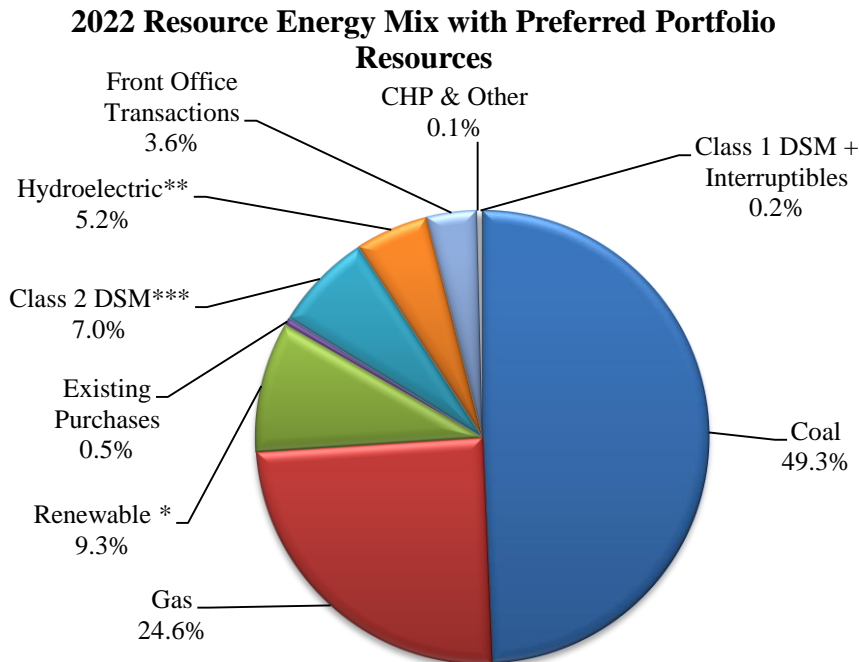
Figure 8.29 – Current and Projected PacifiCorp Resource Energy Mix for 2013 and 2022



* Renewable resources include wind, solar and geothermal.

** Hydroelectric resources include owned, qualifying facilities and contract purchases.

*** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.



* Renewable resources include wind, solar and geothermal.

** Hydroelectric resources include owned, qualifying facilities and contract purchases.

*** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.

Figure 8.30 – Addressing PacifiCorp’s Peak Capacity Deficit, 2013 through 2022

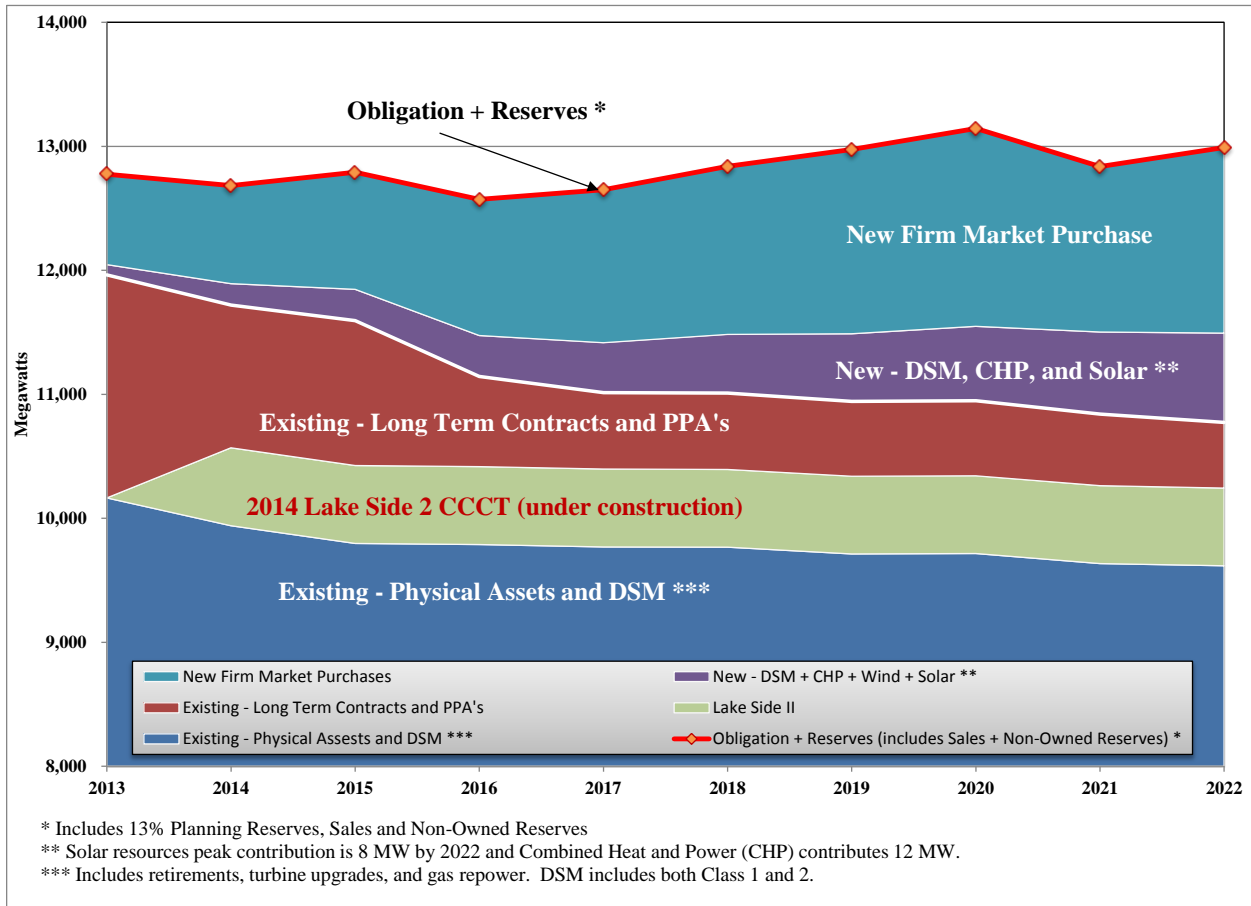


Figure 8.31 – Energy Contribution of the Preferred Portfolio Resources to Load Growth, PacifiCorp System (2013-2022)

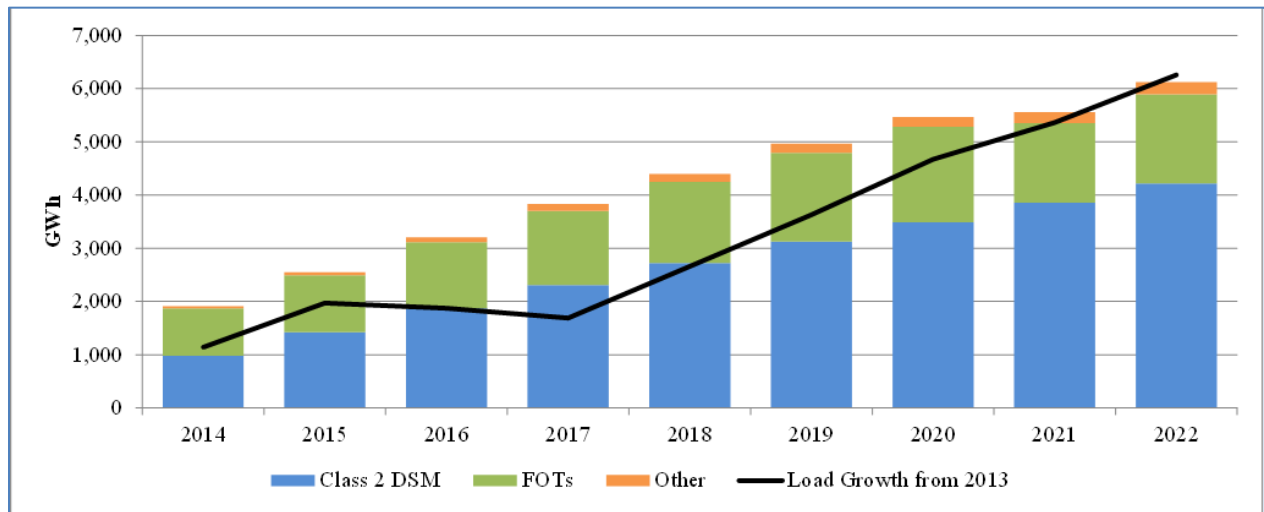


Table 8.9 – Preferred Portfolio Demand Side Management Energy (2013-2022)

Energy Efficiency Energy (MWh) Selected by State and Year										
State	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CA	4,850	4,980	5,500	5,450	5,560	4,680	4,450	4,300	4,730	4,890
OR	168,040	188,540	148,170	145,020	132,770	126,240	108,870	95,900	91,270	99,140
WA	38,200	36,600	36,430	36,740	36,520	30,640	30,530	28,520	28,330	28,630
UT	234,790	224,220	209,570	208,410	203,540	196,600	202,440	174,740	171,900	165,400
ID	10,690	11,090	11,470	12,010	13,540	13,060	14,560	13,770	14,350	14,740
WY	26,850	30,530	34,740	38,680	42,090	43,810	45,250	45,610	50,000	52,840
Total System	483,420	495,960	445,880	446,310	434,020	415,030	406,100	362,840	360,580	365,640
Cumulative	483,420	979,380	1,425,260	1,871,570	2,305,590	2,720,620	3,126,720	3,489,560	3,850,140	4,215,780

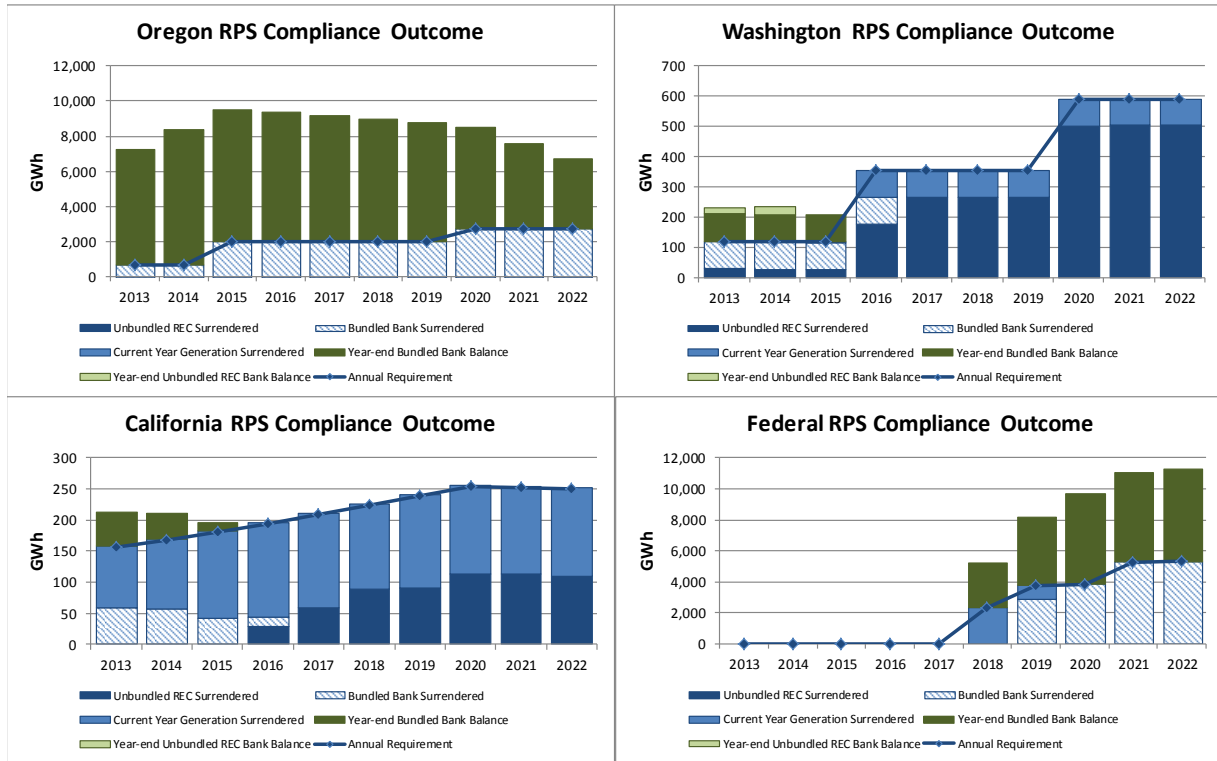
Preferred Portfolio Compliance with Renewable Portfolio Standard Requirements

Figure 8.32 shows PacifiCorp’s forecasted RPS compliance positions for the California, Oregon, and Washington⁷⁸ programs, along with a federal RPS program scenario⁷⁹, covering the period 2013 through 2022 based on the preferred portfolio. Utah’s RPS goal is tied to a 2025 compliance date, so the 2013-2022 position is not shown below. However, PacifiCorp meets the Utah 2025 state target of 20 percent based on eligible Utah RPS resources, and has significant levels of banked RECs to sustain continued future compliance. PacifiCorp anticipates utilizing flexible compliance mechanisms such as banking the use of unbundled RECs as allowed in each state.

⁷⁸ The Washington RPS requirement is tied to January 1st of the compliance year.

⁷⁹ The assumed federal RPS requirements are applied to retail sales, with a target of 4.5 percent beginning in 2018, 7.1 percent in 2019-2020, 9.8 percent in 2021-2022, 12.4 percent in 2023-2024, and 20 percent in 2025.

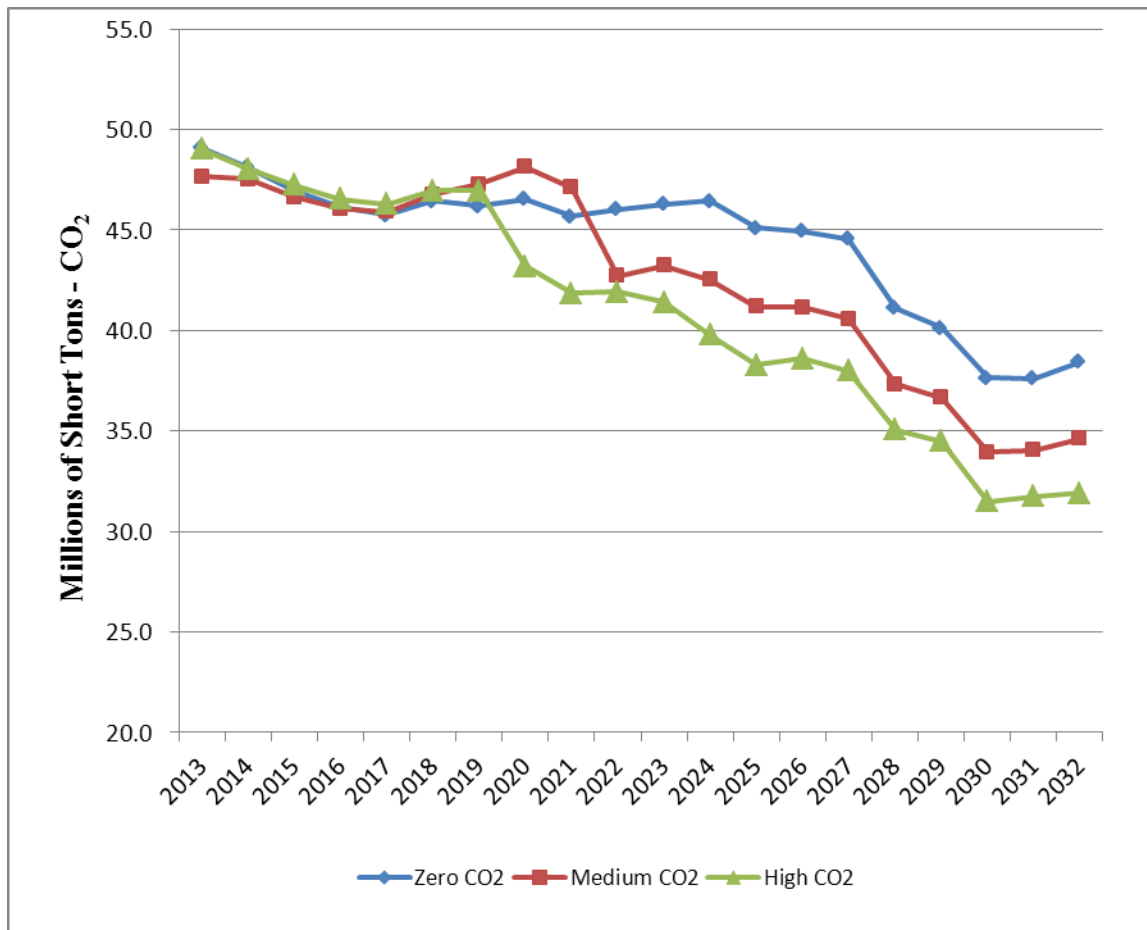
Figure 8.32 – Annual State and Federal RPS Position Forecasts using the Preferred Portfolio



Preferred Portfolio Carbon Dioxide Emissions

Cumulative CO₂ emissions by 2032 for the preferred portfolio under the three CO₂ price scenarios range from 819 million tons to 889 million tons. These emission quantities are reported by the PaR model. Regarding CO₂ emission reduction trends, near-term reductions are driven by plant dispatch changes in response to assumed CO₂ costs. In the longer term, accumulated addition of energy efficiency programs, renewable resources, as well as new gas-fired resources that fill resource needs with assumed end-of-life coal resource retirements contribute to a downward trend in emission levels. Figure 8.33 illustrates the emission trends for the preferred portfolio through 2032 under the zero, medium and high CO₂ price scenarios.

Figure 8.33 – Carbon Dioxide Emission Trend



Sensitivity Analyses

System Optimizer Sensitivity Cases

As described in Chapter 7, sensitivity cases focus on changes to resource-specific assumptions and alternative load growth forecasts. PacifiCorp developed 12 sensitivity cases aligned with the themes used to develop core case portfolios. The sensitivity case themes cover load sensitivities, targeted resource sensitivities, and environmental policy sensitivities, which are described in Confidential Volume III of this IRP report. Sensitivity cases are variants from the System Optimizer portfolios developed under core case definitions. Each sensitivity case was completed under Energy Gateway Scenario 2.

Figure 8.34 shows the cumulative capacity additions by resource type for each of the sensitivity case portfolios in 2032, the end of the 2013 IRP planning horizon. For comparison, portfolios from core case C03 and the preferred portfolio C07a are also included in the figure. Table 8.10 lists the system costs from the System Optimizer model for each of the sensitivity cases, core case C03, and the preferred portfolio (case C07a). The detailed portfolio resource tables are included in Volume II, Appendix K, along with detailed System Optimizer PVRR results.

Figure 8.34– Total Cumulative Capacity of Sensitivity Cases, 2032

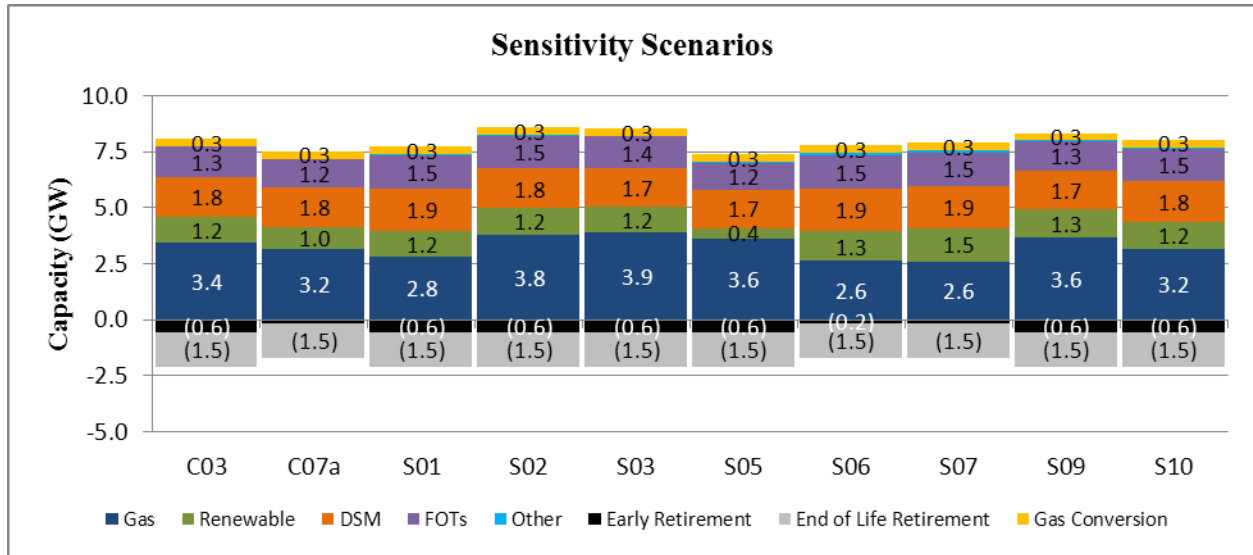


Table 8.10 – PVRR of Sensitivity Cases and the Comparative Core Cases

Case	PVRR (\$m)
C01	\$31,237
C03	\$31,584
Preferred Portfolio (C-07a)	\$27,347
S01	\$30,656
S02	\$33,129
S03	\$31,978
S05	\$31,237
S06	\$31,485
S07	\$31,603
S09	\$38,996
S10	\$31,586

Load Sensitivities (S01, S02, and S03)

PacifiCorp conducted three System Optimizer runs for three alternative load growth scenarios: low load growth (case S01), high load growth (case S02), and 1-in-20 extreme system peak scenario (case S03). Figures 8.35 and 8.36 show how coincident peak and system load forecasts in these sensitivities compare to the base load forecast used to define core cases.

Figure 8.35 – Sensitivity Case Coincidental Peak Load Forecasts

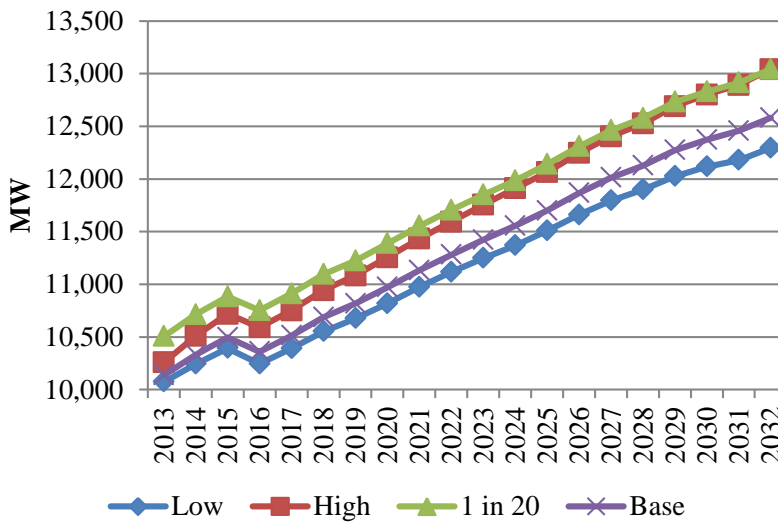
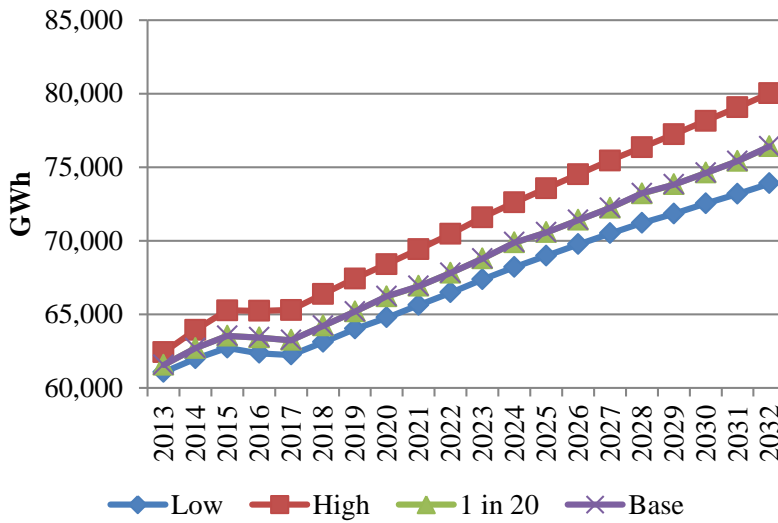


Figure 8.36 – Sensitivity Case Load Forecasts



Under the low load forecast sensitivity, the 2024 CCCT that is in the preferred portfolio is replaced with peaking gas resources added in 2025 and 2026. Similarly, a 2028 CCCT is replaced with a peaking resource in 2029. Under the high load forecast sensitivity, incremental FOTs and DSM meet higher loads through 2018 and a west side 203 MW frame peaking resource is added to the portfolio in 2019. Under the 1-in-20 peak load forecast scenario, FOTs and DSM fill higher capacity requirements through 2017. The portfolio adds a west side 197 MW frame peaking unit in 2018 and an east side 181 MW frame peaking unit in 2020. In the out years (2028 and beyond), peaking units displace a 423 MW CCCT.

Extension of PTC and ITC (S05 and S06)

For this group of sensitivity cases, federal production tax credits (PTCs) and investment tax credits (ITCs) are extended through the end of 2019. Case S05 assumes no RPS requirements and case S06 assumes both state and federal RPS requirements must be met.

Absent RPS assumptions, the extension of the PTC/ITC assumption leads to 144 MW of Wyoming wind in in 2019 (the last year of the extension). With RPS requirements, 2019 wind additions total 500 MW more than in the base case. Figures 8.37 and 8.38 show the addition of wind resources in the two cases. Case S05 wind additions are shown alongside wind additions in the reference case C01 portfolio, which similarly does not include RPS assumptions.

Figure 8.37 – Cumulative Wind Additions, No RPS

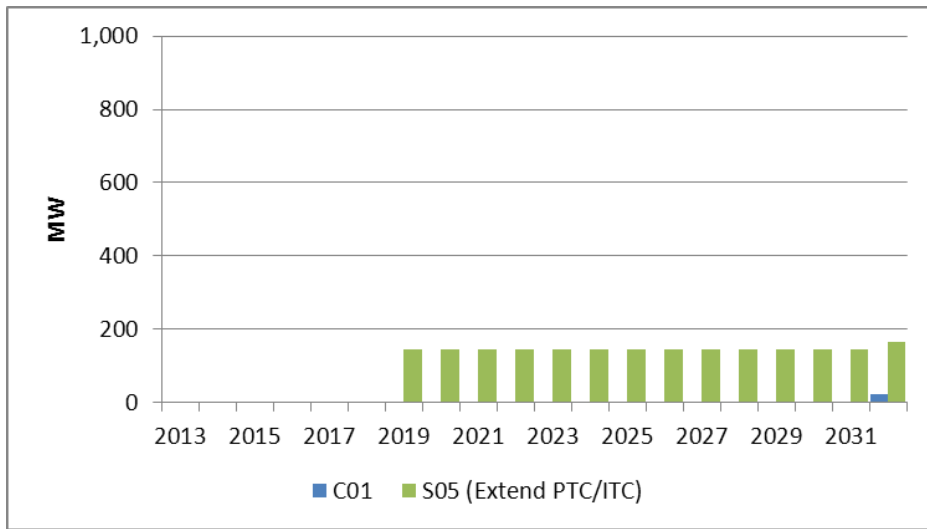
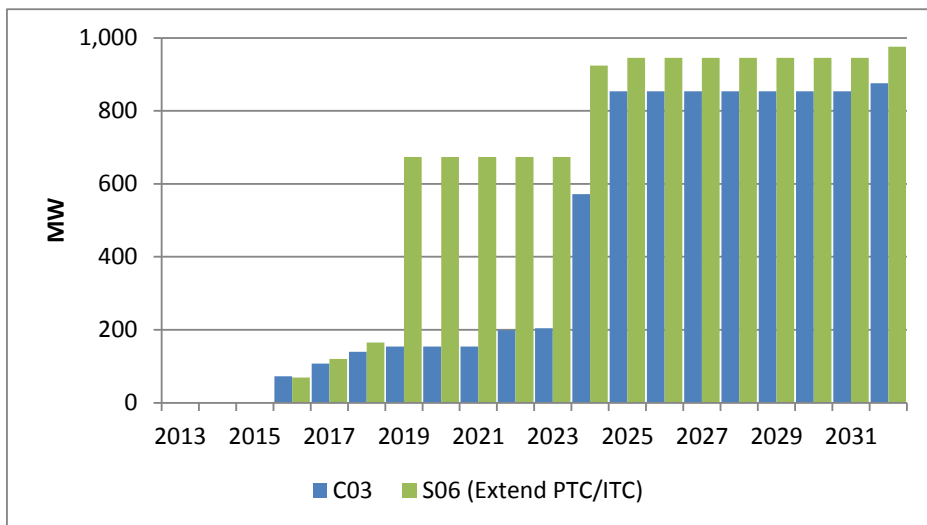


Figure 8.38 – Cumulative Wind Addition, with RPS



Endogenous Selection of Resources to Meet RPS Requirements (S07)

In this case, instead of using the RPS Scenario Maker model to select renewable resources based on state-specific requirements, the resource selections needed to meet RPS requirements were modeled endogenously in the System Optimizer model.

Case S07 produced more renewable capacity at different times and in different locations, and produced system costs that are approximately \$20 million higher than those from case C03. Because the System Optimizer model cannot capture state specific rules, none of the resources, with the exception of the Oregon Geothermal PPA, selected in 2026 could satisfy the Washington requirement that resources be in the Pacific Northwest.⁸⁰ Moreover, there is no objective way to assign generation from resources that were added to meet a “system” RPS requirement back to the specific state to ensure that RPS compliance is achieved in each state.

Table 8.11 compares the renewable resources selected in case S07 with the ones selected by the RPS Scenario Maker model for case C03.

Table 8.11 – Renewable Resources in Case S07 and Case C03

Renewable resource selected in S07:

Resource	Assigned	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
WY Wind (40% CF)	System	0	0	0	1	74	0	0	0	0	0	539	26	0	0	9	0	0	649
UT Wind (29% CF)	System	0	18	12	0	0	0	0	0	16	0	74	0	0	0	0	7	72	199
UT Utility Scale Solar	System	100	0	0	0	0	0	0	0	0	0	0	0	0	0	100	0	0	200
OR Geothermal PPA	System	0	0	0	0	0	0	0	0	0	0	30	0	0	0	0	0	0	30
Total		100	18	12	1	74	0	0	0	16	0	643	26	0	0	109	7	72	1078

Renewable resource selected in C03:

Resource	Assigned	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
WY Wind (40% CF)	System	0	0	0	0	0	0	0	0	368	282	0	0	0	0	0	0	0	650
UT Wind (29% CF)	System	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	22
ID Wind (29% CF)	WA	73	34	33	14	0	0	45	5	0	0	0	0	0	0	0	0	0	204
Total		73	34	33	14	0	0	45	5	368	282	0	0	0	0	0	0	22	876

2013 Business Plan Portfolio (S08)

This sensitivity case was intended to test the impact of PacifiCorp’s 2013 Business Plan resource portfolio in the 2013 IRP modeling environment. However, the changes and updates in the System Optimizer model since the 2013 Business Plan study made it difficult to enforce and merge the previously selected portfolio with the new model inputs. Specifically, Class 2 DSM resources are configured in more detail as compared to what was used to develop the 2013 Business Plan portfolio. It is not practical to reconstruct the previous representation of DSM resources in a way that is compatible with the current modeling system. Consequently, PacifiCorp did not complete this sensitivity case for the 2013 IRP. For comparison purposes, categories of resources in the 2013 Business Plan resource portfolio are shown in Table 8.12.

⁸⁰ Legislation has since been passed in Washington that removes the Pacific Northwest geographic requirement. However, the point remains valid, which is the System Optimizer model does not capture state-specific RPS rules in selecting renewable resources needed to meet RPS requirements.

Table 8.12 – 2013 Business Plan Resource Portfolio

Resource	Capacity (MW)											Resource Totals 2013-2022	
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		
Coal Plant Turbine Upgrades	19	14	-	-	-	-	-	-	-	-	-	-	14
Gas	-	-	638	-	-	-	-	-	-	-	-	-	638
Wind	-	-	-	-	-	-	100	100	100	100	-	-	400
Other Renewables / Solar	4	4	3	3	-	-	-	-	-	-	-	-	10
DSM, Class 1	-	-	-	-	-	-	-	-	1	100	-	-	101
DSM, Class 2	101	86	90	95	93	90	95	97	100	104	110	-	960
Distributed Generation	5	5	5	5	5	5	5	5	5	5	5	5	52
Total Long Term Resources	130	109	736	104	98	95	201	202	305	210	115	-	2,174
Utah Capacity Purchase *	200	200	-	-	200	200	200	200	200	-	-	-	120
East - Firm Market Purchases	62	-	92	51	88	72	130	246	300	81	143	-	120
West - Firm Market Purchases	1,055	918	875	1,078	1,029	1,168	1,217	1,217	1,217	1,217	1,217	-	1,115
Firm Market Purchases	1,317	1,118	967	1,128	1,318	1,440	1,546	1,662	1,717	1,297	1,360	-	1,355

Study includes Naughton 3 gas conversion in 2015
 FOT in resource total are 10-year averages

Resurgence of Renewable Resources (S09)

This sensitivity was designed to target additional selection of renewable resources with high natural gas price and high CO₂ price assumptions while assuming PTCs and ITCs are extended through 2019. As compared with sensitivity case S06, which shares the same input assumptions, but for the use of medium natural gas price and CO₂ prices, the case S09 portfolio did not include additional renewable resources.

Class 3 DSM (S10)

For this sensitivity case, 15 MW of Class 3 DSM resources were added as potential resources in addition to Class 1 DSM resource alternatives. Based on resource needs and economics, 10 MW of the potential Class 3 DSM resource were selected, primarily in 2027, 2031 and 2032, with minimal impact on System Optimizer system costs.

Additional Analysis

Trigger Point Analysis

The Oregon Public Utility Commission (OPUC) guideline 8(c) requires the utility to identify at least one portfolio of resources that is substantially different from the preferred portfolio that can be compared on a risk and cost basis among a range of CO₂ compliance scenarios. As discussed earlier in this chapter, there are several portfolios evaluated across a range of CO₂ emission compliance scenarios that yield extensive coal unit retirements. This includes portfolios developed under cases C05, C09, C14 and C18. Table 8.13 below compares the stochastic mean and risk-adjusted PVRR of these portfolios under Energy Gateway Scenario 2 to the preferred portfolio.

Table 8.13 – Comparison of Trigger Point Portfolios to the Preferred Portfolio

Core Case	Zero CO ₂		Medium CO ₂		High CO ₂	
	Increase in Stochastic Mean PVRR Relative to the Preferred Portfolio (\$b)	Increase in Risk-adjusted PVRR Relative to the Preferred Portfolio (\$b)	Increase in Stochastic Mean PVRR Relative to the Preferred Portfolio (\$b)	Increase in Risk-adjusted PVRR Relative to the Preferred Portfolio (\$b)	Increase in Stochastic Mean PVRR Relative to the Preferred Portfolio (\$b)	Increase in Risk-adjusted PVRR Relative to the Preferred Portfolio (\$b)
C05	3.17	7.17	2.54	7.97	1.42	9.06
C09	4.09	8.47	3.59	9.46	2.33	10.55
C14	2.68	5.88	2.03	6.53	0.97	7.53
C18	7.04	0.83	6.48	0.50	5.51	(0.25)

In each of these cases, the resulting portfolios were developed assuming either high or U.S. hard cap CO₂ price assumptions. Policy makers have not succeeded in passing federal greenhouse gas legislation for consideration by the President. While the U.S. Environmental Protection Agency (EPA) has proposed new source performance standards to regulate greenhouse gas emissions from new sources, it has not finalized those standards, nor has it established a schedule to promulgate rules applicable to existing sources. Concurrently, policy makers continue to debate Federal budget deficits, and deep philosophical differences have thus far proven to be a barrier to budgetary compromise. Given these considerations, the Company does not believe greenhouse gas policies or regulations will be mandated at the levels and on a schedule that contributed to the extensive level of early coal unit retirements and gas conversions observed in the cases summarized in the table above.

Oregon Greenhouse Gas Goals

The OPUC guideline 8(d) requires that a portfolio be constructed that meets state of Oregon energy policies, including state goals for reducing greenhouse emissions. Several of the portfolios developed in this IRP fall below the Oregon goal stated in House Bill 3543 (10 percent below 1990 emission levels by 2020). For PacifiCorp's system, the 1990 emission level was 49.88 million short tons, and 10 percent below this level is 44.89 million short tons. Table 8.13 compares the preferred portfolio with portfolios developed for Energy Gateway Scenario 2 that are in compliance with the emission reduction goal in Oregon.

Table 8.13 – Cost/Risk Comparison of Compliance Portfolios and the Preferred Portfolio, with Medium CO₂ Prices

Case	Stochastic Mean PVRR	Upper Tail Mean PVRR	Emissions in 2020 Thousands of Ton
EG1-C04	33,507	46,307	34,868
EG1-C05	34,035	46,056	34,695
EG1-C08	34,378	48,397	26,999
EG1-C09	35,009	48,382	26,852
EG1-C14	33,401	44,056	36,811
EG2-C04	33,554	46,234	34,955
EG2-C05	33,898	45,965	34,802
EG2-C07a	31,357	35,452	48,124
EG2-C08	34,548	48,357	27,273
EG2-C09	34,944	48,502	27,239
EG2-C14	33,384	44,013	36,934

CHAPTER 9 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2013 IRP action plan identifies steps to be taken during the next two to four years to implement the IRP. The preferred portfolio reflects a snapshot view of the future that accounts for a wide range of uncertainties, and is not intended as a procurement commitment.
- Achieve renewable compliance with unbundled renewable energy credit purchases.
- Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity.
- Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017
- Continue to pursue the Energy Imbalance Market activities in California and the Northwest Power Pool
- Manage and improve the longer term natural gas hedging process and products, and continue to work with stakeholders.
- Acquire up to 1,425 – 1,876 GWh of cost effective Class 2 energy efficiency by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017.
- Develop a pilot program in Oregon for Class 3 time-of-use program as an alternative approach to Class 1 irrigation load control program for managing irrigation load in the west.
- Continue to permit and develop the Naughton Unit 3 natural gas conversion project.
- Complete the installation of the baghouse conversion and NO_x burner compliance projects at Hunter Unit 1 as required by the end of 2014.
- Complete the installation of selective catalytic reduction compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4.
- Evaluate alternative compliance strategies that will meet Regional Haze compliance obligations for Cholla Unit 4.
- Establish a stakeholder group process to review the System Operational and Reliability Benefits Tool (SBT).
- Complete the Sigurd to Red Butte 345kV transmission line according to the construction plan.
- Evaluate through the resource acquisition paths, the fundamentals-based shifts in environmental policy, enactment of regulatory policies, and different load trajectories.
- Continue to use competitive solicitation processes and pursue opportunistic acquisitions identified outside of a competitive procurement process that provide clear economic benefits to customers.

Introduction

PacifiCorp's 2013 IRP action plan identifies the steps the Company will take during the next two to four years to implement the plan that covers the 10 year resource acquisition time frame, 2013-2022. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time horizon that could materially impact resource acquisition strategies.

The resources included in the 2013 IRP preferred portfolio were used to help define the actions included in the action plan, focusing on the size, timing and type of resources needed to meet load obligations, and current and potential future state regulatory requirements. The preferred portfolio resource combination was determined to be the lowest cost on a risk-adjusted basis accounting for cost, risk, reliability, regulatory uncertainty and the long-run public interest.

The 2013 IRP action plan is based upon the latest and most accurate information available at the time of portfolio study. The Company recognizes that the preferred portfolio upon which the action plan is based reflects a snapshot view of the future that accounts for a wide range of uncertainties.

Resource information used in the 2013 IRP, such as capital and operating costs, incorporate the Company's most up to date cost information. However, it is important to recognize that the resources identified in the plan are proxy resources and act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resource identified in the plan with respect to resource type, timing, size, cost and location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition, and the evaluations will comply with then-current laws, regulatory rules and orders.

In addition to the action plan, progress on the prior action plan, and the acquisition path analysis, this chapter covers the following topics:

- Procurement delays
- IRP Action Plan linkage to the business plan
- Resource Procurement Strategy
- Assessment of owning assets vs. purchasing power
- Managing carbon risk for existing plants
- Purpose of hedging
- The treatment of customer and investor risks for resource planning

The Integrated Resource Plan Action Plan

The 2013 IRP action plan, detailed in Table 9.1, provides the Company with a road map for moving forward with new resource acquisitions.

The 2013 IRP Action Plan

The 2013 IRP Action Plan identifies specific actions the Company will take over the next two to four years. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2013 IRP process. Table 9.1 details specific 2013 IRP action items by category.

Table 9.1 – 2013 IRP Action Plan

Action Item	12. Renewable Resource Actions
1a.	<p><u>Wind Integration</u></p> <ul style="list-style-type: none"> Update the wind integration study for the 2015 IRP. The updated wind integration study will consider the implications of an energy imbalance market along with comments and feedback from the technical review committee and IRP stakeholders provided during the 2012 Wind Integration Study.
1b.	<p><u>Renewable Portfolio Standard Compliance</u></p> <ul style="list-style-type: none"> With renewable portfolio standard (RPS) compliance achieved with unbundled renewable energy credit (REC) purchases, the preferred portfolio does not include incremental renewable resources prior to 2024. Given that the REC market lacks liquidity and depth beyond one year forward, the Company will pursue unbundled REC requests for proposal (RFP) to meet its state RPS compliance requirements. <ul style="list-style-type: none"> Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard obligations. Issue at least annually, RFPs seeking historical, then current-year, or forward-year vintage unbundled RECs that will qualify for Oregon renewable portfolio standard obligations. As part of the solicitation and bid evaluation process, evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives. Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify for California renewable portfolio standard obligations.
1c.	<p><u>Renewable Energy Credit Optimization</u></p> <ul style="list-style-type: none"> On a quarterly basis, issue reverse RFPs to sell RECs not required to meet state RPS compliance obligations.
1d.	<p><u>Solar</u></p> <ul style="list-style-type: none"> Issue an RFP in the second quarter of 2013 soliciting Oregon solar photovoltaic resources to meet the Oregon small solar compliance obligation (Oregon House Bill 3039). Coordinate the selection process with the Energy Trust of Oregon to seek 2014 project funding. Complete evaluation of proposals and select potential winning bids in the

	<p>fourth quarter of 2013.</p> <ul style="list-style-type: none"> • Issue a request for information 180 days after filing the 2013 IRP to solicit updated market information on utility scale solar costs and capacity factors.
1e.	<p><u>Capacity Contribution</u></p> <ul style="list-style-type: none"> • Track and report the statistics used to calculate capacity contribution from wind resources and available solar information as a means of testing the validity of the peak load carrying capability (PLCC) method.
Action Item	13. Distributed Generation Actions
2a.	<p><u>Distributed Solar</u></p> <ul style="list-style-type: none"> • Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity. Beginning in June 2014, as stipulated in the Order in Docket No. 11-035-104, the Company will file an Annual Report with program results, system costs, and production data. These reports will also provide an opportunity to evaluate and improve the program as the Company will use this opportunity to recommend changes. Interested parties will have an opportunity to comment on the report and any associated recommendations.
2b.	<p><u>Combined Heat & Power (CHP)</u></p> <ul style="list-style-type: none"> • Pursue opportunities for acquiring CHP resources, primarily through the Public Utilities Regulatory Policies Act (PURPA) Qualifying Facility contracting process. For the 2013 IRP Update, complete a market analysis of CHP opportunities that will: (1) assess the existing, proposed, and potential generation sites on PacifiCorp’s system; (2) assess availability of fuel based on market information; (3) review renewable resource site information (i.e. permits, water availability, and incentives) using available public information; and (4) analyze indicative project economics based on avoided cost pricing to assist in ranking probability of development.
Action Item	14. Firm Market Purchase Actions
3a.	<p><u>Front Office Transactions</u></p> <ul style="list-style-type: none"> • Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017. <ul style="list-style-type: none"> – Resources will be procured through multiple means, such as periodic market RFPs that seek resources less than five years in term, and bilateral negotiations. – Include in the 2013 IRP Update a summary of the progress the Company has made to acquire front office transactions over the 2014 to 2017 forward period.
Action Item	15. Flexible Resource Actions

<p>4a.</p>	<p><u>Energy Imbalance Market (EIM)</u></p> <ul style="list-style-type: none"> • Continue to pursue the EIM activities with the California Independent System Operator and the Northwest Power Pool to further optimize existing resources resulting in reduced costs for customers.
<p>Action Item</p>	<p>16. Hedging Actions</p>
<p>5a.</p>	<p><u>Natural Gas Request for Proposal</u></p> <ul style="list-style-type: none"> • Convene a workshop for stakeholders by October 2013 to discuss potential changes to the Company’s process in evaluating bids for future natural gas RFPs, if any, to secure additional long-term natural gas hedging products.
<p>Action Item</p>	<p>17. Plant Efficiency Improvement Actions</p>
<p>6a.</p>	<p><u>Plant Efficiency Improvements</u></p> <ul style="list-style-type: none"> • Production efficiency studies have been conducted to satisfy requirements of the Washington I-937 Production Efficiency Measure that have identified categories of cost effective production efficiency opportunity. <ul style="list-style-type: none"> – By the end of the first quarter of 2014, complete an assessment of the plant efficiency opportunities identified in the Washington I-937 studies that might be applicable to other wholly owned generation facilities. – Prior to initiating modeling efforts for the 2015 IRP, determine a multi-state “total resource cost test” evaluation methodology to address regulatory recovery among states with identified capital expenditures. – Prior to initiating modeling efforts for the 2015 IRP, present to IRP stakeholders in a public input meeting the Company’s recommended approach to analyzing cost effective production efficiency resources in the 2015 IRP.
<p>Action Item</p>	<p>18. Demand Side Management (DSM) Actions</p>

<p>7a.</p>	<p><u>Class 2 DSM</u></p> <ul style="list-style-type: none"> • Acquire 1,425 – 1,876 gigawatt hours (GWh) of cost-effective Class 2 energy efficiency resources by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017. <ul style="list-style-type: none"> – Collaborate with the Energy Trust of Oregon on a pilot residential home comparison report program to be offered to Pacific Power customers in 2013 and 2014. At the conclusion of the pilot program and the associated impact evaluation, assess further expansion of the program. – Implement an enhanced consolidated business program to increase DSM acquisition from business customers in all states excluding Oregon. <ul style="list-style-type: none"> ▪ Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. ▪ Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014. ▪ Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014. – Accelerate to the 2nd quarter of 2014, an evaluation of waste heat to power where generation is used to offset customer requirements – investigate how to integrate opportunities into the DSM portfolio. – Increase acquisitions from business customers through prescriptive measures by expanding the “Trade Ally Network”. <ul style="list-style-type: none"> ▪ Base case target in all states is 3rd quarter 2014, with an accelerated target of 4th quarter 2013 – Accelerate small-mid market business DSM acquisitions by contracting with third party administrators to facilitate greater acquisitions by increasing marketing, outreach, and management of comprehensive custom projects by 1st quarter 2014. – Increase the reach and effectiveness of “express” or “typical” measure offerings by increasing qualifying measures, reviewing and realigning incentives, implementing a direct install feature for small commercial customers, and expanding the residential refrigerator and freezer recycling program to include commercial units. <ul style="list-style-type: none"> ▪ Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. ▪ Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014. ▪ Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014. – Increase the reach of behavioral DSM programs: <ul style="list-style-type: none"> ▪ Evaluate and expand the residential behavioral pilot. <ul style="list-style-type: none"> ◆ Utah base case schedule is 2nd quarter 2014, with an accelerated target of 4th quarter 2013. ▪ Accelerate commercial behavioral pilot to the end of the first quarter 2014. ▪ Expand residential programs system-wide pending evaluation results. <ul style="list-style-type: none"> ◆ System-wide target is 3rd quarter 2015, with an accelerated target of 3rd quarter 2014. – Increase acquisition of residential DSM resources:
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	<ul style="list-style-type: none"> ▪ Implement cost effective direct install options by the end of 2013. ▪ Expand offering of “bundled” measure incentives by the end of 2013. ▪ Increase qualifying measures by the end of 2013. ▪ Review and realign incentives. <ul style="list-style-type: none"> ◆ Utah schedule is 1st quarter 2014 ◆ Washington base case schedule is 2nd quarter 2014, with accelerated target of 1st quarter 2014. ◆ Wyoming, California, and Idaho base case schedule is 3rd quarter 2014, with an accelerated target of 2nd quarter 2014 – Accelerate acquisitions by expanding refrigerator and freezer recycling to incorporate retail appliance distributors and commercial units – 3rd quarter 2013. – By the end of 2013, complete review of the impact of accelerated DSM on Oregon and the Energy Trust of Oregon, and re-contract in 2014 for appropriate funding as required. – Include in the 2013 IRP Update Class 2 DSM decrement values based upon accelerated acquisition of DSM resources. – Include in the 2014 conservation potential study an analysis testing assumptions in support of accelerating acquisition of cost-effective Class 2 DSM resources, and apply findings from this analysis into the development of candidate portfolios in the 2015 IRP.
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<p>7b.</p>	<p><u>Class 3 DSM</u></p> <ul style="list-style-type: none"> • Develop a pilot program in Oregon for a Class 3 irrigation time-of-use program as an alternative approach to a Class 1 irrigation load control program for managing irrigation loads in the west. The pilot program will be developed for the 2014 irrigation season and findings will be reported in the 2015 IRP.
<p>Action Item</p>	<p>19. Coal Resource Actions</p>
<p>8a.</p>	<p><u>Naughton Unit 3</u></p> <ul style="list-style-type: none"> • Continue permitting and development efforts in support of the Naughton Unit 3 natural gas conversion project. The permit application requesting operation on coal through year-end 2017 is currently under review by the Wyoming Department of Environmental Quality, Air Quality Division. • Issue a request for proposal to procure gas transportation for the Naughton plant as required to support compliance with the conversion date that will be established during the permitting process. • Issue an RFP for engineering, procurement, and construction of the Naughton Unit 3 natural gas retrofit as required to support compliance with the conversion date that will be established during the permitting process.
<p>8b.</p>	<p><u>Hunter Unit 1</u></p> <ul style="list-style-type: none"> • Complete installation of the baghouse conversion and low NO_x burner compliance projects at Hunter Unit 1 as required by the end of 2014.
<p>8c.</p>	<p><u>Jim Bridger Units 3 and 4</u></p> <ul style="list-style-type: none"> • Complete installation of selective catalytic reduction (SCR) compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4 as required by the end of 2015 and 2016, respectively.
<p>8d.</p>	<p><u>Cholla Unit 4</u></p> <ul style="list-style-type: none"> • Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency’s Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives in the 2013 IRP Update.
<p>Action Item</p>	<p>20. Transmission Actions</p>
<p>9a.</p>	<p><u>System Operational and Reliability Benefits Tool (SBT)</u></p> <ul style="list-style-type: none"> • 60 days after filing the 2013 IRP, establish a stakeholder group and schedule workshops to further review the System Benefit Tool (SBT). <ul style="list-style-type: none"> – For the 2013 IRP Update, complete additional analysis of the Energy Gateway West Segment D that evaluates staging implementation of Segment D by sub-segment.

	<ul style="list-style-type: none"> – In preparation for the 2015 IRP, continue to refine the SBT for Energy Gateway West Segment D and develop SBT analyses for additional Energy Gateway segments.
9b.	<p><u>Energy Gateway Permitting</u></p> <ul style="list-style-type: none"> • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: <ul style="list-style-type: none"> – Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – Segment D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach projected through the next 2 to 4 years. – Segment H Cascade Crossing, complete benefits analysis in 2013. – Segment H Boardman to Hemingway, continue to support the project under the conditions of the Boardman to Hemingway Transmission. Project Joint Permit Funding Agreement, projected through 2015.
9c.	<p><u>Sigurd to Red Butte 345 kilovolt Transmission Line</u></p> <ul style="list-style-type: none"> • Complete project construction per plan.
Action Item	21. Planning Reserve Margin Actions
10a.	<p><u>Planning Reserve Margin</u></p> <ul style="list-style-type: none"> • Continue to evaluate in the 2015 IRP the results of a System Optimizer portfolio sensitivity analysis comparing a range of planning reserve margins considering both cost and reliability impacts of different levels of planning reserve margin assumptions. Complete for the 2015 IRP an updated planning reserve margin analysis that is shared with stakeholders during the public process.
Action Item	22. Planning and Modeling Process Improvement Actions
11a.	<p><u>Modeling and Process</u></p> <ul style="list-style-type: none"> • Within 90 days of filing the 2013 IRP, schedule an IRP workshop with stakeholders to discuss potential process improvements that can more efficiently achieve meaningful cost and risk analysis of resource plans in the context of the IRP and implement process improvements in the 2015 IRP.
11b.	<p><u>Cost/Benefit Analysis of DSM Resource Alternatives</u></p> <ul style="list-style-type: none"> • Complete a cost/benefit analysis on the level of detail used to evaluate prospective DSM resources in the IRP. The analysis will consider the tradeoffs between model run-time and resulting resource selections, will be shared with stakeholders early in the 2015 IRP public process, and will inform how prospective DSM resources will be aggregated in developing resource portfolios for the 2015 IRP.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous active action plan items documented in the 2011 Integrated Resource Plan Update report filed with the state commissions on March 31, 2011. Many of these action items have been superseded in some form by items identified in the current IRP action plan.

Action Item 1: Renewable / Distributed Generation 2021-2020

- Acquire up to 800 MW of wind resources by 2020, dictated by regulatory and market developments such as (1) renewable/clean energy standards; (2) carbon regulations; (3) federal tax incentives; (4) economics; (5) natural gas price forecasts; (6) regulatory support for investments necessary to integrate variable energy resources (VERs); and (7) transmission developments. The 800 MW level is supported by consideration of regulatory compliance risks and public policy interest in clean energy resources.
- In the 2013 IRP, PacifiCorp will track and report the statistics used to calculate capacity contribution from its wind resources as a means of testing the validity of the PLCC method.
- Future IRP cycles will include a projection for wind acquisition with and without geothermal until a clearer picture emerges regarding geothermal dry hole risk.
- The Company will continue to refine the wind integration modeling approach; establish a technical review committee (TRC) and a schedule and project plan for the next wind integration study. The TRC will be formed and members identified within 30 days of the effective date of the IRP Order. Within 30 days of the effective date of the IRP Order, a schedule for the study will be established, including full opportunity for stakeholder involvement and progress reviews by the TRC that will allow the final study to be submitted with the next IRP.
- The Company identified over 100 MW of geothermal resources as part of a least-cost resource portfolio. Continue to refine resource potential estimates and update resource costs in 2011-2012 for further economic evaluation of resource opportunities.
- Continue to explicitly include geothermal projects as eligible resources in future all-source RFPs.
- Evaluate procurement of Oregon solar photovoltaic resources in 2012 via the Company's solar RFP.
- Acquire additional Oregon solar resource through RFPs or other means in order to meet the Company's 8.7 MW compliance obligation
- Work with Utah parties to investigate solar program design and deployment issues and opportunities in late 2011 and 2012, using the Company's own analysis of Wasatch Front roof top solar potential and experience with the Oregon solar pilot program. As recommended in the Company's response to comments under Docket No. 07-035-T14, the Company requested that the Utah Commission establish "a process in the fall of 2011 to determine whether a continued or expanded solar program in Utah is appropriate and how that program might be structured." (Rocky Mountain Power, "Re: Docket No. 07-035-T14 – Three year assessment of the Solar Incentive Program", December 15, 2010).
- Investigate, and pursue if cost-effective from an implementation standpoint, commercial/residential solar water heating programs.

- Pursue opportunities for acquiring biomass CHP resources, primarily through the PURPA Qualifying Facility contracting process.
- Proceed with an energy storage demonstration project, subject to Utah Commission approval of the Company’s proposal to defer and recover expenditures through the DSM surcharge.
- Initiate a consultant study in 2011 on incremental capacity value and ancillary service benefits of energy storage.
- Conduct a study of grid flexibility for accommodating variable energy resources (VER) as part of the next IRP filing.
- Develop and refine strategies for renewable portfolio standard compliance in California and Washington.
- PacifiCorp will expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. The Company will be selective in its discussion to avoid conflict between the IRP, RPS Implementation Plan and RPS Compliance Report.

Status

The Company acquired 160 MW of renewable resources between 2010 and 2012. With the decrease in natural gas prices, lower power prices, lack of load and changes in the expectation for the extension of the federal tax incentives, incremental wind in the current preferred portfolio first appears in 2024 and is driven by renewable portfolio requirements. The renewable portfolio standard requirements will be met by purchasing renewable energy credits in the market consistent with the preferred portfolio and Action Item 1b in the 2013 IRP Action Plan.

Using historical wind generation data from wind resources in the PacifiCorp system, the Company completed a study evaluating how much wind capacity has historically been available during peak load conditions. This analysis has been used to update the Company’s capacity contribution assumptions for wind resources as summarized in Volume II, Appendix O of the 2013 IRP.

Case C-16 in the 2013 IRP is one of five core cases in the “Targeted Resources” theme (Cases C-15 through C-18) which evaluates meeting renewable portfolio standards using available geothermal resources, modeled as a power purchase agreement, before using other RPS-eligible renewable technologies. These cases are characterized by alternative assumptions for specific resource types to understand how those assumptions influence resource portfolios, costs and stochastic risk.

For its 2012 Wind Integration Study, PacifiCorp established a technical review committee (TRC). The TRC members were selected based on their experience and background in the field of the wind integration study and regulatory requirements. PacifiCorp held several meetings with the TRC to review the detailed calculations of reserve requirements to integrate wind resources in its balancing authority areas. The six TRC members’ biographies and the wind integration study’s schedule are posted on PacifiCorp’s IRP website. The TRC will provide their report of the wind study in early May 2013 and the Company will file the report within 30 days of the receiving it.

A Geothermal Information Request report (public version) was posted to the IRP website and IRP participants were notified on June 28, 2012. Geothermal resources were explicitly included in the All Source request for proposal (RFP) for 2016 resources, which was subsequently terminated. In addition, geothermal power purchases approximated based on information received from the 2016 All Source RFP were included as proxy resources in the supply side table in Volume I, Chapter 6 of the 2013 IRP.

As a result of the 2010S request for proposals, the Company acquired the Black Cap Solar Facility which is located on 20 acres a few miles west of Lakeview, Oregon. Ideally situated on the sunny side of the Cascade Range, the two-megawatt facility is equipped with a sophisticated tracking system that optimizes the sun's power. Lakeview is in Oregon's High Desert and sits at an elevation of 4,800 feet. The valley opens to the south and enjoys more than 300 days of sunshine a year. Black Cap started generating electricity for customers in October 2012 and will produce approximately 4,500 megawatt-hours of electricity each year – comparable to the energy needed to serve 400 average homes annually. The Company will apply the experience gained through the project in its next request for proposals.

A request for proposals will be issued in the second quarter of 2013 to acquire further Oregon solar resources as identified in the 2103 IRP Action Item 1d.

On October 1, 2012, the Utah Public Service Commission approved a large expansion of the Utah Solar Incentive Program in Docket 11-03-104. The program will incentivize the installation of 60 MW of distributed solar generation in systems sized one MW and below over the next five years. The program began accepting applications on January 15, 2013.

The final Cadmus memo provided to the public on October 31, 2012 provides updated supply curves for commercial/residential solar water heating programs which were used in the 2013 IRP.

The Company continues to pursue resources through PURPA Qualifying Facility contracting process. The 2013 IRP Action item 2b will assess the opportunities and provide a market analysis for acquiring biomass CHP resources in the 2013 IRP Update.

The energy storage demonstration project progressed to the point of testing the five kilowatt-hour electrostatic generator at moderated speed in a partially integrated prototype. At this speed the actual resonances encountered closely matched theoretical models. By the end of 2012 the prototype was being transported to a higher speed spin pit to test the output voltages produced in generation mode. The energy storage demonstration development and demonstrated report was sent to the public in May 2012. Due to lack of supplier funding, in 2013 this project is no longer being pursued by PacifiCorp.

A consultant study was initiated in 2011 on incremental capacity value and ancillary service benefits of energy storage. HDR Engineering (HDR) was retained by PacifiCorp to perform an Energy Storage Study to evaluate a portfolio of energy storage options. The scope of the study was to develop a current catalog of commercially available and emerging large, utility-scale and distribution scale energy storage technologies as well as define respective applications, performance characteristics and estimated capital and operating costs for each technology. The

results are documented in the December 2011 report that was sent to the public on September 4, 2012. The report can be found at the following website:

http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/Report_Energy-Storage-Screening-Study2012.pdf

A study was completed for a needs assessment of PacifiCorp's flexible resources to meet its reserve requirements, which is in Volume II, Appendix F.

In this IRP, the development and refinement for RPS compliance in California and Washington and the RPS compliance strategies and the role of REC sales and purchases are outlined in Volume I, Chapters 3, 7, and 8. This action item has been superseded by Action Item 1b in Table 9.1.

Action Item 2: Intermediate/ Base-load Thermal Supply-side Resources 2014-2016

- Acquire a combined-cycle combustion turbine (CCCT) resource at the Lake Side site in Utah by the summer of 2014; the plant is proposed to be constructed by CH2M Hill E&C, Inc. ("CH2M Hill") under the terms of an engineering, procurement, and construction (EPC) contract. This resource corresponds to the 2014 CCCT proxy resource included in the 2011 IRP preferred portfolio.
- PacifiCorp will reexamine the timing and type of post-2014 gas resources and other resource changes as part of the 2011 business planning process and preparation of the 2011 IRP Update. The reexamination will include documentation of capital cost and operating cost tradeoffs between resource types.
- Consider siting additional gas-fired resources in locations other than Utah. Investigate resource availability issues including water availability, permitting, transmission constraints, access to natural gas, and potential impacts of elevation.
- Issue an all-source RFP in early 2012 for potential acquisition of peaking/intermediate/baseload resources by the summer of 2016 to fill any remaining resource need indicated by an updated load and resource balance reflecting the results of DSM request for proposals, acquisition of front office transactions, reserve margin sensitivity analysis, and other relevant information.

Status

Lake Side 2 project remains on schedule and is within budgeted costs to meet an online date of June 2014. The All Source RFP was issued in January 2012 for a 2016 resources. However, the RFP was later terminated. The need for post-2014 gas resource(s) is delayed until 2024 based on a needs assessment study that PacifiCorp completed as part of the justification in the termination of the All Source RFP in September 2012. The timing of this resource is consistent with the 2013 IRP preferred portfolio. A cost comparison of different gas resources was thus unnecessary due to lack of resource need.

Action Item 3: Firm Market Purchases 2011-2020

- Acquire economic front office transactions or power purchase agreements as needed through summer 2016. Resources will be procured through multiple means, such as periodic mini-RFPs that seek resources less than five years in term, and bilateral negotiations.
- Closely monitor the near-term and long-term need for front office transactions and adjust planned acquisitions as appropriate based on market conditions, resource costs, and load expectations. Actively search for market options that could cost-effectively defer acquisition or construction of a 2016 CCCT resource.

Status

A market RFP was issued in March 2012 which resulted in the acquisition of 125 MW for 2013, 100 MW for 2014, 100 MW for 2015 and 100 MW for 2016 on the east side of the system. Due to the change in the load forecast and reduced resource needs from the needs assessment in the All Source RFP process, no additional front office transactions or power purchases were acquired through the summer of 2016. This action item has been superseded by Action Item 3a in Table 9.1.

Action Item 4: Plant Efficiency Improvements 2011-2020

- Continue to pursue economic plant upgrade projects—such as turbine system improvements and retrofits—and unit availability improvements to lower operating costs and help meet the Company’s future CO₂ and other environmental compliance requirements.
- Successfully complete the dense-pack coal plant turbine upgrade projects scheduled for 2011 and 2012, totaling 33 MW, subject to economics. The 2012 10-year plan includes 13.8 MW capacity increase in 2013.
- Seek to meet the Company’s updated aggregate coal plant net heat rate improvement goal of 478 British thermal unit per kilowatt-hour (Btu/kWh) by 2019. (PacifiCorp Energy Heat Rate Improvement Plan, April 2010).
- Continue to monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules.
- For the next IRP complete a study of cost-effective and reliable production efficiency opportunities at generating facilities (station load reduction opportunities not currently being captured in the IRP) where the Company has sole ownership of the facility. The resource opportunities identified will be modeled against competing demand and supply-side resources in the next IRP. Those selected will be targeted for completion by 2015 provided plant outages are not required.

Status

An ongoing effort to identify promising new potential plant/unit improvement opportunities has been completed through the normal course of business. The effort includes the identification and reporting of heat rate improvement opportunities and future project plans. Along with monitoring turbine and other equipment technologies as above, this item will now also be tracking the aggregate coal plant net heat rate improvement goals. This action item will continue annually.

The identified projects will be documented within the annual Heat Rate Improvement Plan, or HRIP, and will be posted on the IRP website. The HRIP report includes a 10 year forecast of major projects intended to modify the unit design heat rate of the Company's coal fired plants. This action item has been superseded by Action Item 6a in Table 9.1.

Action Item 5: Class 1 DSM 2011-2020

- Acquire at least 140 MW of incremental cost-effective DSM resource by 2013 and up to 250 MW by 2015.
- Finalize an agreement for the commercial curtailment product (which includes customer-owned standby generation opportunities). If cost effective, the company will file for approval by the 3rd quarter of 2012.
- Complete an analysis of the economic feasibility of Class 1 irrigation load control in the west by the second quarter of 2012. If the analysis suggests Class 1 irrigation load control is economic in the west, the Company will source delivery of a program through a request for proposals concurrent with the re-sourcing of Class 1 irrigation load control program delivery in the east by the third quarter of 2012.
- Issue a request for proposal in 2012 to re-procure the delivery of the Cool Keeper program following the 2013 control season. For the request for proposal, the Company will seek market approaches acceptable to Utah regulators to expand the program beyond its current level beginning in 2014.

Status

There were no incremental Class 1 DSM resources added in 2011 or 2012 as a result of the Company's revised load forecast and deferral of need for a 2016 resource. The Company canceled the commercial curtailment product due to the revised/lowered load forecast that also contributed to the cancelation of the All Source Request for Proposals.

The Company completed an analysis of the feasibility and costs of west-side Class 1 irrigation control and collected costs through a 2012 request for proposal. Despite finding the resource reasonably viable, it was not selected as an economic resource in the first ten years of the 2013 IRP preferred portfolio (see action item 7b).

An RFP was issued in January 2013 to re-procure the delivery of Utah's Cool Keeper air conditioner load management program. Provisions in the RFP will allow for program expansion as conditions warrant.

Action Item 6: Class 2 DSM 2011-2020

- Apply the 2011 IRP conservation analysis as the basis for the Company's next Washington I-937 conservation target setting submittal to the Washington Utilities and Transportation Commission for the 2012-2013 biennium. The Company may refine the conservation analysis and update the conservation forecast and biennial target as appropriate prior to submittal based on final avoided cost decrement analysis and other new information.

- Acquire at least 900 MW and up to 1,800 MW of cost-effective Class 2 programs by 2020, equivalent to at least 4,533 GWh and up to 9,066 GWh. Acquire at least 520 MW and up to 1000 MW of cost-effective Class 2 DSM by 2016.
 - Adjusted to reflect 2011 IRP's initial MW contribution from Class 2 resources expected to be acquired in Oregon (reduces the MW contribution from Oregon from 562 MWs by 2020 to 283 MWs, a 279 MW reduction)
- By 1st quarter of 2012 file a residential home residential home comparison report program in Utah and Washington, and investigate broader applications by the end of 2014 that can be implemented by 2016.
- By 3rd quarter 2012 the Company will submit for commission approval a plan to acquire energy efficiency resources from the Company's Special Contract customers in Utah and Idaho that can be reliably verified and delivered by 2016, and will pursue those resources provided the Commissions in those states approve a cost-recovery mechanism for the plan.
- By 1st quarter 2012 issue a system-wide RFP (excluding Oregon) for specific direct install and other direct distribution programs targeting savings from the residential and small commercial sectors that can be delivered beginning in 2013. The Company will seek to acquire all cost-effective resources that are available from the request for proposal. The cost effectiveness analysis will consider any adverse impact on the existing DSM programs. The results of the RFP will be known prior to the Company seeking acknowledgement of the final short list for the all-source RFP. The Company will promptly file for commission approvals to implement the cost-effective programs.
- For the next IRP, prior to beginning modeling and screening of DSM, and as part of the public input process, provide an analysis of alternatives to the current supply curve bundling and ramping methods for modeling energy efficiency measures. By the end of 2012 provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan.
- Leverage the distribution energy efficiency analysis of 19 distribution feeders in Washington (conducted for PacifiCorp by Commonwealth Associates, Inc.) for analysis of potential distribution energy efficiency in other areas of PacifiCorp's system provided the Company receives approval by the appropriate Commission for recovery of the study cost through the demand-side customer efficiency surcharge. (The Washington distribution energy efficiency study final report was completed December 26, 2011.)
-- Include in the 2013 IRP a detailed plan and schedule to implement cost-effective Conservation Voltage Reduction (CVR) in each state as approved by the state.
- By the end of 2013 perform a high-level screening of the remaining 60 percent of its distribution circuits in each of the states to identify circuits where cost-effective energy savings appear viable and detailed circuit study is warranted provided the Company receives approval by the appropriate state commission for recovery of the study cost through the demand-side customer efficiency surcharge.
- In the 2013 IRP include the results of the CVR evaluation to date.

Status

The Company filed its Washington Initiative 937 10 year conservative forecast and 2012-2013 biennial targets with the Washington Utilities and Transportation Commission on January 31, 2012.

The Company exceeded its 2011 and 2012 Class 2 DSM acquisition goals by 242,438 megawatt-hours (MWh) (29 percent), achieving 1,087,747 MWh against the goal amount of 845,036 MWh. The Company proposed offering residential home comparison report programs in Utah and Washington in April, 2012, and after regulatory discussions implemented the report program in August, 2012.

In addition, the Company is actively working with the Energy Trust of Oregon on a pilot program to be offered to PacifiCorp customers in 2013 and 2014. The acquisition of energy efficiency resources from special contract customers was discussed with the Utah DSM Advisory Steering Group in 2013. The steering group recommended the issue be a subject of the next contract negotiations with the special contract customers.

The Company issued a system-wide RFP (excluding Oregon) for specific direct install and other direct distribution programs targeting savings from residential and small commercial sectors in March, 2012. Full processing of the RFP proposals was put on “hold” following the Company’s revised load forecast and cancellation of 2012 All Source RFP pending the results of the 2013 IRP. The Company intends to complete the processing of the proposal’s received for implementation in fourth quarter of 2013.

As part of the modeling and screening of the DSM the Company has disaggregated and narrowed price bundles. Documentation on ramping and supply curve methods was provided to stakeholders. A review of staffing levels to achieve programmatic cost effective energy efficiency targets in the 2013 IRP has been completed. Volume II, Appendix D (Demand-Side Management and Supplemental Resources) provides the Energy Efficiency ramp rates, the DSM potential study and other demand side management studies.

Prior to the end of 2012 no approval had been provided by the major states to conduct detailed analysis for CVR. The high level screening has been completed. The 2013 IRP details for the implantation of CVR projects in Washington have been provided based on the results of Tier 1 and 2 studies. This action item has been superseded by Action Item 7a in Table 9.1.

Action Item 7: Class 3 DSM 2011-2020

- During 2012 update the Conservation Potential Assessment to more accurately reflect Class 1 and 3 DSM resource opportunities in regards to 1) market and regulatory capabilities and climates in each state, 2) interactions within and between Class 1 and Class 3 resource potentials identified, and 3) the impact of existing Class 3 programs on product potential.
- During 2012 have a third-party consultant review and prepare a report on how other utilities treat price-responsive products in their resource planning process (for example, as an adjustment to their load forecast and/or as a firm planning resource), and prepare a recommendation on how the Company might apply contributions from price products to help defer investments in other resource options cost-effectively.
- For the 2013 IRP provide a sensitivity analysis, similar to portfolio development Case 31 in the 2011 IRP, that more accurately reflects incremental Class 3 product opportunities

(incremental to Class 1 products, other Class 3 products, and to existing impacts of Class 3 products the Company is already running).

- Implement in Utah and Washington (subject to regulatory approvals) residential information pilots to test the effects of providing customers greater amounts of usage information on the quantity of electricity they consume. The pilots will leverage the existing Automatic Meter Reading (AMR) metering currently available in these states. Pilots will consist of three test groups each receiving varying levels of usage information:
 - Group 1 – Home comparison reports and energy conservation suggestions.
 - Group 2 – Daily usage data through Home Energy Monitoring software (key component to pricing products)
 - Group 3 – Home comparison reports, energy savings suggestions, and daily usage data through Home Energy Monitoring software

Pilots will be implemented in 2012, run throughout 2013, and an analysis and recommendations prepared in 2014, prior to the development of the 2015 IRP.

- If the analysis of Class 1 irrigation load control in the west (see action item 5) indicates that such programs are non-economic, investigate, through a pilot program in Oregon a Class 3 irrigation time-of-use program as an alternative approach for managing irrigation loads in the west.

Status

The 2012 Conservation Potential Assessment work was expanded to provide a greater assessment of opportunities, interactions and impacts of Class 1 and 3 program potentials, including the impacts of the Company's existing Class 3 products. The report also undertook an assessment of how other utilities treat demand response resources in their integrated resource planning processes. This assessment was distributed to stakeholders in September 2012. The 2012 Conservation Potential Assessment is included in Appendix D. A memo summarizing Cadmus findings regarding treatment of price responsive projects by 23 other utilities in their IRPs was distributed to PacifiCorp IRP public stakeholders in September. Cadmus key findings included the following:

- 1) Like PacifiCorp, most utilities surveyed (13 of the 23) account for existing time-of use (TOU) program impacts directly in their load forecast. Only PacifiCorp and two Missouri utilities directly complete incremental price-responsive programs opportunities with other resources options in IRP models.
- 2) Five of the 23 utilities surveyed did not account for incremental TOU programs in their IRPs at all, due to no expected program growth or limited participation programs that are too small to warrant load adjustments.
- 3) Only PacifiCorp and two other utilities delineate program impacts from event driven pricing programs (e.g., critical peak pricing and demand bidding).

Sensitivity case S-10 in the 2013 IRP provides an analysis that reflects incremental Class 3 products (incremental to Class 1, other Class 3 products, and to existing impacts of Class 3 products the Company is already running).

The implementation of residential information pilots in conjunction with the Home Energy Report programs in Utah and Washington were deemed to be too small to return statistically relevant results and expanding group size was determined cost prohibitive for the value of the information to be obtained. Based on other utility experiences with Home Energy Report programs (and their supporting program evaluations), it is believed information on varying levels of information on customer behavior and savings can be obtained through running variations of the existing Group 1 program (standard Home Energy Report program) and from learning's from the impact the evaluations of other utility programs running such variations.

Because the Oregon Class 1 irrigation load control in the west was not selected as economic in the first ten years of the 2013 IRP preferred portfolio, the Company will investigate through an Oregon Class 3 irrigation time of use pilot program as an alternative for managing irrigation loads in the west – See Action Item 7b in Table 9.1.

Action Item 8: Planning Process Improvements Process Improvement

- Incorporate plug-in electric vehicles and Smart Grid technologies as a discussion topic for the next IRP.

Status

A presentation and question and answer session on PacifiCorp's Smart Grid evaluation and implementation efforts was given to the IRP public stakeholder meeting in December 2012. This action item has been superseded by Action Item 11a in Table 9.1.

Action Item 9: Coal Resource Actions

- The Company will host a technical workshop for stakeholders and the [Oregon] commissioners on February 17, 2012, respectively, for stakeholders that have a confidentiality agreement in place. At the technical workshop, the Company will review with stakeholders the methodology, assumptions and recently completed analysis of upcoming Naughton Unit 3 emission control investments. The Naughton Unit 3 analysis will be provided to stakeholders, subject to confidentiality agreements, as soon as practicable. At the technical workshop, the Company will present the methodology, assumptions and results of a Coal Replacement Study screening analysis performed for Jim Bridger 3, Jim Bridger 4, and Hunter 1 at a minimum. The Company will complete the analysis on as many other units as possible within the time constraints. The Company will also present information pertaining to planned investments in the Craig and Hayden facilities of which the Company has ownership share but does not have operational responsibilities. The screening analysis will be performed using a spreadsheet model that assumes a gas-fired CCCT, scaled to the size of the coal unit being analyzed, replaces the coal unit in 2015. The screening analysis will include line-item results showing annual capital costs and fixed and variable operating costs for each coal unit and the replacement CCCT resource. The screening analysis will be performed on three different market scenarios pairing varying levels of natural gas prices and CO₂ costs. At least one scenario will include a low gas/high CO₂ pairing. The screening analysis will report a rank order of the nominal levelized net PVRR benefit/cost on a per kW-month basis for each scenario. The Company will make available to stakeholders that have signed

appropriate confidentiality agreements the assumptions and results of the screening Study five business days before the technical workshop.

- The Company will include in its 2011 IRP update an updated Coal Replacement Study focusing on those units analyzed in the screening analysis as described above. The updated Coal Replacement Study will be performed using the System Optimizer model and will explore a range of natural gas prices and CO₂ costs in varying combinations. The updated Coal Replacement Study will discuss and evaluate flexibility in the emerging environmental regulations and the associated economics that may present options to the Company to avoid early compliance costs by offering to shut down certain individual units prior to the end of their currently approved depreciable lives. In the updated Study, the Company will provide a concise explanation and transparent example of its treatment of post-2030 costs and will provide an analysis that shows the results of treatments of environmental investments made prior to 2015 both avoidable and unavoidable.

Status

A confidential workshop was held with stakeholders and a commission workshop was held in February 2012 in Salem. Confidential material was distributed in February 2012 to stakeholders that are signatories under the appropriate protective order. The Screening analysis was completed for all units (Naughton Unit 3 was excluded pending completion of updated Naughton Unit 3 Certificate of Public Convenience and Necessity analysis) and the results were reviewed in a February 2012 workshop. Gas-fired CCCT characteristics were reported in the screening model. Four market scenarios were modeled:

- Base gas/base CO₂ price
- Low gas/no CO₂ price
- Base gas/high CO₂ price
- Low gas/high CO₂ price

The information was provided as part of a “Summary Results” worksheet in the screening model. Screening model results were provided to stakeholders in February 2012. Confidential and redacted versions of the Coal Replacement Study were included with the 2011 IRP Update report submitted to the state commissions on March 30, 2012. The Company has analyzed in the 2013 IRP environmental investments required to meet known and prospective compliance obligations across PacifiCorp’s existing coal fleet. Supported by analyses performed as part of the 2013 IRP and analyses performed in recent regulatory filings, the Company plans to convert Naughton Unit 3 to a natural gas-fired facility and to install environmental investments required to meet near term compliance obligations at the Hunter Unit 1, Jim Bridger Unit 3, and Jim Bridger Unit 4 generating units. Installation of emission control equipment at these facilities will reduce emissions of nitrous oxides (NO_x) and sulfur dioxide (SO₂) and contribute to improved visibility in the region. The Company plans to continue to evaluate environmental investments required to meet known and prospective environmental compliance obligations at existing coal units in future IRPs and future IRP Updates.

Building upon modeling techniques developed in the 2011 IRP and 2011 IRP Update, environmental investments required to achieve compliance with known and prospective regulations at existing coal resources have been integrated into the portfolio modeling process in

the 2013 IRP. Potential alternatives to environmental investments associated with known and prospective compliance obligations tied to Regional Haze rules, Mercury and Air Toxics Standards (MATS), regulation of coal combustion residuals (CCR), and regulation of cooling water intakes are considered in the development of *all* resource portfolios developed for the 2013 IRP. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. In addition to integrating coal unit environmental investment decisions into the portfolio development process, the Company has completed detailed financial analysis of near-term investment decisions in Confidential Volume III of the 2013 IRP. This action item has been superseded by Action Item 8a through 8d in Table 9.1.

Action Item 10: Transmission

- In the scenario definition phase of the IRP process, the Company will address with stakeholders the inclusion of any transmission projects on a case-by-case basis.
- Develop an evaluation process and criteria for evaluating transmission additions and review with stakeholders which transmission projects should be included and why.
- Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgement (including Wallula to McNary and Sigurd to Red Butte).

Status

As part of the 2013 IRP the Company has incorporated five separate Energy Gateway scenarios which were run for each of the core cases. The Company has developed an evaluation tool, System Operational and Reliability Benefits Tool (SBT), to evaluate transmission additions. The SBT identifies, measures, and monetizes benefits that are incremental to those identified in the resource portfolio modeling process. Analysis using the SBT supports investment in the Sigurd to Red Butte transmission project and preliminary application of the SBT to the Windstar to Populus transmission project supports continued permitting of Energy Gateway Segment D. The Company has reviewed the tool with stakeholders throughout the 2013 IRP process. In contrast to the 2011 IRP, where analysis of Energy Gateway transmission investments preceded resource portfolio modeling, Energy Gateway transmission investments have been integrated into the portfolio modeling process for the 2013 IRP. This was achieved by replicating the development of resource portfolios among five different Energy Gateway transmission scenarios. Consequently, 94 unique core case resource portfolios were produced in the 2013 IRP, nearly five times the number of core case portfolios developed for the 2011 IRP.

The SBT will continue to be developed and will be applied to additional Energy Gateway transmission projects for analysis in future IRPs. This action item has been superseded by Action Item 9a through 9c in Table 9.1.

Action Item 11: Planning Reserve Margin

- For the 2011 IRP Update include the results of a System Optimizer portfolio sensitivity analysis comparing the resource and cost impacts of a 12 percent versus 13 percent planning reserve margin.

Status

The 2011 IRP Update included a summary of a planning reserve margin analysis that presented the impact on resource need when the planning reserve margin is assumed to change from 13 percent to 12 percent. Appendix I in the 2013 IRP, which was provided and discussed with stakeholders, was completed by Ventyx and provides the resource and cost impact of a 12 percent vs. 13 percent planning reserve margin. This action item has been superseded by Action Item 10a in Table 9.1.

Acquisition Path Analysis

Resource Strategies

PacifiCorp worked with stakeholders to define 19 input scenarios, or “core cases”, which were applied across five different Energy Gateway transmission scenarios totaling 94 different variations of resource portfolios.⁸¹ The 19 different core cases were categorized into four different themes. The array of core case definitions, grouped by theme, provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by shifts in policies and changes to fundamental market conditions. The four core case themes are summarized as follows:

- (9) **Reference:** There are three different core cases developed for the Reference Theme. Each case relied upon base case assumptions for market prices, environmental policy inputs, energy efficiency assumptions, and load projections. RPS assumptions differentiate the three cases in the Reference Theme, with one case assuming no state or federal RPS requirements, one case assuming only state RPS requirements, and one case assuming both state and federal RPS requirements must be met.
- (10) **Environmental Policy:** There are 11 different core cases developed for the Environmental Policy Theme. Five of the 11 cases reflect base case assumptions for Regional Haze requirements on existing coal units, and six of the 11 cases assume more stringent Regional Haze requirements. Differentiating the sets of cases with different Regional Haze compliance requirements are varying assumptions for market prices (low, medium, and high), CO₂ prices (zero, medium, and high), RPS requirements (with and without state and federal RPS), and energy efficiency.
- (11) **Targeted Resources:** There are four different core cases developed for the Targeted Resource Theme. Each of the cases is characterized by alternative assumptions for specific resource types to understand how these assumptions influence resource portfolios, costs, and risk. One of the four cases prevents CCCT resources to be added to the resource portfolio and assumes energy efficiency resources can be acquired at an accelerated rate. The second of the four cases in this theme assumes that geothermal power purchase agreement resources will be used to meet RPS requirements. The third of four cases in this theme assumes a spike in

⁸¹ One of the input scenarios is applicable to four out of the five Energy Gateway transmission scenarios.

power prices over the period 2017 through 2022 and assumes natural gas prices will rise above base case levels over the entirety of the planning horizon. The fourth case in this theme targets clean energy resources and assumes CO₂ prices rise consistent with a federal hard cap scenario, that natural gas prices rise above those assumed in the base case, that federal tax incentives for renewable resources are extended through 2019, and that energy efficiency resources can be acquired at an accelerated rate.

- (12) **Transmission:** The Transmission Theme included one core case, which assumes that third party transmission can be purchased from a newly built line as an alternative to

Given current load expectations, portfolio modeling performed for the 2013 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when FOTs and energy efficiency resources are consistently selected. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2013 IRP shows that new renewable resource needs are driven by RPS compliance obligations, and all else equal, this result is not significantly changed if federal tax incentives are assumed to be extended. Beyond load, the most significant driver affecting resource selection in the 2013 IRP are market price and policy assumptions that trigger early coal unit retirements as an alternative to environmental investments required to meet known and emerging environmental regulations. For these reasons, the acquisition path analysis focuses on load trigger events, and combinations of environmental policy and market price trigger events that would require alternative resource acquisition strategies. For each trigger event, Table 9.2 lists the associated planning scenario and both short-term (2013-2022) and long-term (2023-2032) resource strategies.

Acquisition Path Decision Mechanism

The Utah Commission requires that PacifiCorp provide “[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds.”⁸² PacifiCorp’s decision mechanism is centered on the business planning and IRP processes, which together constitute the decision framework for making resource investment decisions. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and DSM target-setting/valuation processes. In developing the IRP action plan and path analysis, the Company considers common elements across multiple resource strategies (for example, base levels of each resource type across many least-cost portfolios optimized according to different futures), planning contingencies and resource flexibility, and continuous evaluation of market/regulatory developments and resource options.

PacifiCorp uses the IRP and business plan to serve as decision support tools for senior management to determine the most prudent resource acquisition paths for maintaining system

⁸² Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

reliability and low-cost electricity supplies, and to help address strategic positioning issues. The key strategic issues as outlined in this IRP include (1) addressing regulatory risks in the areas of climate change and renewable resource policies; (2) accounting for price risk and uncertainty in making resource acquisition decisions; (3) load uncertainty; and (4) determining the appropriate level and timing of long-term transmission expansion investments, accounting for the regulatory risks and uncertainties outlined above.

Table 9.2 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2013-2022)	Long Term Resource Acquisition Strategy (2023-2032)
Higher sustained load growth	High economic drivers and increased demand from industrial customers	<ul style="list-style-type: none"> • Increase acquisition of FOTs • Increase acquisition of Class 1 DSM direct load control resources in the 2017 – 2020 timeframe • Accelerate acquisition of a gas-fired thermal resource to 2019 • Increase acquisition of RECs to maintain compliance with RPS requirements consistent with load growth expectations by state 	<ul style="list-style-type: none"> • Accelerate acquisition of thermal resources to 2023 • Increase acquisition of Class 1 DSM direct load control resources. • Balance timing of thermal resource acquisition and Class 1 DSM resources with FOTs and cost-effective Class 2 DSM energy efficiency resources • Evaluate cost effective RPS compliance strategies, including tradeoffs between resource acquisition and use of compliance flexibility mechanisms like banking and use of unbundled RECs
Lower sustained load growth	Low economic drivers suppress load requirements	<ul style="list-style-type: none"> • Reduce acquisition of FOTs • Continue to pursue Class 2 DSM energy efficiency resources 	<ul style="list-style-type: none"> • Reduce acquisition of gas-fired thermal resources • Pursue peaking gas-fired resources to meet load growth • Balance timing of thermal resource acquisition and Class 1 DSM resources with FOTs and cost-effective Class 2 DSM energy efficiency resources
Softening of the natural gas market combined with greenhouse gas policies that increase the cost of coal unit operation	<p>Excess gas supply with increasing well productivity and/or technological innovation and dampened demand from limited use in the transportation sector and no liquefied natural gas exports.</p> <p>Legislative action to implement new greenhouse gas polices or new regulations implemented with equivalent costs expected to approach \$75/ton by 2032.</p>	<ul style="list-style-type: none"> • Increase acquisition of FOTs and/or Class 2 DSM energy efficiency resources • Pursue strategic low cost gas conversion of existing coal units • Retire high cost coal units and accelerate acquisition of replacement natural gas-fired thermal resources • Accelerate acquisition of gas-fired thermal resources to 2019 to meet load growth expectations 	<ul style="list-style-type: none"> • Pursue strategic low cost gas conversion of existing coal units • Retire high cost coal units and accelerate acquisition of replacement natural gas-fired thermal resources • Accelerate acquisition of cost-effective renewable resources • Balance timing of thermal resource acquisition and Class 1 DSM resources with FOTs and cost-effective Class 2 DSM energy efficiency resources

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2013-2022)	Long Term Resource Acquisition Strategy (2023-2032)
Strengthening of the natural gas market combined with greenhouse gas policies that increase the cost of coal unit operation	<p>High oil prices support liquefied natural gas exports with lagging global shale development and demand for natural gas in the transportation sector increases beyond 2020.</p> <p>Legislative action to implement new greenhouse gas polices or new regulations implemented with equivalent costs in excess of \$130/ton by 2032.</p>	<ul style="list-style-type: none"> • Increase acquisition of FOTs • Accelerate acquisition of incremental Class 2 DSM energy efficiency resources • Accelerate and increase acquisition of renewable resources 	<ul style="list-style-type: none"> • Pursue strategic low cost gas conversion of existing coal units • Retire high cost coal units and pursue acquisition of low emission replacement thermal resources such as nuclear and generating technologies with carbon capture and sequestration • Accelerate and increase acquisition of renewable resources. • Build additional transmission infrastructure to gain access to cost effective renewable resource opportunities.

Procurement Delays

The main procurement risk is an inability to procure resources in the required time frame to meet the need. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2013 IRP. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or a material change in the market for fuels, materials, electricity, or environmental or other electric utility regulations, may change the Company’s entire resource procurement strategy.

Possible paths PacifiCorp could take if there was either a delay in the online date of a resource or, if it was no longer feasible or desirable to acquire a given resource, include the following:

- Consider alternative bids if they haven’t been released under a current RFP.
- Issue an emergency RFP for a specific resource.
- Move up the delivery date of a potential resource by negotiating with the supplier/developer.
- Rely on near-term purchased power and transmission until a longer-term alternative is identified, acquired through PacifiCorp’s mini-RFPs or sole source procurement.
- Install temporary generators to address some or all of the capacity needs.
- Temporarily drop below the 13 percent planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

Resource differences between PacifiCorp’s 2013 IRP and the 2011 IRP Update relates primarily to a decreased load forecast and lower natural gas and power prices. These drivers result in a significant reduction of resources which include removal of natural gas, wind, FOT, DSM, and distributed generation resources. As compared to the 2011 IRP Update, the 2013 IRP preferred portfolio includes increased distributed solar due to the expanded Utah Solar Incentive Program. Table 9.3 compares the 2013 IRP preferred portfolio with the 2011 IRP Update portfolio for the 10 years covered by both portfolios (2013-2022), indicating year by year capacity differences by major resource categories (yellow highlighted table). The major resource changes since the 2011 IRP Update include the removal of two CCCT resources (CCCT F 2x1 and CCCT G 1x1) included in the portfolio by 2016 and 2019 respectively, reduction in DSM influenced by an updated resource potential study and additional detail in representing DSM in the current IRP modeling framework, increased distributed solar resources, and removal of wind resources. As discussed in Chapter 8 and identified in Table 9.1, renewable energy credits will be used to meet state RPS requirements.

Table 9.3 – Portfolio Comparison, 2013 Preferred Portfolio versus 2011 IRP Update Portfolio

2013 IRP vs 2011 IRP Update												
2013 IRP Preferred Portfolio												
Resource	Capacity (MW)											Resource Totals
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2013-2022
Coal Plant Turbine Upgrades		14	-	-	-	-	-	-	-	-	-	14
Gas	-	645	-	-	-	-	-	-	-	-	-	645
Wind	-	-	-	-	-	-	-	-	-	-	-	-
Other Renewables / Solar	12	14	17	16	18	14	14	14	14	15	15	149
DSM, Class 1	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 2	115	117	103	101	97	92	90	81	80	82	82	956
Distributed Generation	1	1	1	1	1	1	1	1	1	1	1	11
Total Long Term Resources		141	777	121	119	116	106	104	95	96	98	1,774
Utah Capacity Purchase *		200	-	-	-	-	-	-	-	-	-	200
East - Firm Market Purchases	-	-	-	-	-	-	37	151	248	19	161	62
West - Firm Market Purchases		650	709	845	983	1,102	1,172	1,172	1,172	1,172	1,172	1,015
Firm Market Purchases		850	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,277

Study includes Naughton 3 gas conversion in 2015
 FOT in resource total are 10-year averages

2013 IRP Preferred Portfolio less 2011 IRP Update (2012 Business Plan)

Resource	Capacity (MW)											Resource Totals
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2013-2022
Coal Plant Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	8	-	(597)	-	-	-	(393)	-	-	-	(982)
Wind	-	-	-	-	-	-	-	(225)	(225)	-	(75)	(525)
Other Renewables / Solar	7	11	14	16	18	14	14	14	14	15	15	138
DSM, Class 1	(57)	(20)	(97)	-	-	-	-	-	-	-	-	(174)
DSM, Class 2	4	(2)	(19)	(23)	(29)	(28)	(32)	(44)	(45)	(52)	(52)	(269)
Distributed Generation	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(41)
Total Long Term Resources		(50)	(6)	(106)	(607)	(16)	(19)	(640)	(260)	(34)	(116)	(1,853)
Utah Capacity Purchase *	-	-	-	-	-	-	-	-	-	-	-	-
East - Firm Market Purchases	(150)	(300)	(331)	(300)	(300)	(263)	(145)	(52)	(35)	23		(185)
West - Firm Market Purchases	(188)	(52)	(47)	416	506	437	639	377	458	446		299
Firm Market Purchases		(338)	(352)	(378)	116	206	174	494	325	423	469	114

FOT in resource total are 10-year averages

2011 IRP Update (2012 Business Plan - Dec. 2011)

Resource	Capacity (MW)											Resource Totals
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2013-2022
Coal Plant Turbine Upgrades	19	14	-	-	-	-	-	-	-	-	-	14
Gas	-	-	637	-	597	-	-	-	393	-	-	1,627
Wind	-	-	-	-	-	-	-	225	225	-	75	525
Other Renewables / Solar	4	4	3	3	-	-	-	-	-	-	-	10
DSM, Class 1	70	57	20	97	-	-	-	-	-	-	-	174
DSM, Class 2	114	110	118	122	124	126	120	122	125	125	134	1,225
Distributed Generation	5	5	5	5	5	5	5	5	5	5	5	52
Total Long Term Resources	213	191	783	227	726	131	125	745	355	130	214	3,627
Utah Capacity Purchase *	200	200	-	-	-	-	-	-	-	-	-	20
East - Firm Market Purchases	17	150	300	331	300	300	300	296	300	54	138	247
West - Firm Market Purchases	927	838	761	892	567	596	735	533	795	714	726	716
Firm Market Purchases	1,145	1,188	1,061	1,223	867	896	1,035	829	1,095	768	864	983

FOT in resource total are 10-year averages

Table 9.4 provides a comparison between the 2013 Business Plan and the 2013 IRP Preferred Portfolio. The drivers of the differences between the 2013 IRP Preferred Portfolio and the 2013 Business Plan include, reduced loads, removal of wind resources consistent with use of renewable energy credit purchase for RPS compliance, decreased DSM and FOTs due to decrease in load, and increase in distributed solar due to the Utah Solar Incentive Program.

Table 9.4 – Portfolio Comparison, 2013 Business Plan versus 2013 Preferred Portfolio

2013 IRP vs 2013 Business Plan

2013 IRP Preferred Portfolio

Resource	Capacity (MW)											Resource Totals
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2013-2022
Coal Plant Turbine Upgrades		14	-	-	-	-	-	-	-	-	-	14
Gas		-	645	-	-	-	-	-	-	-	-	645
Wind		-	-	-	-	-	-	-	-	-	-	-
Other Renewables / Solar		12	14	17	16	18	14	14	14	15	15	149
DSM, Class 1		-	-	-	-	-	-	-	-	-	-	-
DSM, Class 2		115	117	103	101	97	92	90	81	80	82	956
Distributed Generation		1	1	1	1	1	1	1	1	1	1	11
Total Long Term Resources		141	777	121	119	116	106	104	95	96	98	1,774
Utah Capacity Purchase *		200	-	-	-	-	-	-	-	-	-	20
East - Firm Market Purchases		-	-	-	-	-	37	151	248	19	161	62
West - Firm Market Purchases		650	709	845	983	1,102	1,172	1,172	1,172	1,172	1,172	1,015
Firm Market Purchases		850	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,097

Study includes Naughton 3 gas conversion in 2015
 FOT in resource total are 10-year averages

2013 IRP Preferred Portfolio less 2013 Business Plan

Resource	Capacity (MW)											Resource Totals
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2013-2022
Coal Plant Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Gas		-	7	-	-	-	-	-	-	-	-	7
Wind		-	-	-	-	-	(100)	(100)	(100)	(100)	-	(400)
Other Renewables / Solar		7	11	14	16	18	14	14	14	15	15	138
DSM, Class 1		-	-	-	-	-	-	(1)	(100)	-	-	(101)
DSM, Class 2		29	26	8	9	7	(4)	(7)	(19)	(25)	(29)	(4)
Distributed Generation		(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(41)
Total Long Term Resources		32	40	18	21	21	(94)	(98)	(209)	(113)	(17)	(401)
Utah Capacity Purchase *		-	-	-	(200)	(200)	(200)	(200)	(200)	-	-	(100)
East - Firm Market Purchases		-	(92)	(51)	(88)	(72)	(93)	(95)	(52)	(62)	18	(59)
West - Firm Market Purchases		(268)	(166)	(233)	(46)	(66)	(45)	(45)	(45)	(45)	(45)	(100)
Firm Market Purchases		(268)	(258)	(283)	(335)	(338)	(337)	(339)	(297)	(106)	(27)	(259)

FOT in resource total are 10-year averages

2013 Business Plan (December 2012)

Resource	Capacity (MW)											Resource Totals
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2013-2022
Coal Plant Turbine Upgrades	19	14	-	-	-	-	-	-	-	-	-	14
Gas	-	-	638	-	-	-	-	-	-	-	-	638
Wind	-	-	-	-	-	-	100	100	100	100	-	400
Other Renewables / Solar	4	4	3	3	-	-	-	-	-	-	-	10
DSM, Class 1	-	-	-	-	-	-	-	1	100	-	-	101
DSM, Class 2	101	86	90	95	93	90	95	97	100	104	110	960
Distributed Generation	5	5	5	5	5	5	5	5	5	5	5	52
Total Long Term Resources	130	109	736	104	98	95	201	202	305	210	115	2,174
Utah Capacity Purchase *	200	200	-	-	200	200	200	200	200	-	-	120
East - Firm Market Purchases	62	-	92	51	88	72	130	246	300	81	143	120
West - Firm Market Purchases	1,055	918	875	1,078	1,029	1,168	1,217	1,217	1,217	1,217	1,217	1,115
Firm Market Purchases	1,317	1,118	967	1,128	1,318	1,440	1,546	1,662	1,717	1,297	1,360	1,355

Study includes Naughton 3 gas conversion in 2015
 FOT in resource total are 10-year averages

Resource Procurement Strategy

To acquire resources outlined in the 2013 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide clear economic benefits to customers. Regardless of the method for acquiring resources, the Company will use its IRP models to support resource evaluation as part of the procurement process, with updated assumptions including load forecasts, commodity prices, and regulatory

requirement information available at the time that the resource evaluations occur. This will ensure that the resource evaluations account for a long-term system benefit view in alignment with the IRP portfolio analysis framework as directed by state procurement regulations, and with business planning goals in mind.

The sections below profile the general procurement approaches for the key resource categories covered in the action plan: renewable energy credits, DSM, thermal plants, distributed generation, and market purchases.

Renewable Energy Credits

The Company uses a shelf RFP as the primary mechanism under which the Company will issue subsequent RFPs to meet most of the renewable energy credit acquisition goals over the IRP action plan and business planning horizons.

Demand-side Management

PacifiCorp uses a variety of business processes to implement DSM programs. The outsourcing model is preferred where the supplier takes the performance risk for achieving DSM results. In other cases, PacifiCorp manages the program and contracts out specific tasks. A third method is to operate the program completely in-house. The business process used for any given program is based on operational expertise, performance risk and cost-effectiveness.

To support the DSM procurement program, the IRP models are used for resource valuation purposes to gauge the cost-effectiveness of programs identified for procurement shortlists. For Class 2 DSM programs, PacifiCorp performs a “no cost” load shape decrement analysis to derive program values using its stochastic production cost model, *Planning and Risk*, similar to what was done for the 2011 IRP. The load shape decrement analysis is included in Volume II< Appendix N.

Distributed Generation

Distributed generation, both solar and biomass, were found to be cost-effective resources in the context of IRP portfolio modeling. PacifiCorp’s procurement process will continue to provide an avenue for such new or existing resources to participate. These resources will be advantaged by being given a minimum bid amount (MW) eligibility that is appropriate for such an alternative, but that is also consistent with PacifiCorp’s then-current and applicable tariff filings (qualifying facility (QF) tariffs for example).

PacifiCorp will continue to participate with regulators and advocates in legislative and other regulatory activities that help provide tax or other incentives to renewable and distributed generation resources. The Company will also continue to improve representation of distributed generation resource in the IRP models.

Assessment of Owning Assets versus Purchasing Power

As the Company acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, the Company would be in a better position to control costs, make life extension improvements, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at cost as long as it remains economic. In addition, by owning a plant, the Company can hedge itself from the uncertainty of relying on purchasing power from others.

Depending on contract terms, purchasing power from a third party in a long term contract may help mitigate and may avoid any liabilities associated with closure of a plant. Short-term purchased power contracts could allow the Company to defer a long term resource acquisition. A long-term purchase power contract relinquishes control of construction cost, schedule, ongoing costs and compliance to a third party, and exposes the buyer to default events and contract remedies that will not likely cover the potential negative impacts. Finally, credit rating agencies impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation may affect the Company's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO₂ reduction regulations at the federal, regional, or state levels would prompt the Company to continue to look for measures to lower CO₂ emissions of existing thermal plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO₂ reduction rules will impact what types of measures that would be cost-effective and practical from operational and regulatory perspectives. As noted earlier in the IRP, known and prospective environmental regulations can impact coal plant utilization and investment decisions.

Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. To lower the emission levels for existing thermal plants, options include economic early retirement, changing the fuel type, repowering with more efficient generation equipment, lowering the plant heat rate so it is more efficient, and adoption of new technologies such as CO₂ capture with sequestration when commercially proven. Indirectly, plant carbon risk can be addressed by acquiring offsets in the form of renewable generation and energy efficiency programs. Under an aggressive CO₂ regulatory environment, and depending on fuel costs, coal plant idling and replacement strategies may become tenable options.

High CO₂ costs would shift technology preferences both for new resources and existing resources to those with more efficient heat rates and also away from coal, unless carbon is

sequestered. There may be opportunities to repower some of the existing coal fleet with a different less carbon-intensive fuel such as natural gas, as is currently being pursued for the Naughton Unit 3 generating unit. A major issue is whether new technologies will be available that can be exchanged for existing coal economically, particularly if market and policy drivers lead to large scale and abrupt early retirements across the region and the U.S. as a whole.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the Company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years the Company has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. The Company's risk management policy and hedging program exists to achieve the following goals: (1) to ensure that reliable power is available to serve customers; (2) to reduce net power cost volatility; and (3) to protect customers from significant risk. The purpose is solely to reduce customer exposure to net power cost volatility and adverse price movement. The Company does not speculatively trade commodities. Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. The Company cannot predict the direction or sustainability of changes in forward prices. Therefore, the Company hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the Company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are periodically reviewed at least annually by the Company's risk oversight committee. The risk oversight committee includes the Company's chief financial officer, treasurer, director of risk management, assistant general counsel, controller, and senior vice president of commercial and trading. The risk oversight committee makes recommendations to the president of PacifiCorp Energy, who ultimately must approve any change to the risk management policy. The Company's current policy is also consistent with the guidelines that resulted from collaborative hedging workshops with parties in Utah, Oregon, Idaho and Wyoming that took place in 2011 and 2012.

The main components of the Company's risk management policy and hedging program are natural gas percent hedged volume limits, value-at-risk (VaR) limits and time to expiry VaR (TEVaR) limits. These limits force the Company to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of these open positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas at fixed prices in gradual stages in advance of when it is required to reduce the size of this short position and associated customer risk. Likewise, on the power side, the Company either purchases or sells

power in gradual stages in advance of anticipated open short or long positions to manage price volatility on behalf of customers.

Since 2003, the Company's hedge program has employed a portfolio approach of dollar cost averaging to progressively reduce net power cost risk exposure over a defined time horizon while adhering to best practice risk management governance and guidelines. The Company's current portfolio hedging approach is defined by increasing risk tolerance levels represented by progressively increasing percentage of net power costs across the forward hedging period. The Company incorporated a time to expiry value at risk (TEVaR) metric in May 2010. In May 2012, as a result of multiple hedging collaboratives, the Company reintroduced natural gas percent hedge volume limits of forecast requirements into its policy. There has been no conflict to-date between the new volume limits and the Company's VaR and TEVaR limits, although the volume limits would supersede in such conflict, consistent with the guidelines from the hedging collaboratives.

The primary governance of the Company's hedging activities is documented in the Company's Risk Management Policy. In May 2010, the Company moved from hedging targets based on volume percentages to targets based on the "to expiry value-at-risk" or TEVaR metric. The primary goal of this change was to increase the transparency of the combined natural gas and power exposure by period. It enhances the progressive approach to hedging that the Company has employed for many years and provides the benefit of a more sophisticated measure of risk that responds to changes in the market and changes in open natural gas and power positions. Importantly, the TEVaR metric automatically reduces hedge requirements as commodity price volatility decreases and increases hedge requirements as correlations among commodities diverge, all the while maintaining the same customer risk exposure.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times the Company buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, the Company steadily and adaptively meets its hedge goals through the use of this technique while staying within VaR and TEVaR and natural gas percent hedge volume limits.

The result of these program changes in combination with changes in the market (such as reduced volatility to which the Company's program automatically responds), has been a significant decrease in the Company's longer-dated hedge activity, *i.e.*, four years forward on a rolling basis.

As a result of the hedging collaboratives, the Company made the following material changes to its policy in May 2012: (1) a reduction in the standard hedge horizon from 48 months to 36 months and (2) a percent hedged range guideline for natural gas for each of the three forward 12-month periods, which includes a minimum natural gas open position in each of the forward 12-month periods. The percent hedged range guideline is greater for the first rolling twelve months and gradually smaller for the second and third rolling twelve-month periods. The Company also agreed to provide a new confidential semi-annual hedging report.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the Company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long-run. The Company then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, the Company optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, the Company commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. The Company also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, the Company does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default. In addition, the Company reduces the amount of hedging required to achieve a given risk tolerance through its portfolio hedge management approach, which takes into account offsetting exposures when these commodities are correlated, as opposed to hedging commodity exposures to natural gas and power in isolation without regard for offsets.

Portfolio

The Company has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. The Company may have short or long positions in power depending on the shortfall or excess of the Company's total economic generation relative to customer load requirements at a given point in time.

The Company hedges its net energy (combined natural gas and power) position on a portfolio basis to take full advantage of any natural offsets between its long power and short natural gas positions. The Company's 2011 IRP analysis shows that a "hedge only power" or "hedge only natural gas" approach results in higher risk (*i.e.*, a wider distribution of outcomes). There is a natural need for an electric company with natural gas fired electricity generation assets to have a hedge program that simultaneously manages natural gas and power open positions with appropriate coordinated metrics. The Company's risk management department incorporates daily updates of forward prices for natural gas, power, volatilities and correlations to establish daily changes in open positions and risk metrics which inform the hedging decisions made every day by Company traders.

The Company's hedge program does not rely on a long power position. However, the Company's hedge program takes into account the Company's full portfolio and utilizes continuously updated correlations of natural gas and power prices and thereby takes advantage of offsetting natural gas and power positions in circumstances when prices are correlated and a forecast long power position offsets a forecast short natural gas position. This has the effect of reducing the amount of natural gas hedging that the Company would otherwise pursue. Ignoring this correlation would instead result in the need for more natural gas hedges to achieve the same level of customer risk reduction.

The Company's customers have benefited from offsetting power and natural gas positions. Power and natural gas prices are closely related because natural gas is often the fuel on the margin in efficient dispatch, as is practiced throughout the western U.S. This means power sales tend to be more valuable in periods when natural gas is high cost, producing revenues that are a credit or offset to the high cost fuel. If spot natural gas prices depart from prior forward prices, power prices will tend to do so in the same direction, thereby naturally hedging some of the unexpected cost variance.

Effectiveness Measure

The goal of the hedging program is to reduce volatility in the Company's net power costs primarily due to changes in market prices. The goal is not to "beat the market" and, therefore, should not be measured on the basis of whether it has made or lost money for customers. This reduction in volatility is calculated and reported in the Company's confidential semi-annual hedging report which it began providing as a result of the hedging collaborative.

Instruments

The Company's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. The Company chooses instruments that generally have greater liquidity and lower transaction costs. The Company also considers, with respect to options, the likelihood of disallowance of the option premium in its six jurisdictions. There is no functional difference between financial swaps and fixed price physical transactions; both instruments are equally effective in hedging the Company's fixed price exposure.

External Review

In the Company's 2009 Utah General Rate Case, the Division of Public Utilities requested that Blue Ridge, a consulting firm knowledgeable with commodity hedging, review the Company's hedging program. The Blue Ridge Report affirmatively concluded that the Company's risk management policy and hedging program was well-documented, controlled and adhered to generally accepted industry standards as follows:

Overall, Blue Ridge found that the Company's commercial trading and risk management programs (and the related hedging programs) are well-documented and controlled and adhere to generally accepted standards found elsewhere in the industry. The Company has well-stated goals and strategy that is aimed at mitigating price volatility. In addition,

*our review of the Company's internal documents showed that the Company is self-monitoring compliance with accepted commercial trading and risk management procedures through its own internal audit function.*⁸³

The question has been asked, "Why hedge?" The answer lies in one fundamental statement: prices and supplies for energy commodities (crude oil, natural gas, electricity, etc.) can and have been extremely volatile. The benefit of hedging is that when prices are rising (either rapidly in the short term or gradually in the long term), a hedged portfolio of supply should mitigate the effect of those increases. However, the opposite is also true. When prices fall suddenly, a hedged portion of the supply can cost the utility and its customers the difference between the prices that were available at the current time versus the hedged prices for that supply. This cost (when netted against any gains) along with the administrative costs associated to operate and manage the trading operations is considered the insurance premium associated with a hedged portfolio.

*[H]aving a "no hedge" policy clearly exposes consumers to significant (and likely) price swings. Assuming that an upward price trend continues (despite recent price levels and short-term price forecasts), consumers are very likely to pay higher prices for energy absent some level of hedging and price volatility mitigation.*⁸⁴

The National Regulatory Research Institute (NRRI) provided guidance related to natural gas hedging by utilities. The Utah Division of Public Utilities sponsored a presentation by NRRI to the Utah Commission in June 2009. The NRRI Report⁸⁵ indicates that, for many years, state commissions have suggested that failure to engage in hedging (*i.e.*, buying natural gas in the day-ahead market or spot price) may be imprudent. The NRRI Report provides guidance on standards for determining the prudence of a utility's hedging cost. The NRRI Report states, "Second-guessing and micromanaging should be avoided." It explains, "Second-guessing is contrary to the traditional prudence standard, and in addition, creates distorted incentives for utility hedging." Instead, it recommends that, "[a]ccording to the prudence standard, a commission should maintain authority to evaluate the reasonableness of (1) a hedging strategy *ex ante*, and (2) the execution of the strategy." The NRRI Report suggests that a Commission could set an *ex ante* standard by, for example, defining an acceptable level of risk tolerance to price volatility. The Company agrees with the NRRI Report's recommended approach to Commissions' reviews of the prudence of the Company's risk management policy and hedging program and welcomes direction from the Commissions on the Company's risk management policy and hedging program on a going forward basis.

Dr. Frank Graves of The Brattle Group, retained by the Company to assess its risk management policy and hedging program, summarized his general findings and conclusions as follows:

⁸³ Independent Third-Party Evaluation of Net Power Cost Evaluation Rocky Mountain Power 2009 General Rate Case, Prepared for Utah Division of Public Utilities, Prepared by Blue Ridge Consulting Services, Inc, Docket No. 09-035-23 (Utah PSC October 7, 2009) at 2.

⁸⁴ *Id.* at p 2 and 26.

⁸⁵ Gas Hedging Presentation to The Public Service Commission of Utah Technical Conference, Ken Costello, The National Regulatory Research Institute, Docket No. 09-035-21 (Utah PSC June 3, 2009), available at: [http://www.psc.utah.gov/utilities/electric/09docs/0903521/TechConf%206-3-09/Gas%20Hedging.ppt%20\(UT%20PSC\).pdf](http://www.psc.utah.gov/utilities/electric/09docs/0903521/TechConf%206-3-09/Gas%20Hedging.ppt%20(UT%20PSC).pdf)

First, risk management is about controlling the potential width (and shape) of the distribution of future costs and not about minimizing costs. Even though it is possible to trim or avoid extreme prices with hedging, that trimming cannot reduce expected costs, because the risk protections come at a fair price. What you gain from hedging as avoided “downside” (bad) outcomes, you must lose as avoided “upside” (good) outcomes as well, and vice versa for your hedging counterparty. The two, corresponding positions must balance for no expected net gain. Thus, the minimization of energy costs has nothing to do with good risk management practices.

Second, the Company’s hedging policies and practices, i.e. its analytic methods, risk metrics and controls, and hedging instruments, are fully in line with good industry practices. Like most electric utilities, the Company relies primarily on swaps purchased in regular installments over time. This avoids attempts to second-guess or “time” the market, while also assuring that hedges are steadily accrued, subject to risk-based guidelines for the needed quantity of total hedges. Consistent adherence to these methods, along with evidence of careful monitoring and control of the resulting risk metrics (keeping them within appropriate bounds), are the relevant standards for prudence review of the EBA costs the Company has incurred.

Third, U.S. natural gas markets in the late 2007 through 2011 period (when PacifiCorp entered the hedges) were dominated by the unexpectedly rapid and inexpensive development of shale gas, compounded by the credit crisis and deep recession. During the first two years of this period there were few indications that shale gas would become a major component of U.S. gas supply. Only towards the end of the period did it become evident that shale gas would become a prominent and quite inexpensive part of the natural gas supply in the U.S. Even natural gas exploration and production firms aggressively leading the development of the hydraulic fracturing technology that caused this price drop have been badly surprised by the rapid price reductions.⁸⁶ Therefore, the outlook for natural gas supply and prices were very different throughout the period during which the hedges were entered than it is today. It is imperative that the merits of a hedging program be evaluated based on the market conditions and information availability as of the time of the transaction.

Fourth, it would not have been useful or normal for the Company to have liquidated any of its prior hedges in the middle of this price decline. It might appear so in hindsight, but the spot prices we ultimately observed are not similar to the way risks or expected costs appeared at any time in the hedge procurement period. Utility companies should not and do not generally liquidate hedges if/when the forward price curve shifts and causes prior hedges to become “out of the money” (i.e. to have a higher cost than replacement hedges). Because hedge positions are liquidated at prevailing prices, early liquidation cannot be expected to benefit the Company or its customers; the expected alternative cost (whether re-hedged or not) would have been the then prevailing forward prices – with no net savings likely. (As it turns out, liquidation and not re-hedging, i.e. dramatically

⁸⁶ For example, an August 2009 article in the New York Times cites senior management at exploration and production companies that the continual drop puts the viability of smaller companies at risk. See Clifford Krauss, “Natural Gas Price Plummet to a Seven-Year Low,” New York Times, August 21, 2009.

increasing the Company's risk exposure, would have been cheaper. But this can only be known in hindsight, and pursuing this strategy would have been very speculative, possibly in violation of company risk-control guidelines and prior regulatory agreements about hedging activity.

Fifth, natural gas and power hedges should be considered together, which is what the Company does. The literature and common practice in hedging is solidly on the side of taking advantage of positions that predictably tend to offset each other, in order to reduce the cost and scope of hedging transactions that are needed. Electric and gas operations fit this model very nicely, in that they naturally tend to be correlated. Separating them for review would create perverse and untenable incentives for both regulation and operations.

Dr. Graves also described the purpose and overarching goal of risk management and hedging as follows:

A hedge is a trade designed to reduce risk, where risk is understood to mean the potential width (and shape) of the distribution of future costs (or revenues). Risk management is NOT about improving (reducing) the mean of this distribution of future costs (nor about increasing expected revenues). Risk also should not be confused with after-the-fact regret about whether a hedge proved to be necessary or attractive relative to remaining unhedged. In fact, risk and regret are mostly conflicting or competing goals, in that the more you lock down future prices (reduce ex ante risk) the greater the chance of eventually departing materially from the ex post cost of going unhedged. Conversely, if you wanted to have no regret about realized spot prices being lower than your hedges, than you should not hedge in the first place – but this would be risky! Some of the debate in regulatory review about risk management prudence involves confusion between these two concepts. However, the appropriate reference point is not the realized outcomes, which can only be known in hindsight (and which will only be better or worse than the hedges by luck), but the market information and outlook available at the time the hedges and risk reduction targets were committed.

Commission Review

Six out of six commissions that regulate PacifiCorp have approved net power costs for at least some portion of the 2012 calendar year period without any hedging disallowances. The Oregon Commission in the 2011 Transition Adjustment Mechanism, Docket No. UE 227, in the face of significant hindsight challenges from certain parties, found all of the Company's hedge transactions to be prudent and praised the Company's risk management policy and hedge program. Specifically, the Oregon Commission stated in the order:

The company's Risk Management Policy includes sound hedging goals, methodologies, and targets. Its policies and procedures were well articulated, and its specific hedging targets were made clear in advance to the company and its traders. Moreover, the company's hedging program appears to be robustly designed and well documented. The company provided ample contemporaneous documentation of the policies and procedures in effect at the time the hedges were executed, including its method of identifying, measuring, and managing risk, its hedging targets, its credit policies and

*procedures, and its approved portfolio structures, as well as detailed procedures governing company enforcement of these policies.*⁸⁷

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp “identify which risks will be borne by ratepayers and which will be borne by shareholders.” This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. 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 Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to CO₂ emissions, renewable resources to meet compliance requirement, change in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of CO₂ emission and renewable standard compliance rules.

To address these risks, the Company evaluates resources in the IRP and for competitive procurements using a range of CO₂ prices consistent with the scenario analysis methodology adopted for the Company’s IRP portfolio evaluation process. The Company’s use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the

⁸⁷ Order No. 11 435, Docket UE-227 (Ore. PUC [November 4, 2011]) at page 11.

need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with the Company's resource investments determined to be prudent by state commissions is a risk borne by customers.