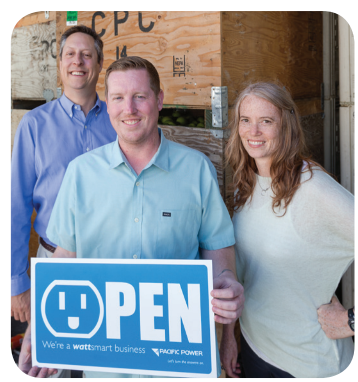
2017 INTEGRATED RESOURCE PLAN

Volume I

April 4, 2017



PACIFICORP

A BERKSHIRE HATHAWAY ENERGY COMPANY

This 2017 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.

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

This report is printed on recycled paper

Cover Photos (Top to Bottom):
Wind Turbine: *Marengo Wind Project*
Solar: *Pavant Solar Plant*
Transmission: *Sigurd to Red Butte Transmission Line*
Demand-Side Management: *Smart thermostat*
Pacific Power wattsmart Business Customer Meeting
Thermal-Gas: *Blundell Geothermal Plant*

TABLE OF CONTENTS

INDEX OF TABLES

INDEX OF FIGURES

CHAPTER 1 – EXECUTIVE SUMMARY

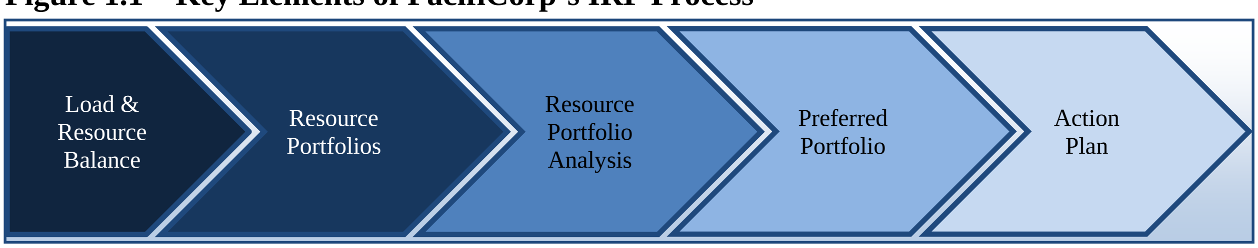
PacifiCorp's 2017 Integrated Resource Plan (IRP) presents the company's plans to provide reliable and reasonably priced service to its customers. The analysis supporting this plan helps PacifiCorp, its customers, and its regulators understand the effect of both near-term and long-term resource decisions on customer bills, the reliability of electric service PacifiCorp customers receive, and changes to emissions from the generation sources used to serve customers. In the 2017 IRP, PacifiCorp presents a cost-conscious plan to transition to a cleaner energy future with near-term investments in both existing and new renewable resources, new transmission infrastructure, and energy efficiency programs.

The primary objective of the IRP is to identify the best mix of resources to serve customers in the future. The best mix of resources is identified through analysis that measures cost and risk. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks, while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly the longer-range elements of the plans, can and do change over time. PacifiCorp's 2017 IRP was developed through an open and public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, regulatory staff, and other interested parties. The public input process began with the first public input meeting in June 2016. Over the subsequent nine months, PacifiCorp met with stakeholders in five states and hosted seven public input meetings. Through this process, PacifiCorp received valuable input from its stakeholders and presented findings from a broad range of studies and technical analyses that shaped and support the 2017 IRP.

As depicted in Figure 1.1, PacifiCorp's 2017 IRP was developed by working through five fundamental planning steps. This includes preparing a load and resource balance, which compares a forecast of load relative to existing resources. In the next planning step, PacifiCorp develops a range of different resource portfolios that meet projected deficiencies in the load and resource balance, each uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system. PacifiCorp then analyzes these different resource portfolios to measure the comparative cost, risk, reliability and emission levels. This resource portfolio analysis informs selection of a preferred portfolio and the associated resource action plan. Throughout this process, PacifiCorp considers a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies are also done to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's IRP Process



Preferred Portfolio Highlights

The 2017 IRP preferred portfolio reflects a cost-conscious transition to a cleaner energy future. Table 1.1 shows that PacifiCorp's resource needs will be met with new renewable resources, demand side management (DSM) resources, and short-term firm market purchases (labeled as front-office transactions or FOTs) through 2028. Over the 20-year planning horizon, the preferred portfolio includes 1,959 MW of new wind resources, 905 MW of upgraded ("repowered") wind resources, 1,040 MW of new solar resources, 2,077 MW of incremental energy efficiency resources, and 365 MW of new direct load control capacity.

Notably, PacifiCorp's analysis demonstrates that—by 2020 and with all-in economic savings for customers—the company can add 905 MW of repowered wind resources, 1,100 MW of new wind resources, and a new 140-mile 500 kV transmission line in Wyoming to access the new wind resources and relieve congestion for existing capacity. The preferred portfolio also assumes existing owned coal capacity will be reduced by 3,650 MW through the end of 2036 (including assumed coal retirements at the end of 2036 not shown below). The first new natural gas resource is added in 2029, one year later when compared to PacifiCorp's 2015 IRP preferred portfolio, subject to technology and IRP reassessments over the next decade.

Table 1.1 – 2017 IRP Preferred Portfolio Summary (Nameplate MW)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
New Resources																					
Summer FOT	500	521	878	807	799	916	844	885	1,042	978	1,040	1,575	1,575	1,566	1,575	1,575	1,575	1,575	1,575	1,539	n/a
Winter FOT	281	332	273	307	319	308	306	287	348	351	297	412	551	516	490	451	437	477	479	766	n/a
DSM - Energy Efficiency	154	128	131	122	123	114	118	118	112	111	109	102	96	95	96	83	75	65	63	63	2,077
DSM - Load Control	0	0	0	0	0	0	0	0	0	0	0	193	140	5	3	3	3	4	3	12	365
Wind	0	0	0	0	1,100	0	0	0	0	0	0	0	0	0	85	0	0	0	0	774	1,959
Solar	0	0	0	0	0	0	0	0	0	0	0	11	97	0	118	237	226	48	291	13	1,040
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	30	0	0	0	0	0	0	0	30
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	200	436	0	0	677	0	0	0	1,313
Existing Resources																					
Reduced Coal Capacity	0	0	(280)	0	(387)	0	0	0	0	(82)	0	(762)	(354)	(357)	(78)	0	(359)	0	(82)	0	(2,741)
Reduced Gas Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(358)	0	0	0	(358)
Repowered Wind Capacity	0	0	794	111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	905

* Note: Energy efficiency resource capacity reflects projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource. FOTs are short-term firm market purchases delivered only in the year shown. Reductions in existing coal and natural gas capacity are shown in the year after the assumed year-end retirement date (909 MW of existing coal capacity is assumed to retire year-end 2036, which would be reflected beginning 2037). Repowered wind capacity reports the amount of existing wind capacity assumed to be repowered in the preferred portfolio.

New Renewable Resources and Transmission

The 2017 IRP preferred portfolio advances PacifiCorp's commitment to low-cost clean energy with plans to add 1,100 MW of new Wyoming wind resources by the end of 2020. These new zero-emission wind facilities will connect to a new 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This time-sensitive project requires that the new wind and transmission assets achieve commercial operation by the end of 2020 to fully achieve the benefits of federal wind production tax credits (PTCs). In addition to providing significant economic benefits for PacifiCorp's customers, the wind and transmission project will provide extraordinary economic development benefits to the state of Wyoming.

Beyond 2020, the preferred portfolio includes an additional 859 MW of new wind—85 MW of Wyoming wind coming online in 2031, and 774 MW of Idaho wind in 2036. New solar resource additions totaling 1,040 MW come on-line over the 2028 to 2036 timeframe. Approximately 77 percent of the new solar is located in Utah (beginning 2031), and the remaining 23 percent is located on the west side of PacifiCorp's system (beginning 2028).

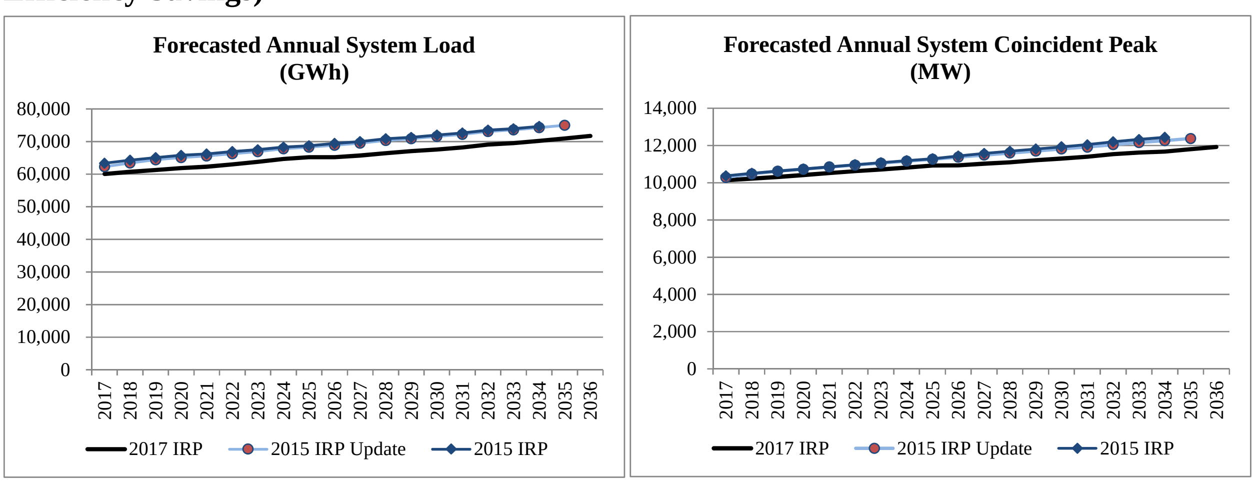
Wind Repowering

PacifiCorp executed wind-turbine-generator (WTG) equipment purchases in December 2016 to preserve the option to repower existing wind generation facilities and obtain PTC benefits for customers. Analysis performed in the 2017 IRP supports repowering 905 MW of existing wind resources by the end of 2020 and demonstrates that this exciting project will save customers hundreds of millions of dollars. The scope of the repowering project involves installing new nacelles and longer blades. With the installation of modern technology and improved control systems, the repowered wind facilities will produce more zero-emission energy for a longer period of time at reduced operating costs. Existing towers and foundations will remain in place, resulting in minimal environmental impact and permitting requirements.

Demand Side Management

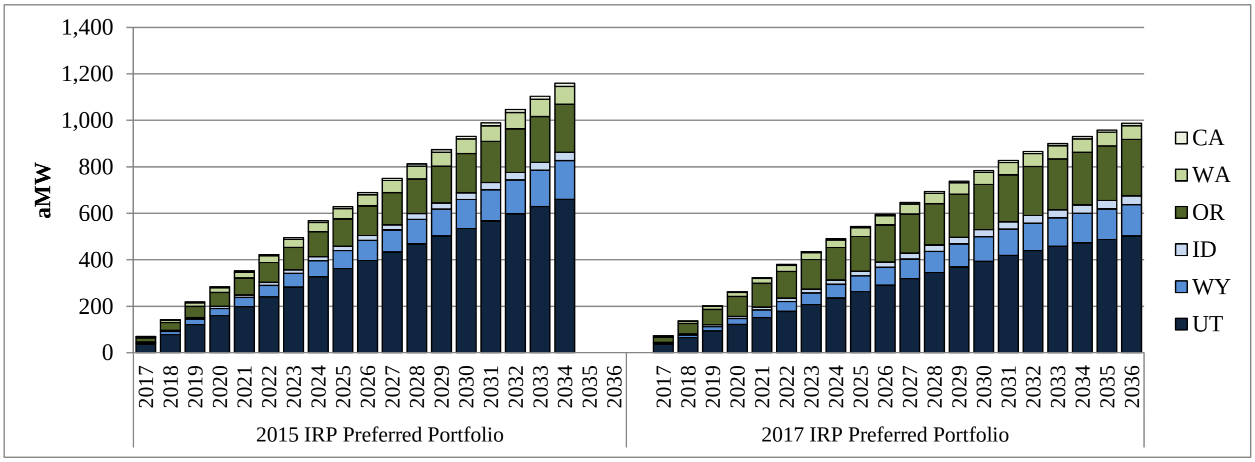
PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 1.2 shows that PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2015 IRP and 2015 IRP Update. On average, forecasted system load is down 5.3 percent and forecasted coincident system peak is down 3.5 percent when compared to the 2015 IRP Update. Through the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 0.94 percent for load and 0.86 percent for peak. Changes to PacifiCorp's load forecast are driven by reduced industrial class loads, due in large part to lower commodity prices, and continued gains in energy conservation as evidenced by a drop in the average use per customer.

Figure 1.2 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



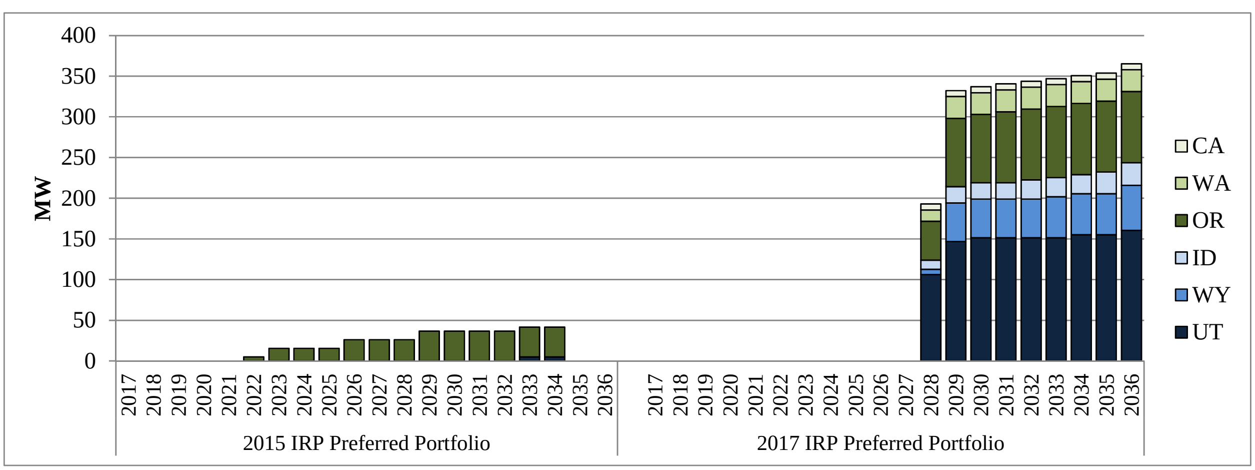
DSM resources continue to play a key role in PacifiCorp's resource mix. Over the first ten years of the planning horizon, accumulated acquisition of new incremental energy efficiency resources meets 88 percent of forecasted load growth from 2017 through 2026 (up from 86 percent in the 2015 IRP). Figure 1.3 compares total energy efficiency savings by state in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. Decreased selection of energy efficiency resources relative to the 2015 IRP is driven by reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives.

Figure 1.3 – Comparison of Total Energy Efficiency Savings between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



In addition to continued investment in energy efficiency programs, the preferred portfolio identifies an increasing role for direct load control programs with total capacity reaching 365 MW by the end of the planning period. Figure 1.4 compares total incremental capacity of direct load control program capacity by state in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. The significant increase in direct load control capacity and expansion of state programs is coincident with assumed coal unit retirements, signaling the importance of these capacity-based programs in PacifiCorp's transitioning resource mix.

Figure 1.4 – Comparison of Total Direct Load Control Capacity between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



Wholesale Power Market Purchases

Figure 1.5 shows that base case forecasted wholesale power prices and natural gas prices used in the 2017 IRP are significantly lower than the base case market prices used in the 2015 IRP and are more closely aligned with those used in PacifiCorp's 2015 IRP Update. Over the last couple of IRP cycles, growth in natural gas supplies, primarily from prolific shale plays in North America, have continued to outpace expectations. With continued declines in forward natural gas prices and on-going reductions in regional electric load growth expectations, forward power prices have also declined significantly since the 2015 IRP.

Figure 1.5 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

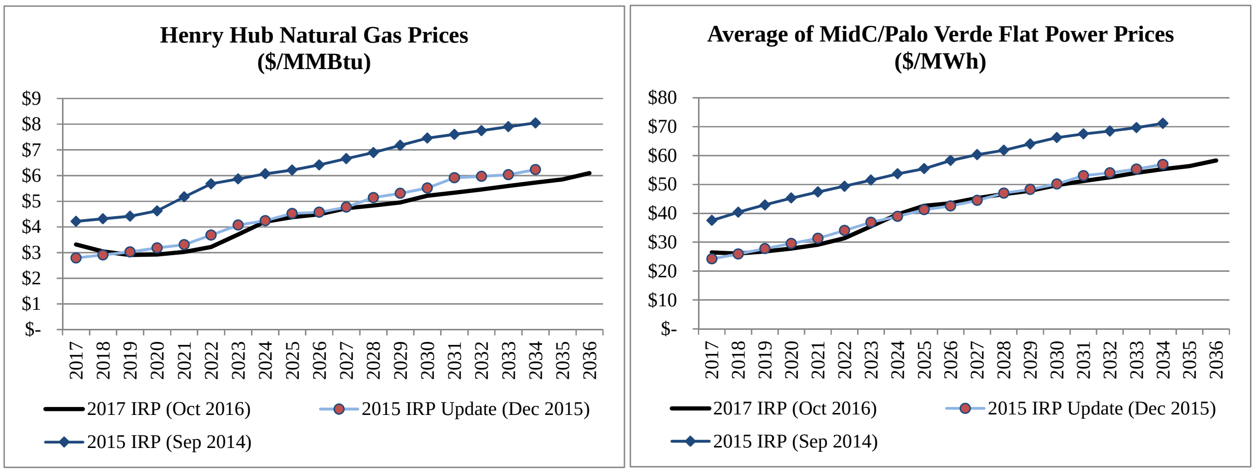
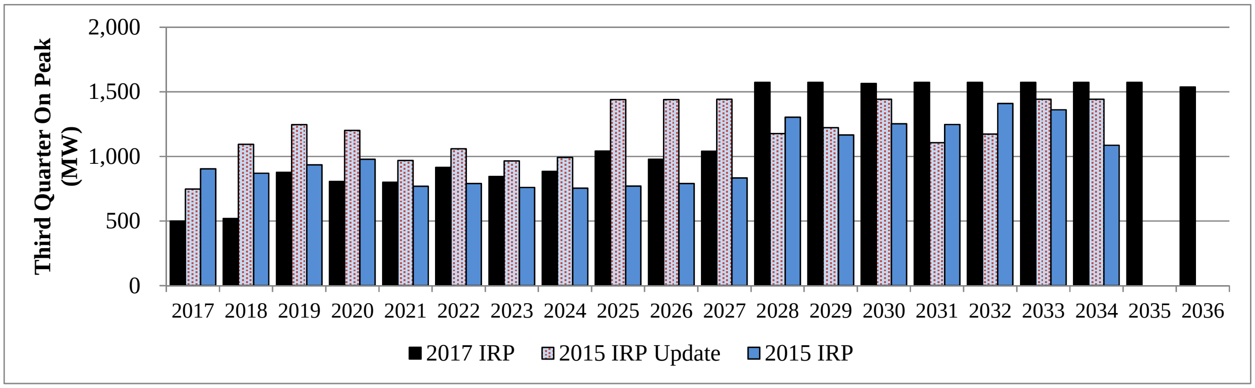


Figure 1.6 compares wholesale market firm purchases from the 2017 IRP preferred portfolio to the market purchases included in the preferred portfolio of recent IRPs. While market conditions for firm wholesale power purchases are favorable, reduced loads and continued investment in energy efficiency programs reduce the need for wholesale power purchases through 2027 relative to the 2015 IRP Update. Over this period, average annual wholesale power purchases are down by 27 percent relative to the 2015 IRP Update and are on par with wholesale power purchases projected in the 2015 IRP. Longer-term wholesale power purchases increase coincident with assumed coal unit retirements. In this 2017 IRP, PacifiCorp evaluated regional resource adequacy and determined that its wholesale power purchase limits are reasonable. PacifiCorp will, however, continue to monitor potential shortfalls in regional supply through its on-going planning process.

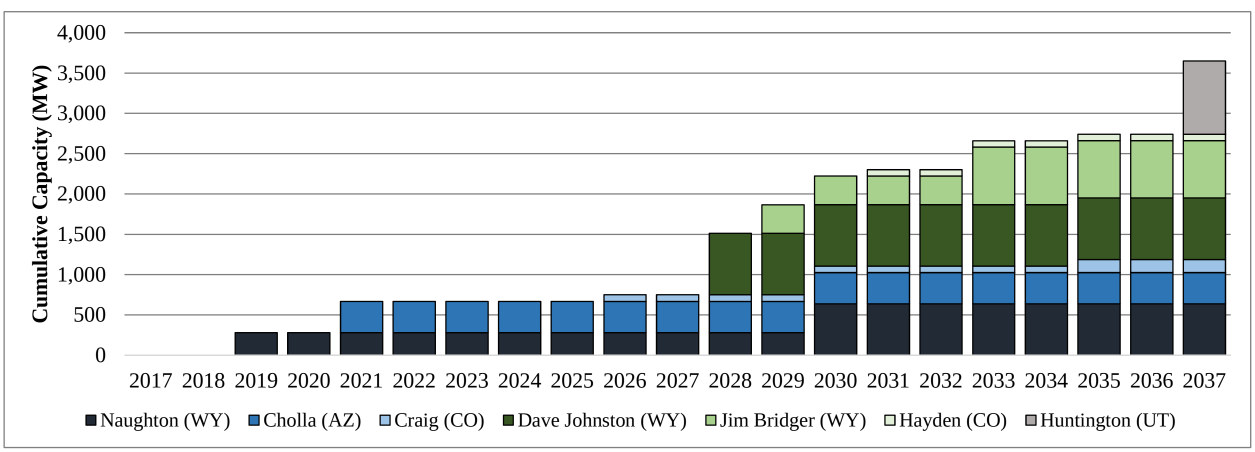
Figure 1.6 – Comparison of Summer Market Purchases in Recent IRPs



Existing Coal Resources

Supported by analysis of potential Regional Haze compliance alternatives, the 2017 IRP preferred portfolio does not include any incremental selective catalytic reduction (SCR) equipment. Avoiding installation of this equipment will save customers hundreds of millions of dollars and retain compliance-planning flexibility associated with the Clean Power Plan or other potential state and federal environmental policies. As in past IRPs, the 2017 IRP studies a range of Regional Haze compliance scenarios, reflecting potential bookend alternatives that consider early retirement outcomes as a means to avoid installation of expensive SCR equipment. The individual unit-specific outcomes assumed in the 2017 IRP preferred portfolio will ultimately be determined by on-going rulemaking; litigation results; and future negotiations with state and federal agencies, partner plant owners, and other vested stakeholders. Consequently, individual unit retirements reflected in the preferred portfolio, while reasonable for planning purposes, are not firm commitments for early unit closures. Figure 1.7 summarizes coal unit retirements assumed in the preferred portfolio. By the end of the planning horizon, PacifiCorp assumes 3,650 MW of existing coal capacity will be retired.

Figure 1.7 – 2017 IRP Preferred Portfolio Coal Unit Retirements



*Note: Retired capacity is reported in the first year in which the unit is no longer available to meet summer coincident peak load.

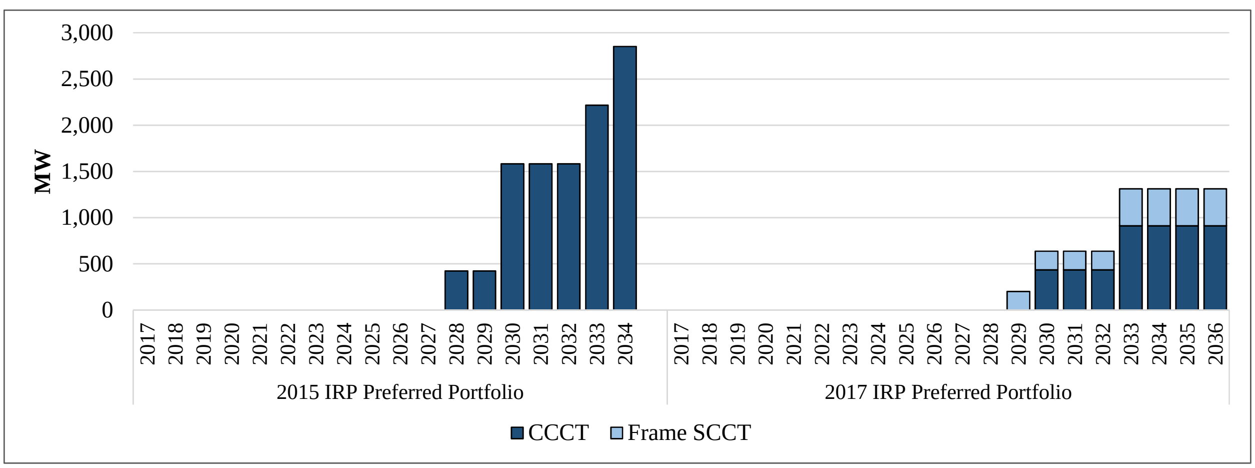
Reflecting an updated operating permit from the state of Wyoming, PacifiCorp assumes Naughton Unit 3 retires at the end of 2018—one year later than in the 2015 IRP Update.

PacifiCorp will continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2018 if proven to be cost effective for customers. PacifiCorp's analysis also assumes Cholla Unit 4 retires at the end of 2020. This early closure assumption was considered in PacifiCorp's Regional Haze compliance analysis to account for changes in market conditions, characterized by reduced loads and wholesale power prices. As with Naughton Unit 3, PacifiCorp will continue to analyze potential early-closure scenarios for Cholla Unit 4 as part of its on-going planning process. Longer term, the preferred portfolio reflects an early retirement of Craig Unit 1 at the end of 2025, Jim Bridger Unit 1 at the end of 2028, and Jim Bridger Unit 2 at the end of 2032. Assumed end-of-life retirements include four units at the Dave Johnston plant at the end of 2027, Naughton Units 1 and 2 at the end of 2029, Hayden at the end of 2030, Craig Unit 2 at the end of 2034, and two units at the Huntington plant at the end of 2036.

Natural Gas Resources

Figure 1.8 compares total new natural-gas-fired resource capacity in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. The first natural gas resource, a 200 MW frame simple cycle combustion turbine (SCCT), is added to the portfolio in 2029—one year later than the first natural gas resource in the 2015 IRP. The first combined combustion turbine (CCCT), a 436 MW G-class 1x1, is added to the system in 2030—two years later than the first CCCT in the 2015 IRP. In aggregate, the 2017 IRP preferred portfolio includes 1,313 MW of new natural-gas-fired capacity, a reduction of 1,540 MW of natural gas resources relative to the 2015 IRP preferred portfolio. Reduced loads, on-going investment in energy efficiency programs, and increased renewables reduce the need for new natural gas resources in the 2017 IRP. Recognizing the long time horizon before the first natural gas plant is added, PacifiCorp will continue to evaluate potential long-term supply alternatives, including the potential penetration of energy storage, through its on-going resource planning over the next decade.

Figure 1.8 – Comparison of Total New Natural Gas Resources between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio

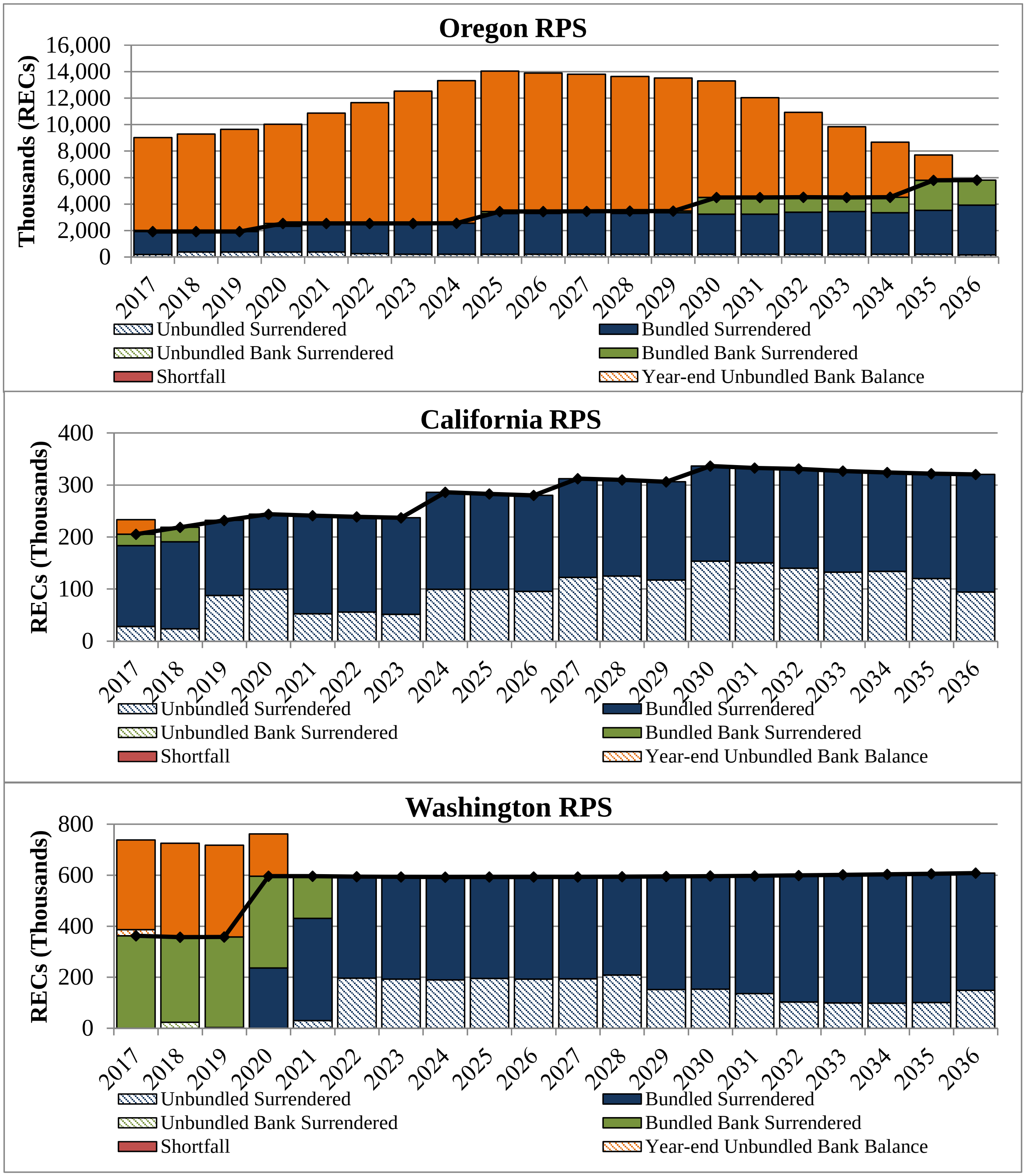


Renewable Portfolio Standards

Figure 1.9 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for the wind repowering project and new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources, they also contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2034 with the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio. A small increment of annual purchases of unbundled renewable energy credits (REC), labeled "Unbundled Surrendered" in Figure 1.9 below, beginning at under 160 thousand RECs in 2018, is required to achieve Oregon RPS compliance through 2036. The California RPS compliance position is also improved by the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio and similarly requires a small amount of unbundled REC purchases under 150 thousand RECs per year to achieve compliance through the planning horizon. Washington RPS compliance is achieved with the benefit of the repowered wind assets located in the west side, Marengo and Leaning Juniper, new renewable resources added to the west side beginning 2028, and unbundled REC purchases under 200 thousand RECs per year. Under current allocation mechanisms, Washington customers do not benefit from the repowered wind and new renewable resources added to the east side of PacifiCorp's system. While not shown in Figure 1.9, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources before considering the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio.

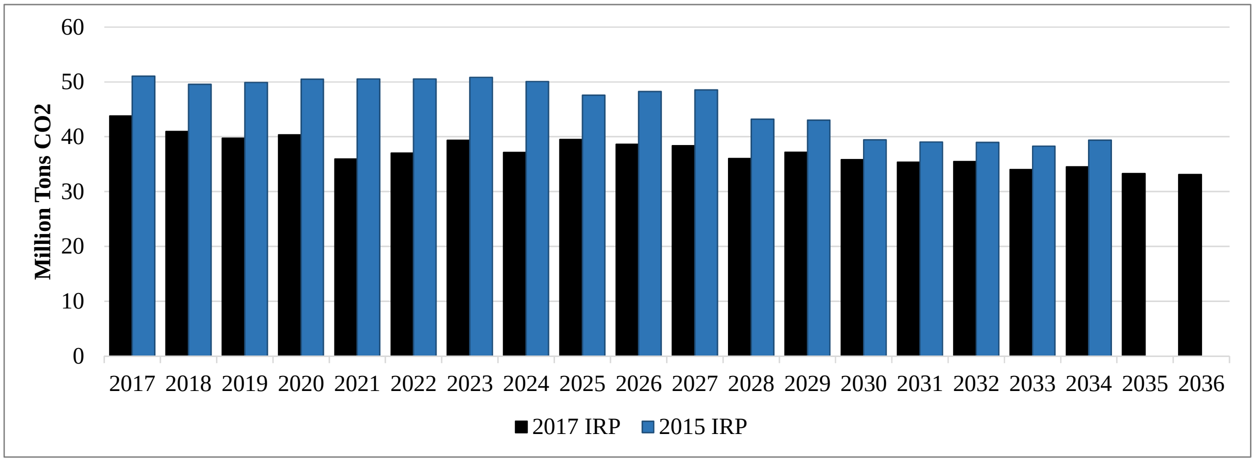
Figure 1.9 – Annual State RPS Compliance Forecast



Carbon Dioxide Emissions

The 2017 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors, including PacifiCorp's participation in the Energy Imbalance Market (EIM), which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going expansion of renewable resources and transmission; and Regional Haze compliance that capitalizes on flexibility. Figure 1.10 compares projected annual CO_2 emissions between the 2017 IRP and 2015 IRP preferred portfolios. Over the first 10 years of the planning horizon, average annual CO_2 emissions are down by over 10.5 million tons (21 percent) relative to the 2015 IRP. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.8 million tons in 2017 to 33.1 million tons in 2036—a 24.5 percent reduction.

Figure 1.10 – Comparison of CO_2 Emission Forecasts between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



Load and Resource Balance

A key element of PacifiCorp's IRP process is to assess its load and resource balance over the 20-year planning horizon. The load and resource balance relies on the ability for specific types of resources to meet our forecasted coincident system peak load while accounting for reserve requirements, which ensures reliable electric service for PacifiCorp customers. In developing the resource plan, PacifiCorp applies a 13 percent planning reserve margin to account for near-term and longer-term planning uncertainties.

Capacity Balance

Table 1.2 shows PacifiCorp's summer capacity position from 2017 through 2026, with coal unit retirement assumptions and incremental energy efficiency savings from the 2017 IRP preferred portfolio before adding any incremental new generating resources. With continued load growth and assumed coal unit retirements, summer margins drop over time, but remain higher than the 13 percent target planning margin throughout the first 10 years of the planning horizon.

Table 1.2 – PacifiCorp 10-Year Summer Capacity Position Forecast (MW)

System (Summer)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Existing Resource Capacity Contribution	10,493	10,494	10,109	10,194	10,069	9,980	10,062	10,043	9,920	9,912
Available FOT Capacity Contribution	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670
Total Existing Resource + FOTs	12,162	12,163	11,778	11,864	11,738	11,650	11,731	11,712	11,589	11,581
Obligation Net of Incremental DSM	9,730	9,743	9,743	9,758	9,793	9,824	9,829	9,850	9,892	9,831
13% Planning Reserve Margin	1,290	1,292	1,292	1,294	1,298	1,302	1,303	1,306	1,311	1,303
Obligation + 13% Planning Reserves	11,020	11,035	11,035	11,052	11,092	11,126	11,132	11,156	11,203	11,135
System Position with Available FOTs	1,142	1,129	743	812	647	524	599	556	386	447
Reserve Margin with Available FOTs	25.0%	24.8%	20.9%	21.6%	19.9%	18.6%	19.4%	18.9%	17.2%	17.8%

In response to stakeholder feedback from the 2015 IRP planning cycle, PacifiCorp developed a winter load and resource balance for the 2017 IRP. Table 1.3 shows PacifiCorp's annual winter capacity position from 2017 through 2026, with coal unit retirement assumptions and incremental energy efficiency savings from the 2017 IRP preferred portfolio before adding any incremental new generating resources. Accounting for available market purchases, PacifiCorp substantially exceeds its 13 percent target planning reserve margin over the winter peak through this period. With continued load growth and assumed coal unit retirements, winter margins drop over time, but remain significantly higher than the 13 percent target planning margin.

Table 1.3 – PacifiCorp 10-Year Winter Capacity Position Forecast (MW)

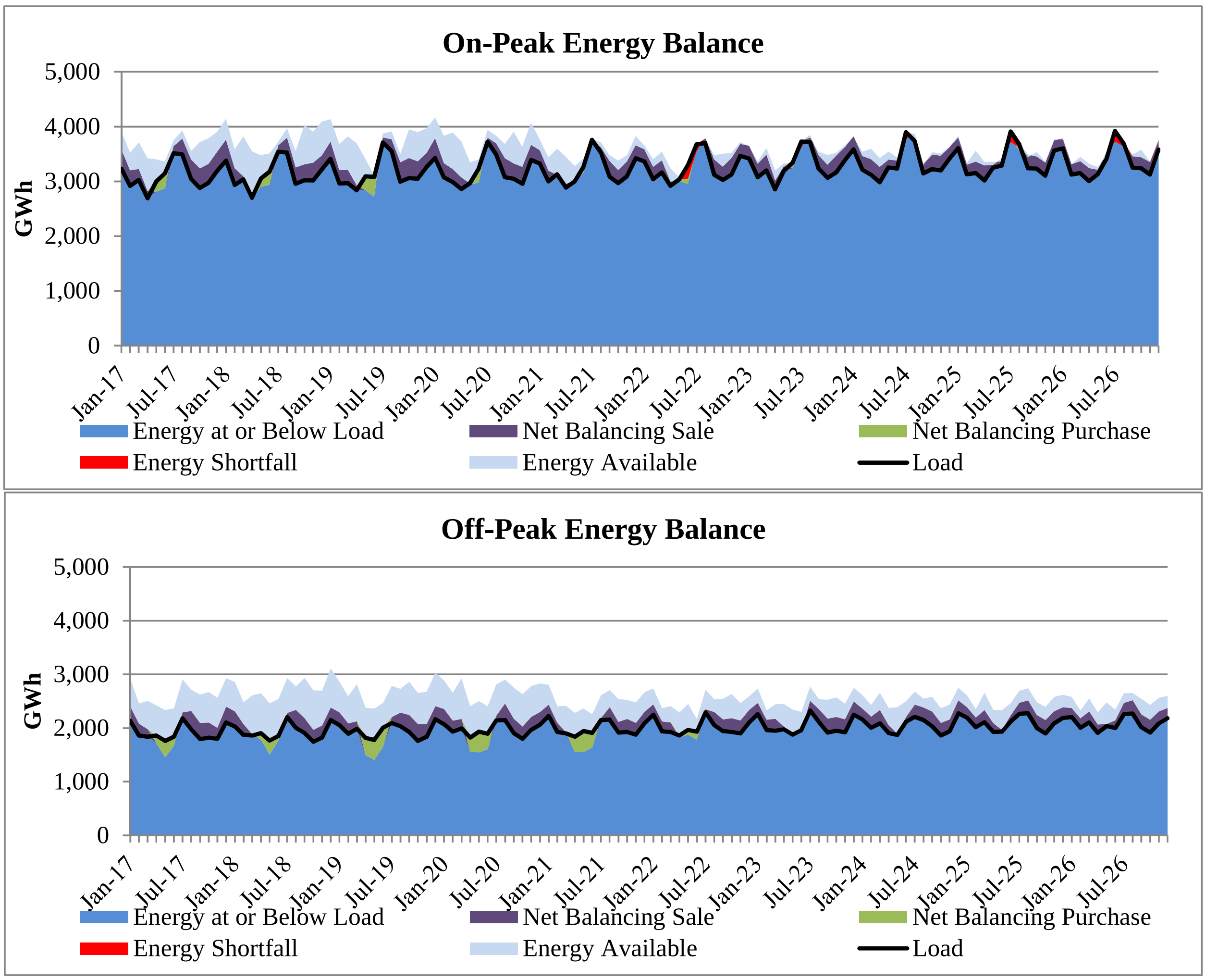
System (Winter)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Existing Resource Capacity Contribution	11,417	11,369	11,112	11,110	10,047	10,037	9,978	9,908	9,905	9,878
Available FOT Capacity Contribution	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670
Total Existing Resource + FOTs	13,087	13,038	12,781	12,779	11,717	11,707	11,647	11,577	11,574	11,548
Obligation Net of Incremental DSM	8,441	8,453	8,453	8,400	8,443	8,472	8,503	8,487	8,511	8,467
13% Planning Reserve Margin	1,123	1,124	1,124	1,117	1,123	1,127	1,131	1,129	1,132	1,126
Obligation + 13% Planning Reserves	9,564	9,578	9,578	9,518	9,566	9,599	9,634	9,616	9,643	9,593
System Position with Available FOTs	3,523	3,461	3,204	3,261	2,151	2,108	2,013	1,961	1,931	1,954
Reserve Margin with Available FOTs	55.0%	54.2%	51.2%	52.1%	38.8%	38.2%	37.0%	36.4%	36.0%	36.4%

Energy Balance

The capacity position shows how existing resources and loads balance during the coincident peak summer and winter periods, accounting for assumed coal unit retirements and incremental energy efficiency savings from the 2017 IRP preferred portfolio. Outside of these peak periods, PacifiCorp economically dispatches its resources to meet changes in load while taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, PacifiCorp can dispatch resources that, in aggregate, exceed then-current PacifiCorp customer load obligations, facilitating off-system wholesale market power sales that reduce costs for PacifiCorp customers. Conversely, at times when system resource costs are greater than prevailing market prices, system balancing wholesale market power 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 PacifiCorp manages net power costs on behalf of its customers.

Figure 1.11 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 recent wholesale power and natural gas prices.[1] The figure shows expected monthly energy production from system resources during on-peak and off-peak periods in relation to load, reflecting coal unit retirement assumptions and incremental energy efficiency savings from the 2017 IRP preferred portfolio before adding any new generating resources. 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 periods. Figure 1.11 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 indicate short energy positions without addition of any new generating resources to the portfolio. During on-peak periods, the first energy shortfall appears in summer 2022. There are no energy shortfalls during off-peak periods over this timeframe.

Figure 1.11 – Economic System Dispatch of Existing Resources in Relation to Monthly Load



[1] On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday. Off-peak periods are all other hours.

2017 IRP Advancements and Supplemental Studies

IRP Advancements

During each IRP planning cycle, PacifiCorp identifies and implements advancements to continuously improve the IRP for its customers, other stakeholders, and regulatory commissions. Some of the key advancements implemented in the 2017 IRP include:

- Winter Peak Analysis
  In response to stakeholder feedback received during the 2015 IRP, PacifiCorp incorporated in its 2017 IRP comprehensive analysis of how its resource plan meets winter peak load obligations. The coincident peak for PacifiCorp's system occurs during the summer, and prior IRP planning cycles have historically focused on ensuring that resource plans have sufficient capacity to cover summer coincident peak load. For the first time, the 2017 IRP enforces the target planning reserve margin on both the summer and winter coincident system peak load, allowing PacifiCorp to report a winter load and resource balance, evaluate direct load control programs targeting the winter peak, and evaluate and report market purchases used to satisfy winter peak load forecasts.

- Resource Portfolio Development Process
  PacifiCorp improved its resource portfolio development process to more efficiently produce alternative combinations of resources that could be used to serve our customers over time. This was achieved by initially evaluating a comprehensive range of Regional Haze compliance cases under different market price and environmental policy scenarios, and then using stochastic risk metrics to evaluate the relative performance of alternative compliance outcomes. Results from this analysis established coal unit retirement assumptions for subsequent core case and sensitivity case studies, addressing stakeholder feedback from the 2015 IRP requesting that portfolios considered for selection as the preferred portfolio be compared among common Regional Haze compliance assumptions. Further, PacifiCorp implemented a core case modeling framework targeting specific types of resources having operating characteristics not explicitly valued until the stochastic risk phase of portfolio analysis. This structure allowed PacifiCorp to evaluate a more diverse mix of potential resource portfolios among a broader range of market price and environmental policy scenarios to compare the relative performance of these portfolios using stochastic risk metrics.

- Stakeholder Requests
  Efficiencies gained through improvements to the resource development process better positioned PacifiCorp to develop additional studies requested by stakeholders during the public input process. PacifiCorp and stakeholders identified and requested alternative modeling scenarios that were informed by the initial and intermediate analysis that was reviewed during the public input process. This is an improvement over past IRP planning cycles, where a more rigid set of pre-defined core case and sensitivity cases limited the ability to explore alternative assumptions. This improved process in the 2017 IRP enabled PacifiCorp to develop additional Regional Haze compliance cases and alternative environmental policy cases in response to stakeholder requests. Results from some of these studies led PacifiCorp to consider additional scenarios, which directly influenced the resource mix in the preferred portfolio.

- Clean Power Plan Modeling
  In the 2015 IRP, PacifiCorp developed a modeling framework to assess the CO_2 emission rate targets identified in the Environmental Protection Agency's draft Clean Power Plan (CPP) rule. Due to modeling limitations, PacifiCorp was not able to explicitly capture the impact of the emission rate targets in stochastic risk analysis, which is used to compare the relative cost and risk performance of different resource portfolios. In the 2017 IRP, PacifiCorp identified different mass cap emission targets outlined in the final CPP, enabling us to leverage existing modeling capabilities to reflect the impact of CPP emission limits in stochastic risk analysis.

- Solar Integration Costs
  In previous IRPs, a solar integration study to define incremental operating reserve requirements and associated costs to manage the variability and uncertainty of solar resources connected to PacifiCorp's system had not been developed. In the 2017 IRP, PacifiCorp's flexible reserve study outlines incremental reserve requirements associated with solar resources and accompanying estimates for solar resource integration costs.

- Public Input Meetings
  In response to requests to improve participation in IRP public input meetings, PacifiCorp coordinated with stakeholders to include video conference connections with locations in Cheyenne, Wyoming, and Denver, Colorado, to supplement the existing video conference connection between Portland, Oregon, and Salt Lake City, Utah.

Supplemental Studies

PacifiCorp's 2017 IRP relies on numerous supplemental studies that support the derivation of specific modeling assumptions critical to its long-term resource plan. A description of these studies, discussed in more detail in appendices filed with the 2017 IRP, is provided below.

- Conservation Potential Assessment
  An updated conservation potential assessment (CPA), prepared by Applied Energy Group (commissioned by PacifiCorp) and the Energy Trust of Oregon was prepared to develop demand side management resource potential and cost assumptions specific to PacifiCorp's service territory. The CPA supports the cost and DSM savings data used during the portfolio development process.

- Private Generation Resource Assessment
  This supplemental study, prepared by Navigant Consulting, Inc., was refreshed for the 2017 IRP to produce updated private generation penetration forecasts for solar photovoltaic, small-scale wind, small-scale hydro, combined heat and power reciprocating engines, and combined heat and power micro-turbines specific to PacifiCorp's service territory. The private generation penetration forecasts from this study are applied as a reduction to forecasted load throughout the IRP modeling process.

- Western Resource Adequacy Evaluation
  PacifiCorp updated its analysis of regional resource adequacy to support its assumptions for wholesale power market purchase limits adopted for the 2017 IRP. The western resource adequacy evaluation presents data from the Western Electricity Coordinating Council's Power Supply Assessment, reviews recent resource adequacy studies performed for the Pacific Northwest region, and summarizes PacifiCorp's historical peak

period market purchase data. PacifiCorp's review of regional resource adequacy continues to support the use of wholesale power market purchases as a resource in the IRP planning process.

- Planning Reserve Margin Study
  The 2017 IRP was developed targeting a 13 percent planning reserve margin, which influences the need for new resources and is applied during the portfolio development process. In the 2017 IRP planning reserve margin study, PacifiCorp analyzes the relationship between cost and reliability among ten different planning reserve margin levels, accounting for variability and uncertainty in load and generation resources.

- Capacity Contribution Study
  PacifiCorp updated its wind and solar capacity contribution values for the 2017 IRP, which were developed using the capacity factor approximation method. Capacity contribution is defined as the availability of wind and solar resources among hours having the highest loss-of-load probability, and the resulting values are used in the 2017 IRP load and resource balance and in the portfolio development process.

- Flexible Reserve Study
  PacifiCorp expanded the scope of what has historically been titled as the wind integration study to include an overall assessment of flexible reserve demands driven by variability and uncertainty in load, wind, solar, and non-wind and non-solar generation resources. The updated study was prepared by PacifiCorp in coordination with a technical review committee and estimates flexible reserve needs and integration costs for wind and solar resources. Operating reserves estimated from the study are used in cost and risk analysis modeling and estimated wind and solar integration costs are applied during the portfolio development process.

- Stochastic Parameter Update
  PacifiCorp's preferred portfolio selection process relies, in part, on stochastic risk analysis using a Monte Carlo random sampling process. Stochastic variables include natural gas and wholesale electricity prices, load, hydro generation, and unplanned thermal outages. For its 2017 IRP, PacifiCorp updated its stochastic parameter input assumptions with more current historical data.

- Smart Grid
  PacifiCorp has included in the 2017 IRP appendix an update on its Smart Grid efforts with a focus on transmission and distribution systems and customer information.

- Energy Storage Screening Studies
  Two energy storage studies were conducted to support the 2017 IRP. The Battery Energy Storage Study prepared by DNV-GL catalogues commercially available and emerging battery energy storage technologies with forecasts and estimates for both performance and costs. The Bulk Energy Storage Study prepared by Black & Veatch is an update to the work HDR and Navigant Consulting performed for the 2015 IRP. The Bulk Energy Storage Study incorporates updated information on three pumped hydro energy storage projects and a compressed air energy storage project in PacifiCorp's service territory.

Action Plan

The 2017 IRP action plan identifies specific resource actions PacifiCorp will take over the next two to four years to deliver resources included in the preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed during the development of the 2017 IRP, and other resource activities described in the 2017 IRP. Table 1.4 details specific 2017 IRP action items by category.

Table 1.4 - 2017 IRP Action Plan

Action Item	1. Renewable Resource Actions
1a	**<u>Wind Repowering</u>** • PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016. – Continue to refine and update the economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed. – By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills). – Pursue regulatory review and approval as necessary. – By May 2018, issue the engineering, procurement, and construction (EPC) notice to proceed to begin implementing the wind repowering for specific projects consistent with updated financial analysis. – By December 31, 2020, complete installation of wind repowering equipment on all identified projects.
1b	**<u>Wind Request for Proposals</u>** • PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020. – April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP. – May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission. – May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP. – June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and Necessity (CPCN) application with the Public Service Commission of Wyoming. – By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Washington Utilities and Transportation Commission.

<table>
<tr><td></td><td>
– By August 2017, issue the Wyoming wind RFP to the market.
– By October 2017, Wyoming wind RFP bids are due.
– November-December, 2017, complete initial shortlist bid evaluation.
– By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission.
– By March 2018, receive CPCN approval from the Wyoming Public Service Commission.
– Complete construction of new wind projects by December 31, 2020.
</td></tr>
<tr><td>1c</td><td>
<u>Renewable Portfolio Standard Compliance</u>
• PacifiCorp will issue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements.
– As needed, issue RFPs seeking then-current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2020.
– As needed, issue RFPs seeking low-cost then-current-year, forward-year, or older vintage unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets, deferring the currently projected 2035 initial shortfall after accounting for preferred portfolio renewable resources.
</td></tr>
<tr><td>1d</td><td>
<u>Renewable Energy Credit Optimization</u>
• Before filing the 2017 IRP Update, evaluate potential opportunities to re-allocate RECs from Utah, Wyoming, and Idaho to Oregon, Washington, or California.
• Maximize the sale of RECs that are not required to meet state RPS compliance obligations.
</td></tr>
<tr><th>Action Item</th><th>2. Transmission Actions</th></tr>
<tr><td>2a</td><td>
<u>Aeolus to Bridger/Anticline</u>
• By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary.
– June-July 2017, file a CPCN application with the Public Service Commission of Wyoming.
– By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way.
– By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed.
– By April 2019, issue EPC final notice to proceed.
– Complete construction of the transmission line by December 31, 2020.
</td></tr>
</table>

<table>
<tr><td>2b</td><td><u>Energy Gateway Permitting</u>
Continue permitting for the Energy Gateway transmission plan, with the following near-term targets:
For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits.
For Segments D, E, and F, continue to support the projects by providing information and participating in public outreach.
For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.</td></tr>
<tr><td>3c</td><td><u>Wallula to McNary 230 kV Transmission Line</u>
Complete Wallula to McNary project construction per plan with a 2018 expected in-service date. Continue to support the permitting and construction process for Walla Walla to McNary.</td></tr>
<tr><td>4d</td><td><u>Planning Studies</u>
Complete planning studies that include proposed coal unit retirement assumptions from the 2017 IRP preferred portfolio and two other scenarios.
Summarize studies in the 2017 IRP Update.</td></tr>
<tr><td>Action Item</td><td>3. Firm Market Purchase Actions</td></tr>
<tr><td>3a</td><td><u>Front Office Transactions</u>
Acquire economic short-term firm market purchases for on-peak summer deliveries from 2017 through 2019 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means:
Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price.
Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price.
Prompt month-forward, balance-of-month, day-ahead, and hour-ahead non-brokered transactions.</td></tr>
</table>

<table>
<tr><th>Action Item</th><th>4. Demand Side Management (DSM) Actions</th></tr>
<tr><td>4a</td><td><u>Class 2 DSM</u>
• Acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2017 IRP.
<table><tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr><tr><td>2017</td><td>646</td><td>154</td></tr><tr><td>2018</td><td>559</td><td>128</td></tr><tr><td>2019</td><td>571</td><td>131</td></tr><tr><td>2020</td><td>527</td><td>122</td></tr></table>*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.</td></tr>
<tr><th>Action Item</th><th>5. Coal Resource Actions</th></tr>
<tr><td>5a</td><td><u>Hunter Units 1 and 2</u>
• The EPA's final Regional Haze Federal Implementation Plan (FIP) for Utah requires the installation of selective catalytic reduction (SCR) on Hunter Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
• As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.</td></tr>
<tr><td>5b</td><td><u>Huntington Units 1 and 2</u>
• The EPA's final Regional Haze FIP for Utah requires the installation of SCR on Huntington Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
• As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.</td></tr>
<tr><td>5c</td><td><u>Dave Johnston Unit 3</u>
• The EPA's final Regional Haze FIP requires the installation of SCR at Dave Johnston Unit 3 in 2019 or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. PacifiCorp's commitment to the latter must be included in a permit before the 2019 compliance deadline.
• PacifiCorp will update its analysis of the commitment to shut down Dave Johnston Unit 3 by the end of 2027 as part of its 2017 IRP Update.</td></tr>
</table>

5d	**<u>Jim Bridger Units 1 and 2</u>** • The Wyoming Regional Haze State Implementation Plan (SIP) and EPA's final Regional Haze FIP for Wyoming require the installation of SCR on Jim Bridger Units 1 and 2 in 2021 and 2022. • PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units and will provide the associated analysis in its 2017 IRP Update.
5e	**<u>Naughton Unit 3</u>** • PacifiCorp will update its economic analysis of natural gas conversion in its 2017 IRP Update.
5f	**<u>Wyodak</u>** • Continue to pursue PacifiCorp's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.
5g	**<u>Cholla Unit 4</u>** • EPA has approved the Arizona SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025, with the option of natural gas conversion thereafter. • PacifiCorp will update its evaluation of Cholla Unit 4 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.
5h	**<u>Craig Unit 1</u>** • EPA is yet to approve the Colorado SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Craig Unit 1 as a coal-fueled resource by the end of 2025, with an option for natural gas conversion. • PacifiCorp will update its evaluation of Craig Unit 1 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update, as required.

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 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.

Compliance associated with Regional Haze requirements continued to be a key area of focus for the 2017 IRP. PacifiCorp developed resource portfolios among seven potential Regional Haze scenarios (including a reference case), assessing how different inter-temporal and fleet-tradeoff compliance outcomes might influence new resource needs and system costs. Regional Haze scenarios outlining different potential compliance requirements were analyzed concurrent with other environmental policies, including analysis of EPA's Clean Power Plan. Coal-fired units subject to near-term Regional Haze requirements were analyzed and included analysis of compliance alternatives for Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1, Jim Bridger 2, Naughton 3, Cholla 4, and Craig 1. In addition, PacifiCorp's 2017 IRP also focused on analysis of transmission expansion opportunities and renewable resources including a repowering project to extend the operating life of existing renewable resources while lowering operating costs through the use of production tax credit benefits.

Other significant studies conducted to support the 2017 IRP include:

- An updated demand-side resource potential assessment;
- A private generation study for PacifiCorp's service territory;
- Energy storage studies examining storage potential;
- A planning reserve margin study to determine selection of a planning reserve margin for the 2017 IRP;
- A western region regional adequacy assessment;
- A wind and solar capacity contribution study;
- A flexible reserve study developed in coordination with a technical review committee;
- Updated stochastic parameters; and
- An updated load and resource balance.

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 as they relate to capital budgeting; and
- Improve the overall transparency of PacifiCorp's resource planning processes to public stakeholders.

This chapter outlines the components of the 2017 IRP, summarizes the role of the IRP, and provides an overview of the public process.

2017 Integrated Resource Plan Components

The basic components of PacifiCorp's 2017 IRP include:

- Set of IRP principles and objectives adopted for the IRP effort (this chapter).
- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3)
- Description of PacifiCorp's transmission planning efforts and activities (Chapter 4)
- Load and resource balance covering the Company's load forecast, existing resources, and determination of the load and energy positions for the front ten years of the twenty year planning horizon (Chapter 5)
- Profile of resource options considered for addressing future capacity and energy needs (Chapter 6)
- Description of the IRP modeling, including a description of the resource portfolio development process, cost and risk analysis, and preferred portfolio selection process (Chapter 7)
- Presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp's preferred portfolio (Chapter 8)
- Presentation of PacifiCorp's 2017 IRP action plan linking the Company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks (Chapter 9)

The IRP appendices, included as a Volume II, contain the items listed below.

- Load Forecast Details (Volume II, Appendix A),
- IRP Regulatory Compliance (Volume II, Appendix B),
- Public Input Process (Volume II, Appendix C),
- Demand Side Management Resources (Volume II, Appendix D),
- Smart Grid discussion (Volume II, Appendix E),
- Flexible Reserve Study (Volume II, Appendix F),
- Historical plant water consumption data (Volume II, Appendix G),
- Stochastic Parameters (Volume II, Appendix H),
- Planning Reserve Margin Study (Volume II, Appendix I),
- Assessment of resource adequacy for western power markets (Volume II, Appendix J),
- Detailed capacity expansion tables (Volume II, Appendix K),
- Stochastic simulation results (Volume II, Appendix L),
- Case study fact sheets (Volume II, Appendix M),
- Wind and solar capacity contributions (Volume II, Appendix N),
- Private generation study (Volume II, Appendix O), and
- Energy storage studies (Volume II, Appendix P)

In an effort to improve transparency PacifiCorp is also providing data discs for the 2017 IRP. These discs support and provide additional details for the analysis described within the document. Discs containing confidential information are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings.

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[1] The main role of the IRP is to serve as a roadmap for determining and implementing the Company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, 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 Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public input process allowing stakeholder involvement in all phases of plan development. The Company organized five state meetings and held seven public meetings, some of which spanning two days to facilitate information sharing, collaboration, and expectations for the 2017 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 input meetings/conferences and highlights major agenda items covered. Volume II, Appendix C (Public Input Process) provides more details concerning the public input process.

Table 2.1 – 2017 IRP Public Input Meetings

Meeting Type	Date	Main Agenda Items
State Meeting	6/6/2016	Washington state stakeholder comments
State Meeting	6/7/2016	Idaho state stakeholder comments
State Meeting	6/10/16	Oregon state stakeholder comments
State Meeting	6/13/2016	Utah state stakeholder comments
State Meeting	6/14/2016	Wyoming state stakeholder comments
General Meeting	6/21/16	2017 IRP kick-off meeting
General Meeting	7/20/16	Environmental Policy, Transmission, Regional Integration, Renewable Portfolio Standards (RPS) / Request for Proposals (RFPs)

[1] 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.

Meeting Type	Date	Main Agenda Items
General Meeting (2-Day)	8/25/16	Portfolio Development, Private Generation Study, Supply-Side Resources, Energy Storage
	8/26/16	Update on RPS/RFPs, Conservation Potential Assessment, Load Forecast
General Meeting (2-Day)	9/22/16	Portfolio Development, Stochastic Modeling, Resource Adequacy and Front Office Transactions, Loss of Load Probability and Planning Reserve Margin, Capacity Contribution Study
	9/23/16	Load and Resource Balance, Flexible Capacity Reserve Study, Smart Grid
General Meeting (phone conference)	11/17/16	Updated Capacity Contribution Study, Official Forward Price Curve
General Meeting (2-Day)	1/26/17	Portfolio Summaries
	1/27/17	Sensitivity Studies
General Meeting (2-Day)	3/2/17	Draft Preferred Portfolio Overview, Market Price Scenarios, Portfolios
	3/3/17	Sensitivity Studies, Preferred Portfolio Selection Process

In addition to the public input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and consultation throughout the IRP process. The Company maintains a public website (https://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. Additionally, a stakeholder Feedback Form was used to provide opportunities for stakeholders to submit additional input and ask questions throughout the 2017 IRP public input process. The submitted forms are located on the PacifiCorp's IRP website: https://www.pacificorp.com/es/irp/irpcomments.html in the comments section.

CHAPTER 3 – THE PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- North American natural gas markets continue to be driven by high supply. In 2009, the Marcellus shale play, centered in Pennsylvania and West Virginia, produced almost no natural gas; by spring 2013, it was producing over 9 BCF/D. Today the Marcellus is producing 18 BCF/D, and the Utica, much of which underlies the Marcellus, produces another 4 BCF/D. The Marcellus and Utica plays are expected to account for 40 percent of the nation's gas supply by 2020, spurred by increased drilling efficiency. Day-ahead 2016 Henry Hub prices averaged $2.49/MMBtu, down 64 percent and 69 percent in nominal and real dollars, respectively, from 2007 prices.
- Federal and state tax credits, declining capital costs, and improved technology performance have put wind and solar "in the money" in areas of high potential. Wind and solar will therefore dominate United States capacity additions for the next decade. More transmission, new storage technologies, and market design changes are needed to better integrate new wind and solar resources into the grid.
- The U.S. Environmental Protection Agency (EPA) issued a proposed rule under §111(d) of the Clean Air Act (111(d) or the 111(d) rule) to regulate greenhouse gas emissions from existing sources in June 2014. On August 3, 2015, the EPA issued a final rule, referred to as the Clean Power Plan (CPP), regulating carbon emissions from existing power plants. On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP, suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. The stay remains in effect at this time.
- PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary energy imbalance market (EIM) November 1, 2014, the first western energy market outside of California. The EIM has produced significant monetary benefits ($142.62 million total footprint-wide benefits as of December 31, 2016). A significant contributor to EIM benefits are transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area.
- Near-term procurement activities focused on three areas—natural gas asset management and supply, the purchase and sale of renewable energy credits, and Oregon solar resources.

Introduction

Chapter 3 profiles the major external influences that affect PacifiCorp's long-term resource planning and 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.

Major issues in the power industry market include capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). As discussed elsewhere in this IRP, future natural gas prices, the role of gas-fired generation and the falling costs and increasing efficiencies of renewables are some of the critical factors affecting the selection of the portfolio that best achieves least-cost, least-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. A high-level summary of the Company's greenhouse gas emissions mitigation strategy is included as well as a review of significant policy developments for currently regulated pollutants.

Other topics covered in this chapter include regulatory updates on the EPA, 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 serving demand with resources with the lowest operating cost and by providing reliability benefits arising from access to larger portfolio of resources.

PacifiCorp actively participates in the wholesale market by 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 sub-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 supply that would go unused in all but the most unusual circumstances and would substantially diminish the ability to cost-effectively match delivery patterns to the profile of customer demand.

The benefits of access to an integrated wholesale market have grown with the increased penetration of intermittent generation such as solar and wind. Intermittent generation tends to come online and go offline abruptly in correlation with changing weather conditions. Federal and state (where applicable) tax credits, declining capital costs, and improved technology performance have put wind and solar "in the money" in areas of high potential. Wind and solar will therefore dominate United States capacity additions for the next decade. More transmission, new storage technologies, and market design changes are needed to better integrate these resources into the grid.

There are currently several long-haul renewable-driven transmission projects under development.[1] These projects connect areas of high renewable potential and low population density to areas of high population density with less renewable potential. In the Western Interconnection, this includes PacifiCorp's proposed 416-mile, 1,500 MW Gateway South project, with an online date of 2023, to transport Wyoming wind to central Utah. Similarly, Gateway West, a 1000-mile project jointly proposed by PacifiCorp and Idaho Power, would transport Wyoming wind to western Idaho to be picked up for westward delivery In the eastern interconnection, the Plains & Eastern Clean Line, a 700 mile, 600 KV, 4,000 MW direct-current line has been announced to go live in 2020. This line will transport Oklahoma wind to Tennessee for distribution by the Tennessee Valley Authority to systems in areas with little native wind

[1] To date, at least fourteen renewable-driven transmission projects are in some stage of development.

potential. This long-haul, ultra-high-voltage, direct-current line will be the first in the United States.[2]

The intermittency of renewable generation also increases the need for fast-responding energy storage, which is essential for grid stability and resiliency. Pumped storage has been the traditional energy storage option but expansion is extremely limited due to topography limitations, with the best resources already harnessed. Of the remaining mechanical, thermal, and chemical storage options, lithium-ion batteries have shown the most promise in terms of cost and performance improvement. Battery modules have fallen to under $500/KWh and are expected to reach $150-$250/KWh by 2020. PJM[3] already offers higher payments for fast-responding storage such as batteries and fly wheels. These energy storage technologies can ramp up instantaneously − quicker than combustion turbines − but do not last long. State regulatory commissions are also encouraging development of energy storage options. For example, the California Public Utility Commission requires investor-owned utilities to procure, in total, 1,325 MW of storage by 2020.[4]

Increased renewable generation has also contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp and CAISO formed the EIM, which became operational November 1, 2014. By December 2015, Nevada Energy joined, followed by Puget Sound Energy and Arizona Public Service in 2016. Entities scheduled to join the EIM include PGE (October 2017), Idaho Power Company (April 2018), Seattle City Light (April 2019), and the Balancing Authority of Northern California (April 2019). The Mexican system operator El Centro Nacional de Control de Energia has also announced intentions to join the EIM. This larger EIM footprint brings greater resource and geographical diversity, which allows for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's balancing authority areas.

As with all markets, electricity markets are faced with a wide range of uncertainties, although 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 numerous data services track the status of new resource additions. A review of the WECC power supply assessment is provided in Volume II, Appendix J (Western Resource Adequacy Evaluation). The latest assessment, published December 2016, indicates that even when including only existing and under-construction units, WECC as a whole has ample resources through 2026. WECC's Californian and Mexican sub-regions, however, fall short starting 2024. The WECC sub-regions in which PacifiCorp operates (Northwest Power Pool and Rocky Mountain Reserve Group) are both capacity sufficient through 2026.

[2] *A Greener Grid*, The Economist, January 14th – 20th 2017.
[3] PJM is the Pennsylvania-New Jersey-Maryland Interconnection.
[4] The California Public Utilities Commission's storage procurement mandate was authorized by California Assembly Bill 2514, as amended by Assembly Bill 2227.

There are other uncertainties that greatly influence future prices but are more difficult to analyze. 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 are a critical determinant of western electricity prices, and this trend is expected to continue over the term of this IRP's planning horizon. Another critical uncertainty affecting the 2017 IRP, as in past IRPs, is the uncertainty surrounding future greenhouse gas policies, both federal and state. PacifiCorp's official forward price curve incorporates potential impacts of EPA's finalized 111(d) rule, the Clean Power Plan (CPP). Other price scenarios developed for the IRP consider impacts of potential future CO_2 emission policies incremental to requirements established in EPA's CPP.

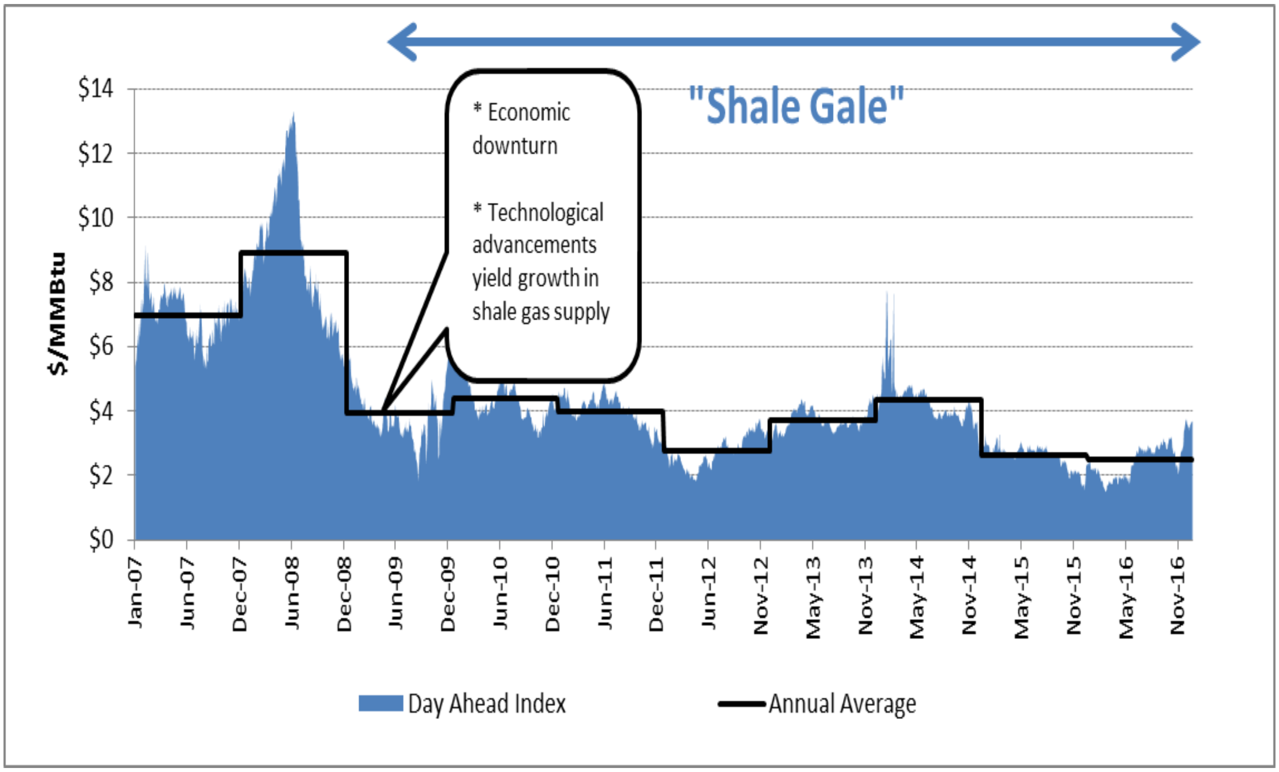
Natural Gas Uncertainty

Over the last decade, North American natural gas markets have undergone a remarkable paradigm shift. As shown in Figure 3.1, Henry Hub day-ahead gas prices hit a high of $13.31/MMBtu on July 2, 2008, and a low of $1.49/MMBtu on March 4, 2016. Day-ahead prices averaged $7.93/MMBtu through 2008, dropped to $3.94/MMBtu in 2009, and have averaged $3.47/MMBtu since 2010. Day-ahead 2016 Henry Hub prices averaged $2.49/MMBtu, down 64 percent and 69 percent in nominal and real dollars, respectively, from 2007 prices. The relative price placidity since 2009, labeled the "Shale Gale," reflects increased supplies (mostly Appalachian supply).[5]

In 2009, the Marcellus shale play, centered in Pennsylvania and West Virginia, produced almost no natural gas; by spring 2013, it was producing over 9 BCF/D. By late 2016, the Marcellus was producing 18 BCF/D, and the Utica, much of which underlies the Marcellus, was producing 4 BCF/D. In short, supply from the Marcellus and Utica plays continues to grow as volumes and costs prove to be, respectively, higher and lower than anticipated. The Marcellus and Utica plays currently account for 30 percent of the nation's gas supply and are expected to account for 40 percent by 2020, spurred by increased drilling efficiency.

[5] Other significant shale gas plays include Eagle Ford (TX), Haynesville (LA/TX), Permian (TX/NM), Niobrara (CO/WY), and Bakken (ND/MT). The Permian, in particular, is the center of renewed activity.

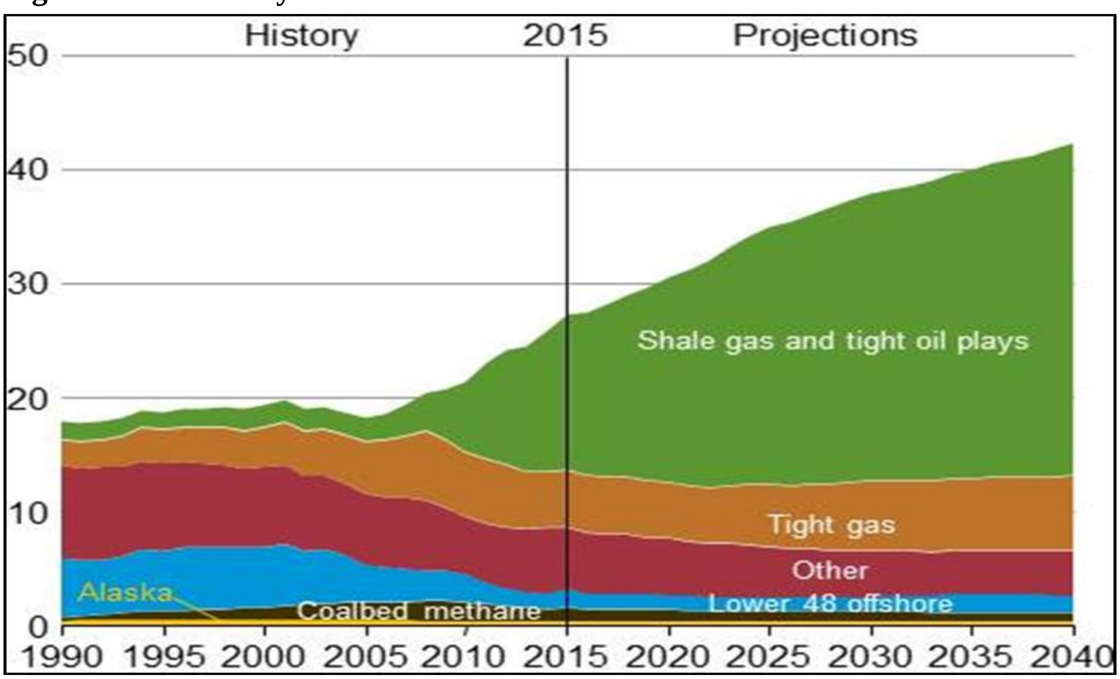
Figure 3.1 – Henry Hub Day-Head Gas Price History



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

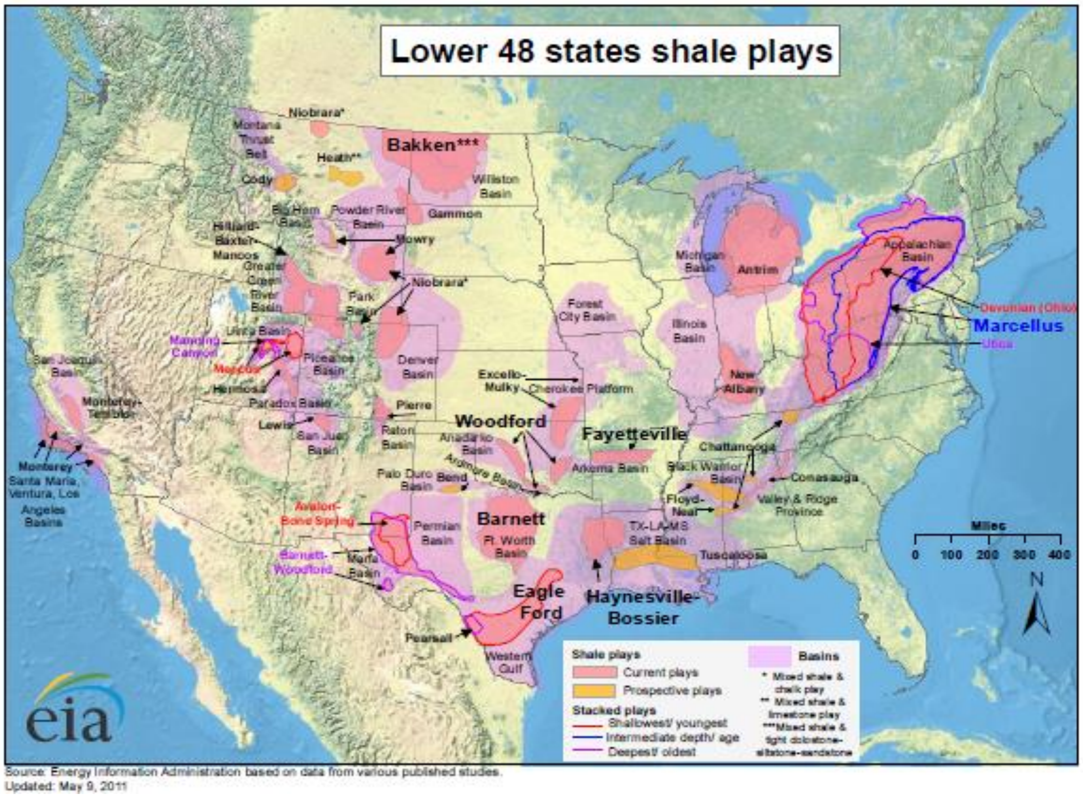
Historically, depletion of conventional mature resources largely offset unconventional resource growth. But as shale gas "came into its own," production gains outpaced depletion. Figure 3.2 through Figure 3.4 show United States natural gas production by source and location.

Figure 3.2 – U.S. Dry Natural Gas Production



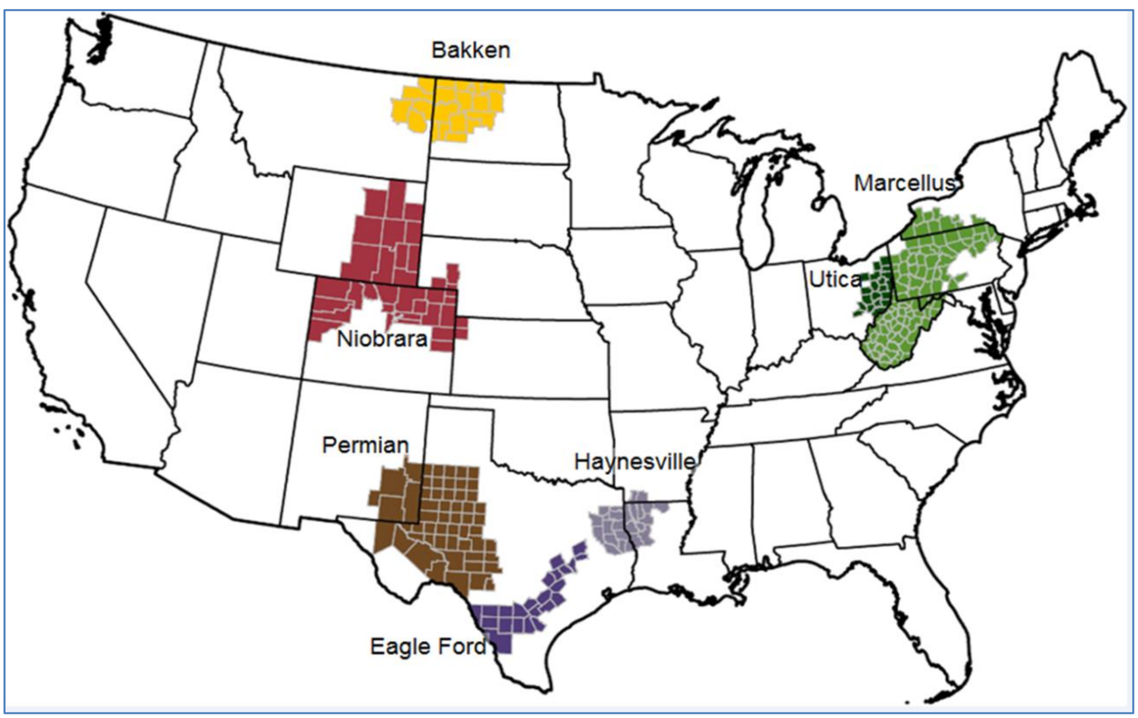
Source: 2016 Annual Energy Outlook, U.S. Department of Energy, Energy Information Administration

Figure 3.3 – Lower 48 States Shale Plays



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

Figure 3.4 – Plays Accounting for All Natural Gas Production Growth 2011 -2014



Source: *Drilling Productivity Report*, January 2017, U.S. Department of Energy, Energy Information Administration

Figure 3.5 shows Henry Hub NYMEX futures as of January 20, 2017. While futures are mildly in contango, it would appear that price expectations offer little "signal-to-drill." But as producers chase production efficiencies the signal-to-drill price becomes lower. Producers have discovered the economies of scale of deeper wells, longer laterals, clustered well spacing, and repetitive fracking. One of the deepest and longest wells (8,500 feet deep with 18,544-foot laterals) was drilled in Ohio. The well was fracked 124 times (compared to the norm of 30-40 times) and used 51 million tons of sand.[6] The producer estimated that supersizing the well yielded a cost savings of 30 percent. Producers have therefore been a victim of their own success. For example, in 2015, Equitable Resources (EQT) drilled a Utica well that produced so much natural gas that it depressed EQT's stock price due to its deleterious effect on gas prices.[7]

Moreover, while West Texas Intermediate is only hovering around $53/barrel, it is enough to spur oil-targeted drilling in "sweet spots" within western Canada, the Permian, and Bakken. Slowly recovering oil prices are bringing more price-insensitive gas to market. This is especially true of Permian Basin oil wells, whose output contains 20-50 percent natural gas. With crude's price collapse, United States production finally fell to 8.8 million barrels per day (MMbpd) in 2016 from a high of 9.6 MMbpd in 2015. Today, United States production is back to 9 MMbpd, and Goldman Sachs forecasts another 600,000 bpd by the end of 2017. Even though over a hundred energy producers have gone bankrupt, they keep pumping. This production resiliency is a function of (1) declining technology costs, (2) increased production efficiencies, and (3) variable operating costs (not full cycle costs) being less than $40.00 per barrel. The Energy Information Administration (EIA) estimated that, as of December 2016, 5,379 wells remain drilled but uncompleted. These wells can be put into production quickly and represent a significant source of supply.[8] United States production can ramp up quickly.

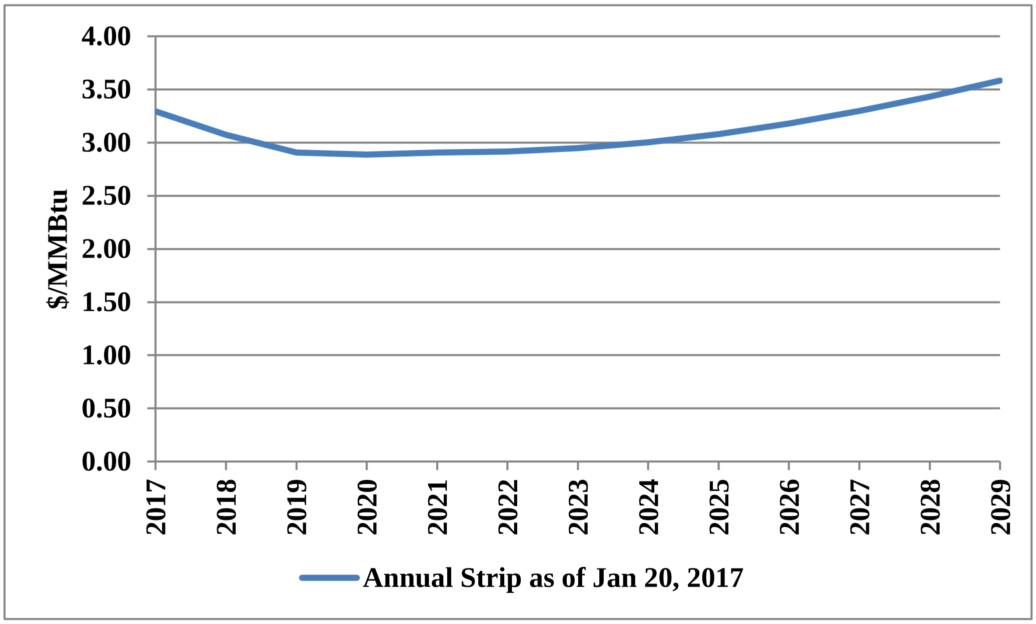
This resiliency of supply coupled with the flexibility to quickly ramp up production will shorten the length of asynchronous supply and demand cycles. Unexpected weather-induced demand spikes or cuts, as well as supply disruptions, will still whipsaw prices for short periods of time. But LNG startups, outages or dial backs could swing prices for longer periods given the magnitude of volumes coupled with locational concentration.[9] Until 2024, the global LNG market is expected to be in oversupply, and the United States LNG tends to be the marginal supply given its high variable operating costs. Since Europe is a major offtaker for United States LNG, exports are expected to drop precipitously during summer months given little European summer LNG demand. Summer feed gas normally bound for liquefaction would then be diverted into the market, depressing prices. This dial back will act to also moderate winter prices by increasing storage and the likelihood of entering winter with an overhang. Thus, seasonal demand fluctuations for LNG abroad are expected to swing Henry Hub prices given the magnitude of volumes and proximity to Henry Hub.

Prices finally begin to break out by 2024 as global LNG demand catches up to supply. The key drivers of demand both before and after 2024 are (1) LNG exports, (2) Mexican exports, and (3) power generation. Of the three, power generation is by far the largest user, but exports (especially LNG) are the fastest growing, at least through 2024.[10] After 2024, the power sector

[6] *Two Years into Oil Slump, U.S. Shale Firms are Ready to Pump More,* Wall Street Journal, September 27, 2016.
[7] *Gas Driller Hits a Gusher–and Sinks its Own Stock*, Wall Street Journal, November 26, 2015.
[8] EIA does not distinguish between oil and gas wells since over 50 percent of wells produce both.
[9] Current and expected facilities are mostly concentrated in the Gulf Coast.
[10] The power sector is expected to maintain pre- and post-2024 annual growth of approximately 2.5 percent. LNG and Mexican exports average a pre-2024 annual rate of 24 percent and 7.8 percent, respectively, versus a post-2024 annual growth of 2.4 percent and 1.5 percent.

maintains most of it pre-2024 growth, whereas the export sectors' growth rates drop precipitously and level off.

Figure 3.5 – Henry Hub NYMEX Futures



The continued build out of Appalachian take-away capacity will keep western regional natural gas markets well connected to North American supply. Rocky Mountain production slows as Appalachian volumes push westward and exert downward price pressure on Opal vis-à-vis Henry Hub. Similarly, West Coast prices are pressured as more Rockies gas, previously destined for the east, moves west to compete with Canadian gas to serve California. 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 AECO. This is likely to continue as AECO loses market share to the Marcellus in serving AECO's Ontario, Midwest, and even West Coast markets. In short, the challenge in gauging the uncertainty in natural gas markets will be timing. The North American natural gas supply curve continues to flatten as production efficiencies expose an ever-increasing resilient, flexible, and low-cost resource base. In that environment, managing long-term boom-and-bust cycles is not as crucial as managing shorter-term market perturbations.

The Future of Federal Environmental Regulation and Legislation

PacifiCorp faces continuously changing electricity plant emission regulations. Although the exact nature of these changes is uncertain, they are expected to impact the cost of future resource alternatives and the cost of existing resources in the company's generation portfolio. PacifiCorp monitors these regulations to determine the potential impact on its generating assets. PacifiCorp also participates in rulemaking processes by filing comments on various proposals, participating in scheduled hearings, and providing assessments of proposals.

Federal Climate Change Legislation

To date, no federal legislative climate change proposal has been passed by the U.S. Congress. The election of Donald Trump as U.S. President reduces the likelihood of federal climate change legislation in the near term.

Federal Renewable Portfolio Standards

Since 2010, there has been no significant activity in the development of a federal renewable portfolio standard (RPS). Accordingly, PacifiCorp's 2017 IRP assumes no federal RPS requirement over the course of the planning horizon.

Federal Policy Update

New Source Performance Standards for Carbon Emissions – Clean Air Act § 111(b)

New Source Performance Standards (NSPS) are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. On August 3, 2015, the EPA issued a final rule limiting carbon emissions from coal-fueled and natural-gas-fueled power plants. New natural-gas-fueled power plants can emit no more than 1,000 pounds of carbon dioxide (CO_2) per megawatt-hour (MWh). New coal-fueled power plants can emit no more than 1,400 pounds of CO_2/MWh. The final rule largely exempts simple cycle combustion turbines from meeting the standards.

Carbon Emission Guidelines for Existing Sources – Clean Air Act § 111(d)

On August 3, 2015, the EPA issued a final rule, referred to as the Clean Power Plan (CPP), regulating carbon emissions from existing power plants. Under the final rule, states would be required to submit compliance plans by September 6, 2016, but a state may seek an extension to September 6, 2018, to submit a state plan. On August 3, 3015, EPA also issued a proposed federal plan and model trading rules for public comment. The public comment period closed January 21, 2016. Under section 111(d) of the Clean Air Act, states are required to develop standards of performance, which are the degree of emission limitation achievable through the application of the best system of emission reduction (BSER).

On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. If parties petition for a writ of certiorari before the Supreme Court, the stay will remain in effect until the Supreme Court takes action to either deny the petition or, if the Supreme Court hears the case, the stay remains in effect until the court enters its judgment. Oral argument on the CPP litigation was held September 27, 2016, before the D.C. Circuit Court of Appeals.

In the final rule, EPA set forth emission reduction goals for each state based on EPA's formulation of BSER, which is made up of three building blocks: (1) heat rate improvements at existing coal-fueled resources; (2) increased use of natural gas resources; and (3) increased deployment of zero-emitting resources. States would be required to meet the emission reduction goal by 2030, as well as interim goals, which would be met over three interim compliance periods: 2022-2024, 2025-2027, and 2028-2029. Using its formulation of BSER, EPA established uniform national interim and final carbon emission performance standards at 1,305 lb CO_2/MWh for coal-fueled power plants and 771 lb CO_2/MWh for natural-gas-fueled power plants, which in turn were used to establish projected mass-based and rate-based compliance targets for individual states.

Under the final rule, states have a number of implementation options: states may choose to adopt the rate-based standard and apply them on a subcategory or state-specific blended rate basis, or states may choose to adopt the standards as a mass-based state goal. In the final rule, EPA provided state mass-based goals that it stated are equivalent to the rate-based emissions goals. Under a mass-based implementation program, compliance would be demonstrated through reported stack emissions and the retirement of carbon allowances. Under a rate-based implementation program, compliance would be demonstrated through the use of megawatt-hour credits referred to as emission rate credits (ERCs) from renewable energy and, potentially, energy efficiency. States also have the option to trade with other affected resources in other states implementing similar approaches (e.g., rate state with other rate states or mass state with other mass states) so long as those states meet certain "trading ready" minimum requirements.

The federal plan proposal also includes model rules for rate-based and mass-based trading programs for potential use by any state in developing its state plan. The mass-based federal plan proposal includes a proposed allowance allocation methodology and a method for states to address leakage through allowance set-asides.

On March 28, 2017, President Trump issued an Executive Order directing the EPA to review the Clean Power Plan and, if appropriate, suspend, revise, or rescind the Clean Power Plan, as well as related rules and agency actions. PacifiCorp will continue to follow activities related to this Executive Order.

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the general public, and establish the maximum allowable concentration allowed for each "criteria" pollutant in outdoor air. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide (NO_X), particulate matter (PM), and sulfur dioxide (SO_2). The standards are set at a level that protects public health with an adequate margin of safety. If an area is determined to be out of compliance with an established NAAQS standard, the state is required to develop a state implementation plan for that area. And that plan must be approved by EPA. The plan is developed so that once implemented, the NAAQS for the particular pollutant of concern will be achieved.

In October 2015, EPA issued a final rule modifying the standards for ground-level ozone from 75 parts per billion (ppb) to 70 ppb. Under the final rule, EPA will designate areas in the country as being in "attainment" or "nonattainment" of the revised standards by October 2017. State compliance dates will be set depending on the ozone level in the area. PacifiCorp facilities will only be affected to the extent they are located in an ozone nonattainment area.

Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility in certain national park and wilderness areas. On June 15, 2005, EPA issued final amendments to its regional haze rule. These amendments apply to the provisions of the regional haze rule that require emission controls known as the Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. These pollutants include fine PM, NO_X, SO_2, 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 guidelines, as well as establishing BART emissions limits for those facilities. States are also required to periodically update or revise their implementation plans to reflect current visibility data and the effectiveness of the state's long-term strategy for achieving reasonable progress toward visibility goals. On December 14, 2016, EPA issued a final rule setting forth revised and clarifying requirements for periodic updates in state implementation plans. States are currently required to submit the next periodic update by July 31, 2021.

The regional haze rule is intended to achieve natural visibility conditions by 2064 in specific National Parks and Wilderness Areas, many of which are located in Utah and Wyoming where PacifiCorp operates generating units, as well as Arizona where PacifiCorp owns but does not operate a coal unit, and in Colorado and Montana where PacifiCorp has partial ownership in generating units operated by others, but are nonetheless subject to the regional haze rule.

<u>Utah Regional Haze</u>
In May 2011, the state of Utah issued a regional haze state implementation plan (SIP) requiring the installation of SO_2, NO_x and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NO_X and PM portions. EPA's approval of the SO_2 SIP was appealed to federal circuit court. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NO_X and PM SIP. PacifiCorp and the state's appeals were dismissed. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an updated BART analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, recognizing NO_X controls previously installed on Hunter Unit 3, and concluding that no incremental controls (beyond those included in the May 2011 SIP and already installed) were required at the Hunter and Huntington units. On June 1, 2016, EPA issued a final rule to partially approve and partially disapprove the Utah's regional haze SIP and propose a federal implementation plan (FIP). The final rule requires the installation of selective catalytic reduction (SCR) controls at four of PacifiCorp's units in Utah: Hunter Units 1 and 2, and Huntington Units 1 and 2. On September 2, 2016, PacifiCorp filed petitions for administrative and judicial review of EPA's final rule and requested a stay of the effective date of the final rule. Unless the EPA's FIP is stayed or reversed, the controls are required to be installed by August 4, 2021.

<u>Wyoming Regional Haze</u>
On January 10, 2014, EPA issued a final action in Wyoming requiring installation of the following NO_X and PM controls at PacifiCorp facilities:

- Naughton Unit 3 by December 31, 2014: SCR equipment and a baghouse
- Jim Bridger Unit 3 by December 31, 2015: SCR equipment
- Jim Bridger Unit 4 by December 31, 2016: SCR equipment
- Jim Bridger Unit 2 by December 31, 2021: SCR equipment
- Jim Bridger Unit 1 by December 31, 2022: SCR equipment
- Dave Johnston Unit 3: SCR within five years or a commitment to shut down in 2027
- Wyodak: SCR equipment within five years

Different aspects of EPA's final action were appealed by a number of entities. PacifiCorp appealed EPA's action requiring SCR at Wyodak. PacifiCorp successfully requested a stay of EPA's action as it pertains to Wyodak pending resolution of the appeals. For Naughton Unit 3, in its final action EPA indicated support for the conversion of the unit to natural gas and stated that it would expedite consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. PacifiCorp obtained a construction permit and revised regional haze BART permit from the state of Wyoming to convert Naughton Unit 3 to natural gas in 2018. In late 2017 PacifiCorp submitted a petition to the state of Wyoming requesting that the requirement to convert to gas be delayed one year. As of January 2017, that request is undergoing public comment. Wyoming has not yet submitted a revised regional haze SIP incorporating this alternative compliance approach to EPA.

Arizona Regional Haze

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of SO_2, NO_X and PM controls on Cholla Unit 4, which is owned by PacifiCorp but operated by Arizona Public Service. EPA approved in part and disapproved in part the Arizona SIP and issued a FIP requiring the installation of SCR equipment on Cholla Unit 4. PacifiCorp filed an appeal 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. For the Cholla FIP requirements, the court stayed the appeals while parties attempt to agree on an alternative compliance approach. In July 2016, the EPA issued a proposed rule to approve an alternative Arizona SIP, which includes converting Cholla 4 to a natural gas-fired unit in 2025. The comment period on EPA's proposed rule closed September 2, 2016, and PacifiCorp is awaiting EPA's final action.

Colorado Regional Haze

The Colorado regional haze SIP required SCR controls at Craig Unit 2 and Hayden Units 1 and 2. In addition, the SIP required the installation of selective non-catalytic reduction (SNCR) technology at Craig Unit 1 by 2018. Environmental groups appealed EPA's action, and PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation other than PacifiCorp entered into a settlement agreement that requires installation of SCR equipment at Craig Unit 1 in 2021. In February 2015, the State of Colorado submitted a revised SIP to EPA for approval. As part of a further agreement between the owners of Craig Unit 1, state and federal agencies, and parties to previous settlements, the owners of Craig agreed to retire Unit 1 by December 31, 2025, or convert the unit to natural gas by August 31, 2023. The terms of this agreement are currently being considered by the Colorado Air Quality Board; EPA review and approval will then be required.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective 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 were required to comply with the new standards by April 16, 2015. However, individual sources may have been 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. In June 2015, the U.S. Supreme Court found that EPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the D.C. Circuit Court of Appeals ruled that MATS may be enforced as EPA modifies the rule to comply with the Supreme Court decision. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants. CCRs have historically been considered exempt wastes under an amendment to the Resource Conservation and Recovery Act (RCRA); however, EPA issued a final rule in December 2014 to regulate CCRs for the first time. Under the final rule, EPA will regulate CCRs as non-hazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of CCRs. The final rule was effective October 19, 2015. Under the final rule, surface impoundments and landfills utilized for CCRs may need to close unless they can meet more stringent regulatory requirements. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCRs. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCRs and hence are not subject to the final rule.

The final CCR regulation was set up to be enforced by citizen suits; however, in September 2016, the Senate passed, and in December 2016 President Obama signed, the Coal Combustion Residuals Regulatory Improvement Act, which sets forth the process and standards for EPA approval (and withdrawal) of a state's permitting program for coal combustion residual units. A state may incorporate either the requirements of the EPA rule into its permit program or other state requirements that, based on site-specific conditions, are at least as protective as the EPA rule.

The legislation:

- Authorizes the EPA to operate permit programs in states that have not been authorized.
- Clarifies that a coal ash residual unit is subject to the EPA rule until a permit is issued by either a state or EPA.
- Provides the EPA with inspection and enforcement authorities. Before EPA can take enforcement action in an authorized state, EPA must consider any other actions against the facility and determine if an enforcement action by EPA "is likely to be necessary" to ensure the facility is operating in accordance with its permit requirements.
- Authorizes EPA to operate a permit program in Indian country.
- Provides a permit shield for facilities that are operating in accordance with a state- or EPA-issued permit.

- Preserves other legal authorities or regulatory determinations in effect before enactment.

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 other 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 May 2014, EPA issued a final rule, effective October 2014, under § 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule established requirements 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 United States 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. for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently use closed-cycle cooling towers but withdraw more than two million gallons of water per day. The 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 and entrainment (i.e., when organisms are drawn into the facility) standards. The standards will be set on a case-by-case basis to be determined through site-specific studies and will be incorporated into each facility's discharge permit.

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. On November 3, 2015, EPA finalized revised effluent limit guidelines. The rule does not allow the discharge of bottom ash or fly ash transport water and directly impacts the Wyodak, Dave Johnston, and Naughton facilities.

2015 Tax Extender Legislation

On December 18, 2015, President Obama signed tax extender legislation (H.R. 2029) that retroactively and prospectively extended certain expired and expiring federal income tax deductions and credits.

Bonus Depreciation

Fifty percent bonus depreciation was extended for property acquired and placed in service during 2015, 2016, and 2017. For property acquired and placed in service during 2018, 40 percent of the eligible cost of the property qualifies for bonus depreciation. For property acquired and placed in service during 2019, 30 percent of the eligible cost of the property qualifies for bonus depreciation. For property placed in service after December 31, 2019, there will be no bonus depreciation.[11]

[11] There is an exception for long-production-period property (generally property with a construction period longer than one year and a cost exceeding $1 million). Costs incurred on long-production-period property may qualify for bonus depreciation if physical construction has begun before the placed-in-service date of the bonus phase-out.

Production Tax Credit (Wind)
The production tax credit (PTC), currently 2.3 cents per kilowatt-hour (inflation adjusted), has been extended and phased out for wind property for which construction begins before January 1, 2020, as follows:

- 2015 – 100% retroactive
- 2016 – 100% (construction begins before January 1, 2017)
- 2017 – 80% (construction begins before January 1, 2018)
- 2018 – 60% (construction begins before January 1, 2019)
- 2019 – 40% (construction begins before January 1, 2020)

Production Tax Credit (Geothermal and Hydro)
The PTC for geothermal and hydro were granted a two-year extension as follows (no phase-out period was adopted):

- 2015 – 100% retroactive
- 2016 – 100% (construction begins before January 1, 2017)

30% Energy Investment Tax Credit (Wind)
The investment tax credit (ITC) has been extended and phased out for wind property for which construction begins before January 1, 2020, as follows:

- 2015 – 30% retroactive
- 2016 – 30% (construction begins before January 1, 2017)
- 2017 – 24% (construction begins before January 1, 2018)
- 2018 – 18% (construction begins before January 1, 2019)
- 2019 – 12% (construction begins before January 1, 2020)

30% Energy Investment Tax Credit (Solar)
The ITC has been extended and steps down for solar property for which construction begins before January 1, 2022, as follows:

- 2015 – 30% retroactive
- 2016 – 30% (construction begins before January 1, 2017)
- 2017 – 30% (construction begins before January 1, 2018)
- 2018 – 30% (construction begins before January 1, 2019)
- 2019 – 30% (construction begins before January 1, 2020)
- 2020 – 26% (construction begins before January 1, 2021)
- 2021 – 22% (construction begins before January 1, 2022)
- 2022 – 10% (construction begins on or after January 1, 2022)

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, 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.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target.

In 2002, California established a renewable portfolio standard (RPS) requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded a number of times since its inception. Most recently, Governor Jerry Brown signed into law Senate Bill (SB) 350 in October 2015, which requires utilities to procure 50 percent of their electricity from renewables by 2030. SB 350 also requires California utilities to develop integrated resource plans that incorporate a greenhouse gas emission reduction planning component. The California Public Utilities Commission is currently developing rules to implement this new program.

Oregon

In 2007, the Oregon Legislature passed House Bill (HB) 3543 – Global Warming Actions, which establishes greenhouse gas reduction goals for the state that: (1) end the growth of Oregon greenhouse gas emissions by 2010; (2) reduce greenhouse gas levels to 10 percent below 1990 levels by 2020; and (3) reduce greenhouse gas levels to at least 75 percent below 1990 levels by 2050. In 2009, the legislature passed SB 101, which requires the Public Utility Commission of Oregon (OPUC) to submit a report to the legislature before November 1 of each even-numbered year regarding the estimated rate impacts for Oregon's regulated electric and natural gas companies of 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, 2014.

On July 3 2013, the Oregon Legislature passed SB 306, which directs the legislative revenue officer to prepare a report examining the feasibility of imposing a clean air fee or tax as a new revenue option. The report includes an evaluation of how to treat imported and exported energy sources. A final report was published December 2014.

In 2007, Oregon enacted SB 838 establishing an RPS requirement in Oregon. Under SB 838, utilities are required to deliver 25 percent of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed SB 1547-B, the Clean Electricity and Coal Transition Plan, into law. SB 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged—27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040. The bill changes the renewable energy certificate (REC) life to five years, while allowing RECs generated from the effective date of the bill passage until the end of 2022 from new long-term renewable projects to have unlimited life. The bill also includes provisions to create a community solar program in Oregon and encourage greater reliance on electricity for transportation.

Washington

In November 2006, Washington voters approved Initiative 937 (I-937), the Washington Energy Independence Act, which imposes targets for energy conservation and the use of eligible renewable resources on electric utilities. Under I-937, utilities must supply 15 percent of their energy from renewable resources by 2020. Utilities must also set and meet energy conversation targets starting in 2010.

In 2008, the Washington Legislature approved the Climate Change Framework E2SHB 2815, which establishes the following state greenhouse gas emissions reduction limits: (1) reduce emissions to 1990 levels by 2020; (2) reduce emissions to 25 percent below 1990 levels by 2035; and (3) by 2050, reduce emissions to 50 percent below 1990 levels or 70 percent below Washington's forecasted emissions in 2050.

In July 2015, Governor Inslee released an executive order that directed the Washington Department of Ecology to develop new rules to reduce carbon emissions in the state. Ecology initiated the rulemaking process in September 2015 and finalized the Clean Air Rule on January 5, 2016. After further stakeholder engagement, the proposed rule was withdrawn on February 26, 2016, to make updates. The Department of Ecology anticipates releasing a new proposed rule for public review in spring 2016. The only PacifiCorp resource that would be subject to the proposed Clean Air Rule is the Chehalis natural gas plant.

Utah

In March 2008, Utah enacted the Energy Resource and Carbon Emission Reduction Initiative, which includes provisions to require utilities to pursue renewable energy to the extent that it is cost effective. It sets out a goal for utilities to use eligible renewable resources to account for 20 percent of their 2025 adjusted retail electric sales.

On March 10, 2016, the Utah legislature passed SB 115–The Sustainable Transportation and Energy Plan (STEP). The bill supports plans for electric vehicle infrastructure and clean coal research in Utah and authorizes the development of a renewable energy tariff for new Utah customer loads. The legislation establishes a five-year pilot program to provide mandated funding for electric vehicle infrastructure and clean coal research, and discretionary funding for solar development, utility-scale battery storage, and other innovative technology and air quality initiatives. The legislation also allows PacifiCorp to recover its variable power supply costs through an energy balancing account and establishes a regulatory accounting mechanism to manage risks and provide planning flexibility associated with environmental compliance or other economic impairments that may affect PacifiCorp's coal-fueled resources in the future. The deferrals of variable power supply costs went into effect in June 2016, and implementation and approval of the other programs was completed by January 1, 2017.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted greenhouse gas emission performance standards applicable to all electricity generated in 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 for Oregon and California are currently set at 1,100 lb CO_2/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. In March 2013, the Washington Department of Commerce issued a new rule, effective April 6, 2013, lowering the emissions performance standard to 970 lb CO_2/MWh.

Renewable Portfolio Standards

An RPS requires a 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 facilities, purchasing renewable energy from another supplier's facilities, using Renewable Energy Credits (RECs) that 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 renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and use of REC trading. By the end of 2016, twenty-nine states, the District of Columbia, and three territories had adopted a mandatory RPS, and eight states and one territory had adopted RPS goals.[12]

In PacifiCorp's service territory, California, Oregon, and Washington have each 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

	California	Oregon	Washington	Utah
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015)	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• Initiative Measure No. 937 (2006)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 40% by December 31, 2024 • 45% by December 31, 2027 • 50% by December 31, 2030 and beyond * Based on the retail load for a three-year compliance period	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 * Based on the retail load for that year	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond * Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective • Annual targets are based on the adjusted[13] retail sales for the calendar year 36 months before the target year

California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills that have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33

[12] National Conference of State Legislatures (NCSL) http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

[13] Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture sequestration and DSM.

percent by 2020.[14] SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities. In October 2015, SB 350, the Clean Energy and Pollution Reduction Act, was signed into law.[15] SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050. SB 350 also expanded the state's renewables portfolio standard to 50 percent by 2030.

SB 2 (1X) created multi-year RPS compliance periods, which were expanded by SB 350. The California Public Utilities Commission approved compliance periods and corresponding RPS procurement requirements, which are shown in Table 3.2.

Table 3.2 – California Compliance Period Requirements

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)
Compliance Period 4 (2021-2024)	(34.8% * 2021 Retail Sales) + (36.5% * 2022 Retail Sales) + (38.3% * 2023 Retail Sales) + (40% * 2024 Retail Sales)
Compliance Period 5 (2025-2027)	(41.7% * 2025 Retail Sales) + (43.3% * 2026 Retail Sales) + (45% * 2027 Retail Sales)
Compliance Period 6 (2028-2030)	(46.7% * 2028 Retail Sales) + (48.3% * 2029 Retail Sales) + (50% * 2030 Retail Sales)

SB 2 (1X) 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 and maximum limits on certain procurement content categories that can be used for compliance.

Portfolio Content Category 1 includes eligible renewable energy and RECs that meet either of the following criteria:

- 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;[16] or
- Have an agreement to dynamically transfer electricity to a California balancing authority.

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

[14] http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[15] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350
[16] 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 is permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource will count toward this portfolio content category

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.[17]

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 as shown in Table 3.3.

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) Compliance Period 4 (2021-2024) Compliance Period 5 (2025-2027) Compliance Period 6 (2028-2030)	Category 1 – Minimum of 75% of Requirement Category 3 – Maximum of 10% of Requirement

In December 2011, the California Public Utilities Commission (CPUC) confirmed that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits in the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the CPUC and annual procurement reports with the California Energy Commission (CEC). SB 350 did not change the portfolio content categories for eligible renewable energy resources or the portfolio balancing requirements exemption provided to PacifiCorp. For utilities subject to the portfolio balancing requirements, the CPUC extended the compliance period 3 requirements through 2030. The CPUC is in the process of an extensive rulemaking to implement the remaining requirements under SB 350.

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 CPUC and CEC websites.

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. Renewable resources must be certified as eligible for the California RPS by the CEC and tracked in the Western Renewable Energy Generation Information System (WREGIS).

Oregon

Oregon established the Oregon RPS with passage of SB 838 in 2007. The law, called the Oregon Renewable Energy Act, was adopted in June 2007 and provides a comprehensive renewable energy policy for the state.[18] Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet a target of at least 25 percent renewable energy by 2025. In March 2016, the Legislature passed SB

[17] 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.
[18] http://www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf

1547,[19] also referred to as Oregon's Clean Electricity and Coal Transition Act. In addition to requiring Oregon to transition off coal by 2030, the new law doubled Oregon's RPS requirements, which are to be staged at 27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040 and beyond. Other components of SB 1547 include:

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.
- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.
- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, in order to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[20]

SB 1547 also modified the Oregon REC banking rules as follows:

- RECs generated before March 8, 2016, have an unlimited life.
- RECs generated during the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, have an unlimited life.
- RECs generated on or after March 8, 2016, from resources that came online before March 8, 2016, expire five years beyond the year the REC was generated.
- RECs generated beyond the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, expire five years beyond the year the REC is generated.
- RECs generated from projects coming online after December 31, 2022, expire five years beyond the year the REC is generated.
- Banked RECs can be surrendered in any compliance year regardless of vintage (eliminates the "first-in, first-out" provision under SB 838).

To qualify as eligible, the RECs must be from a resource certified as Oregon RPS eligible by the Oregon Department of Energy and tracked in WREGIS.

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

[19] https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

[20] 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. The Public Utility Commission of Oregon determined that PacifiCorp's share of the Oregon Solar Initiative was 8.7 megawatts.

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.

PacifiCorp files an annual RPS compliance report by June 1 of every year and a renewable implementation plan on or before January 1 of even-numbered years, unless otherwise directed by the Public Utility Commission of Oregon. These compliance reports and implementation plans are available on PacifiCorp's website.[21]

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 in 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 SB 202, the Energy Resource and Carbon Emission Reduction Initiative.[22] The Energy Resource and Carbon Emission Reduction Initiative is codified in Utah Code Title 54 Chapter 17. 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 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. Following PacifiCorp's December 31, 2009 progress report, the Utah Division of Public Utilities' report to the Legislature stated: "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."

[21] www.pacificpower.net/ORrps
[22] http://le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

PacifiCorp filed its most recent progress report on December 31, 2014. This report showed that the Company is positioned to meet its 20 percent target requirement of approximately 5.2 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

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.

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[23] 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 in the Pacific Northwest or delivered into Washington on a real-time basis without shaping, storage, or integration services. 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 by June 1 of every year with the Washington Utilities and Transportation Commission demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[24]

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.

Transportation Electrification

The electric transportation market remains in an emerging state,[25] and plug-in electric vehicles currently comprise a negligible share of PacifiCorp's load. But this rapidly evolving market represents a potential driver of future load growth and an opportunity to increase the efficiency of the electrical system and provide benefits for all PacifiCorp customers. In addition, increased adoption of electric transportation has the ability to improve air quality, reduce greenhouse gas

[23] http://www.secstate.wa.gov/elections/initiatives/text/I937.pdf
[24] https://www.pacificpower.net/about/rr/wrcr/wrr.html
[25] In 2016, the market share of plug-in electric vehicles was under 1percent: https://www.nada.org/WorkArea/DownloadAsset.aspx?id=21474846613

emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low and moderate income populations.

Given the negligible share of PacifiCorp's load, a forecast explicitly identifying the load associated with electric transportation on PacifiCorp's system is currently unavailable. Electric vehicle load is, however, currently captured and reflected in the Company's load forecast. PacifiCorp continues to actively engage with local, regional, and national stakeholders and participate in state regulatory processes that can inform future planning and load forecasting efforts.

Hydroelectric Relicensing

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

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation and can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system. With the exception of the Klamath River, Weber and Prospect No. 3 hydroelectric projects, all of PacifiCorp's applicable generating facilities now operate under contemporary licenses from the Federal Energy Regulatory Commission (FERC). Under a 2010 settlement agreement, amended in 2016, the 169 MW Klamath Hydroelectric Project will operate under its existing license through December 31, 2020. Project operations are then anticipated to end in 2021 with the decommissioning of the project. The assumed date of Klamath project removal in the IRP is January 1, 2021. The 3.85 MW Weber project and the 7.2 MW Prospect No. 3 project are currently in the FERC relicensing process.

The FERC hydroelectric relicensing process can be extremely political and often controversial. 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 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.

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 criteria. 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. Because some of the responsible state and federal agencies have the ability to place mandatory conditions in the license, 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 in the relicensing process to require installation of fish passage facilities (fish ladders and screens) and to specify their design. 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 negotiations with stakeholders to resolve complex relicensing issues through settlement agreements that are submitted to FERC for incorporation into a new license. FERC welcomes license applications that reflect broad stakeholder involvement or that incorporate measures agreed upon through multi-party settlement agreements. History demonstrates that with such support, FERC generally accepts proposed new license terms and conditions reflected in settlement agreements.

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, 2016, PacifiCorp had incurred approximately $16 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 settlement efforts continue for the Weber, Prospect No. 3, and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result 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 the hydroelectric relicensing process by pursuing interest-based resolutions 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 balancing customer costs and risks. PacifiCorp also has reached agreements with licensing stakeholders to decommission projects where that has been the most cost-effective outcome for customers.

Utah Rate Design Information

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission of Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No. 13-035-184. The goals for rate design are (generally) to reflect the cost 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 so high usage during a billing month is charged a higher rate than low usage. This gives customers 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 a critical peak pricing program or an expansion of time-of-use rates. These types of rate designs are discussed in more detail in Volume I, Chapter 6 (Resource Options). As part of the Sustainable Transportation and Energy Plan (STEP) legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

With the growth in the number of customers adopting private distributed generation, rates will need to evolve to address the change in usage requirements and ensure appropriate cost recovery from these customers. Additionally, with net metering, which is currently required to be offered, the netting process uses the retail rate to compensate customers for energy they put on the grid. A deeper consideration of the implications of current rates and rate designs is necessary to address these growing issues and ensure the appropriate price signals are set for the changing circumstances. To this end, the company proposed a new rate design for residential customer generators who participate in net metering. The proposed rates are intended to mitigate the shift of fixed costs from net metering customers to other customers.

Commercial and Industrial Rate Design

Commercial and industrial rates in Utah include customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are generally intended to recover costs that do not vary with energy 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, about 16 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.

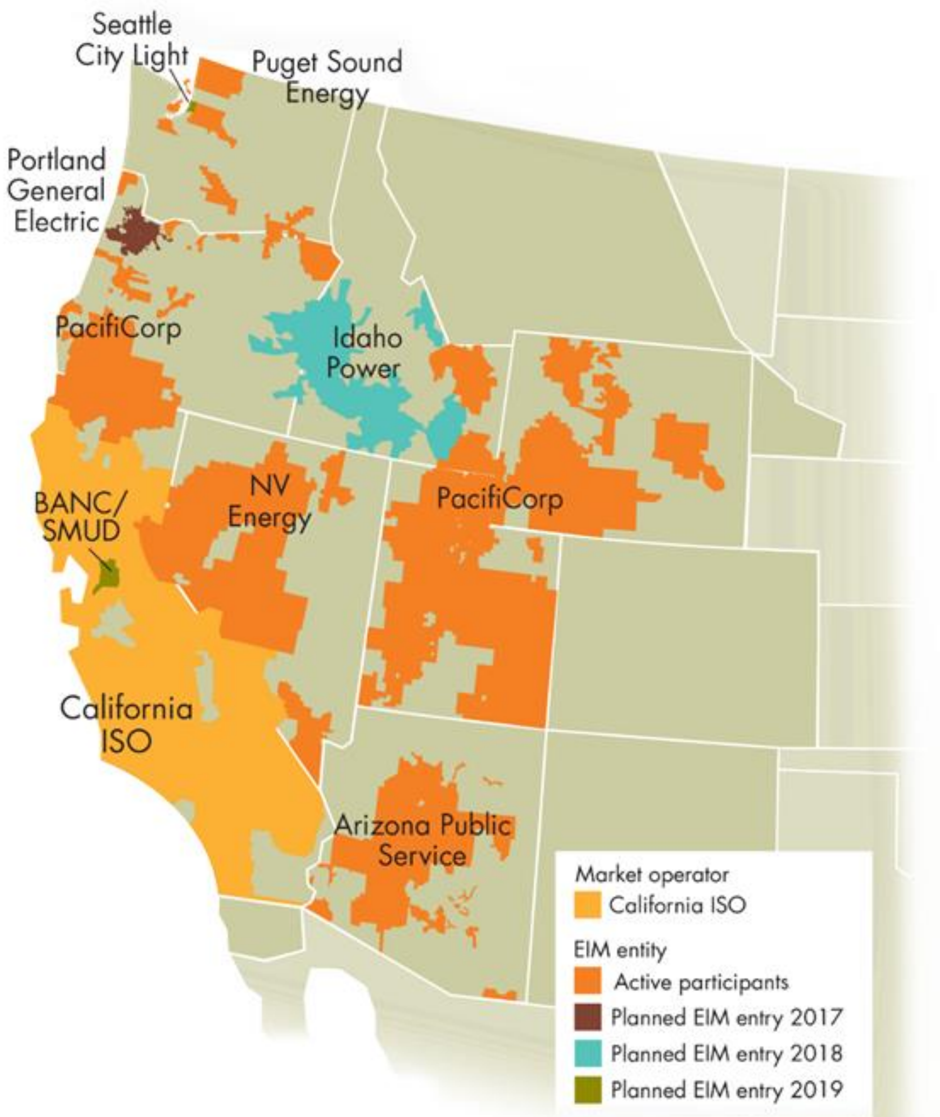
Irrigation Rate Design

Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, a 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. The 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 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. 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 service to the participating customers when energy costs are higher.

Energy Imbalance Market

PacifiCorp and the CAISO launched the EIM November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California. The EIM covers eight states—California, Nevada, Arizona, Idaho, Oregon, Utah, Washington, and Wyoming—and uses CAISO advanced market systems to dispatch the least-cost resources every five minutes. Since the launch of the EIM, NV Energy joined the market December 1, 2015; Puget Sound Energy and Arizona Public Service joined October 1, 2016. Entities scheduled to join the EIM include PGE (October 2017), Idaho Power Company (April 2018), Seattle City Light (April 2019), and the Balancing Authority of Northern California (April 2019). PacifiCorp continues to work with the CAISO, existing and prospective EIM entities, and stakeholders to enhance market functionality and support market growth.

Figure 3.6 – Energy Imbalance Market Expansion



The EIM has produced significant monetary benefits ($142.62 million total footprint-wide benefits as of December 31, 2016), quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every 15 minutes and every five minutes within and across the EIM footprint; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexibility reserves in all EIM balancing authority areas, also referred to as diversity benefits, which reduces cost by aggregating load, wind, and solar variability and forecast errors of the EIM footprint.

A significant contributor to EIM benefits are transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area to serve California load. The transfer volumes are therefore a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the five and 15-minute market dispatch intervals.

The CAISO is exploring expanding into a regional ISO, which requires changes to California laws that mandate that the governing board of the CAISO be appointed by California's governor. As of March 2017, a proposal for regional ISO governance has not been submitted to the California Legislature for consideration. California SB 350 authorized the California Legislature to consider making changes to current laws that would create an independent governance structure for a regional ISO up until the conclusion of the 2017 legislative session, which ends September 15, 2017. If legislation is passed, PacifiCorp will coordinate with its state regulatory authorities on evaluating next steps.

Recent Resource Procurement Activities

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources 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
2017 Transfer Frequency Response RFP	Purchase transferred frequency response	Closed	January 2017	February 2017
2016 Natural Gas Asset Management and Supply RFP	Canadian natural gas transportation and supply	Closed	April 2016	June 2016
2016 Renewable RFP	Purchase renewable energy resources and credits	Closed	April 2016	September 2016
2015 Market Resource RFP	Purchase firm power for PacifiCorp's western balancing authority	Closed	November 2015	November 2015
Renewable energy credits (Sale)	Excess system RECs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Oregon compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Washington compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Ongoing	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Ongoing	Based on specific need	Ongoing

Demand Side Management (DSM) Resources

In 2016, through competitive procurement processes, the company selected vendors to continue and adaptively manage the successful, cost-effective delivery of its two largest Class 2 DSM programs: Home Energy Savings and wattsmart Business. Home Energy Savings vendor services include the management of incentives for lighting, appliances, new homes, and other energy efficiency measures and the delivery of wattsmart starter kits containing efficient light bulbs and water-saving measures. Wattsmart Business vendor services include management of trade ally networks to deliver energy efficiency options to commercial, industrial, and irrigation customers; targeted offerings for small business customers; point-of-purchase incentives for efficient lighting; efficiency options for oil and gas customers; and engineering services for large custom projects. In 2017, PacifiCorp will evaluate and re-procure, as appropriate, the delivery contract(s) for residential behavior program(s).

2017 Transfer Frequency Response Request for Proposals

As a member of the Northwest Power Pool Frequency Response Sharing Group, the company must demonstrate annually that it used reasonable commercial efforts to secure transferred frequency response for our own units as a balancing authority area operator under BAL-003.01. PacifiCorp submitted an RFP to market to demonstrate reasonable commercial efforts. PacifiCorp evaluated the bids received and found all bids uneconomic relative to available alternatives. No new transactions were completed based on the RFP.

Natural Gas Asset Management and Supply Request for Proposals

PacifiCorp issued a Natural Gas Asset Management and Supply RFP in April 2016 seeking natural gas supply offers at the Kingsgate point of delivery. In purchasing natural gas under the RFP, PacifiCorp proposed temporarily assigning a portion of its existing transportation capacity to the awarded bidder. No viable transactions were completed as a result of the RFP.

Renewable Resource and REC Request for Proposals

In April 2016, PacifiCorp issued RFPs to market seeking cost-effective renewables and RECs that could be used to meet the state RPS requirements in California, Oregon, and Washington. With the extension and phasing out of federal tax incentives for renewables, the company initiated a timely RFP to evaluate the potential customer benefits from acquiring renewable resources or RECs in the near term. The issuance of the RFP was also driven by policy changes to the Oregon and California RPS, which increased the compliance requirements for both states.

After careful evaluation of both the resource and REC bids received, the company opted to pursue a REC purchase strategy, which proved to be the least-cost, least-risk procurement option.

2015 Market Resource Request for Proposals

PacifiCorp issued a 2015 Market Resource RFP in November 2015 seeking firm physical power delivered to PacifiCorp’s western balancing authority area for term 2016 through 2018. No viable transactions were completed as a result of the RFP.

Renewable Energy Credits (Sale) Request for Proposals

On an ongoing basis, and based on availability, PacifiCorp issues short-term RFPs to sell RECs that are not required to be held and or retired for meeting regulatory requirements, such as state RPS compliance obligations.

Short-Term Market Power Request for Proposals

PacifiCorp issued a short-term market power RFP in October 2015. PacifiCorp will continue to evaluate the need to issue short-term market power RFPs on an as-needed basis for system balancing purposes.

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, PacifiCorp's planned transmission projects are well aligned to respond to a change in policy direction and comply with increasing reliability requirements, while providing sufficient flexibility to ensure resources can cost-effectively and reliably meet customer demand.
- Given the long periods of time necessary to site, permit and construct major new transmission lines, these projects need to be planned in advance.
- PacifiCorp's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- PacifiCorp requests acknowledgment of its plan to construct the Wallula to McNary portion of the Walla Walla to McNary transmission project (Energy Gateway Segment A) based on customer need and associated regulatory requirements. PacifiCorp requests acknowledgement of its plan to construct the Aeolus to Bridger/Anticline portion of Gateway West (Energy Gateway Sub-Segment D2) based on customer benefits and the inclusion of this segment in the 2017 PacifiCorp IRP preferred portfolio.
- While construction of the balance of future Energy Gateway segments (i.e., Gateway West, Gateway South, and Boardman to Hemingway) is beyond the scope of acknowledgement for this IRP, these segments continue to offer benefits under multiple future resource scenarios. Thus, continued permitting of these segments is warranted to ensure the Company is well positioned to advance these projects as required.

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 numerous benefits associated with a robust transmission network:

1. Reliable delivery of energy to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to meet aggregate electrical demand and customers' energy requirements at all times, taking into account scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Economic exchange of electric power between PacifiCorp and third-party systems and electric utility industry participants.
4. Development of economically feasible generation resources in areas where it is best suited.
5. Access to diverse energy resource areas to support customer needs.
6. Protection against extreme market conditions where limited transmission constrains energy supply.
7. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).
8. Increased capability and capacity to access 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 demand continues 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 two customer-type agreements—network customer or point-to-point transmission service. For the network customers, PacifiCorp uses customer ten-year load and resource (L&R) forecasts, as well as network transmission service requests. Each year, the Company solicits L&R data from each of its network customers to determine future load and resource requirements for all transmission network customers. These customers include PacifiCorp Energy Supply Management (ESM) (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 Power Electric Cooperative (including Moon Lake Electric Association), Bonneville Power Administration, Basin Electric Power Cooperative, Black Hills Power, Tri-State Generation & Transmission, the United States Department of the Interior Bureau of Reclamation, and the Western Area Power Administration.

The Company uses its customers' L&R forecasts and best available information, including transmission service requests, to determine project need and investment timing. If customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios or schedules for its project investment, as appropriate. In accordance with FERC guidelines, the Company is able to reserve transmission network capacity based on these 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 L&R forecasts.[1] A 20-year planning horizon and ability to reserve transmission capacity to meet existing and 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.

For point-to-point transmission service, the OATT requires the Company to accommodate the service on existing transmission infrastructure using existing capacity or build transmission system infrastructure as required to provide the service. The required action is determined with each point-to-point transmission service request through FERC-approved study processes that identify the transmission need.

[1] For example, PacifiCorp's application to begin the Environmental Impact Statement (EIS) process for the Gateway West segment of its Energy Gateway Transmission Expansion Project was filed with the Bureau of Land Management (BLM) in 2007. A partial Record of Decision was received in late April 2013, and a supplemental Record of Decision was received in January 2017.

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. PacifiCorp's transmission system operations also responds to requests issued by Peak Reliability as the NERC Reliability Coordinator. 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 portions 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, PacifiCorp 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.

This chapter provides:

- Justification supporting acknowledgement of the Company's plan to construct the Wallula to McNary and Aeolus to Bridger/Anticline transmission projects.
- Support for the Company's plan to continue permitting Gateway South and the balance of Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of the Company's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the Company to defer the need for larger scale infrastructure investment.

Request for Acknowledgement of Wallula to McNary

The Wallula to McNary transmission project is required to satisfy PacifiCorp's federal regulatory obligations to its transmission customers under its OATT. Specifically obligations include an active transmission service agreement with a transmission customer where service is contingent upon completion of the project. The project consists of a 30-mile, 230 kilovolt (kV) transmission line between Wallula, Washington, and McNary, Oregon, and represents a portion of the Walla Walla, Washington, to McNary Energy Gateway transmission project (Segment A). Since 2008, the Company has worked with stakeholders to permit the transmission project. In 2009, the Company decided to move forward with building the Wallula-to-McNary portion of the transmission line and delay development of the Wallula-to-Walla-Walla portion based on continuing evaluation of evolving regional transmission and resource plans. In 2011, PacifiCorp obtained a certificate of public convenience and necessity from the Public Utility Commission of Oregon. In 2014, transmission customers determined a continued need for the Wallula to McNary transmission line, which prompted the Company to restart permitting and rights-of-way acquisition activities. In addition, federal, county and local public outreach activities were reinitiated in 2015. The project is estimated to be placed into service in 2017-2018, subject to completion of permitting, rights-of-way acquisition, and interconnection to the McNary substation. To meet its obligation to transmission customers under the OATT, the Company requests acknowledgement of the Wallula to McNary transmission project in the 2017 IRP.

Factors Supporting Acknowledgement

The key driver supporting PacifiCorp's request for acknowledgement of the Wallula to McNary transmission project is meeting its obligations to its transmission customers consistent with its OATT. Without the transmission line, there is no available capacity to serve transmission customers on the existing Wallula to McNary transmission line. This new line will enable the Company to meet its obligation to serve transmission customers under the OATT and an executed transmission service agreement, and improve reliability in the area by providing a second connection between Wallula and McNary and a possible future connection between Walla Walla and Wallula (see "Plan to Continue – Wallula to McNary" section below). The transmission line will support future resource growth, including access to renewable energy, and transmission needs.

Currently there are only two megawatts posted for available transfer capacity on the existing line between Wallula and McNary, which is insufficient to satisfy the request for service that drives the need for the project. By contrast, there was sufficient capacity associated with the new line that was already in the permitting stage between Wallula and McNary that could be used for the requested transmission service. Based on this information, it was determined that no new studies were required to grant the transmission service request. The maximum transfer capability of the upgraded Wallula to McNary path will be determined by completion of studies in concurrence with the Western Electricity Coordination Commission Project Coordination, Path Rating and Progress Report Processes guideline.

The rate offered by PacifiCorp to the transmission customer was a rolled-in or embedded rate. Under FERC precedent, transmission rates are designed using an embedded cost approach, which is the rolled-in embedded cost for the system as expanded. Embedded cost rates are justified for transmission facilities that are part of the transmission network, such as the facilities that will be installed as part of the Wallula to McNary project. Under FERC transmission pricing policy and precedent, network transmission facilities enjoy a presumption of rolled-in rate treatment so long as any degree of network integration or benefit is shown, and that benefit need not be large to be significant. PacifiCorp's OATT contains additional guidance on cost assignment. In section 1.27, "Network Upgrades" are defined as "Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System." Network Upgrade costs are typically shared by all network customers. The network concept is supported by projected use of the new line by area network customers in an outage condition of the existing line.

Reliability benefits correspond to the fact that with only a single line between Wallula and McNary, line outages, either planned or unplanned, cause disruption of service to customers. This disruption can result in loss of service under existing contracts or reduced reliability for customers served from the Wallula substation. The second line provides service reliability in a single line outage condition. Additionally, the new line will provide lightning protection, allowing continued operation of the line if there is a lightning strike, whereas the existing line is not protected. In the past, customer service has been disrupted due to line outages caused by lightning strikes on the existing line. Constructing a second 230 kV line between the Wallula and McNary substations will provide additional flexibility and added reliability to customers served in the area and is required to comply with PacifiCorp's OATT and Federal Power Act obligations. With the new line in place, outages on either the new or existing line can occur without interruption of customer service, thus providing added reliability of service. The Walla Walla to McNary transmission project alleviates a constrained transmission path used to move resources into and out of the Walla Walla and Wallula areas. At this time, only the Wallula to McNary transmission line segment is being constructed to meet a customer request for point-to-point service under PacifiCorp's OATT. The segment between Walla Walla and Wallula will be completed when there is a transmission customer need.

The below sections of the OATT outline the FERC requirements associated with providing transmission service as requested. These requirements mandate completion of the project.

- OATT section 28.2: As a Transmission Provider, PacifiCorp is obligated to "plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System."

- OATT section 15.4: **"**If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service consistent with its planning obligations in Attachment K...."

These sections of the OATT require the transmission provided to perform transmission system upgrades as required to serve customer need driven either from network or point-to-point transmission service requests. The network needs are generated from the outcome of the yearly network L&R planning study that shows projected load growth and required system changes to meet this growth. The point-to-point needs are driven by specific point-to- point requests where system changes are required to meet the requested service.

Plan to Continue – Wallula to McNary

The Wallula to McNary transmission project will offer benefits under multiple, future resource scenarios. In addition, as part of its asset exchange agreement with Idaho Power Company, there is an option for Idaho Power to partner with PacifiCorp to construct the remaining Walla Walla to Wallula portion of the transmission line.[2] To ensure the Company is well positioned to advance the projects as required to meet customer need, PacifiCorp believes it is prudent to finalize permitting, acquire rights-of-way, and construct the Wallula to McNary segment of the Walla Walla to McNary transmission project.

Request for Acknowledgement of Aeolus to Bridger/Anticline

The 2017 PacifiCorp IRP preferred portfolio includes the Aeolus to Bridger/Anticline transmission segment (Energy Gateway West, Sub-Segment D2). This segment is included in the preferred portfolio as a component of the least-cost, least-risk strategy for existing and future capacity delivery. The Aeolus to Bridger/Anticline transmission line relieves existing congestion

[2] FERC Docket Nos. EC15-54 and ER15-680.

and facilitates the addition of new wind resources in Wyoming that can take full advantage of the federal production tax credits (PTCs) and maximize customer benefits.

The 500 kV transmission segment extends 140 miles between the planned Aeolus substation near Medicine Bow, Wyoming, and the new annex substation (Bridger/Anticline) that is located near the existing Bridger substation in western Wyoming. This transmission segment represents a portion of the Windstar to Populus transmission project (Segment D), which is part of Energy Gateway West. The Company, with stakeholder involvement, has pursued permitting of the Energy Gateway West transmission project since 2008. On April 26, 2013 the BLM released its final Environmental Impact Statement (EIS). The Record of Decision was released on November 14, 2013, which provided a right-of-way grant for the federal properties. This transmission segment was part of four Energy Gateway scenarios analyzed in the IRP and was ultimately chosen to be included in the 2017 IRP preferred portfolio. Based on the IRP analysis, the Aeolus to Bridger/Anticline transmission segment would be placed into service by the end of 2020, subject to completion of local permitting and private rights-of-way acquisitions. To align development of the Aeolus to Bridger/Anticline transmission segment with additional wind projects that will further decarbonize PacifiCorp's portfolio and qualify for the full value of PTCs by year-end 2020, thereby maximizing customer benefits, the Company requests acknowledgment in this IRP of the Aeolus to Bridger/Anticline transmission segment.

Factors Supporting Acknowledgement

Acknowledgment of the Aeolus to Bridger/Anticline transmission segment is supported by the extensive analysis and demonstrated customer benefits that led to the inclusion of the transmission line in the 2017 IRP preferred portfolio. This transmission segment will allow PacifiCorp to implement system improvements, relieve existing congestion, and add incremental Wyoming wind resources to support customer needs and deliver benefits to customers in the most cost-effective way. Timing of construction is driven by the phase-out schedule of federal PTCs, particularly the 2020 in-service requirements for 100 percent PTC eligibility. In addition to supporting renewable resource additions in PacifiCorp's generation portfolio, qualifying them for full value of the PTCs, the new transmission segment will increase transfer capability out of eastern Wyoming and alleviate voltage issues.

PacifiCorp's transmission system in eastern Wyoming is operating at capacity, specifically the known WECC path #37 TOT 4A, which limits transfer of resources from eastern Wyoming. The TOT 4A cut plane is a WECC-defined path in southeastern Wyoming consisting of three 230 kV transmission lines. The Aeolus to Bridger/Anticline transmission segment increases the transfer capability from east to west across Wyoming by 750 MW. The WECC-rated path #37 TOT 4A from the rating path catalog has a non-simultaneous rating of 1,025 MW. However, the interaction with WECC path #38, TOT 4B, limits the transfer capability of TOT 4A in real-time operations. TOT 4A is currently identified as a constrained path in the mainly 230 kV transmission system in eastern Wyoming. To relieve existing congestion and add resources in eastern Wyoming, new transmission is required to increase transfer capability out of eastern Wyoming.

Completion of the new transmission segment will allow the addition of up to 1,270 MWs of additional wind resources (depending on re-dispatch) added to the system east of the TOT 4A cut plane. PacifiCorp's preferred portfolio includes 1,100 MW of new wind resources, which reflects a least-cost, least risk mix when the anticipated economic re-dispatch of resources in the area is considered. Importantly, the transmission project includes critical voltage support, which is the system limitation in the area. The new transmission capacity, voltage support, generation re-dispatch, and a generator tripping scheme will allow for a disproportionate amount of wind generation to be integrated into the system. The 230 kV transmission system today east of the TOT 4A cut plane is operating at the limits of the system and has fully exhausted the ability to interconnect additional resources behind the cut plane. The addition of this new transmission segment has the potential to provide a path for projects sited east of the TOT 4A interconnected at or near Aeolus Substation.

Voltage control issues under certain operating conditions have been identified on the transmission system in southeastern Wyoming, with additions of wind resources in the area exacerbating the issue. An identified solution to the voltage control issues is the addition of transmission lines in the area. The transmission system in the area will benefit with the addition of the new transmission segment by reducing voltage issues behind the TOT 4A cut plane that currently restrict the addition of new resources interconnected behind the cut plane.

Other customer benefits of the new transmission segment include increased reliability of the transmission system, congestion relief, reduction of capacity and energy losses on the transmission system, and greater flexibility managing existing generation resources. Reliability will be augmented with the addition of the new transmission segment, which will provide support to the underlying 230 kV system during outages. Most of these outages result in a deration of TOT 4A transfer capacity and some outage scenarios require significant generation curtailment. The new 500 kV transmission segment will significantly reduce, if not eliminate, many of the impacts caused by the 230 kV outages. Increased energy imbalance market (EIM) and transmission wheeling opportunities under the OATT will also result from the additional system capacity. Capacity and energy losses on the transmission system are reduced with the new transmission segment, which has the potential to provide significant monetary savings over time.

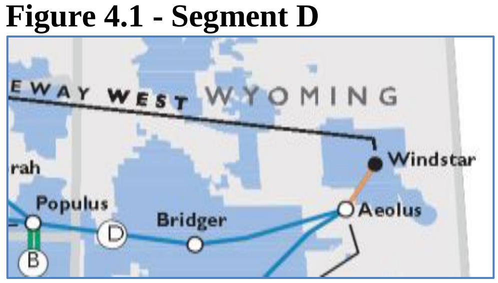
Gateway West – Continued Permitting

In addition to the Windstar to Populus line (Energy Gateway Segment D), the Gateway West transmission project also includes the Populus to Hemingway transmission segment (Energy Gateway Segment E). In a future IRP, the Company will support a request for acknowledgement to construct the balance of Gateway West with a cost-benefit analysis for the project. While the Company is not requesting acknowledgement in this IRP of a plan to construct these segments at this time, the Company will continue to permit the projects.

Windstar to Populus (Segment D)

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

Figure 4.1 - Segment D



- D1—A single-circuit 230 kV line that will run approximately 75 miles between the existing Windstar substation in eastern Wyoming and the planned Aeolus substation near Medicine Bow, Wyoming;

- D2—A single-circuit 500 kV line running approximately 140 miles from the planned

Aeolus substation to a new annex substation (Anticline) near the existing Bridger substation in western Wyoming; and

- D3—A single-circuit 500 kV line running approximately 200 miles between the new annex substation (Anticline) and the recently constructed Populus substation in southeast Idaho.

Populus to Hemingway (Segment E)

Figure 4.2 - Segment E

The Populus to Hemingway transmission project consists of two single-circuit 500 kV lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho.

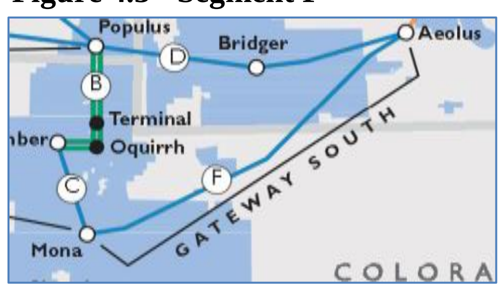
The Gateway West project would enable the Company to more efficiently dispatch system resources, improve performance of the transmission system (i.e., reduce line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long term.

Under the National Environmental Policy Act, the BLM has completed the EIS for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the Record of Decision on November 14, 2013, providing a right-of-way grant for all of Segment D and most of Segment E of the project. The Agency chose to defer its decision on the western-most portion of Segment E of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later Record of Decision include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway. A Record of Decision for these final sections of Segment E was issued on January 19, 2017.

Gateway South – Continued Permitting

As part of PacifiCorp's Energy Gateway Transmission Expansion, the Company is planning to build a high-voltage transmission line, known as Gateway South (Segment F), which extends approximately 400 miles from the planned Aeolus substation in southeastern Wyoming into the Clover substation near Mona, Utah.

Figure 4.3 - Segment F



The BLM published its Notice of Intent in the Federal Register in April 2011, followed by public scoping meetings throughout the project area. Comments on this project from agencies and other interested stakeholders were considered as the BLM developed the draft EIS, which was issued in February 2014. A final EIS was released May 2016 and the Record of Decision was signed December 13, 2016.

Plan to Continue Permitting – Gateway West and Gateway South

The Gateway West and Gateway South transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure the Company is well positioned to advance the projects, it is prudent for PacifiCorp to continue to permit the balance of Gateway West and Gateway South transmission projects. The Records of Decision and rights-of-way grants contain many conditions and stipulations that must be met and accepted before a project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management to review progress.

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 well in advance. 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 PacifiCorp's proposal of the Energy Gateway Transmission Expansion Plan.

Background

Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on the generation additions identified in the IRP. 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 PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements. Please refer to the regional maps of wind, solar, biomass, and geothermal potential available on PacifiCorp's Energy Gateway project website to see an overlay of the Energy Gateway project and renewable resource potential.[3] 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. PacifiCorp 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

[3] http://www.pacificorp.com/tran/tp/eg.html

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 Pacific Northwest loads and northern California.

- ***Rocky Mountain Area Transmission Study***
  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 to 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***
  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 (NTTG) Transmission Planning Reports***

In the 2016-2017 NTTG Draft Regional Transmission Plan, Energy Gateway (both Gateway West and Gateway South and Gateway West) were listed as necessary for acceptable system performance. The study also established that the amount of new Wyoming wind that is added over time impacts the transmission system reliability west of Wyoming. Additionally three interregional projects were included in the study (SWIP North, Cross Tie and TransWest Express), which showed that all three projects relied on Energy Gateway to attain their full transfer capability rating.

"After analyzing the steady-state performance of stressed conditioned cases, a rigorous contingency analysis commenced… then, NTTG's Technical Committee determined additional facilities would be needed to meet the reliability criteria…."

- ***WECC/Transmission Expansion Policy and Planning Committee (TEPPC) Annual Reports* and *Western Interconnection Transmission Path Utilization Studies***
  These analyses measure the historical use 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

To address 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 of reliability that spans 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 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 NTTG and WECC's 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.[4]

[4] http://www.oatioasis.com/ppw/index.html

Additionally, an extensive 18-month stakeholder process on Gateway West and Gateway South was conducted. 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, PacifiCorp 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 always 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 PacifiCorp 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 (for example, 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, 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 PacifiCorp 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 to explore potential joint-development opportunities with Idaho Power Company on its Boardman to Hemingway project and with Portland General Electric Company (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate PacifiCorp's east and west balancing authority 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 potential 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 that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line were feasible, and that the second new proposed 230 kV line and proposed 500 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 Company and the Bonneville Power Administration (BPA) that provides for the Company's participation through the permitting phase of the project. The Boardman to Hemingway project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). Idaho Power leads the permitting efforts on the Boardman to Hemingway project, and PacifiCorp continues to support these activities under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement. The proposed line provides additional connectivity between PacifiCorp's west and east balancing authority areas and supports the full projected line rating for the Gateway projects at full build out. PacifiCorp plans to continue forward in support of the project under the Permit Funding agreement and will assess next steps post-permitting based on customer need and possible benefits.

In January 2013, PacifiCorp began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint development or firm capacity rights on PacifiCorp's Oregon system. The Company further notes that it had a memorandum of understanding with PGE for the development of Cascade Crossing that terminated by its own terms. PacifiCorp had continued to evaluate potential partnership opportunities with PGE once it announced its intention to pursue Cascade Crossing with BPA. However, because PGE decided to end discussions with BPA and instead pursue other options, PacifiCorp is not actively pursuing this opportunity. PacifiCorp continues to look to partner with third parties on transmission development as opportunities arise.

In May 2013, PacifiCorp completed the Mona to Oquirrh project. In November 2013, the Bureau of Land Management issued a partial Record of Decision providing a right-of-way grant for all of Segment D and most of Segment E of Energy Gateway. The agency chose to defer its decision on the western-most portion of Segment E of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area.

Specifically, the sections of Gateway West that were deferred for a later Record of Decision include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In May 2015, the Sigurd to Red Butte project was completed and placed in-service.

In December 2016, the Bureau of Land Management issued its Record of Decision and right-of-way grant for the Gateway South project.

In January 2017, the Bureau of Land Management issued its Record of Decision and right-of-way grant, previously deferred as part of the November 2013 partial Record of Decision, for the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

PacifiCorp evaluated four Energy Gateway scenarios in this 2017 IRP:

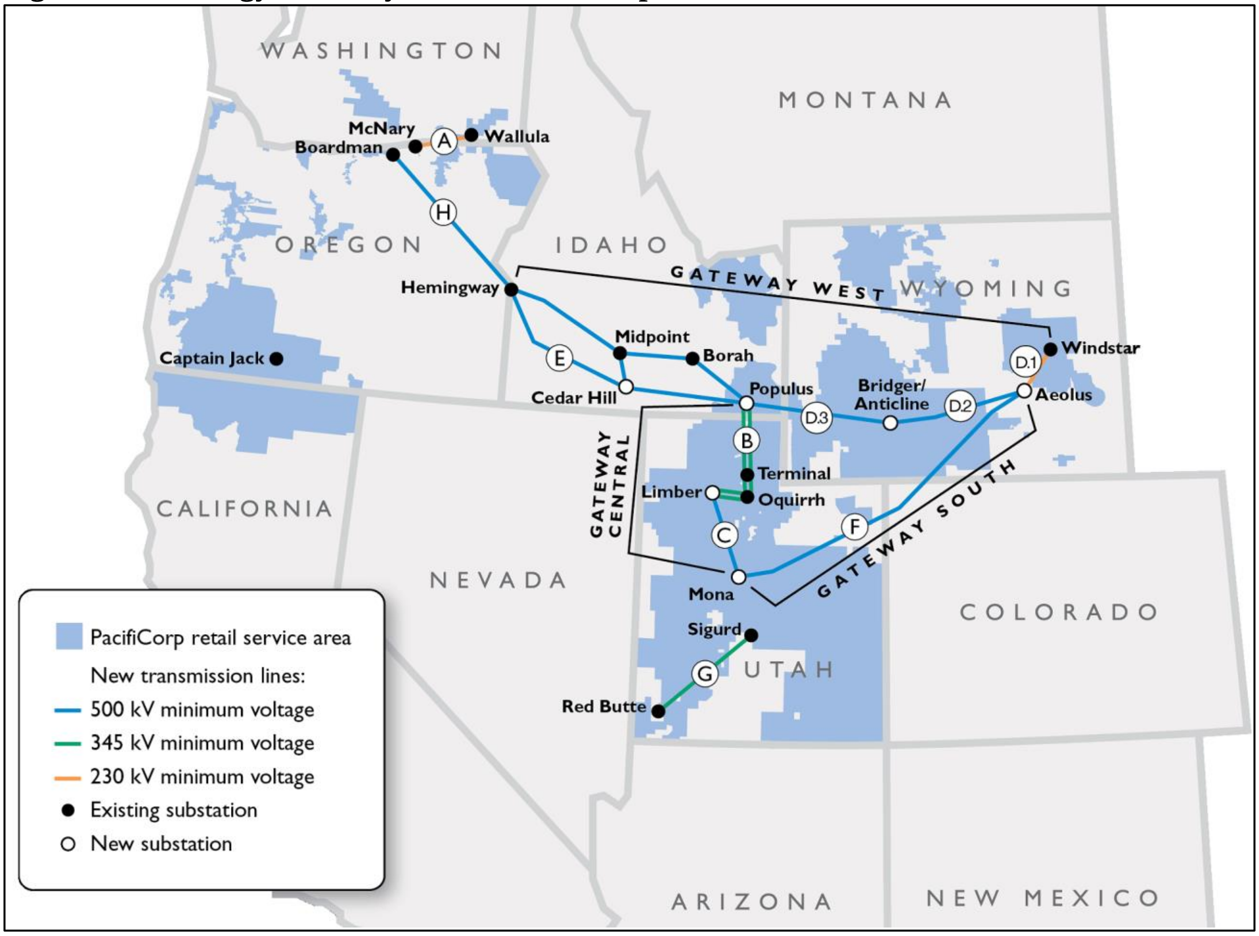
- Energy Gateway 1: Segment D Windstar to Aeolus 230 kV (one new line and one re-built line) and Aeolus to Bridger/Anticline 500 kV line;
- Energy Gateway 2: Segment F Windstar to Aeolus 230 kV (one new line and one re-built line) and Aeolus to Mona/Clover 500 kV line;
- Energy Gateway 3: Segments D & F Windstar to Aeolus 230 kV (one new line and one re-built line) and Aeolus to Bridger/Anticline, Bridger/Anticline to Populus and Aeolus to Mona/Clover 500 kV lines; and
- Energy Gateway 4: Segment D2 Aeolus to Bridger/Anticline 500 kV line.

This analysis demonstrates that Energy Gateway 4 (Aeolus to Bridger/Anticline) showed potential to align development of this new transmission line with new PTC-eligible wind resources and provide value for PacifiCorp customers. PacifiCorp refined its analysis during the IRP process, to understand how the most current assumptions would influence potential customer benefits associated with this new transmission line. The refined analysis shows that the Energy Gateway 4 scenario, Aeolus to Bridger/Anticline, in conjunction with new wind additions and PTCs, is the most cost-effective Energy Gateway transmission segment, providing the most benefit to customers. Energy Gateway 4 is therefore a component of the 2017 IRP preferred portfolio.

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, Gateway South, and Boardman to Hemingway), PacifiCorp has been proactive in deferring in-service dates as needed due to permitting schedules, moderated load growth, changing customer needs, and system reliability improvements.

PacifiCorp 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 4.4 – 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 and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: local permitting completed • Scheduled in-service: 2018 is sponsor driven
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: rights-of-way acquisition underway • Scheduled in-service: 2021
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	75 mi	• Status: permitting underway • Scheduled in-service: 2019-2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: permitting underway • Scheduled in-service: 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in-service: 2020-2024
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in-service: 2020-2024
(F)	500 kV single circuit	400 mi	• Status: permitting underway

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
Aeolus-Mona			• Scheduled in-service: 2020-2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: construction began May 2013 • Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	500 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in-service: sponsor driven

Efforts to Maximize Existing System Capability

In addition to investing in the Energy Gateway transmission projects, PacifiCorp continues to make other system improvements that have helped maximize efficient use of the existing transmission system and defer the need for larger-scale, longer-term infrastructure investment. Despite limited new transmission capacity being added to the system over the last 20 to 30 years, PacifiCorp has maintained system reliability and maximized system efficiency through other smaller-scale, incremental projects.

System-wide, the Company has instituted more than 155 grid operating procedures and 17 special protection schemes to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the EIM since November 2014. The EIM provides for more efficient dispatch of participating resources in real-time through an automated system that dispatches generation across the EIM footprint, which currently includes the PacifiCorp east and west balancing authority areas, the NV Energy, Puget Sound Energy, Arizona Public Service balancing authority areas, and the CAISO balancing authority area (collectively, EIM Area) for use as short-term balancing resources to ensure energy supply matches demand. Entities scheduled to join the EIM include PGE (October 2017), Idaho Power Company (April 2018), Seattle City Light (April 2019), and the Balancing Authority of Northern California (April 2019). By broadening the pool of lower-cost resources that can be accessed to balance systems, reliability is enhanced and system costs are reduced across the entire EIM Area. In addition, the automated system is able to identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

Transmission System Improvements Placed In-Service Since the 2015 IRP

- Constructed the new Standpipe substation and installed a synchronous condenser located in Wyoming.
- Installed an additional 230/115 kV 250 MVA transformer at Casper substation located in Wyoming.
- Installed shunt capacitors at Fry substation located in Oregon.
- Installed a load-shedding scheme at Grass Creek and Thermopolis substations located in Wyoming.
- Installed a phase-shifting transformer and series reactor at Upalco substation located in Utah.
- Installed an additional 230/115 kV 250 MVA transformer and 230 kV ring bus at Union Gap substation located in Washington.
- Expanded the 230 kV ring bus at Pomona Heights substation located in Washington.
- Installed new relays on the Rigby to Sugarmill 161 kV line located in Idaho.

- Installed new relays on the Rigby to Jefferson 161 kV line located in Idaho.
- Installed a phase-shifting transformer at Pinto substation located in Utah.
- Constructed the new Whetstone substation located in Oregon.
- Constructed a 10-mile, 46 kV line from the Holden substation tap to the Flowell-Robison line located in Utah.
- Converted the Highland substation to 138 kV located in Utah.
- Installed a 138/46kV transformer at Snyderville substation located in Utah.

Planned Transmission System Improvements

- Replace the existing 115/69 kV transformer at Weed substation with a 50 MVA LTC unit located in California.
- Replace 500 kV line relays at several 500 kV substations located in Oregon.
- Energize one circuit of the 230kV Ben Lomond to Parrish line as a three-terminal 138kV line from Ben Lomond to Syracuse and Parrish located in Utah.
- Install a new remedial action scheme (RAS) in the Goshen/Rigby area located in Idaho.
- Reconstruct the Goshen-Jefferson 161kV line located in Idaho.
- Energize Red Butte-St. George 345 kV line at 138 kV located in Utah.
- Install a new bay with a breaker and half scheme at Spanish Fork substation located in Utah.
- Install a second 700 MVA 345/138 kV transformer at Syracuse substation located in Utah.
- Install backup bus differential relays at various substations located in Utah and Wyoming.
- Replace breakers identified as over-dutied with higher-capability breakers in various substations located in Utah, Wyoming, and Idaho.
- Replace an existing oil breaker at the Treasureton 138 kV substation with a SF6 breaker and add a circuit switcher in series with the breaker located in Utah.
- Replace conductor on the Moxee- Hopland section of the Moxee- Union Gap 115 kV line located in Washington.
- Construct two new 500-230 kV substations, Snow Goose and Sams Valley, located in Oregon.
- Rebuild the 230 kV portion of the Troutdale substation, located in Oregon, into a six breaker ring bus configuration.
- Rebuild the 115 kV main and transfer bus into a breaker and half scheme at the Union Gap substation in Washington.
- Construct a 138 kV line from Croydon substation to Silver Creek substation located in Utah.
- Replace conductor between Hazelwood and BPA Albany and construct a new 115 kV ring bus at Hazelwood substation located in Oregon.
- Replace the 25 MVA 115 kV–69 kV transformer at Dry Gulch with a 50 MVA transformer located in Washington.
- Convert portions of Portland, Oregon area transmission network to 115 kV from 57 kV and 69 kV.
- Install an additional 115 kV–69 kV transformer at Yreka substation located in California.
- Install a new 230 kV–115 kV transformer at Ponderosa substation and a new seven-mile 115 kV transmission line between Ponderosa and Baldwin substations located in Oregon.

These investments help maximize the existing system's capability, improve the Company's ability to serve growing customer loads, improve reliability, increase transfer capacity across WECC Paths, reduce the risk of voltage collapse and maintain compliance with NERC and WECC reliability standards.

CHAPTER 5 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability at the time of the coincident system summer and winter peak periods.
- For capacity expansion planning, the Company uses a 13 percent target planning reserve margin applied to PacifiCorp's obligation, which is calculated as projected load less private generation, less Class 2 demand side management (DSM) energy efficiency savings, and less interruptible load.
- A 2016 Private Generation Long-Term Resource Assessment (2017-2036) study prepared by Navigant Consulting, Inc. produced estimates on private generation penetration levels specific to PacifiCorp's six-state territory. The study provided expected penetration levels by resource type, along with high and low penetration sensitivities. PacifiCorp's 2017 IRP resource needs assessment treats base case private generation penetration levels as a reduction in load.
- PacifiCorp's system coincident peak load is forecasted to grow at a compounded average annual growth rate of 0.85 percent over the period 2017 through 2026. On an energy basis, PacifiCorp expects system-wide average load growth of 0.91 percent per year from 2017 through 2026. Loads growth rates are before the impact of new energy efficiency savings.
- After accounting for load growth, coal unit retirement assumptions, and front-office transaction (FOT) availability, and after incorporating future energy efficiency savings, PacifiCorp's system planning reserve margin in summer and winter exceeds the 13 percent target planning reserve margin for the period ended 2025.

Introduction

This chapter presents PacifiCorp's assessment of its load and resource balance, focusing on the first ten years of the IRP's 20-year study period, 2017 through 2026. The Company's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are summarized in Volume II, Appendix A (Load Forecast Details). 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 composed of a year-by-year comparison of projected loads against the existing resource base, including available FOTs, assumed coal unit retirements and incremental new energy efficiency savings from the 2017 IRP preferred portfolio, before adding new generating resources. In response to stakeholder feedback in the previous IRP cycle, this 2017 IRP includes the modeling of the winter coincident peak as an improvement over previous IRPs.

System Coincident Peak Load Forecast

The system coincident peak load is the annual maximum hourly load on the system. The Company's long-term load forecasts (both energy and coincident peak) for each state and the system are summarized in Volume II, Appendix A (Load Forecast Details).

The 2017 IRP relies on PacifiCorp's December 2016 load forecast. Table 5.1 shows the annual summer coincident peak load stated in megawatts as reported in the capacity load and resource balance, before any load reductions from Class 2 DSM and private generation. The system summer peak load grows at a compounded average annual growth rate (CAAGR) of 0.85 percent over the period 2017 through 2026.

Table 5.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency and Private Generation

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System	10,164	10,277	10,384	10,486	10,608	10,718	10,804	10,907	11,028	11,049

Existing Resources

On a system coincident basis, PacifiCorp is a summer-peaking utility. For the forecasted 2017 summer coincident peak, PacifiCorp owns or has interests in resources with an expected system summer peak capacity of 11,645 MW. Table 5.2 provides anticipated system summer peak capacity ratings by resource category as reflected in the IRP load and resource balance for 2017. Note that capacity ratings in the following tables provide resource capacity value at the time of system coincident peak, rounded to the nearest megawatt.

Table 5.2 – 2017 Capacity Contribution at System Summer Peak for Existing Resources

Resource Type[1/]	L&R Balance Capacity at System summer peak (MW)[2/]	Percent of Total (%)
Pulverized Coal	5,919	50.8%
Gas-CCCT	2,377	20.4%
Gas-Other	357	3.1%
Hydroelectric	958	8.2%
DSM[3/]	426	3.7%
Renewables	294	2.5%
Qualifying Facilities—Renewables	705	6.1%
Purchase[4/]	267	2.3%
Qualifying Facilities	146	1.3%
Interruptible Contracts	195	1.7%
Total	**11,645**	**100%**

1/ Sales and Non-Owned Reserves are not included.
2/ Represents the capacity available at the time of system summer 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 (direct load control) and Class 2 (energy efficiency) 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 PacifiCorp's existing coal-fueled thermal plants and Table 5.4 lists existing natural-gas-fueled plants. The assumed end-of-life dates are used for the 2017 IRP modeling of existing coal resources.

Table 5.3 – Coal-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	Assumed End-of-Life Year	L&R Balance Capacity at System summer peak (MW)
Cholla 4	100	AZ	2042	387
Colstrip 3	10	MT	2046	74
Colstrip 4	10	MT	2046	74
Craig 1	19	CO	2034	82
Craig 2	19	CO	2034	82
Dave Johnston 1	100	WY	2027	106
Dave Johnston 2	100	WY	2027	106
Dave Johnston 3	100	WY	2027	220
Dave Johnston 4	100	WY	2027	330
Hayden 1	24	CO	2030	45
Hayden 2	13	CO	2030	33
Hunter 1	94	UT	2042	418
Hunter 2	60	UT	2042	269
Hunter 3	100	UT	2042	471
Huntington 1	100	UT	2036	459
Huntington 2	100	UT	2036	450
Jim Bridger 1	67	WY	2037	354
Jim Bridger 2	67	WY	2037	359
Jim Bridger 3	67	WY	2037	345
Jim Bridger 4	67	WY	2037	350
Naughton 1	100	WY	2029	156
Naughton 2	100	WY	2029	201
Naughton 3[1/]	100	WY	2029	280
Wyodak	80	WY	2039	268
TOTAL – Coal				**5,919**

[1/] Naughton Unit 3 may be retired at the end of 2018.

Table 5.4 – Natural-Gas-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	Assumed End-of-Life Year	L&R Balance Capacity at System summer peak (MW)
Chehalis	100	WA	2043	464
Currant Creek	100	UT	2045	533
Gadsby 1	100	UT	2032	64
Gadsby 2	100	UT	2032	69
Gadsby 3	100	UT	2032	105
Gadsby 4	100	UT	2032	40
Gadsby 5	100	UT	2032	40
Gadsby 6	100	UT	2032	40
Hermiston (owned)	50	OR	2036	227
Lake Side	100	UT	2047	530
Lake Side 2	100	UT	2054	623
TOTAL – Gas and Combined Heat & Power				**2,734**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 2,333 MW of wind resources. Since the 2015 IRP Update, the Company has entered into power purchase agreements totaling 40 MW.

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

Table 5.5 – Owned Wind Resources

Wind Project	State	Capacity (MW)	L&R Balance Capacity at System summer peak (MW)
Foote Creek I[1/]	WY	32	6
Leaning Juniper	OR	101	12
Goodnoe Hills Wind	WA	94	11
Marengo	WA	140	17
Marengo II	WA	70	8
Glenrock Wind I	WY	99	16
Glenrock Wind III	WY	39	6
Rolling Hills Wind	WY	99	16
Seven Mile Hill Wind	WY	99	16
Seven Mile Hill Wind II	WY	20	3
High Plains	WY	99	16
McFadden Ridge 1	WY	29	4
Dunlap 1	WY	111	18
TOTAL – Owned Wind		**1,032**	**148**

[1/] PacifiCorp's share is 32 MW of the 40 MW project.

Table 5.6 – Non-Owned Wind Resources

Power Purchase Agreements/Exchanges	State	PPA or QF	Capacity (MW)	L&R Balance Capacity at System Summer Peak (MW)
Combine Hills	OR	PPA	41	5
Foote Creek IV	WY	PPA	17	3
Rock River I	WY	PPA	50	8
Stateline Wind	OR/WA	PPA	175	21
Three Buttes Wind Power (Duke)	WY	PPA	99	16
Top of the World	WY	PPA	200	32
Wolverine Creek	ID	PPA	65	10
Casper Wind (Chevron)	WY	QF	17	3
Chopin	WA	QF	10	1
Foote Creek II	WY	QF	2	0
Foote Creek III	WY	QF	25	4
Latigo Wind	UT	QF	60	9
Mariah Wind	OR	QF	10	1
Meadow Creek Project – Five Pine	ID	QF	40	6
Meadow Creek Project – North Point	ID	QF	80	13
Mountain Wind Power I	WY	QF	61	10
Mountain Wind Power II	WY	QF	80	13
Orchard Wind[1/]	WA	QF	40	5
Oregon Wind Farms I & II	OR	QF	65	8
Orem Family Wind	OR	QF	10	1
Pioneer Wind Park I	WY	QF	80	13
Power County Wind Park North	ID	QF	23	4
Power County Wind Park South	ID	QF	23	4
Spanish Fork Wind Park 2	UT	QF	19	3
Three Mile Canyon	WA	QF	10	1
Small QF	WY	QF	0.2	0
TOTAL – Purchased Wind			**1301**	**191**

[1/] New since 2015 IRP Update

Solar

PacifiCorp has a total of 54 solar projects under contract representing 1,164 MW of nameplate capacity. Of these, two projects totaling 100 MW are new since the 2015 IRP Update.

Table 5.7 – Non-Owned Solar Resources

Power Purchase Agreements/Exchanges	PPA or QF	State	Capacity (MW)	L&R Balance Capacity at System Summer Peak (MW)
Black Cap	PPA	OR	2	1
Utah Solar PV Program	PPA	UT	2	1
Old Mill	PPA	OR	5	3
Oregon Solar Incentive Projects	PPA	OR	10	5
Small Solar	QF	UT	0.5	0
Adams Solar Center	QF	OR	10	6
Bear Creek Solar Center	QF	OR	10	6
Beatty Solar	QF	OR	5	3
Beryl Solar	QF	UT	3	1
Black Cap Solar II	QF	OR	8	5
Bly Solar Center	QF	OR	9	6
Buckhorn Solar	QF	UT	3	1
Cedar Valley Solar	QF	UT	3	1
Chiloquin Solar	QF	OR	10	5
Collier Solar	QF	OR	10	6
Elbe Solar Center	QF	OR	10	6
Enterprise Solar	QF	UT	80	47
Escalante Solar I	QF	UT	80	47
Escalante Solar II	QF	UT	80	47
Escalante Solar III	QF	UT	80	47
Ewauna Solar	QF	OR	1	1
Ewauna Solar 2	QF	OR	3	2
Fiddler's Canyon Solar 1-3	QF	UT	9	5
Granite Mountain – East	QF	UT	80	47
Granite Mountain – West	QF	UT	50	30
Granite Peak Solar	QF	UT	3	1
Greenville Solar	QF	UT	2	1
Iron Springs	QF	UT	80	47
Ivory Pine Solar	QF	OR	10	6
Laho Solar	QF	UT	3	1
Merrill Solar	QF	OR	10	6
Milford Flat Solar	QF	UT	3	2
Milford Solar 2	QF	UT	3	1
Norwest Energy 2 (Neff)	QF	OR	10	6
Norwest Energy 4 (Bonanza)	QF	OR	6	4
Norwest Energy 7 (Eagle Point)	QF	OR	10	6
Norwest Energy 9 Pendleton	QF	OR	6	3
OR Solar 2, LLC (Agate Bay)	QF	OR	10	6
OR Solar 3, LLC (Turkey Hill)	QF	OR	10	6
OR Solar 5, LLC (Merrill)	QF	OR	8	5
OR Solar 6, LLC (Lakeview)	QF	OR	10	6
OR Solar 7, LLC (Jacksonville)	QF	OR	10	6
OR Solar 8, LLC (Dairy)	QF	OR	10	6
Pavant Solar	QF	UT	50	29
Pavant Solar II LLC	QF	UT	50	30
Pavant Solar III LLC[1/]	QF	UT	20	12
Quichapa Solar 1-3	QF	UT	9	5
South Milford Solar	QF	UT	3	2
Sprague River Solar	QF	OR	7	5
Sweetwater Solar[1/]	QF	WY	80	48
Three Peaks Solar	QF	UT	80	47
Tumbleweed Solar	QF	OR	10	5
Utah Red Hills Renewable Park	QF	UT	80	47
Woodline Solar	QF	OR	8	5
TOTAL – Purchased Solar			**1,164**	**690**

[1/] New since 2015 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 that is rated at 0.28 MW. PacifiCorp has a six-year power purchase agreement with a 3.65 MW QF geothermal project near Lakeview, Oregon, which became operational September 2016.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 19 projects totaling approximately 100 MW of nameplate capacity. At least one project is located in each state in PacifiCorp's service territory.

Renewables Net Metering

Installation rates for net metering facilities have been relatively consistent for the last few years over most of PacifiCorp's service territory. Utah, however, has seen tremendous growth—an approximate 180 percent increase year over year—in the amount of residential solar being interconnected. Table 5.8 provides a breakdown of net metered capacity and customer counts from data collected on November 30, 2016.

Table 5.8 – Net Metering Customers and Capacities

Fuel	Solar	Wind	Gas[1/]	Hydro	Mixed[2/]
Nameplate (kW)	184,548.20	793.66	884	658.40	1130.11
Capacity (percentage)	98.16%	0.42%	0.47%	0.35%	0.60%
Number of customers	22,355	198	4	14	60
Customer (percentage)	98.78%	0.87%	0.02%	0.06%	0.27%

[1/] Gas includes: biofuel, waste gas, and fuel cells

[2/] Mixed includes projects with multiple technologies, one project is solar and biogas and the others are solar and wind

Hydroelectric Generation

PacifiCorp owns 1,135 MW of hydroelectric generation capacity and purchases the output from 127 MW of other hydroelectric resources.[1] These resources provide 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

[1] PacifiCorp's 2016 10-K shows 1,135 MW of Net Facility Capacity.

its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control, which lead 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 5.9, which shows 2017 capacity included in the load and resource balance.

Table 5.9 – Hydroelectric Contracts - Load and Resource Balance Capacities

Hydroelectric Contracts by Load and Resource Balance Category	L&R Balance Capacity at System summer peak (MW)
Hydroelectric	89
Qualifying Facilities—Hydroelectric	38
Total Contracted Hydroelectric Resources	**127**

Table 5.10 provides the operational capacity for each of PacifiCorp's owned hydroelectric generation facilities at system summer peak (2017).

Table 5.10 – PacifiCorp Owned Hydroelectric Generation Facilities – Load and Resource Balance Capacities

Plant	State(s)	L&R Balance Capacity at System summer peak (MW)
West		
Big Fork	MT	4
Klamath – Dispatch	CA	56
Klamath – Flat	CA	11
Klamath – Shape	OR	86
Lewis – Dispatch	WA	390
Lewis – Shape[1/]	WA	94
Rogue	OR	31
Small West Hydro[2/]	CA/OR/WA	2
Umpqua – Flat	OR	24
Umpqua – Shape	OR	89
East		
Bear River – Dispatch	ID/UT	53
Bear River – Shape	ID/UT	16
Small East Hydro[3/]	ID/UT/WY	14
TOTAL – Hydroelectric before Contracts		**869**
Plus Hydroelectric Contracts		**127**
TOTAL – Hydroelectric with Contracts		**996**

[1/] Cowlitz County PUD owns Swift No. 2, and is operated in coordination with the other projects by PacifiCorp

[2/] Includes Bend, Fall Creek, and Wallowa Falls

[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 5.11 lists the estimated impacts to average annual hydro generation from expected Federal Energy Regulatory Commission (FERC) orders and relicensing settlement commitments. PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned in accordance with the Klamath Hydroelectric Settlement Agreement in the year 2020 and that other projects currently in relicensing will receive new operating licenses, but that additional operating restrictions will be imposed in new licenses, such as higher bypass flow requirements, that will reduce generation available from these facilities.

Table 5.11 – Estimated Impact of FERC License Renewals and Relicensing Settlement Commitments on Hydroelectric Generation

Years	Incremental Lost Generation (MWh)	Cumulative Lost Generation (MWh)
2017-2018	1,631	1,631
2019-2020	9,485	11,116
2021-2036	628,000	639,116

Demand Side Management (DSM)

DSM resources/products vary in their dispatchability, reliability, term of load reduction 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. The reliability resource options are used to avoid outages or high resource costs as a result of weather conditions, plant outages, market prices, and unanticipated system failures. PacifiCorp categorizes DSM resources into four general classes based on their relative characteristics:

- **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 a 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. Program examples include residential and small commercial central air conditioner load control programs that are dispatchable, and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design 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 or service incentives to customers to improve the efficiency of existing or new customer-owned facilities through: (1) the installation of more efficient equipment, such as lighting, motors, air conditioners, or appliances; (2) upgrading building efficiency through improved insulation levels, windows, etc.; or (3) behavioral modifications, such as strategic energy management efforts at business facilities and home energy reports for residential customers. 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, comprehensive home improvement retrofit programs, 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. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making Class 3 DSM resources less suitable to incorporate into resource planning, at least until their size and customer behavior profile provide sufficient information for a reliable diversity result (predictable impact) 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 being avoided. The impacts of Class 3 DSM resources may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs.

- **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 are also 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. Similar to Class 3 DSM resources, the impacts of Class 4 DSM programs may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. 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.

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 expanded to new heights in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1 through 4) and resource planning considerations. Work continues on the expansion of cost-effective 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.

For a summary of current DSM program offerings in each state, refer to Volume II, Appendix D (Demand-Side Management Resources).

Table 5.12 below summarizes the Company's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental Class 2 DSM is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing Class 2 DSM in Table 5.12 is shown as having zero MW.[2]

Table 5.12 – Existing DSM Resource Summary

Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2017-2036 Period
1	Residential/small commercial air conditioner load control	122 MW summer peak	Yes.
	Irrigation load management	204 MW summer peak[1/]	Yes.
	Interruptible contracts	195 MW Year-round availability	Yes.
2	PacifiCorp and Energy Trust of Oregon programs	0 MW[2/]	No. Class 2 DSM programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
3	Time-based pricing	98 MW summer peak	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	55-149 GWh (capacity impacts are unavailable due to lack of information on end use loads being saved	No. Historical savings from customer response to pricing structure is reflected in load forecast.
4	Energy education	Energy and capacity impacts are not available/measured	No. Historical savings from customer participation are reflected in the load forecast.

[1/] Assumes six percent for planning reserves in addition to realized irrigation load curtailment in Idaho and Utah of 170 MW and 20 MW, respectively, with an additional 3 MW from the Oregon pilot through 2020.
[2/] Due to the timing of the 2017 IRP load forecast, there is a small amount (100 MW) of existing Class 2 DSM in Table 5.14 (System Capacity Loads and Resources without Resource Additions).

Private Generation

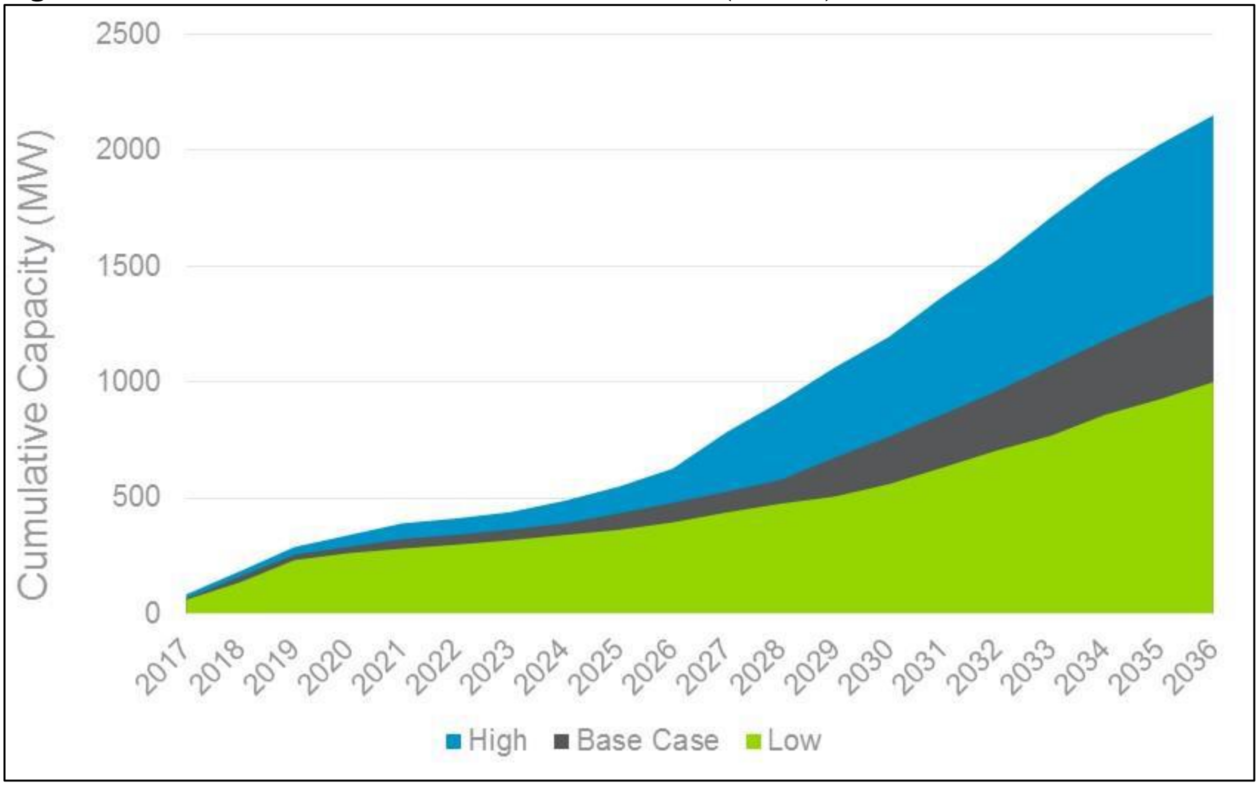
For the 2017 IRP, PacifiCorp contracted with Navigant Consulting Inc. (Navigant) to update the assessment of private generation penetration performed for the 2015 IRP with new market and incentive developments. Deliverables included: (1) technical potential; (2) market potential; and (3) levelized cost of energy for each private generation resource in each of the six states served by the Company. Specific technologies studied included solar photovoltaic, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

Navigant estimates approximately 1.4 GW of cumulative private generation capacity will be installed in PacifiCorp's territory from 2017-2036 in the base case scenario.[3] As shown in Figure 5.1, the low and high scenarios project a cumulative installed capacity of 1.00 GW and 2.10 GW by 2036, respectively. The main drivers between the different scenarios include variation in

[2] The historical effects of previous Class 2 DSM savings are backed out of the load forecast before the modeling for new Class 2 DSM.
[3] The complete Navigant Study is available in Volume II, Appendix O (Private Generation Study).

technology costs, system performance, and electricity rate assumptions. As in the 2015 IRP, the Navigant study identifies expected levels of customer-sited private generation, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes.

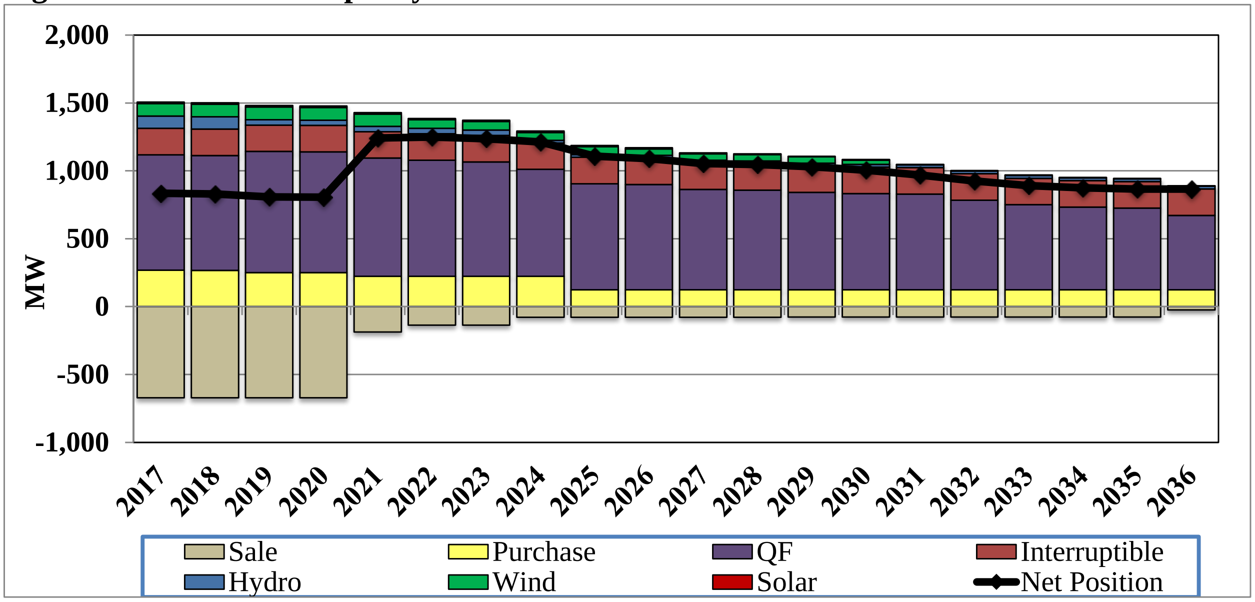
Figure 5.1 – Private Generation Market Penetration (MW_{AC}), 2017-2036



Power Purchase Contracts

PacifiCorp obtains the remainder of its capacity and energy requirements through long-term firm contracts, short-term firm contracts, and spot market purchases. Figure 5.2 presents the contract capacity in place for 2017 through 2036. As shown, major capacity reductions in purchases and hydro contracts occur. For planning purposes, PacifiCorp assumes that current purchases from small 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 5.2 – Contract Capacity in the 2017 Summer Load and Resource Balance



Load and Resource Balance

Capacity and Energy Balance Overview

The purpose of the load and resource balance is to compare annual obligations with the annual capability of PacifiCorp's existing resources, without new generating resource additions. This is done with 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 summer peak load hours. It is a key part of the load and resource balance because it helps guide the timing and severity of potential future resource need. It is developed by first reducing the hourly system load by hourly private generation projections to determine the net system coincident peak load for each of the first ten years (2017-2026) of the planning horizon. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are further netted from the peak load forecast to compute the annual peak-hour obligation. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. The annual resource deficit or surplus is then computed by multiplying the obligation by the target planning reserve margin (PRM) and then subtracting the result from existing resources, accounting for available FOTs.

The energy balance shows the average monthly on-peak and off-peak surplus or deficit of energy over the first ten years of the planning horizon (2017-2026). The average obligation (load less existing DSM programs, new DSM programs from the preferred portfolio, and projected private generation) is computed and subtracted from the average existing resource availability for each month and time-of-day period. The usefulness of the energy balance is limited because 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 during the resource portfolio development process described in Chapter 8 (Modeling and Portfolio Selection Results).

Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculations. The main component categories consist of the following: resources, obligation, reserves, position, and available FOTs.

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—thermal, hydroelectric, renewable, QFs, purchases, existing Class 1 DSM, sales, and non-owned reserves. Categories in the obligation section include load (net of private generation), interruptible contracts, existing Class 2 DSM, and new Class 2 DSM from the preferred portfolio.

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 summer or winter peak, as applicable. 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 coal-fueled units, six natural-gas-fueled plants, and one cogeneration unit. These thermal resources account for roughly two-thirds of the firm capacity available in the PacifiCorp system.

Hydroelectric
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 summer peak, an approach consistent with current Western Electric Coordinating Council (WECC) capacity reporting practices. The energy associated with stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. Also accounted for are energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation. Over 90 percent of the hydroelectric capacity is 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. The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. For purposes of the 2017 IRP, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability. PacifiCorp updated its capacity contribution values for solar and wind resources, differentiated by resource type and balancing authority area, which is presented in Volume II, Appendix N (Wind and Solar Capacity Contribution Study). The resulting capacity contribution values are shown in Table 5.13 below.

Table 5.13 Summer Peak Capacity Contribution Values for Wind and Solar

	East Balancing Authority Area			West Balancing Authority Area		
	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV
Capacity Contribution Percentage	15.8%	37.9%	59.7%	11.8%	53.9%	64.8%

Purchase

This includes all major purchases contracts for firm capacity and energy in the PacifiCorp system.[4] The capacity balance counts these by the maximum contract availability at time of system summer peak. The energy balance counts contracts at optimal economic model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

Qualifying Facilities (QF)

All QFs that provide capacity and energy are included in this category. Like other power purchases, the capacity balance counts them at maximum system summer peak availability and the energy balance counts them at optimal economic model dispatch.

Dispatchable Load Control (Class 1 DSM)

Existing dispatchable load control program capacity is categorized as an increase to resource capacity. This is in line with the treatment of DSM capacity in the latest version of the System Optimizer model that PacifiCorp uses to select resources.

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 summer peak and the energy balance counts them by expected model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

Non-owned Reserves

Non-owned reserve capacity is categorized as a decrease to resource capacity to represent the capacity required to provide reserves as a balancing are authority for load and generation that are in PacifiCorp's balancing authority area (BAA) but not owned by PacifiCorp's. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. The annual reserve obligation is about 3 MW and 38 MW on the west and east BAAs, respectively. The non-owned reserves do not contribute to the energy obligation because the requirement is for capacity only.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less private generation, existing Class 2 DSM, new Class 2 DSM from the preferred portfolio, and interruptible contracts. The following are descriptions of each of these components:

[4] PacifiCorp has curtailment contracts for approximately 172 MW on peak capacity that are treated as firm purchases. PacifiCorp has the right to curtail the customer's load as needed for economic purposes. The customer in turn may or may not pay market-based rates for energy used during a curtailment period.

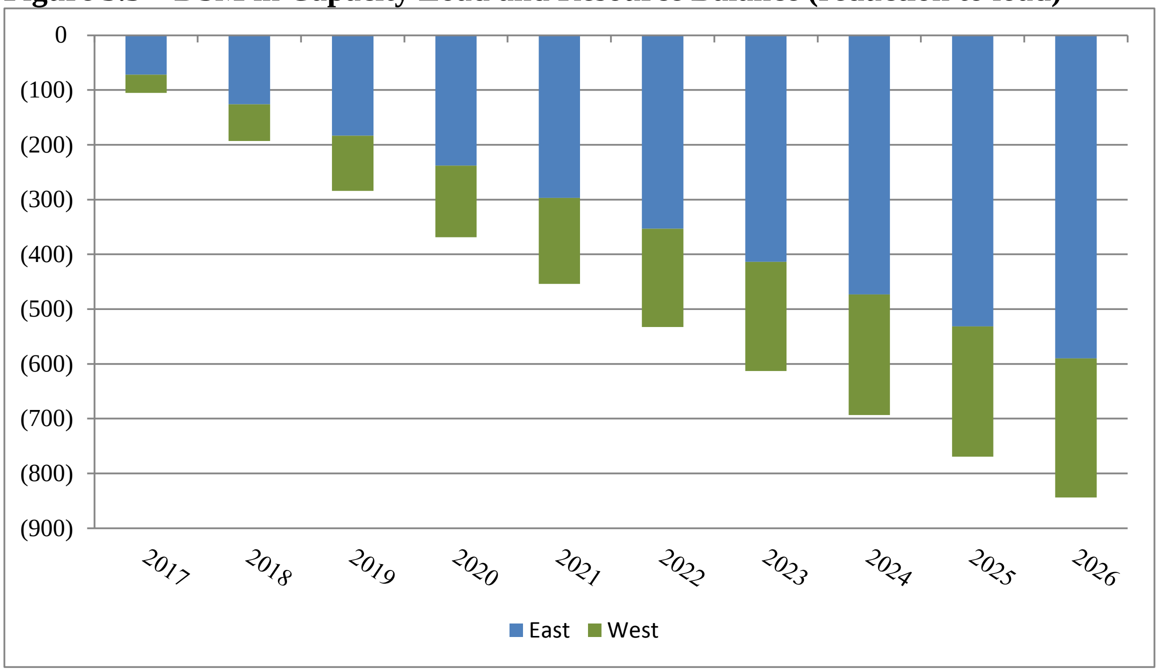
Load Net of Private Generation

The largest component of the obligation is retail load. In the 2017 IRP, the hourly retail load at a location is first reduced by hourly private generation at the same location. The system coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year. Loads reported by east and west balancing authority areas thus reflect loads at the time of PacifiCorp's coincident system summer peak. The energy balance counts the load on monthly basis by on-peak and off-peak hours. The net load is simply referred to as load in the context of load and resources balances and portfolio selection and evaluation.

Class 2 DSM

An adjustment is made to load to remove the projected embedded Class 2 DSM as a reduction to load. Due to timing issues with the vintage of the load forecast, there is a level of 2016 Class 2 DSM that is not incorporated in the forecast. The 2016 Class 2 DSM forecast (100 MW) has been accounted for by adding an existing Class 2 DSM resource in the load and resource balance. The DSM line also includes the selected Class 2 DSM from the 2017 IRP preferred portfolio.

Figure 5.3 – DSM in Capacity Load and Resource Balance (reduction to load)



Interruptible Contracts

PacifiCorp has interruptible contracts for approximately 195 MW of load interruption capability beginning in 2017. These contracts allow the use of 195 MW of capacity for meeting reserve requirements. 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 full planning reserves are not held for the load that may be curtailed. As with Class 1 DSM, this resource is categorized as a decrease to the peak load.

Planning Reserves
Planning reserves represent an incremental planning requirement, applied as an increase to the obligation to ensure that there will be sufficient capacity available on the system to manage uncertain events (i.e., weather, outages) and known requirements (i.e., operating reserves).

Position
The position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources. 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.

Capacity Balance Determination

Methodology
The capacity balance is developed by first determining the system coincident peak load 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 summer and winter peak periods, as applicable, and summed as follows:

> **Existing Resources** = Thermal + Hydro + Renewable + Firm Purchases + Qualifying Facilities + Existing Class 1 DSM – Firm Sales – Non-owned Reserves

The peak load, interruptible contracts, existing Class 2 DSM, and new Class 2 DSM from the preferred portfolio are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

> **Obligation** = Load – Interruptible Contracts – New and Existing Class 2 DSM

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 13 percent target planning reserve margin (PRM) adopted for the 2017 IRP. The formula for this calculation is:

> **Planning Reserves** = Obligation x PRM

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

> **Capacity Position** = (Existing Resources + Available FOTs) – (Obligation + Reserves)

Capacity Balance Results
Table 5.14 and Table 5.15 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target planning reserve margin of 13 percent to calculate the planning reserve amount. Balances for PacifiCorp's system as well as east and west BAAs are shown. While west and east BAA balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis. Also note that new QF wind and solar projects listed earlier in the chapter are reported under the QF line item rather than the renewables line item.

Table 5.14 – Summer Peak – System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East										
Thermal	6,406	6,406	6,126	6,126	5,739	5,739	5,739	5,739	5,735	5,645
Hydroelectric	103	106	113	113	113	113	113	92	92	92
Renewable	201	201	201	201	199	191	191	191	191	181
Purchase	249	249	249	249	221	221	221	221	121	121
Qualifying Facilities	656	646	689	681	672	661	657	603	598	594
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(652)	(652)	(652)	(652)	(172)	(172)	(172)	(146)	(146)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
East Existing Resources	**7,249**	**7,241**	**7,012**	**7,004**	**7,058**	**7,038**	**7,034**	**6,987**	**6,878**	**6,856**
Load	7,008	7,093	7,141	7,231	7,331	7,420	7,485	7,564	7,661	7,663
Private Generation	(33)	(51)	(72)	(80)	(86)	(91)	(94)	(98)	(104)	(112)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
DSM	(138)	(190)	(246)	(298)	(355)	(410)	(468)	(527)	(584)	(641)
East obligation	**6,643**	**6,657**	**6,629**	**6,657**	**6,695**	**6,725**	**6,728**	**6,744**	**6,779**	**6,714**
Planning Reserves (13%)	889	891	887	891	896	900	900	902	907	898
East Obligation + Reserves	**7,532**	**7,547**	**7,516**	**7,548**	**7,591**	**7,624**	**7,628**	**7,646**	**7,685**	**7,612**
East Position	**(283)**	**(306)**	**(504)**	**(544)**	**(533)**	**(586)**	**(594)**	**(659)**	**(807)**	**(756)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247
Hydroelectric	855	859	717	806	635	549	644	648	634	651
Renewable	93	93	93	93	93	62	62	57	57	56
Purchase	18	18	1	1	1	1	1	1	1	1
Qualifying Facilities	195	200	202	207	198	195	186	185	184	182
Class 1 DSM	3	3	3	3	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)	(80)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
West Existing Resources	**3,244**	**3,253**	**3,097**	**3,191**	**3,011**	**2,942**	**3,028**	**3,056**	**3,042**	**3,056**
Load	3,155	3,184	3,243	3,255	3,276	3,298	3,319	3,343	3,367	3,386
Private Generation	(1)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(5)	(6)
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(67)	(97)	(126)	(152)	(175)	(196)	(214)	(232)	(248)	(263)
West obligation	**3,087**	**3,086**	**3,115**	**3,101**	**3,098**	**3,099**	**3,101**	**3,106**	**3,114**	**3,117**
Planning Reserves (13%)	401	401	405	403	403	403	403	404	405	405
West Obligation + Reserves	**3,488**	**3,487**	**3,519**	**3,504**	**3,501**	**3,502**	**3,505**	**3,510**	**3,518**	**3,523**
West Position	**(245)**	**(235)**	**(423)**	**(313)**	**(489)**	**(560)**	**(477)**	**(454)**	**(476)**	**(467)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System										
Total Resources	10,493	10,494	10,109	10,194	10,069	9,980	10,062	10,043	9,920	9,912
Obligation	9,730	9,743	9,743	9,758	9,793	9,824	9,829	9,850	9,892	9,831
Reserves	1,290	1,292	1,292	1,294	1,298	1,302	1,303	1,306	1,311	1,303
Obligation + Reserves	11,020	11,035	11,035	11,052	11,092	11,126	11,132	11,156	11,203	11,135
System Position	(527)	(541)	(927)	(858)	(1,023)	(1,146)	(1,070)	(1,113)	(1,284)	(1,223)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**

[1/] The DSM line includes selected Class 2 DSM from the 2017 IRP preferred portfolio.

Table 5.15 – Winter Peak – System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East										
Thermal	6,514	6,514	6,234	6,234	5,847	5,847	5,847	5,847	5,843	5,753
Hydroelectric	71	72	72	72	72	72	72	72	72	72
Renewable	201	201	201	199	191	191	191	191	191	181
Purchase	734	734	734	734	235	235	235	121	121	121
Qualifying Facilities	647	688	680	676	668	658	604	600	595	591
Class 1 DSM	21	21	21	21	21	21	21	21	21	21
Sale	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(146)	(146)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
East Existing Resources	**7,981**	**8,023**	**7,735**	**7,729**	**6,826**	**6,816**	**6,762**	**6,670**	**6,661**	**6,640**
Load	5,550	5,617	5,686	5,597	5,770	5,847	5,923	5,956	5,919	5,924
Private Generation	(11)	(17)	(24)	(28)	(31)	(32)	(33)	(35)	(37)	(40)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class2 DSM	(92)	(132)	(173)	(213)	(256)	(297)	(340)	(383)	(425)	(469)
East obligation	**5,252**	**5,274**	**5,294**	**5,161**	**5,288**	**5,323**	**5,355**	**5,343**	**5,262**	**5,220**
Planning Reserves (13%)	708	711	714	696	713	717	721	720	709	704
East Obligation + Reserves	**5,961**	**5,985**	**6,007**	**5,857**	**6,001**	**6,040**	**6,076**	**6,063**	**5,971**	**5,924**
East Position	**2,020**	**2,039**	**1,728**	**1,872**	**826**	**776**	**686**	**607**	**689**	**716**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308
Hydroelectric	993	915	943	937	784	782	783	779	786	786
Renewable	93	93	93	93	93	62	62	57	56	55
Purchase	6	1	1	1	1	1	1	1	1	1
Qualifying Facilities	200	192	195	197	190	183	177	176	175	171
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(162)	(162)	(162)	(154)	(154)	(113)	(113)	(81)	(81)	(81)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
West Existing Resources	**3,436**	**3,345**	**3,377**	**3,381**	**3,221**	**3,221**	**3,215**	**3,238**	**3,244**	**3,238**
Load	3,264	3,290	3,305	3,416	3,359	3,378	3,399	3,416	3,540	3,557
Private Generation	(1)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(5)	(6)
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(74)	(109)	(143)	(174)	(201)	(225)	(246)	(267)	(286)	(304)
West obligation	**3,188**	**3,180**	**3,160**	**3,239**	**3,155**	**3,149**	**3,149**	**3,144**	**3,249**	**3,247**
Planning Reserves (13%)	414	413	411	421	410	409	409	409	422	422
West Obligation + Reserves	**3,603**	**3,593**	**3,571**	**3,661**	**3,565**	**3,559**	**3,558**	**3,553**	**3,671**	**3,670**
West Position	**(167)**	**(248)**	**(194)**	**(280)**	**(344)**	**(338)**	**(343)**	**(315)**	**(428)**	**(431)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System										
Total Resources	11,417	11,369	11,112	11,110	10,047	10,037	9,978	9,908	9,905	9,878
Obligation	8,441	8,453	8,453	8,400	8,443	8,472	8,503	8,487	8,511	8,467
Reserves	1,123	1,124	1,124	1,117	1,123	1,127	1,131	1,129	1,132	1,126
Obligation + Reserves	9,564	9,578	9,578	9,518	9,566	9,599	9,634	9,616	9,643	9,593
System Position	1,854	1,791	1,534	1,592	481	438	344	292	262	285
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**

[1/] The DSM line includes selected Class 2 DSM from the 2017 IRP preferred portfolio.

Figure 5.4 through Figure 5.7 are graphic representations of the above tables for annual capacity position for the summer system, winter system, east BAA, and west BAA. Also shown in the system capacity position graph are available FOTs, which can be used to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 6 (Resource Options) and Volume II, Appendix J (Western Resource Adequacy Evaluation).

Figure 5.4 – Summer System Capacity Position Trend

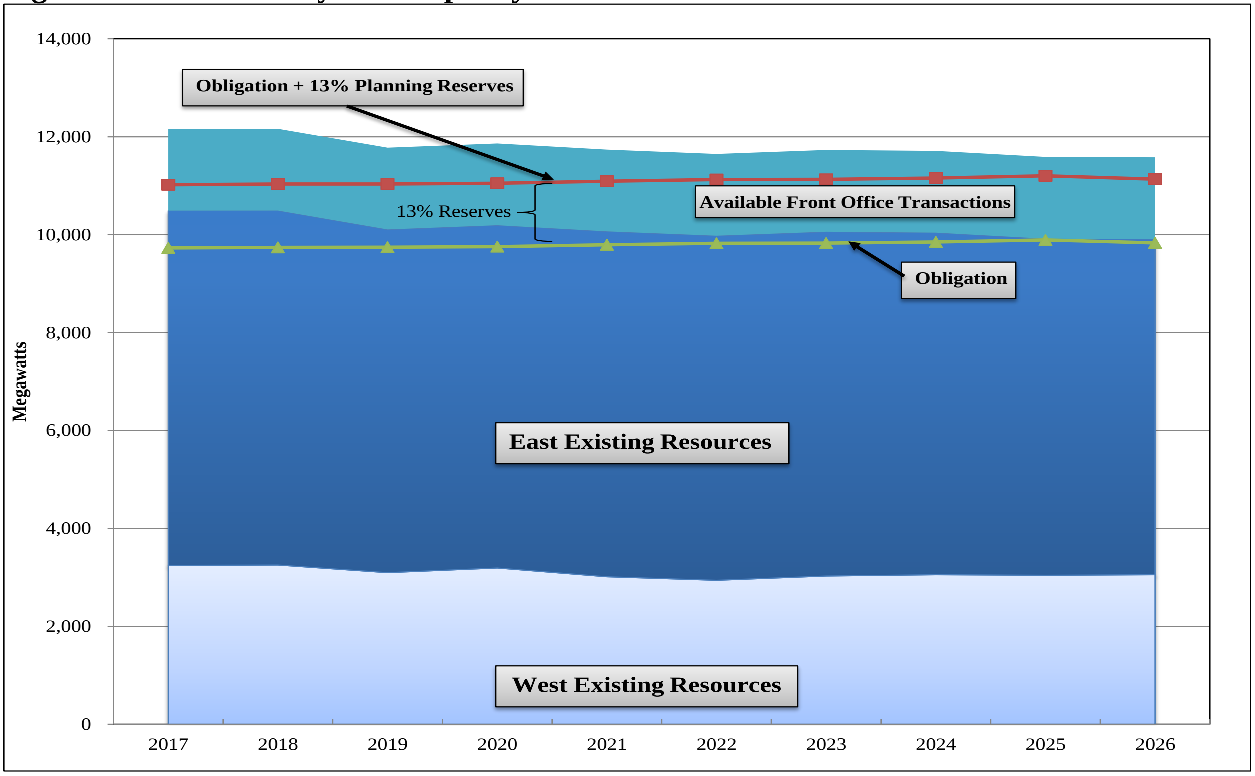


Figure 5.5 – Winter System Capacity Position Trend

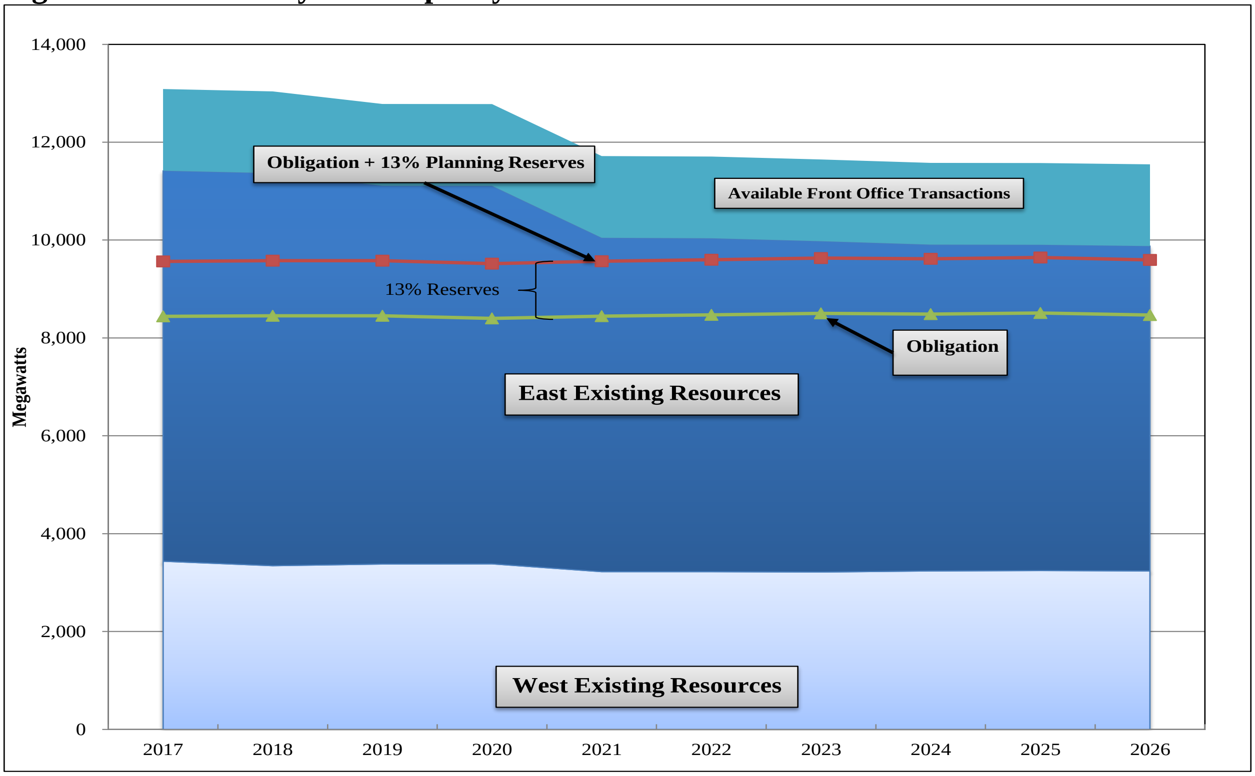


Figure 5.6 – East Summer Capacity Position Trend

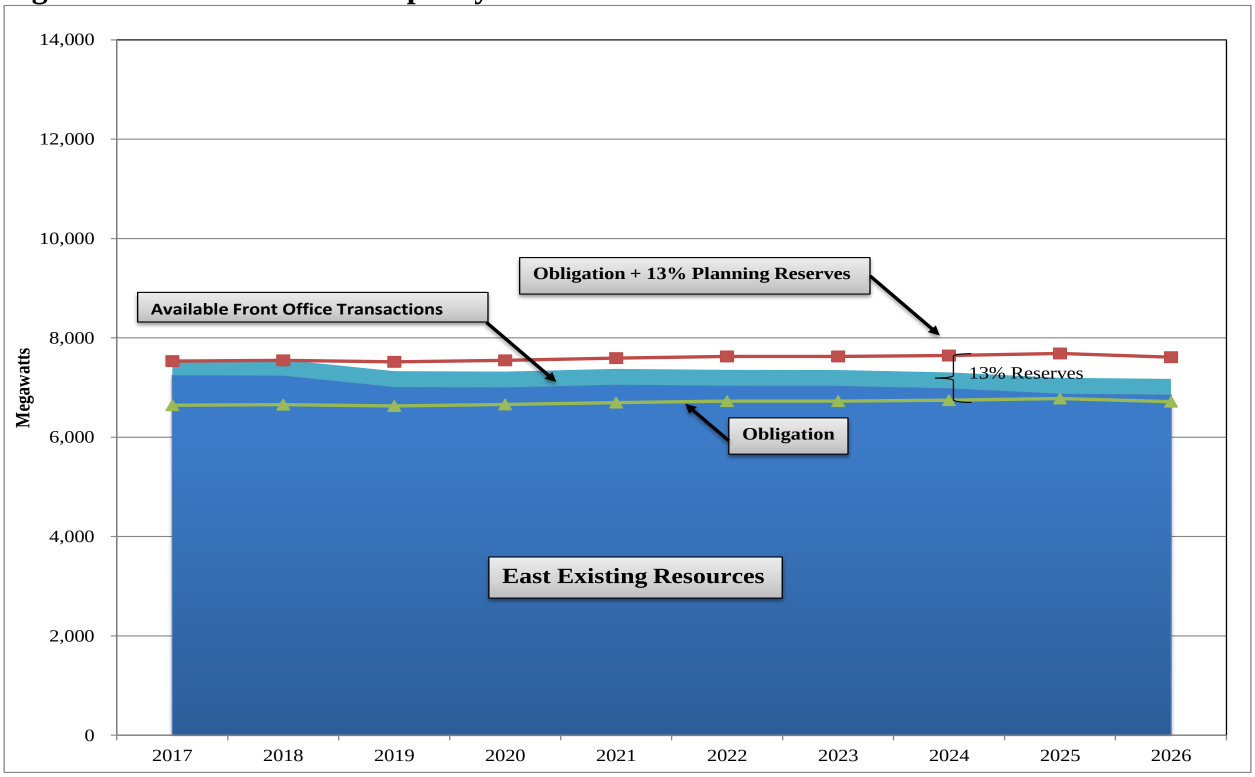
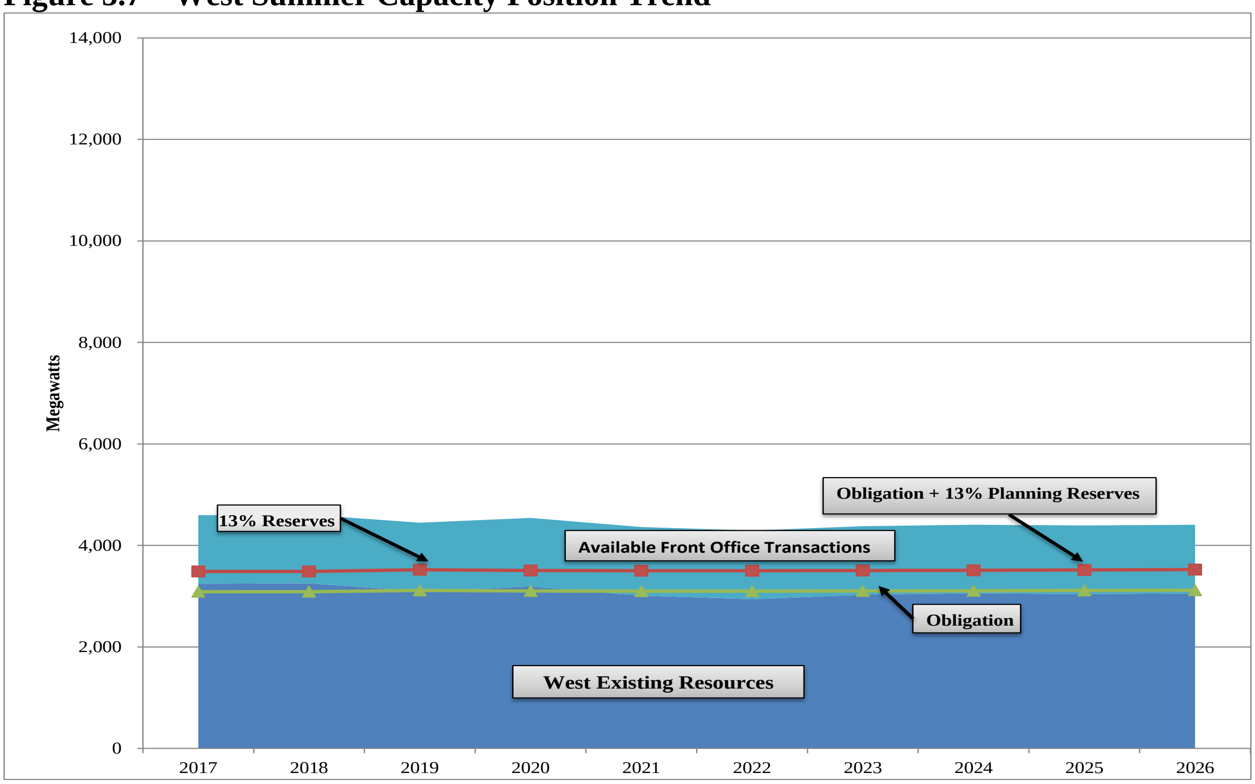


Figure 5.7 – West Summer Capacity Position Trend



Energy Balance Determination

Methodology
The energy balance shows the 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. This is calculated using the formulas that follow. Please refer to the section on load and resource balance components for details on how energy for each component is counted.

> **Existing Resources** = Thermal + Hydro + Existing Class 1 DSM + Renewable + Firm Purchases + QF + Interruptible Contracts – Sales

The average obligation is computed using the following formula:

> **Obligation** = Load + Firm Sales

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

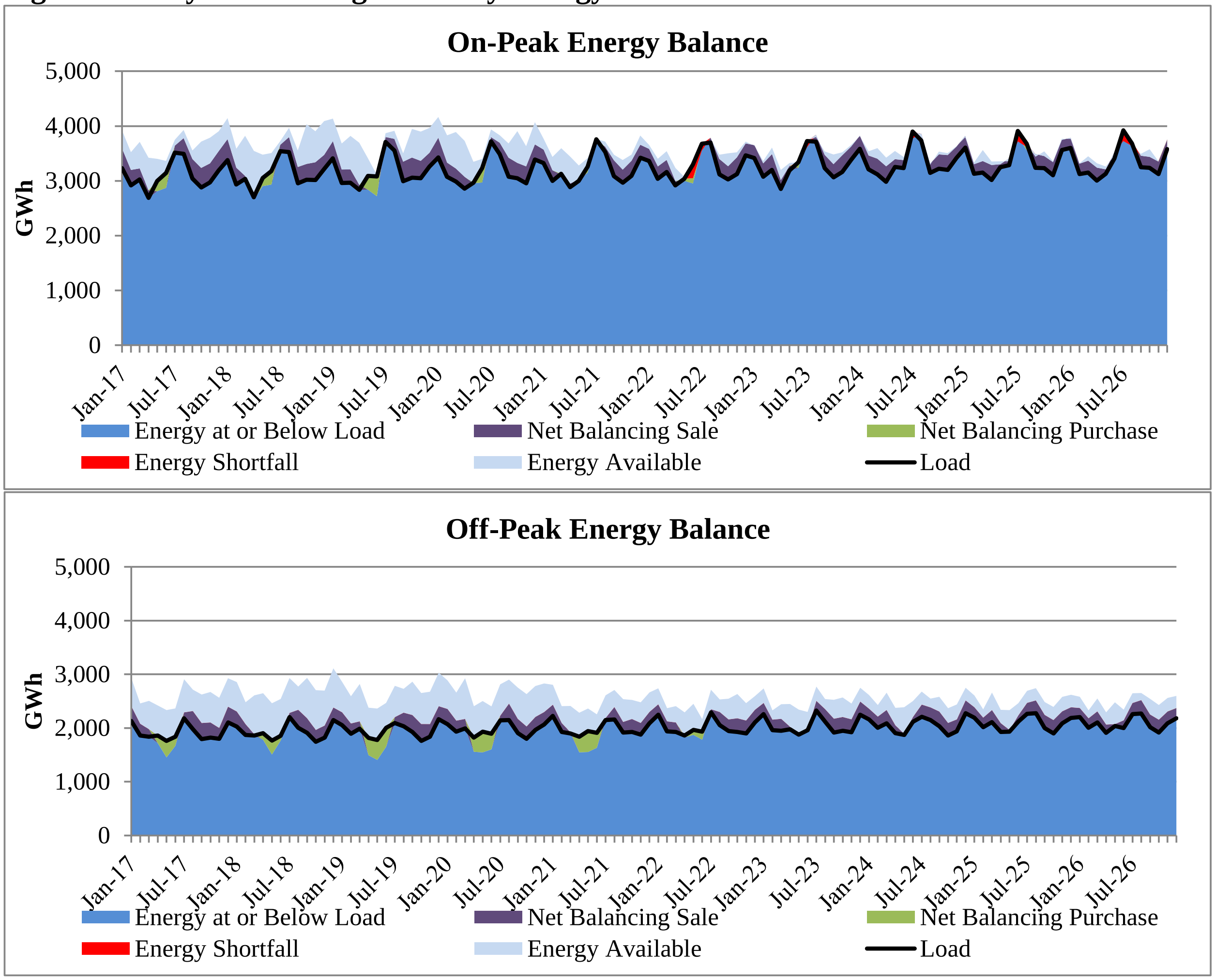
> **Energy Position** = Existing Resources – Obligation – Operating Reserve Requirements

Energy Balance Results

The capacity position shows how existing resources and loads, accounting for coal unit retirements and incremental energy efficiency savings from the preferred portfolio, balance during the coincident peak summer and winter. Outside of these peak periods, PacifiCorp economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when variable costs of the system resources are less than the prevailing market price for power, PacifiCorp 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 PacifiCorp manages net power costs.

Figure 5.8 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given the assumptions about resource availability and wholesale power and natural gas prices. At times, resources are economically dispatched above load levels facilitating net system balancing sales. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 5.8 also shows 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 indicate short energy positions without the addition of incremental resources to the portfolio. During on-peak periods, the first energy shortfall appears in summer 2022, and continuers in the subsequent years. During off-peak periods, there are no energy shortfalls through the 2026 timeframe.

Figure 5.8 – System Average Monthly Energy Positions



CHAPTER 6 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, public input meeting comments and third party studies.
- Generally, resource costs have remained stable since the 2015 IRP and any cost increases have been modest. Renewable resource costs in particular, have continued to fall.
- As with the 2015 IRP both large utility scale solar photovoltaic options and geothermal purchase power agreements (PPAs) have been included as supply-side options in the 2017 IRP and updated to reflect current conditions.
- The number of combustion turbine types and configurations has been slightly modified to reflect different siting locations and are identified in the Supply Side Resource options table.
- Energy storage systems continue to be of interest to PacifiCorp stakeholders. Options for advanced large batteries (one megawatt), pumped hydro and compressed air energy storage are included in the 2017 IRP.
- A Demand-Side Resource Potential Assessment for 2017-2036, conducted by Applied Energy Group, served as the basis for updated resource characterizations covering demand-side management (DSM) resources. The demand-side resource information was converted into supply curves by resource type and competes 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 allowed by the Northwest Power Act.
- Transmission integration costs and transmission reinforcement costs are based on the timing and location of resource selection.

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 utility-scale supply-side generation, 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 various 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. Renewable resources, particularly solar and wind resource options, have been reviewed and updated to capture recent trends in cost and performance. Solar resource options include utility-size photovoltaic systems (PV) with both fixed and single axis tracking. A variety of gas-fueled generating resources were selected after consultation with major suppliers and large engineering-consulting firms. Stakeholder feedback and industry journals also influenced the selection of resources. 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 decreasing cost trend. 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 and compressed air energy storage projects. Additionally, in response to stakeholder requests, multiple different battery energy storage configurations were also evaluated. New coal-fueled resources received minimal focus during this cycle due to ongoing environmental, economic, permitting and sociopolitical obstacles for siting new coal-fueled generation.

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 2015 IRP. This resource list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. 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 (2016) third-party, cost and performance estimates;
- Prior third-party, cost and performance studies or updated earlier estimates;
- Publicly available cost and performance 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 2016 Black & Veatch estimates prepared for simple cycle and combined cycle options. For this IRP cycle, the energy storage effort was performed by two different consultants. The bulk energy storage portion of the 2014 HDR Engineering (HDR) that focused on pumped storage and compressed air energy storage was updated by Black & Veatch. The battery energy storage part of the 2014 HDR study was updated by DNV-GL.

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 2015 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 used to develop the cost and performance information provided in the Supply Side Resource table include O&M costs for the Company's Gadsby GE LM6000PC peaking units and the Lake Side 2 combined cycle plant.

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 obtaining updated equipment pricing for wind turbine equipment from original equipment suppliers and reviews of capital costs prepared by engineering firms by engineer-procure-construct firms.

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for some generation technologies 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 2015 IRP and the 2017 IRP has not changed significantly. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices over the period from October 2015 through September 2016. Similar information was presented in the 2015 IRP and is shown in Figure 6.2. These figures illustrate near term changes in capital costs of generation resources.

Figure 6.1 - World Carbon Steel Pricing by Type

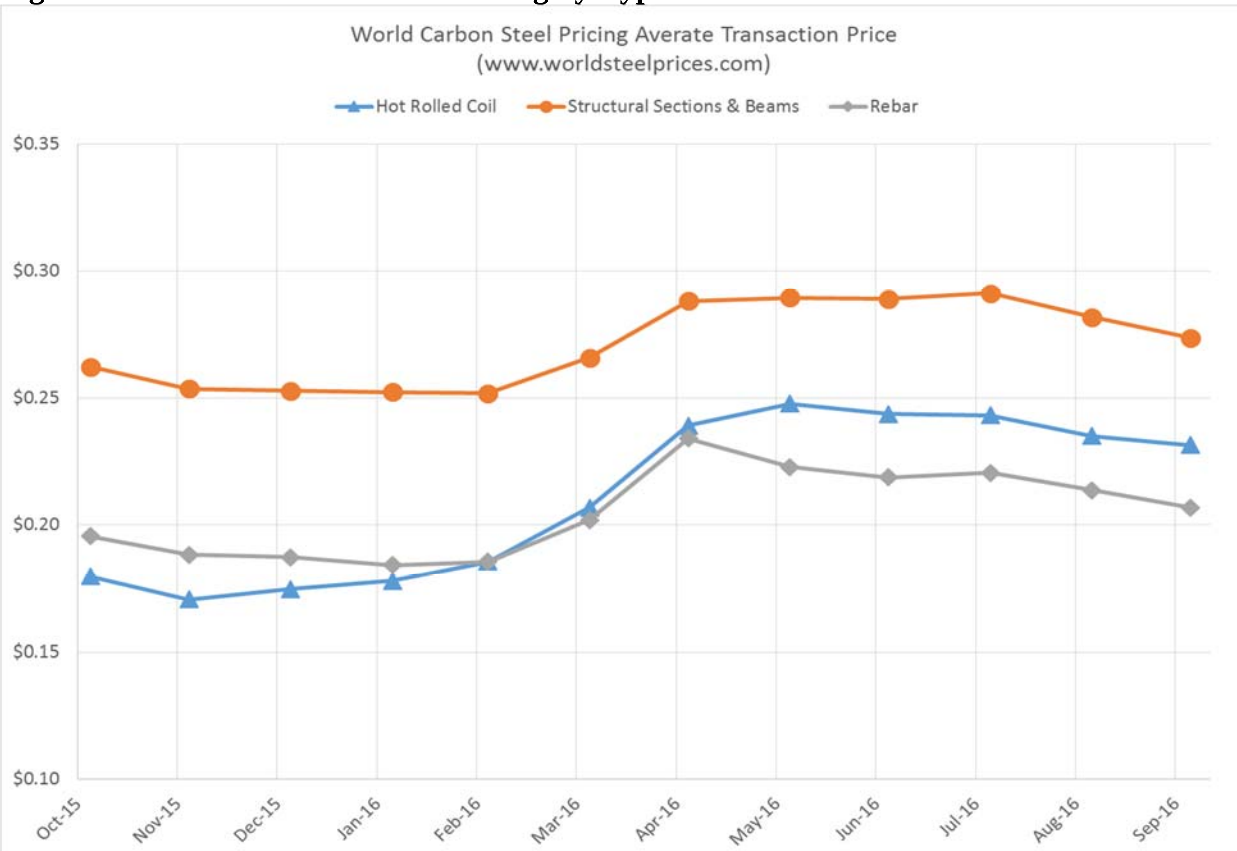
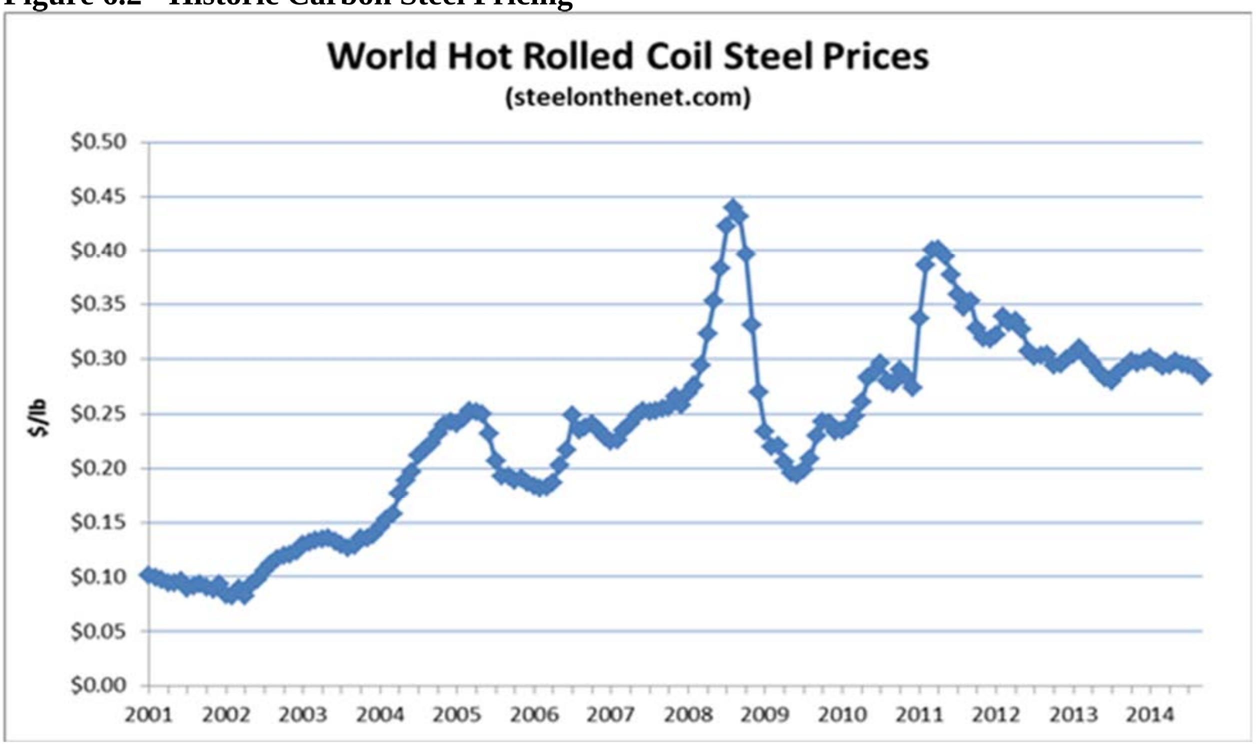


Figure 6.2 - Historic Carbon Steel Pricing



Prices for solar photovoltaic (PV) panels as well as balance of plant costs have fallen since the 2015 IRP. Real prices are projected to flatten out for the next several years given large demand to meet the 30 percent federal ITC deadline at the end of 2016 and recently announced panel tariffs on certain Chinese imports, 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 2015 IRP. Long-term (10+ years) pricing for this equipment remains challenging to forecast.

Some generation technologies, such as integrated gasification combined cycle (IGCC), have shown significant cost uncertainty because only a few units have been built and operated. Recent experience with the significant cost overruns on IGCC projects such as Southern Company's Kemper County IGCC plant illustrate the difficulty in accurately estimating capital costs of these emerging 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 option 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, PacifiCorp 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 lists the cost and performance attributes for supply-side resource options designated by generic, elevation-specific regions where resources could potentially be located:

- ISO conditions (sea level and 59 degrees F); this is used as a reference for certain modeling purposes.
- 1,500 feet elevation: eastern Oregon/Washington.
- 3,000 feet elevation: southern/central Oregon
- 4,500 feet elevation: northern Utah, specifically Salt Lake/Utah/Tooele/Box Elder counties
- 5,050 feet elevation: central Utah, southern Idaho, central Wyoming.
- 6,500 feet 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 2016 dollars. Similar to the approach taken for the 2015 IRP, it is not currently envisioned that new combined cycle resources could be economically permitted in northern Utah, specifically Salt Lake/Utah/Davis/Box Elder counties due to state implementation plans for these counties regarding particulate matter of 2.5 microns and less ($PM_{2.5}$).

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 – 2017 Supply Side Resource Table (2016$)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	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 Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Natural Gas	SCCT Aero x3, ISO	0	142	2021	30	1,421	7.54	27.14	9204	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2, ISO	0	221	2021	30	1,036	5.05	18.78	8981	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1, ISO	0	240	2021	35	584	5.50	13.28	9604	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6, ISO	0	111	2021	35	1,572	7.45	29.82	8279	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1, ISO	0	407	2022	40	1,405	1.76	20.52	6363	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO	0	51	2022	40	443	0.15	5.39	8865	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1, ISO	0	816	2023	40	1,043	1.67	13.79	6352	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO	0	102	2023	40	348	0.16	4.44	8812	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1, ISO	0	498	2022	40	1,226	1.70	17.66	6317	2.5	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1, ISO	0	63	2022	40	378	0.16	4.86	8878	0.8	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1, ISO	0	998	2023	40	913	1.62	12.00	6308	2.5	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1, ISO	0	126	2023	40	302	0.16	4.05	8830	0.8	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	1,500	138	2021	30	1,464	7.76	27.96	9169	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	1,500	208	2021	30	1,097	5.35	19.88	9000	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	1,500	228	2021	35	616	5.81	14.02	9604	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	1,500	111	2021	35	1,572	7.45	29.82	8279	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	1,500	385	2022	40	1,484	1.86	21.68	6362	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	1,500	51	2022	40	443	0.15	5.39	9012	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	1,500	772	2023	40	1,102	1.77	14.57	6353	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	1,500	102	2023	40	348	0.16	4.44	8969	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	1,500	471	2022	40	1,297	1.80	18.67	6317	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	1,500	63	2022	40	378	0.16	4.86	9035	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	1,500	944	2023	40	965	1.71	12.69	6304	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	1,500	126	2023	40	302	0.16	4.05	8906	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	3,000	130	2021	30	1,548	8.21	29.58	9183	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	3,000	196	2021	30	1,164	5.67	21.10	9016	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	3,000	216	2021	35	651	6.13	14.81	9611	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	3,000	111	2021	35	1,572	7.45	29.82	8279	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	3,000	365	2022	40	1,569	1.97	22.92	6366	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	3,000	51	2022	40	443	0.15	5.39	9055	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	3,000	731	2023	40	1,164	1.86	15.39	6352	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	3,000	102	2023	40	348	0.16	4.44	9012	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	3,000	446	2022	40	1,370	1.90	19.73	6321	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	3,000	63	2022	40	378	0.16	4.86	9087	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	3,000	893	2023	40	1,020	1.81	13.41	6308	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	3,000	126	2023	40	302	0.16	4.05	9039	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	5,050	121	2021	30	1,668	8.85	31.86	9189	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	5,050	182	2021	30	1,259	6.14	22.82	9032	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	5,050	200	2021	35	702	6.61	15.97	9614	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	5,050	111	2021	35	1,572	7.45	29.82	8286	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	5,050	338	2022	40	1,693	2.12	24.74	6374	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	5,050	51	2022	40	443	0.15	5.39	9172	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	5,050	677	2023	40	1,257	2.01	16.63	6365	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	5,050	102	2023	40	348	0.16	4.44	9141	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	5,050	414	2022	40	1,477	2.05	21.26	6326	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	5,050	63	2022	40	378	0.16	4.86	9211	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	5,050	828	2023	40	1,100	1.95	14.45	6317	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	5,050	126	2023	40	302	0.16	4.05	9158	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	6,500	111	2021	30	1,809	9.60	34.56	9195	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	6,500	173	2021	30	1,324	6.45	24.00	9003	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	6,500	190	2021	35	739	6.96	16.81	9605	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	6,500	106	2021	35	1,637	7.75	31.04	8377	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	6,500	319	2022	40	1,793	2.25	26.20	6395	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	6,500	51	2022	40	443	0.15	5.39	9524	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	6,500	639	2023	40	1,332	2.13	17.61	6385	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	6,500	102	2023	40	348	0.16	4.44	9461	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	6,500	394	2022	40	1,551	2.15	22.33	6336	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	6,500	63	2022	40	378	0.16	4.86	9524	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	6,500	789	2023	40	1,155	2.05	15.18	6327	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	6,500	126	2023	40	302	0.16	4.06	9469	0.8	3.8	11	0.0006	0.0072	0.255	117

Table 6.1 – 2017 Supply Side Resource Table (2016$) (Continued)*

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	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 Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Coal	SCPC with CCS	4,500	526	2034	40	6,078	6.71	69.22	13087	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	IGCC with CCS	4,500	466	2034	40	5,884	11.28	55.78	10823	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW	4,500	-139	2031	20	1,334	6.20	74.52	14372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Coal	SCPC with CCS	6,500	692	2034	40	6,883	7.26	64.29	13242	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	IGCC with CCS	6,500	456	2034	40	6,663	13.52	60.76	11047	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW	6,500	-139	2031	20	1,511	6.71	69.22	14372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Geothermal	Blundell Dual Flash 90% CF	4,500	35	2021	40	6,131	1.12	100.51	n/a	5.0	5.0	10	n/a	n/a	n/a	n/a
Geothermal	Greenfield Binary 90% CF	4,500	43	2023	40	6,793	1.12	100.51	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Geothermal	Generic Geothermal PPA 90% CF	4,500	30	2021	20	0	77.34	0.00	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 38% CF WA	1,500	100	2022	30	1,800	0.00	36.45	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 38% CF OR	1,500	100	2022	30	1,774	0.00	36.45	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 38% CF ID	4,500	100	2022	30	1,811	0.00	36.45	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 31% CF UT	4,500	100	2022	30	1,735	0.00	36.45	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.3 MW turbine 43% CF WY	6,500	100	2022	30	1,737	0.65	36.45	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT	4,500	50.0	2019	25	1,724	0.00	18.45	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT	4,500	50.0	2019	25	1,822	0.00	19.41	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR	4,800	50.0	2019	25	1,762	0.00	18.47	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR	4,800	50.0	2019	25	1,857	0.00	19.44	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	CSP Trough w Natural Gas	4,500	100	2022	30	6,448	0.00	68.46	11750	Included with CF	0	725	n/a	n/a	n/a	n/a
Solar	CSP Tower 24% CF	4,500	100	2022	30	6,141	0.00	68.46	n/a	Included with CF	0	725	n/a	n/a	n/a	n/a
Solar	CSP Tower Molten Salt 30% CF	4,500	100	2022	30	7,367	0.00	68.46	n/a	Included with CF	0	750	n/a	n/a	n/a	n/a
Biomass	Forestry Byproduct	1,500	5	2022	30	4,383	0.99	42.04	0	0	0	0	0.1	0.2	0.4	205
Storage	Pumped Storage 1 (3,800 MWh)	4,457	393	2022	50	3,468	0.00	21.10	77%	3	5.8	0	0	0	0	0
Storage	Pumped Storage 2 (12,000 MWh)	580	1,200	2022	50	3,601	0.00	15.58	77%	3	5.8	0	0	0	0	0
Storage	Pumped Storage 3 (7,000 MWh)	6,359	700	2017	50	2,861	0.00	16.86	77%	3	5.8	0	0	0	0	0
Storage	CAES (15,360 MWh)	4,640	320	2021	30	2,138	0.77	18.90	4,227	3	1.5	0	0.001	0.009	0	117
Nuclear	Advanced Fission	5,000	2,234	2025	40	6,524	11.37	98.35	10,710	7.7	7.3	96	0	0	0	0
Nuclear	Small Modular Reactor x 12	5,000	570	2031	40	9,676	15.00	167.77	10,710	7.7	7.3	65	0	0	0	0

* Note, capital cost and capacity factor data shown for Wyoming wind do not reflect adjustments made to these assumptions during the portfolio selection process (outlined in Volume I, Chapter 8 (Modeling and Portfolio Selection Results), This updated assessment, based on the most current market information, focused on projects that could achieve on-line dates by the end of 2020.

Table 6.2 - Total Resource Cost for Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3, ISO	0	$1,421	7.871%	$111.81	27.14	1.331%	0.36	32.97	60.47	$172.28
Intercooled SCCT Aero x2, ISO	0	$1,036	7.871%	$81.57	18.78	1.198%	0.22	32.17	51.17	$132.74
SCCT Frame "F" x1, ISO	0	$584	7.373%	$43.04	13.28	0.287%	0.04	34.40	47.72	$90.76
IC Recips x 6, ISO	0	$1,572	7.871%	$123.77	29.82	0.143%	0.04	29.66	59.52	$183.29
CCCT Dry "G/H", 1x1, ISO	0	$1,405	7.256%	$101.94	20.52	0.153%	0.03	22.79	43.34	$145.29
CCCT Dry "G/H", DF, 1x1, ISO	0	$443	7.256%	$32.15	5.39	0.000%	0.00	31.75	37.14	$69.29
CCCT Dry "G/H", 2x1, ISO	0	$1,043	7.256%	$75.68	13.79	0.153%	0.02	22.75	36.56	$112.25
CCCT Dry "G/H", DF, 2x1, ISO	0	$348	7.256%	$25.26	4.44	0.000%	0.00	31.56	36.00	$61.26
CCCT Dry "J/HA.02", 1x1, ISO	0	$1,226	7.256%	$88.98	17.66	0.153%	0.03	22.63	40.31	$129.29
CCCT Dry "J/HA.02", DF, 1x1, ISO	0	$378	7.256%	$27.44	4.86	0.000%	0.00	31.80	36.66	$64.10
CCCT Dry, "J/HA.02" 2X1, ISO	0	$913	7.256%	$66.25	12.00	0.153%	0.02	22.60	34.61	$100.87
CCCT Dry "J/HA.02", DF, 2X1, ISO	0	$302	7.256%	$21.89	4.05	0.000%	0.00	31.63	35.68	$57.56
SCCT Aero x3	1,500	$1,464	7.871%	$115.20	27.96	1.331%	0.37	32.84	61.18	$176.37
Intercooled SCCT Aero x2	1,500	$1,097	7.871%	$86.35	19.88	1.198%	0.24	32.24	52.36	$138.71
SCCT Frame "F" x1	1,500	$616	7.373%	$45.43	14.02	0.287%	0.04	34.40	48.46	$93.89
IC Recips x 6	1,500	$1,572	7.871%	$123.77	29.82	0.143%	0.04	29.66	59.52	$183.29
CCCT Dry "G/H", 1x1	1,500	$1,484	7.256%	$107.71	21.68	0.153%	0.03	22.79	44.50	$152.21
CCCT Dry "G/H", DF, 1x1	1,500	$443	7.256%	$32.15	5.39	0.000%	0.00	32.28	37.67	$69.82
CCCT Dry "G/H", 2x1	1,500	$1,102	7.256%	$79.98	14.57	0.153%	0.02	22.76	37.35	$117.33
CCCT Dry "G/H", DF, 2x1	1,500	$348	7.256%	$25.26	4.44	0.000%	0.00	32.13	36.57	$61.82
CCCT Dry "J/HA.02", 1x1	1,500	$1,297	7.256%	$94.09	18.67	0.153%	0.03	22.63	41.33	$135.42
CCCT Dry "J/HA.02", DF, 1x1	1,500	$378	7.256%	$27.44	4.86	0.000%	0.00	32.36	37.22	$64.66
CCCT Dry, "J/HA.02" 2X1	1,500	$965	7.256%	$70.04	12.69	0.153%	0.02	22.58	35.29	$105.33
CCCT Dry "J/HA.02", DF, 2X1	1,500	$302	7.256%	$21.88	4.05	0.000%	0.00	31.90	35.95	$57.83
SCCT Aero x3	3,000	$1,548	7.871%	$121.86	29.58	1.331%	0.39	16.85	46.82	$168.68
Intercooled SCCT Aero x2	3,000	$1,164	7.871%	$91.63	21.10	1.198%	0.25	16.54	37.89	$129.53
SCCT Frame "F" x1	3,000	$651	7.373%	$47.97	14.81	0.287%	0.04	17.63	32.49	$80.45
IC Recips x 6	3,000	$1,572	7.871%	$123.77	29.82	0.143%	0.04	15.19	45.05	$168.82
CCCT Dry "G/H", 1x1	3,000	$1,569	7.256%	$113.86	22.92	0.153%	0.04	11.68	34.63	$148.49
CCCT Dry "G/H", DF, 1x1	3,000	$443	7.256%	$32.15	5.39	0.000%	0.00	16.61	22.00	$54.15
CCCT Dry "G/H", 2x1	3,000	$1,164	7.256%	$84.48	15.39	0.153%	0.02	11.65	27.07	$111.55
CCCT Dry "G/H", DF, 2x1	3,000	$348	7.256%	$25.27	4.44	0.000%	0.00	16.53	20.97	$46.24
CCCT Dry "J/HA.02", 1x1	3,000	$1,370	7.256%	$99.45	19.73	0.153%	0.03	11.60	31.36	$130.80
CCCT Dry "J/HA.02", DF, 1x1	3,000	$378	7.256%	$27.44	4.86	0.000%	0.00	16.67	21.53	$48.97
CCCT Dry, "J/HA.02" 2X1	3,000	$1,020	7.256%	$74.02	13.41	0.153%	0.02	11.57	25.00	$99.03
CCCT Dry "J/HA.02", DF, 2X1	3,000	$302	7.256%	$21.88	4.05	0.000%	0.00	16.58	20.63	$42.52

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3	5,050	$1,668	7.871%	$131.28	31.86	1.331%	0.42	13.99	46.28	$177.56
Intercooled SCCT Aero x2	5,050	$1,259	7.871%	$99.10	22.82	1.198%	0.27	13.76	36.85	$135.95
SCCT Frame "F" x1	5,050	$702	7.373%	$51.73	15.97	0.287%	0.05	14.64	30.66	$82.38
IC Recips x 6	5,050	$1,572	7.871%	$123.77	29.82	0.143%	0.04	12.62	42.48	$166.25
CCCT Dry "G/H", 1x1	5,050	$1,693	7.256%	$122.87	24.74	0.153%	0.04	9.71	34.48	$157.36
CCCT Dry "G/H", DF, 1x1	5,050	$443	7.256%	$32.14	5.39	0.000%	0.00	13.97	19.36	$51.49
CCCT Dry "G/H", 2x1	5,050	$1,257	7.256%	$91.24	16.63	0.153%	0.03	9.69	26.35	$117.59
CCCT Dry "G/H", DF, 2x1	5,050	$348	7.256%	$25.25	4.44	0.000%	0.00	13.92	18.36	$43.62
CCCT Dry "J/HA.02", 1x1	5,050	$1,477	7.256%	$107.15	21.26	0.153%	0.03	9.63	30.93	$138.08
CCCT Dry "J/HA.02", DF, 1x1	5,050	$378	7.256%	$27.43	4.86	0.000%	0.00	14.03	18.89	$46.32
CCCT Dry, "J/HA.02" 2X1	5,050	$1,100	7.256%	$79.80	14.45	0.153%	0.02	9.62	24.09	$103.89
CCCT Dry "J/HA.02", DF, 2X1	5,050	$302	7.256%	$21.88	4.05	0.000%	0.00	13.95	18.00	$39.88
SCCT Aero x3	6,500	$1,809	7.871%	$142.42	34.56	1.331%	0.46	9.11	44.13	$186.55
Intercooled SCCT Aero x2	6,500	$1,324	7.871%	$104.23	24.00	1.198%	0.29	8.92	33.21	$137.44
SCCT Frame "F" x1	6,500	$739	7.373%	$54.47	16.81	0.287%	0.05	9.52	26.38	$80.85
IC Recips x 6	6,500	$1,637	7.871%	$128.85	31.04	0.143%	0.04	8.30	39.39	$168.24
CCCT Dry "G/H", 1x1	6,500	$1,793	7.256%	$130.14	26.20	0.153%	0.04	6.34	32.58	$162.71
CCCT Dry "G/H", DF, 1x1	6,500	$443	7.256%	$32.14	5.39	0.000%	0.00	9.44	14.83	$46.97
CCCT Dry "G/H", 2x1	6,500	$1,332	7.256%	$96.63	17.61	0.153%	0.03	6.33	23.96	$120.59
CCCT Dry "G/H", DF, 2x1	6,500	$348	7.256%	$25.25	4.44	0.000%	0.00	9.38	13.82	$39.07
CCCT Dry "J/HA.02", 1x1	6,500	$1,551	7.256%	$112.54	22.33	0.153%	0.03	6.28	28.64	$141.18
CCCT Dry "J/HA.02", DF, 1x1	6,500	$378	7.256%	$27.43	4.86	0.000%	0.00	9.44	14.30	$41.73
CCCT Dry, "J/HA.02" 2X1	6,500	$1,155	7.256%	$83.81	15.18	0.153%	0.02	6.27	21.47	$105.29
CCCT Dry "J/HA.02", DF, 2X1	6,500	$302	7.256%	$21.90	4.06	0.000%	0.00	9.38	13.44	$35.34
SCPC with CCS	4,500	$6,078	7.157%	$434.98	69.22	0.000%	0.00	0.00	69.22	$504.20
IGCC with CCS	4,500	$5,884	6.853%	$403.29	55.78	0.000%	0.00	0.00	55.78	$459.06
PC CCS retrofit @ 500 MW	4,500	$1,334	7.157%	$95.50	74.52	0.000%	0.00	0.00	74.52	$170.02
SCPC with CCS	6,500	$6,883	7.157%	$492.59	64.29	0.000%	0.00	0.00	64.29	$556.89
IGCC with CCS	6,500	$6,663	6.853%	$456.64	60.76	0.000%	0.00	0.00	60.76	$517.40
PC CCS retrofit @ 500 MW	6,500	$1,511	7.135%	$107.82	69.22	0.000%	0.00	0.00	69.22	$177.04

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)*

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transport ation	Total	Total Fixed ($/kW-Yr)
Blundell Dual Flash 90% CF	4,500	$6,131	6.311%	$386.94	100.51	0.918%	0.92	0.00	101.43	$488.37
Greenfield Binary 90% CF	4,500	$6,793	6.311%	$428.75	100.51	0.918%	0.92	0.00	101.43	$530.18
Generic Geothermal PPA 90% CF	4,500	$0	6.311%	$0.00	0.00	0.000%	0.00	0.00	0.00	$0.00
2.0 MW turbine 38% CF WA,2021	1,500	$1,800	7.067%	$127.20	36.45	3.061%	1.12	0.00	37.57	$164.76
2.0 MW turbine 38% CF OR, 2021	1,500	$1,774	7.067%	$125.37	36.45	3.061%	1.12	0.00	37.57	$162.94
2.0 MW turbine 38% CF ID, 2021	4,500	$1,811	7.067%	$127.99	36.45	3.061%	1.12	0.00	37.57	$165.56
2.0 MW turbine 31% CF UT, 2021	4,500	$1,735	7.067%	$122.65	36.45	3.061%	1.12	0.00	37.57	$160.21
3.3 MW turbine 43% CF WY, 2021	6,500	$1,737	7.067%	$122.78	36.45	3.061%	1.12	0.00	37.57	$160.35
2.0 MW turbine 38% CF WA,2024	1,500	$1,800	7.067%	$127.20	36.45	3.061%	1.12	0.00	37.57	$164.76
2.0 MW turbine 38% CF OR, 2024	1,500	$1,774	7.067%	$125.37	36.45	3.061%	1.12	0.00	37.57	$162.94
2.0 MW turbine 38% CF ID, 2024	4,500	$1,811	7.067%	$127.99	36.45	3.061%	1.12	0.00	37.57	$165.56
2.0 MW turbine 31% CF UT, 2024	4,500	$1,735	7.067%	$122.65	36.45	3.061%	1.12	0.00	37.57	$160.21
3.3 MW turbine 43% CF WY, 2024	6,500	$1,737	7.067%	$122.78	36.45	3.061%	1.12	0.00	37.57	$160.35
PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2019	4,500	$1,724	7.716%	$133.00	18.45	1.461%	0.27	0.00	18.72	$151.72
PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2019	4,500	$1,822	7.716%	$140.61	19.41	1.461%	0.28	0.00	19.69	$160.30
PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2019	4,800	$1,762	7.716%	$135.94	18.47	1.461%	0.27	0.00	18.74	$154.68
PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2019	4,800	$1,857	7.716%	$143.26	19.44	1.461%	0.28	0.00	19.72	$162.98
PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2023	4,500	$1,724	7.716%	$133.00	18.45	1.461%	0.27	0.00	18.72	$151.72
PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2023	4,500	$1,822	7.716%	$140.61	19.41	1.461%	0.28	0.00	19.69	$160.30
PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2023	4,800	$1,762	7.716%	$135.94	18.47	1.461%	0.27	0.00	18.74	$154.68
PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2023	4,800	$1,857	7.716%	$143.26	19.44	1.461%	0.28	0.00	19.72	$162.98
CSP Trough w Natural Gas	4,500	$6,448	7.067%	$455.68	68.46	0.000%	0.00	17.90	86.36	$542.04
CSP Tower 24% CF	4,500	$6,141	7.067%	$434.05	68.46	0.000%	0.00	0.00	68.46	$502.51
CSP Tower Molten Salt 30% CF	4,500	$7,367	7.067%	$520.66	68.46	0.000%	0.00	0.00	68.46	$589.13
Forestry Byproduct	1,500	$4,383	7.067%	$309.79	42.04	0.000%	0.00	0.00	42.04	$351.83
Pumped Storage 1 (3,800 MWh)	4,457	$3,468	6.517%	$226.05	21.10	0.000%	0.00	0.00	21.10	$247.15
Pumped Storage 2 (12,000 MWh)	580	$3,601	6.517%	$234.67	15.58	0.000%	0.00	0.00	15.58	$250.25
Pumped Storage 3 (7,000 MWh)	6,359	$2,861	6.517%	$186.44	16.86	0.000%	0.00	0.00	16.86	$203.30
CAES (15,360 MWh)	4,640	$2,138	7.871%	$168.30	18.90	0.000%	0.00	0.00	18.90	$187.20
Advanced Fission	5,000	$6,524	7.018%	$457.89	98.35	5.816%	5.72	0.00	104.07	$561.96
Small Modular Reactor x 12	5,000	$9,676	7.018%	$679.08	167.77	11.478%	19.26	0.00	187.03	$866.11

* Note, capital cost and capacity factor data shown for Wyoming wind do not reflect adjustments made to these assumptions during the portfolio selection process (outlined in Volume I, Chapter 8 (Modeling and Portfolio Selection Results), This updated assessment, based on the most current market information, focused on projects that could achieve on-line dates by the end of 2020.

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
Brownfield Site										
Dave Johnston										
SCCT Aero x3	5,050	$1,483	7.871%	$116.70	31.86	1.331%	0.42	53.22	85.51	$202.21
Intercooled SCCT Aero x2	5,050	$1,136	7.871%	$89.40	22.82	1.198%	0.27	52.32	75.41	$164.81
SCCT Frame "F" x1	5,050	$589	7.373%	$43.46	15.97	0.287%	0.05	55.69	71.70	$115.16
IC Recips x 6	5,050	$1,370	7.871%	$107.82	29.82	0.143%	0.04	47.99	77.86	$185.68
CCCT Dry "G/H", 1x1	5,050	$1,519	7.256%	$110.23	24.74	0.153%	0.04	36.92	61.70	$171.92
CCCT Dry "G/H", DF, 1x1	5,050	$397	7.256%	$28.83	5.39	0.000%	0.00	53.13	58.52	$87.34
CCCT Dry "J/HA.02", 1x1	5,050	$1,334	7.256%	$96.81	21.26	0.153%	0.03	36.64	57.93	$154.75
CCCT Dry "J/HA.02", DF, 1x1	5,050	$342	7.256%	$24.79	4.86	0.000%	0.00	53.35	58.21	$83.00
Hunter										
SCCT Aero x3	5,050	$1,483	7.871%	$116.70	31.86	1.331%	0.42	13.99	46.28	$162.98
Intercooled SCCT Aero x2	5,050	$1,136	7.871%	$89.40	22.82	1.198%	0.27	13.76	36.85	$126.25
SCCT Frame "F" x1	5,050	$589	7.373%	$43.46	15.97	0.287%	0.05	14.64	30.66	$74.12
IC Recips x 6	5,050	$1,370	7.871%	$107.82	29.82	0.143%	0.04	12.62	42.48	$150.30
CCCT Dry "G/H", 1x1	5,050	$1,519	7.256%	$110.23	24.74	0.153%	0.04	9.71	34.48	$144.71
CCCT Dry "G/H", DF, 1x1	5,050	$397	7.256%	$28.83	5.39	0.000%	0.00	13.97	19.36	$48.19
CCCT Dry "J/HA.02", 1x1	5,050	$1,334	7.256%	$96.81	21.26	0.153%	0.03	9.63	30.93	$127.74
CCCT Dry "J/HA.02", DF, 1x1	5,050	$342	7.256%	$24.79	4.86	0.000%	0.00	14.03	18.89	$43.68
Huntington										
SCCT Aero x3	5,050	$1,483	7.871%	$116.70	31.86	1.331%	0.42	13.99	46.28	$162.98
Intercooled SCCT Aero x2	5,050	$1,136	7.871%	$89.40	22.82	1.198%	0.27	13.76	36.85	$126.25
SCCT Frame "F" x1	5,050	$589	7.373%	$43.46	15.97	0.287%	0.05	14.64	30.66	$74.12
IC Recips x 6	5,050	$1,370	7.871%	$107.82	29.82	0.143%	0.04	12.62	42.48	$150.30
CCCT Dry "G/H", 1x1	5,050	$1,519	7.256%	$110.23	24.74	0.153%	0.04	9.71	34.48	$144.71
CCCT Dry "G/H", DF, 1x1	5,050	$397	7.256%	$28.83	5.39	0.000%	0.00	13.97	19.36	$48.19
CCCT Dry "G/H", 2x1	5,050	$1,163	7.256%	$84.41	16.63	0.153%	0.03	9.69	26.35	$110.76
CCCT Dry "G/H", DF, 2x1	5,050	$322	7.256%	$23.36	4.44	0.000%	0.00	13.92	18.36	$41.72
CCCT Dry "J/HA.02", 1x1	5,050	$1,334	7.256%	$96.81	21.26	0.153%	0.03	9.63	30.93	$127.74
CCCT Dry "J/HA.02", DF, 1x1	5,050	$342	7.256%	$24.79	4.86	0.000%	0.00	14.03	18.89	$43.68

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
Jim Bridger										
SCCT Aero x3	6,500	$1,608	7.871%	$126.60	34.56	1.331%	0.46	9.11	44.13	$170.73
Intercooled SCCT Aero x2	6,500	$1,195	7.871%	$94.02	24.00	1.198%	0.29	8.92	33.21	$127.23
SCCT Frame "F" x1	6,500	$621	7.373%	$45.77	16.81	0.287%	0.05	9.52	26.38	$72.15
IC Recips x 6	6,500	$1,426	7.871%	$112.25	31.04	0.143%	0.04	8.30	39.39	$151.64
CCCT Dry "G/H", 1x1	6,500	$1,609	7.256%	$116.74	26.20	0.153%	0.04	6.34	32.58	$149.32
CCCT Dry "G/H", DF, 1x1	6,500	$397	7.256%	$28.84	5.39	0.000%	0.00	9.44	14.83	$43.66
CCCT Dry "J/HA.02", 1x1	6,500	$1,401	7.256%	$101.69	22.33	0.153%	0.03	6.28	28.64	$130.33
CCCT Dry "J/HA.02", DF, 1x1	6,500	$342	7.256%	$24.79	4.86	0.000%	0.00	9.44	14.30	$39.09
Naughton										
SCCT Aero x3	6,500	$1,608	7.871%	$126.60	34.56	1.331%	0.46	14.00	49.02	$175.62
Intercooled SCCT Aero x2	6,500	$1,195	7.871%	$94.02	24.00	1.198%	0.29	13.71	38.00	$132.02
SCCT Frame "F" x1	6,500	$621	7.373%	$45.77	16.81	0.287%	0.05	14.63	31.49	$77.26
IC Recips x 6	6,500	$1,426	7.871%	$112.25	31.04	0.143%	0.04	12.76	43.84	$156.10
CCCT Dry "J/HA.02", 1x1	6,500	$1,401	7.256%	$101.69	22.33	0.153%	0.03	9.65	32.01	$133.70
CCCT Dry "J/HA.02", DF, 1x1	6,500	$342	7.256%	$24.79	4.86	0.000%	0.00	14.50	19.36	$44.15
Wyodak										
SCCT Aero x3	6,500	$1,608	7.871%	$126.60	34.56	1.331%	0.46	53.26	88.28	$214.88
Intercooled SCCT Aero x2	6,500	$1,195	7.871%	$94.02	24.00	1.198%	0.29	52.15	76.43	$170.46
SCCT Frame "F" x1	6,500	$621	7.373%	$45.77	16.81	0.287%	0.05	55.63	72.49	$118.26
IC Recips x 6	6,500	$1,426	7.871%	$112.25	31.04	0.143%	0.04	48.52	79.61	$191.86

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
SCCT Aero x3, ISO	0	33%	59.60	na	295	27.15	7.54	12.11%	0.91	-	-	95.20	-	95.20
Intercooled SCCT Aero x2, ISO	0	33%	45.92	na	295	26.49	5.05	12.11%	0.61	-	-	78.07	-	78.07
SCCT Frame "F" x1, ISO	0	33%	31.39	na	295	28.33	5.50	13.92%	0.77	-	-	65.99	-	65.99
IC Recips x 6, ISO	0	33%	63.40	na	295	24.42	7.45	9.18%	0.68	-	-	95.96	-	95.96
CCCT Dry "G/H", 1x1, ISO	0	78%	21.26	na	295	18.77	1.76	10.71%	0.19	-	-	41.98	-	41.98
CCCT Dry "G/H", DF, 1x1, ISO	0	12%	65.92	na	295	26.15	0.15	0.00%	0.00	-	-	92.22	-	92.22
CCCT Dry "G/H", 2x1, ISO	0	78%	16.43	na	295	18.74	1.67	11.33%	0.19	-	-	37.02	-	37.02
CCCT Dry "G/H", DF, 2x1, ISO	0	12%	58.28	na	295	25.99	0.16	0.00%	0.00	-	-	84.43	-	84.43
CCCT Dry "J/HA.02", 1x1, ISO	0	78%	18.92	na	295	18.63	1.70	10.71%	0.18	-	-	39.44	-	39.44
CCCT Dry "J/HA.02", DF, 1x1, ISO	0	12%	60.98	na	295	26.19	0.16	0.00%	0.00	-	-	87.32	-	87.32
CCCT Dry, "J/HA.02" 2X1, ISO	0	78%	14.76	na	295	18.61	1.62	11.33%	0.18	-	-	35.17	-	35.17
CCCT Dry "J/HA.02", DF, 2X1, ISO	0	12%	54.76	na	295	26.05	0.16	0.00%	0.00	-	-	80.97	-	80.97
SCCT Aero x3	1500	33%	61.01	na	295	27.05	7.76	12.11%	0.94	-	-	96.76	-	96.76
Intercooled SCCT Aero x2	1500	33%	47.98	na	295	26.55	5.35	12.11%	0.65	-	-	80.53	-	80.53
SCCT Frame "F" x1	1500	33%	32.48	na	295	28.33	5.81	13.92%	0.81	-	-	67.43	-	67.43
IC Recips x 6	1500	33%	63.40	na	295	24.42	7.45	9.18%	0.68	-	-	95.96	-	95.96
CCCT Dry "G/H", 1x1	1500	78%	22.28	na	295	18.77	1.86	10.71%	0.20	-	-	43.10	-	43.10
CCCT Dry "G/H", DF, 1x1	1500	12%	66.42	na	295	26.58	0.15	0.00%	0.00	-	-	93.15	-	93.15
CCCT Dry "G/H", 2x1	1500	78%	17.17	na	295	18.74	1.77	11.33%	0.20	-	-	37.88	-	37.88
CCCT Dry "G/H", DF, 2x1	1500	12%	58.81	na	295	26.46	0.16	0.00%	0.00	-	-	85.43	-	85.43
CCCT Dry "J/HA.02", 1x1	1500	78%	19.82	na	295	18.63	1.80	10.71%	0.19	-	-	40.45	-	40.45
CCCT Dry "J/HA.02", DF, 1x1	1500	12%	61.51	na	295	26.65	0.16	0.00%	0.00	-	-	88.32	-	88.32
CCCT Dry, "J/HA.02" 2X1	1500	78%	15.42	na	295	18.59	1.71	11.33%	0.19	-	-	35.91	-	35.91
CCCT Dry "J/HA.02", DF, 2X1	1500	12%	55.02	na	295	26.27	0.16	0.00%	0.00	-	-	81.45	-	81.45
SCCT Aero x3	3000	33%	58.35	na	293	26.94	8.21	12.11%	0.99	-	-	94.49	-	94.49
Intercooled SCCT Aero x2	3000	33%	44.81	na	293	26.45	5.67	12.11%	0.69	-	-	77.61	-	77.61
SCCT Frame "F" x1	3000	33%	27.83	na	293	28.19	6.13	13.92%	0.85	-	-	63.01	-	63.01
IC Recips x 6	3000	33%	58.40	na	293	24.29	7.45	9.18%	0.68	-	-	90.82	-	90.82
CCCT Dry "G/H", 1x1	3000	78%	21.73	na	293	18.67	1.97	10.71%	0.21	-	-	42.59	-	42.59
CCCT Dry "G/H", DF, 1x1	3000	12%	51.51	na	293	26.56	0.15	0.00%	0.00	-	-	78.23	-	78.23
CCCT Dry "G/H", 2x1	3000	78%	16.33	na	293	18.63	1.86	11.33%	0.21	-	-	37.03	-	37.03
CCCT Dry "G/H", DF, 2x1	3000	12%	43.99	na	293	26.44	0.16	0.00%	0.00	-	-	70.59	-	70.59
CCCT Dry "J/HA.02", 1x1	3000	78%	19.14	na	293	18.54	1.90	10.71%	0.20	-	-	39.79	-	39.79
CCCT Dry "J/HA.02", DF, 1x1	3000	12%	46.59	na	293	26.66	0.16	0.00%	0.00	-	-	73.40	-	73.40
CCCT Dry, "J/HA.02" 2X1	3000	78%	14.49	na	293	18.50	1.81	11.33%	0.20	-	-	35.01	-	35.01
CCCT Dry "J/HA.02", DF, 2X1	3000	12%	40.45	na	293	26.52	0.16	0.00%	0.00	-	-	67.12	-	67.12

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
SCCT Aero x3	5050	33%	61.42	na	295	27.10	8.85	12.11%	1.07	-	-	98.45	-	98.45
Intercooled SCCT Aero x2	5050	33%	47.03	na	295	26.64	6.14	12.11%	0.74	-	-	80.55	-	80.55
SCCT Frame "F" x1	5050	33%	28.50	na	295	28.36	6.61	13.92%	0.92	-	-	64.39	-	64.39
IC Recips x 6	5050	33%	57.51	na	295	24.44	7.45	9.18%	0.68	-	-	90.09	-	90.09
CCCT Dry "G/H", 1x1	5050	78%	23.03	na	295	18.80	2.12	10.71%	0.23	-	-	44.18	-	44.18
CCCT Dry "G/H", DF, 1x1	5050	12%	48.99	na	295	27.05	0.15	0.00%	0.00	-	-	76.19	-	76.19
CCCT Dry "G/H", 2x1	5050	78%	17.21	na	295	18.77	2.01	11.33%	0.23	-	-	38.22	-	38.22
CCCT Dry "G/H", DF, 2x1	5050	12%	41.49	na	295	26.96	0.16	0.00%	0.00	-	-	68.61	-	68.61
CCCT Dry "J/HA.02", 1x1	5050	78%	20.21	na	295	18.66	2.05	10.71%	0.22	-	-	41.14	-	41.14
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	44.07	na	295	27.17	0.16	0.00%	0.00	-	-	71.40	-	71.40
CCCT Dry, "J/HA.02" 2X1	5050	78%	15.20	na	295	18.63	1.95	11.33%	0.22	-	-	36.01	-	36.01
CCCT Dry "J/HA.02", DF, 2X1	5050	12%	37.94	na	295	27.01	0.16	0.00%	0.00	-	-	65.11	-	65.11
SCCT Aero x3	6500	33%	64.53	na	289	26.57	9.60	12.11%	1.16	-	-	101.87	-	101.87
Intercooled SCCT Aero x2	6500	33%	47.54	na	289	26.02	6.45	12.11%	0.78	-	-	80.79	-	80.79
SCCT Frame "F" x1	6500	33%	27.97	na	289	27.76	6.96	13.92%	0.97	-	-	63.66	-	63.66
IC Recips x 6	6500	33%	58.20	na	289	24.21	7.75	9.18%	0.71	-	-	90.87	-	90.87
CCCT Dry "G/H", 1x1	6500	78%	23.81	na	289	18.48	2.25	10.71%	0.24	-	-	44.79	-	44.79
CCCT Dry "G/H", DF, 1x1	6500	12%	44.68	na	289	27.53	0.15	0.00%	0.00	-	-	72.36	-	72.36
CCCT Dry "G/H", 2x1	6500	78%	17.65	na	289	18.45	2.13	11.33%	0.24	-	-	38.47	-	38.47
CCCT Dry "G/H", DF, 2x1	6500	12%	37.16	na	289	27.34	0.16	0.00%	0.00	-	-	64.67	-	64.67
CCCT Dry "J/HA.02", 1x1	6500	78%	20.66	na	289	18.31	2.15	10.71%	0.23	-	-	41.35	-	41.35
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	39.70	na	289	27.53	0.16	0.00%	0.00	-	-	67.38	-	67.38
CCCT Dry, "J/HA.02" 2X1	6500	78%	15.41	na	289	18.29	2.05	11.33%	0.23	-	-	35.98	-	35.98
CCCT Dry "J/HA.02", DF, 2X1	6500	12%	33.62	na	289	27.37	0.16	0.00%	0.00	-	-	61.14	-	61.14
SCPC with CCS	4500	90%	63.77	na	0	-	6.71	0.00%	0.00	-	-	NC	-	NC
IGCC with CCS	4500	86%	61.25	na	0	-	11.28	0.00%	0.00	-	-	NC	-	NC
PC CCS retrofit @ 500 MW	4500	90%	21.51	na	0	-	6.20	0.00%	0.00	-	-	NC	-	NC
SCPC with CCS	6500	90%	70.44	na	0	-	7.26	0.00%	0.00	-	-	NC	-	NC
IGCC with CCS	6500	86%	69.03	na	0	-	13.52	0.00%	0.00	-	-	NC	-	NC
PC CCS retrofit @ 500 MW	6500	90%	22.39	na	0	-	6.71	0.00%	0.00	-	-	NC	-	NC

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)*

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
Blundell Dual Flash 90% CF	4500	90%	61.77	na	0	-	1.12	0.00%	0.00	-	-	62.89	(19.98)	42.91
Greenfield Binary 90% CF	4500	90%	67.06	na	0	-	1.12	0.00%	0.00	-	-	68.19	(19.98)	48.20
Generic Geothermal PPA 90% CF	4500	90%	-	na	0	-	77.34	0.00%	0.00	-	-	77.34	-	77.34
2.0 MW turbine 38% CF WA,2021	1500	35%	53.74	na	0	-	0.00	0.00%	0.00	0.57	-	54.31	(19.98)	34.33
2.0 MW turbine 38% CF OR, 2021	1500	35%	53.14	na	0	-	0.00	0.00%	0.00	0.57	-	53.72	(19.98)	33.73
2.0 MW turbine 38% CF ID, 2021	4500	35%	54.00	na	0	-	0.00	0.00%	0.00	0.57	-	54.57	(19.98)	34.59
2.0 MW turbine 31% CF UT, 2021	4500	31%	59.00	na	0	-	0.00	0.00%	0.00	0.57	-	59.57	(19.98)	39.59
3.3 MW turbine 43% CF WY, 2021	6500	43%	42.57	na	0	-	0.65	0.00%	0.00	0.57	-	43.79	(19.98)	23.81
2.0 MW turbine 38% CF WA,2024	1500	38%	49.50	na	0	-	0.00	0.00%	0.00	0.57	-	50.07	(7.99)	42.08
2.0 MW turbine 38% CF OR, 2024	1500	38%	48.95	na	0	-	0.00	0.00%	0.00	0.57	-	49.52	(7.99)	41.53
2.0 MW turbine 38% CF ID, 2024	4500	38%	49.74	na	0	-	0.00	0.00%	0.00	0.57	-	50.31	(7.99)	42.31
2.0 MW turbine 31% CF UT, 2024	4500	31%	59.00	na	0	-	0.00	0.00%	0.00	0.57	-	59.57	(7.99)	51.58
3.3 MW turbine 43% CF WY, 2024	6500	43%	42.57	na	0	-	0.65	0.00%	0.00	0.57	-	43.79	(7.99)	35.80
PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2019	4500	27%	64.62	na	0	-	0.00	0.00%	0.00	0.60	-	65.23	(8.84)	56.39
PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2019	4500	31%	58.84	na	0	-	0.00	0.00%	0.00	0.60	-	59.44	(8.05)	51.39
PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2019	4800	25%	70.91	na	0	-	0.00	0.00%	0.00	0.60	-	71.52	(9.73)	61.79
PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2019	4800	29%	64.60	na	0	-	0.00	0.00%	0.00	0.60	-	65.21	(8.86)	56.34
PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2023	4500	27%	64.62	na	0	-	0.00	0.00%	0.00	0.60	-	65.23	(5.91)	59.32
PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2023	4500	31%	58.84	na	0	-	0.00	0.00%	0.00	0.60	-	59.44	(5.39)	54.06
PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2023	4800	25%	70.91	na	0	-	0.00	0.00%	0.00	0.60	-	71.52	(6.50)	65.01
PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2023	4800	29%	64.60	na	0	-	0.00	0.00%	0.00	0.60	-	65.21	(5.93)	59.28
CSP Trough w Natural Gas	4500	33%	187.51	na	294	7.37	0.00	0.00%	0.00	0.60	-	195.48	(8.59)	186.89
CSP Tower 24% CF	4500	24%	239.02	na	0	-	0.00	0.00%	0.00	0.60	-	239.62	(11.25)	228.37
CSP Tower Molten Salt 30% CF	4500	30%	224.17	na	0	-	0.00	0.00%	0.00	0.60	-	224.78	(10.79)	213.98
Forestry Byproduct	1500	91%	44.14	na	0	-	0.99	0.00%	0.00	-	-	NC	-	NC
Pumped Storage 1 (3,800 MWh)	4457	40%	70.08	77%	293	24.03	0.00	0.00%	0.00	-	-	94.11	-	94.11
Pumped Storage 2 (12,000 MWh)	580	42%	68.56	77%	289	23.68	0.00	0.00%	0.00	-	-	92.24	-	92.24
Pumped Storage 3 (7,000 MWh)	6359	42%	55.70	77%	295	24.16	0.00	0.00%	0.00	-	-	79.86	-	79.86
CAES (15,360 MWh)	4640	30%	71.23	50%	295	24.94	0.77	5.46%	0.04	-	-	96.98	-	96.98
Advanced Fission	5000	86%	74.98	na	0	-	11.37	0.00%	0.00	-	-	86.35	-	86.35
Small Modular Reactor x 12	5000	86%	115.55	na	0	-	15.00	0.00%	0.00	-	-	130.55	-	130.55

* Note, capital cost and capacity factor data shown for Wyoming wind do not reflect adjustments made to these assumptions during the portfolio selection process (outlined in Volume I, Chapter 8 (Modeling and Portfolio Selection Results), This updated assessment, based on the most current market information, focused on projects that could achieve on-line dates by the end of 2020.

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
Brownfield Site														
Dave Johnston														
SCCT Aero x3	5050	33%	69.95	na	289	26.56	8.85	12.11%	1.07	-	-	106.43	-	106.43
Intercooled SCCT Aero x2	5050	33%	57.01	na	289	26.11	6.14	12.11%	0.74	-	-	90.00	-	90.00
SCCT Frame "F" x1	5050	33%	39.84	na	289	27.79	6.61	13.92%	0.92	-	-	75.16	-	75.16
IC Recips x 6	5050	33%	64.23	na	289	23.95	7.45	9.18%	0.68	-	-	96.32	-	96.32
CCCT Dry "G/H", 1x1	5050	78%	25.16	na	289	18.42	2.12	10.71%	0.23	-	-	45.93	-	45.93
CCCT Dry "G/H", DF, 1x1	5050	12%	83.09	na	289	26.51	0.15	0.00%	0.00	-	-	109.75	-	109.75
CCCT Dry "J/HA.02", 1x1	5050	78%	22.65	na	289	18.28	2.05	10.71%	0.22	-	-	43.20	-	43.20
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	78.96	na	289	26.62	0.16	0.00%	0.00	-	-	105.74	-	105.74
Hunter														
SCCT Aero x3	5050	33%	56.38	na	294	26.98	8.85	12.11%	1.07	-	-	93.28	-	93.28
Intercooled SCCT Aero x2	5050	33%	43.67	na	294	26.52	6.14	12.11%	0.74	-	-	77.08	-	77.08
SCCT Frame "F" x1	5050	33%	25.64	na	294	28.23	6.61	13.92%	0.92	-	-	61.40	-	61.40
IC Recips x 6	5050	33%	51.99	na	294	24.33	7.45	9.18%	0.68	-	-	84.46	-	84.46
CCCT Dry "G/H", 1x1	5050	78%	21.18	na	294	18.72	2.12	10.71%	0.23	-	-	42.24	-	42.24
CCCT Dry "G/H", DF, 1x1	5050	12%	45.84	na	294	26.93	0.15	0.00%	0.00	-	-	72.92	-	72.92
CCCT Dry "J/HA.02", 1x1	5050	78%	18.70	na	294	18.58	2.05	10.71%	0.22	-	-	39.54	-	39.54
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	41.55	na	294	27.05	0.16	0.00%	0.00	-	-	68.75	-	68.75
Huntington														
SCCT Aero x3	5050	33%	56.38	na	294	26.98	8.85	12.11%	1.07	-	-	93.28	-	93.28
Intercooled SCCT Aero x2	5050	33%	43.67	na	294	26.52	6.14	12.11%	0.74	-	-	77.08	-	77.08
SCCT Frame "F" x1	5050	33%	25.64	na	294	28.23	6.61	13.92%	0.92	-	-	61.40	-	61.40
IC Recips x 6	5050	33%	51.99	na	294	24.33	7.45	9.18%	0.68	-	-	84.46	-	84.46
CCCT Dry "G/H", 1x1	5050	78%	21.18	na	294	18.72	2.12	10.71%	0.23	-	-	42.24	-	42.24
CCCT Dry "G/H", DF, 1x1	5050	12%	45.84	na	294	26.93	0.15	0.00%	0.00	-	-	72.92	-	72.92
CCCT Dry "G/H", 2x1	5050	78%	16.21	na	294	18.69	2.01	11.33%	0.23	-	-	37.14	-	37.14
CCCT Dry "G/H", DF, 2x1	5050	12%	39.69	na	294	26.84	0.16	0.00%	0.00	-	-	66.69	-	66.69
CCCT Dry "J/HA.02", 1x1	5050	78%	18.70	na	294	18.58	2.05	10.71%	0.22	-	-	39.54	-	39.54
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	41.55	na	294	27.05	0.16	0.00%	0.00	-	-	68.75	-	68.75

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2016 Dollars ($)		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
Jim Bridger														
SCCT Aero x3	6500	33%	59.06	na	289	26.55	9.60	12.11%	1.16	-	-	96.37	-	96.37
Intercooled SCCT Aero x2	6500	33%	44.01	na	289	26.00	6.45	12.11%	0.78	-	-	77.24	-	77.24
SCCT Frame "F" x1	6500	33%	24.96	na	289	27.74	6.96	13.92%	0.97	-	-	60.62	-	60.62
IC Recips x 6	6500	33%	52.46	na	289	24.19	7.75	9.18%	0.71	-	-	85.11	-	85.11
CCCT Dry "G/H", 1x1	6500	78%	21.85	na	289	18.47	2.25	10.71%	0.24	-	-	42.81	-	42.81
CCCT Dry "G/H", DF, 1x1	6500	12%	41.54	na	289	27.50	0.15	0.00%	0.00	-	-	69.19	-	69.19
CCCT Dry "J/HA.02", 1x1	6500	78%	19.07	na	289	18.30	2.15	10.71%	0.23	-	-	39.75	-	39.75
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	37.18	na	289	27.50	0.16	0.00%	0.00	-	-	64.84	-	64.84
Naughton														
SCCT Aero x3	6500	33%	60.75	na	294	27.00	9.60	12.11%	1.16	-	-	98.51	-	98.51
Intercooled SCCT Aero x2	6500	33%	45.67	na	294	26.44	6.45	12.11%	0.78	-	-	79.34	-	79.34
SCCT Frame "F" x1	6500	33%	26.72	na	294	28.20	6.96	13.92%	0.97	-	-	62.86	-	62.86
IC Recips x 6	6500	33%	54.00	na	294	24.60	7.75	9.18%	0.71	-	-	87.06	-	87.06
CCCT Dry "J/HA.02", 1x1	6500	78%	19.57	na	294	18.60	2.15	10.71%	0.23	-	-	40.55	-	40.55
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	42.00	na	294	27.97	0.16	0.00%	0.00	-	-	70.13	-	70.13
Wyodak														
SCCT Aero x3	6500	33%	74.33	na	291	26.78	9.60	12.11%	1.16	-	-	111.87	-	111.87
Intercooled SCCT Aero x2	6500	33%	58.97	na	291	26.22	6.45	12.11%	0.78	-	-	92.42	-	92.42
SCCT Frame "F" x1	6500	33%	40.91	na	291	27.97	6.96	13.92%	0.97	-	-	76.81	-	76.81
IC Recips x 6	6500	33%	66.37	na	291	24.40	7.75	9.18%	0.71	-	-	99.23	-	99.23

Additionally, total resource costs were prepared for three natural gas-fired combined cycle combustion turbine resource options at an elevation of 5,050 feet at varying capacity factors to show how these costs are affected by dispatch. Table 6.3 shows the total resource cost results for this analysis.

Table 6.3 - Total Resource Cost, for various Capacity Factors (Mills/kWh, 2016$)

Total Resource Cost (Mills/kWh)			
Capacity Factor CCCT	**40%**	**78%**	**94%**
Capacity Factor Duct Fire	**10%**	**12%**	**22%**
CCCT Dry "G/H", 1x1	$66.06	$44.18	$40.26
CCCT Dry "G/H", DF, 1x1	$85.99	$76.19	$53.92
CCCT Dry "G/H", 2x1	$54.57	$38.22	$35.29
CCCT Dry "G/H", DF, 2x1	$76.91	$68.61	$49.75
CCCT Dry "J/HA.02", 1x1	$60.33	$41.14	$37.70
CCCT Dry "J/HA.02", DF, 1x1	$80.21	$71.40	$51.37
CCCT Dry, "J/HA.02" 2X1	$50.45	$36.01	$33.42
CCCT Dry "J/HA.02", DF, 2X1	$72.70	$65.11	$47.87

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)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Commercial Operation Year	The resource availability year is the earliest year the technology associated with the given generating resource is commercially available for procurement and installation. The total implementation time is the number of years necessary to implement all phases of resource development and construction: site selection, permitting, maintenance contracts, IRP approval, RFP process, owner’s engineering, construction, commissioning and grid interconnection.
Design Life (years)	Average number of years the resource is expected to be "used and useful,” based on various factors such as manufacturer’s 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, contractor fees/profit and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, owner’s contingency), and financial costs (AFUDC, capital surcharge, property taxes and escalation during construction, if applicable).

Term	Description
Var O&M ($/MWh)	Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance and fired hour fees.
Fixed O&M ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment and training.
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
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.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (expressed as NO_2) in pounds of NOx 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 Resources

Acronyms	Description
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)
PPA	Power Purchase Agreement
PC CCS	Pulverized Coal equipped with Carbon Capture and Sequestration
PV Poly-Si	Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers
Recip	Reciprocating Engine
SCCT	Simple Cycle Combustion Turbine
SCPC	Super-Critical Pulverized Coal

Resource Descriptions

The following are brief descriptions of each of the resources listed in Table 6.1.

Wind

Wind, 2.0 MW turbine 38% NCF WA/OR/ID – a wind resource based on 2.0 MW wind turbines located in Washington, Oregon or Idaho with an estimated annual net capacity factor of 38%. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 2.0 MW turbine 31% NCF UT – a wind resource based on 2.0 MW wind turbines located in Utah with an estimated annual net capacity factor of 31%. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 3.3 MW turbine 43% NCF WY – a wind resource based on 3.3 MW wind turbines located in Wyoming with an estimated annual net capacity factor of 43%. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Solar

Solar, PV Fixed Tilt 26.8% NCF UT (1.35 MWdc/MWac) – a large utility scale (50 MW) solar photovoltaic resource using crystalline silica panels in a fixed tilt configuration located in southwestern Utah. A similar resource with the same DC/AC ratio built in southeastern Oregon would have a 24.9% net capacity factor.

Solar, PV Single Axis Tracking 31.1% NCF UT (1.25 MWdc/MWac) – a large utility scale (50 MW) solar photovoltaic resource using crystalline silica solar panels in a single axis tracking system located in southwestern Utah. A similar resource with the same DC/AC ratio built in southeastern Oregon is estimated to have a 28.8% net capacity factor.

Solar, CSP Trough w Natural Gas – a concentrated solar resource using parabolic trough technology. The system would be equipped with natural gas fueled boiler to supply steam during cloudy or evening hours.

Solar, CSP Tower 24% CF – a concentrated solar resource using a power tower technology feeding a boiler based system for power production. The boiler based system could use natural gas as a backup fuel for the boiler during cloudy or evening hours in which case the capacity factor would be variable.

Solar, CSP Tower Molten Salt 30% CF – a concentrated solar resource using a power tower technology. The boiler based system would use molten salt as the heat transfer medium with natural gas as a backup fuel for the boiler during cloudy or evening hours. A four to six hour storage system would allow a capacity factor increase of about six percent.

Biomass

Biomass, Forestry Byproduct **–** a resource fueled by forestry byproducts. Resources tend to be smaller and constrained by the economically available fuel. It is expected that these types of resources would not be developed by the Company but would be secured through power purchase agreements.

Geothermal

Geothermal, Blundell Dual Flash 90% CF – a dual flash geothermal resource located at the Roosevelt Hot Springs in southern Utah.

Geothermal, Greenfield Binary 90% CF **-** a geothermal resource based on binary technology assuming development of a new geothermal resource.

Geothermal, Generic Geothermal PPA 90% CF **–** power and electric energy provided through a power purchase agreement.

Natural Gas

Natural Gas, SCCT Aero x3 – a resource based on three General Electric LM6000PF-Sprint simple cycle aero-derivative combustion turbines fueled on natural gas. The scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/volatile organic compounds (VOC) emissions.

Natural Gas, Intercooled SCCT Aero x **2** – a resource based on two General Electric LMS100PA+ simple cycle aero-derivative intercooled combustion turbine fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. An air-cooled intercooler is assumed.

Natural Gas, SCCT Frame "F" x1 - a resource based on one General Electric 7FA.05 simple cycle frame type combustion turbine fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions.

Natural Gas, IC Recips x6 - a resource based on six Wartsila 18V50SG reciprocating engines fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions.

Natural Gas, CCCT Dry "G/H", 1x1 - a combined cycle resource based on one frame-type General Electric 7HA.01 combustion turbine, one 3-pressure heat recovery steam generator and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air cooled condenser.

Natural Gas, CCCT Dry "G/H", DF, 1x1 – an option that can be added to a combined cycle plant to increase its capacity by the addition of duct burners in the heat recovery steam generator. This increases the amount of steam generated in the heat recovery steam generator. The amount of duct firing is up to the owner. Depending on the amount of duct firing added, the size of the steam turbine, steam turbine generator and associated feedwater, steam condensing and cooling systems may need to be increased. This description also applies to the following technologies that are listed on Table 6.1: CCCT Dry "G/H", DF, 2x1; CCCT Dry "J/HA.02", DF, 1x1; CCCT Dry "J/HA.02", DF, 2x1.

Natural Gas, CCCT Dry "G/H", 2x1 - a combined cycle resource based on two frame-type General Electric 7HA.01 combustion turbines, two 3-pressure heat recovery steam generators and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air cooled condenser.

Natural Gas, CCCT Dry "J/HA.02", 1x1 - a combined cycle resource based on one frame-type General Electric 7HA.02 combustion turbine (air-cooled), one 3-pressure heat recovery steam generator and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air cooled condenser.

Natural Gas, CCCT Dry "J/HA.02", 2x1 - a combined cycle resource based on two frame-type Mitsubishi M501GAC combustion turbines (air-cooled), two 3-pressure heat recovery steam generators and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air cooled condenser.

Storage

Storage, Pumped Storage – a moderately sized (600 MW) pumped storage system using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for eight hours combined with recharging that capacity over 16 hours. Total development time is estimated at 10 years for permitting.

Storage, Lithium Ion Battery – a battery technology of lithium ion batteries located close to the load center. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year.

Storage, Sodium-Sulfur Battery – a battery technology of sodium-sulfur batteries. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year.

Storage, Vanadium RedOx Battery – a battery technology based vanadium ReDOx flow battery. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year.

Storage, CAES **–** A compressed air energy storage (CAES) system consists of air storage reservoir replacing the compressor on a conventional gas turbine. The gas turbine exhaust powers a power turbine providing a simple cycle gas turbine energy at lower costs than a conventional gas turbine. Off-peak energy is used to compress air into the storage reservoir. A system size of 320 MW is assumed. The air storage reservoir is assumed to be solution mined to size. Natural gas is required to generate power.

Nuclear

Nuclear, Advanced Fission – a large 2,234 MW nuclear resource 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. The assumed location for this resource is the proposed Blue Castle site near Green River, Utah which is in development. It is expected that the resource would be available no earlier than 2025.

Nuclear, Small Modular Reactor – such systems hold the promise of being built off-site and transported to a location at lower cost than traditional nuclear facilities. A nominal 570 MW concept is included. It is recognized that this concept is still in the design and licensing stage and is not commercially available, requiring at least 10 years for nuclear availability.

Coal

Coal, SCPC with CCS – conventional coal-fired generation resource including a supercritical boiler (up to 4000 psig) using pulverized coal with all emission controls including scrubber, fabric filters (baghouse), mercury control, selective catalytic reduction (SCR) and carbon capture and sequestration (CCS) to reduce carbon dioxide emissions by 90%.

Coal, PC CCS retrofit @ 500 MW – a retrofit of an existing conventional coal-fired boiler and steam turbine resource. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output and would remove carbon dioxide by 90% and provide a marginal improvement in other emissions.

Coal, IGCC with CCS – an advanced Integrated Gasification Combined Cycle (IGCC) resource to facilitate lower cost carbon capture and sequestration costs. An IGCC plant produces a synthetic fuel gas from coal using an advanced oxygen blown gasifier and burning the synthetic fuel gas in a conventional combustion turbine combined cycle power facility. The IGCC would utilize the latest advanced combustion turbine technology and provide fuel gas cleanup to achieve ultra-low emissions of sulfur dioxide, nitrogen oxides using selective catalytic reduction systems, mercury and particulate. Carbon dioxide would be removed from the synthetic fuel gas before combustion thereby reducing carbon dioxide emissions by more than 90%.

Resource Options Descriptions

Wind

PacifiCorp commissioned a study of utility scale wind generation by Black & Veatch in 2016 to get market based estimates of the capital cost to build new wind projects, the ongoing operation and maintenance costs, and energy production for projects of a nominal 100 MW size. PacifiCorp reviewed operation and maintenance costs for existing Company owned projects and communicated with wind equipment manufacturers and construction companies for supplemental cost information that was used to inform the 2017 IRP. The wind turbine generator (WTG) selection and net capacity factors are based upon the analysis performed by Black & Veatch to design projects that delivered the lowest cost of energy to customers. Black & Veatch chose Vestas 2.0 MW WTGs for their sample layouts in Washington, Oregon, Idaho and Utah, and chose Vestas 3.3 MW WTGs for their sample layouts in Wyoming. While Vestas WTGs are sited in the IRP, WTGs from all manufacturers that meet PacifiCorp's quality standards would be acceptable for new wind farm construction.

Federal Production Tax Credits (PTCs) were extended in December 2015 and included a graduated phase out structure that reduces the value of the credits between 2017 and 2020. The PTC extension led to increasing demand for WTGs in the United States during 2016 and is expected to stimulate demand through 2018 at a minimum. The phase out period has impacted the timing of WTG purchases as developers have purchased WTGs earlier in the development and construction process to secure more PTC benefits. Black & Veatch estimates the cost of WTGs and wind projects will increase through 2018 because of increased market demand, followed by five years of declining prices as the market adjusts to the expiration of the PTCs.

Wind Capital Costs

Capital cost estimates for wind resources in the IRP are based upon a combination of the Black & Veatch study and communications with wind equipment and construction companies. 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. Assigned capacity factor values for wind resources are 43 percent in Wyoming, 38% in Washington, Oregon and Idaho, and 31 percent in Utah. 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 $0.573/MWh (in 2016 dollars) for resource selection. To capture the costs of integrating solar into the system, PacifiCorp applied a value of $0.603/MWh (in 2016 dollars). Additional detailed information can be found in the Company's 2017 flexible reserve study (Volume II, Appendix F). Integration costs were incorporated into wind capital costs based on a 30-year project life expectancy and generation performance.

Solar

Three solar technologies are included in the supply side resource table: single axis tracking (SAT) photovoltaic (PV), fixed tilt PV and concentrated solar. Based upon current technology and market conditions, PV resources have lower capital intensity and are better suited to PacifiCorp's service territory than concentrated solar systems. PacifiCorp evaluates projects based upon the cost of the energy produced over the life of the project. Among large utility scale solar projects, SAT projects often have lower energy costs than fixed tilt projects because the additional generation produced by the tracking system more than offsets the higher capital cost over the life of the resource. The choice of which mounting system to use is site and project specific.

PacifiCorp commissioned a study of utility scale solar PV generation by Black & Veatch in 2016 to get market based estimates of the capital cost to build new solar projects, the ongoing operation and maintenance costs, and energy production for projects of a nominal 50 MW size in Utah and Oregon. To estimate costs and generation for fixed tilt and SAT 50 MW projects, Black & Veatch created a project design that included: solar resource information, selection of components, layout, DC to AC ratio and loss factors. PacifiCorp applied various owner's costs to the Black & Veatch estimate to create the capital costs reported in Table 6.1.

In December 2015, the 30% investment tax credit (ITC) for solar generation was extended through 2019, phase out values of 26% and 22% were put in place for 2020 and 2021 respectively, and a 10% permanent value for commercial projects will begin in 2022. The extension of the ITC combined with the falling cost of PV modules has fueled the continued growth of the solar market across the United States. Increases in inverter sizes and mounting systems that are more easily assembled in the field are lowering capital costs as well. PacifiCorp's estimated capital costs for PV in the 2017 IRP are based upon Black & Veatch's study results and PacifiCorp's estimated owner's costs. The IRP estimates new 50 MW SAT PV projects in Utah and Oregon will cost less than $1,900 per kW and new 50 MW fixed tilt PV projects will cost less than $1,800 per kW. Black & Veatch estimates the capital cost of new PV projects will decrease by about 25% over the next ten years.

There was significant solar development activity in PacifiCorp's service territory between 2012 and 2016. Over the course of those five years, 199 solar projects with nameplates of 10 MW or greater have initiated generation interconnection requests with PacifiCorp. The total nameplate capacity of those 199 projects is over 12,500 MW. There were 95 new generation projects greater than 10 MW that entered PacifiCorp's generation interconnection queue during 2016; of these 95 new projects, 86 are solar, 8 are wind and 1 is energy storage. The nameplate capacity of the 86 solar projects added in 2016 alone is over 8,300 MW. While many projects that have initiated generation interconnection studies over the past 15 years have not been built, the number and size of the 2016 interconnection solar projects is testament to the tremendous solar development activity that is underway within PacifiCorp's service territory.

Biomass

Cost and performance data for biomass based resources were obtained from third-party studies. The Pacific Northwest and Atlantic Southeast are generally considered good regions for siting biomass generation plants because the climate supports the abundant growth of fuel resources. In general, large-scale (greater than 50 MW) plants are rare, which is why the resource is represented as a 5 MW plant in the supply side resource table. Many biomass products have multiple potential uses including industrial manufacturing, agriculture and energy generation. Because these other uses increase the demand and cost of the source material, biomass electric generation facilities often operate in areas that pay high prices for electricity production or have significant regulatory or incentive structures in place to support biomass based electric generation. Select coal plants in the United States and other parts of the world 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. The greatest challenge to building large biomass generation plants or retrofitting existing coal units is the cost and the availability, reliability, and homogeneity of a long-term fuel supply. The cost and logistical challenges of acquiring, transporting, processing and handling large quantities of biomass fuel pose significant challenges. While PacifiCorp currently does not own any biomass plants, the Company does purchase power from a number of biomass resources in Oregon through power purchase agreements.

Geothermal

Geothermal resources are a desirable renewable generation resource given their base-load operating profile combined with high reliability and availability. However, geothermal resources have significantly higher development costs and exploration risks than other renewable technologies such as wind and solar. PacifiCorp has commissioned several studies of geothermal options during the past ten years to determine if additional sources of production can be added to the Company's generation portfolio in a cost effective manner. A 2010 study commissioned by PacifiCorp and completed by Black & Veatch focused on geothermal projects near to PacifiCorp's service territory that were in advanced phases of development and could demonstrate commercial viability. PacifiCorp commissioned Black & Veatch to perform additional analysis of geothermal projects in the early stages of development and a report was issued in 2012. An evaluation of the Company's Roosevelt Hot Springs geothermal resource was commissioned in 2013. The geothermal capital costs in the 2017 supply side resource option are built on the understanding gained from these earlier reports, publically available capital costs from the Geothermal Resources Council and publicly available prices for energy supplied under power purchase agreements.

The cost recovery mechanisms currently available to PacifiCorp as a regulated electric utility are not compatible with the inherent risks associated with the development of geothermal resources for power generation. The primary risks of geothermal development are dry holes, well integrity and insufficient resource adequacy (flow, temperature and pressure). These risks cannot be fully quantified until wells are drilled and completed. The cost to validate total production capability of a geothermal resource can be as high as 35 percent of total project costs. Exploration test wells typically cost between $500,000 and $1.5 million per well. Full production and injection wells cost between $4-5 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 these inherently risky development efforts.

To mitigate the financial risks of geothermal development, PacifiCorp would use a Request for Proposals (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. Several geothermal projects submitted proposals in response to the 2016 Oregon Renewables RFP, but none of the geothermal projects were selected as a new PacifiCorp generation source. 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.

Supply and Location of Renewable Resources

In the 2017 IRP, the availability of certain renewable resources is contingent upon transmission availability. Table 6.6 shows the total cumulative selection limits for solar and geothermal resources. Table 6.7 shows the total cumulative selection limits for wind resources, varying depending on whether a case includes an Energy Gateway project assumption.

Table 6.6 - Cumulative Maximum Renewable Selection Limits

Type	Renewable Resource	Capacity Factor	Total MW Available	
			2021	2022-2036
Wind	Oregon Wind (Arlington/ Medford)	38%	400	400
	Washington Wind (Walla Walla)	38%	0	0
	Utah Wind (South)	31%	500	500
	Idaho Wind (Goshen)	38%	150	800
Solar	Oregon Solar (Lakeview)	25/29%	405	405
	Washington Solar (Yakima)	25/29%	655	655
	Utah Solar (South)	27/31%	805	805
Geothermal	Utah Geothermal (Blundell)	90%	35	30
	Utah Geothermal (Milford)	90%	30	30
	Oregon Geothermal (Neal Hot Springs)	90%	30	30

Solar = Fixed Tilt / Single Tracking

Table 6.7 - Cumulative Maximum Renewable Selection Limits

Type	Renewable Resource	Capacity Factor	Total MW Available											
			No Gateway		Gateway 1		Gateway 2		Gateway 3		Gateway 4		Gateway 4 + Repower	
			2021	2022-2036	2021	2022-2036	2021	2022-2036	2021	2022-2036	2021	2022-2036	2021	2022-2036
Wind	Wyoming Wind (Aeolius)	43%	300	0	300	440	300	440	300	1,200	1,200	0	1,100	0

Natural Gas

Natural gas-fueled generating resources offer several important services that support the safe and reliable operation of the energy grid in an economic manner. They include technologies that are capable of providing peaking, intermediate and base generation.

A variety of natural gas-fueled generating resources that are and will continue to be available for a several years are included in the Supply Side Resource Table (Table 6.1). The variety of natural gas resources were selected to provide for generating performance and services essential to safe and reliable operation of the energy grid. Natural gas resources generate cost competitive power while producing low air emissions. Natural gas-fueled resources have proven to be highly reliable and safe. Performance, cost and operating characteristics for each resource were provided at elevations of 1,500, 3,000, 5,050 and 6,500 feet above mean sea level, representative of geographic areas in which the resource could be located. Performance, cost and operating characteristics were also provided at ISO conditions (zero feet above mean sea level and 59 °F) as a reference. The essential services provided by the resource are peaking, intermediate and base generation.

Three simple cycle combustion turbine options and one reciprocating engine option were offered to provide peaking generating services. Peaking generating services require the ability to start and reach near full output in less than ten minutes. Peaking generating services also require the ability in increase (ramp up) and decrease (ramp down) very quickly in response to sudden changes in power demand as well as increases and decreases in production from intermittent power sources. Peaking generation provides the ability to meet peak power demand that exceeds the capacity of intermediate and base generation. Peak generation also provides reserves to meet system upsets.

Options for peaking resources included in the supply side resources are: 1) three each General Electric (GE) LM6000 PF aero-derivative simple cycle combustion turbines, 2) two each GE LMS 100PA+ aero-derivative simple cycle combustion turbines, 3) one each GE 7F frame simple cycle combustion turbine, and 4) six each Wasilla 18V50SG reciprocating internal combustion engines. All of these options are highly flexible and efficient. Higher heating value heat rates for the resource ranged from 9,204 Btu/kW-hr for the LM6000 PF to 8,279 Btu/kW-hr for the 18V50SG engines. Installation of high temperature oxidation catalysts for carbon monoxide (CO) control and an SCR system for nitrogen oxides (NOx) control would be available for these resources.

Eight combined cycle combustion turbine options were provided for intermediate and base generating service. Intermediate generating service requires resources that are able to efficiently operate at production rates well below full production in compliance with air emissions regulations for long periods of time. Intermediate generating service also requires the ability to change production rates quickly. Intermediate generation services provide cost effective means of providing power demand that is greater than base load and lower than peak demands. Base generating service requires a highly cost effective turbine that is capable of operating at full production for long periods of time. Base generation provides for the minimum level of power demand over a day or longer period of time at a very low cost.

Options for intermediate and base generation were based on two size classes of engines. The “G/H” size was represented by a GE HA.01. The “J/HA.02” was represented by the GE HA.02. Each engine was arranged in a one combustion turbine to one steam turbine (1x1) and a two combustion turbine to one steam turbine (2x1) configuration to obtain four resource options. The combined cycle resources offered high heating value heat rates from 6,317 to 6,374 Btu/kW-hr. Installation of oxidation catalysts for carbon monoxide (CO) control and SCR systems for nitrogen oxides (NOx) control is expected. All of the combined cycle options included dry cooling allowing them to be located in areas with water resource concerns.

Duct Firing (DF) of the combined cycle is shown in the Supply Side Resource table. Duct firing 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 at high ambient temperatures. Duct firing is shown in the Supply Side Resource table as a fixed value for each combined cycle combination. In practice the amount of duct firing is a design consideration which is selected during the development of combined cycle generating facilities.

While equipment provided by specific manufacturers is used for cost and performance information in the supply side resource table, more than one manufacturer produces these type of equipment. The costs and performance used here is representative of the cost and performance that would be expected from any of the manufacturers. Final selection of a manufacturer's equipment would be made based on a bid process.

New natural gas resources were assumed to be installed at greenfield sites on either the east or west side of PacifiCorp's system. Greenfield development includes the costs of high pressure natural gas laterals, electrical power transmission lines, ambient air monitoring, permitting, real estate, rights of way and water rights. Resources additions at a brownfield site, such as an existing coal-fueled generating facility, costs are reduced to reflect infrastructure at the site.

Energy Storage

For the 2017 IRP, two energy storage studies were conducted to update the studies performed for previous IRP's. 1) The battery Energy Storage Study focuses only on battery technologies. 2) The Bulk Energy Storage Study focuses on pumped hydro and compressed air energy storage (CAES). The estimates and information in the studies was used to inform the 2017 IRP and may be used to develop alternative applications to traditional utility transmission and distribution issues. The energy storage studies are available at www.pacificorp.com/es/irp.html.

A Battery Energy Storage Summary Supply-Side Resource Table (available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2016_IRP_Update_for_Battery_Storage.pdf) was created to provide information not included in the traditional Supply-Side Resource Table (SSR Table). This table provides inputs for five size scenarios: four different durations (1, 2, 4 and 8 hours) at a power capacity of 1 MW and a single larger scale 8 MW system with a duration of 4 hours for a total usable energy capacity of 32 MWhs. Information for sodium sulfur batteries is only available for systems of approximately 8 MWhs; therefore data for the other sodium sulfur system sizes are listed as N/A. The data for all technologies is standardized at a 20 year system life meaning that degradation was taken into account such that each system would last 20 years. Thus the maximum annual generation is limited due to expected degradation. Bulk energy storage systems are included in Table 6.1.

Battery Energy Storage Study

The Battery Energy Storage Study (available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf) was provided by DNV-GL to update engineering estimates for the cost and performance of utility scale battery energy storage technologies, maintain a current catalog of commercially available and emerging battery energy storage technologies with forecasts and estimates of performance and costs, and provide a probabilistic cost forecast for each of the technologies, broken out by technology costs, energy conversion system costs and O&M costs.

Table 6.8 identifies the battery technologies and data updated for the 2017 IRP cycle. Note that for the 2017 IRP, lithium ion batteries were split into the three most common sub-chemistries and two emerging zinc technologies were added.

Table 6.8 - Updated Battery Technologies and Data

Updated Battery Technologies
Lithium ion batteries (Li-Ion)
Lithium Nickel Manganese Cobalt Oxide (LiNiMnCoO2 or NCM)
Lithium Iron Phosphate (LiFePO4)
Lithium Titanate (Li4Ti5O12 or LTO)
Flow batteries:
Vanadium Redox (VRB)
Emerging technologies
Zinc Bromine (ZnBr) Redox
Zinc Hybrid Cathode (Zinc-air)
Sodium sulfur batteries (NaS)
Updated Battry Data
Stage of Commercial Development
Typical project size (kW & kWh)
Largest project size installed (kW & kWh)
Current total power capacity (MW) installed
Current total energy storage capacity (MWh) installed
Performance Characteristics
Power Capacity
Energy Capacity
Recharge Rates
Roundtrip Efficiency
Availability
Degradation
Expected Life
Environmental Impact upon disposal

Table 6.9 - Battery Storage Study Summary Cost and Capacity Results (2016$)

Average Battery Data	1 MW Power Capacity				8 MW
Duration	1 hour	2 hours	4 hours	8 hours	4 hours
Lithium Ion					
Capital Cost ($)	1,657,492	2,549,054	4,332,178	7,898,425	31,136,475
Annual O&M ($/yr)	13,485	18,470	28,440	48,380	227,520
System Efficiency (AC out/AC in)	81%	81%	81%	81%	81%
Technical Life (years)	20	20	20	20	20
Maximum Annual Generation (MWh/yr)	184	368	736	1,472	5,888
EFOR (%)	3%	3%	3%	3%	3%
POR (%)	1%	1%	1%	1%	1%
Spinning Reserves (MW)	1	1	1	1	8
Ramp Rate (MW/sec)	50	50	50	50	400
Assumed recharge C-Rate (MW/MWh)	1	1	1	1	1
Sodium Sulfur					
Capital Cost ($)	N/A	N/A	N/A	7,504,817	N/A
Annual O&M ($/yr)	N/A	N/A	N/A	53,415	N/A
System Efficiency (AC out/AC in)	N/A	N/A	N/A	80%	N/A
Technical Life (years)	N/A	N/A	N/A	20	N/A
Maximum Annual Generation (MWh/yr)	N/A	N/A	N/A	1,448	N/A
EFOR (%)	5%	5%	5%	5%	5%
POR (%)	1%	1%	1%	1%	1%
Spinning Reserves (MW)	1	1	1	1	8
Ramp Rate (MW/sec)	0	0	0	0	1
Assumed recharge C-Rate (MW/MWh)	1	1	1	1	1
Flow					
Capital Cost ($)	2,434,917	3,003,617	4,867,017	8,593,817	37,201,242
Annual O&M ($/yr)	15,500	21,500	33,500	57,500	460,000
System Efficiency (AC out/AC in)	72%	72%	72%	72%	72%
Technical Life (years)	20	20	20	20	20
Maximum Annual Generation (MWh/yr)	500	1,000	2,000	4,000	16,000
EFOR (%)	5%	5%	5%	5%	5%
POR (%)	2%	2%	2%	2%	2%
Spinning Reserves (MW)	1	1	1	1	8
Ramp Rate (MW/sec)	25	25	25	25	200
Assumed recharge C-Rate (MW/MWh)	1	1	1	1	1

In addition to updating the cost estimates, cost trend forecasts for the next ten years were developed. Capital cost forecasts were broken out by storage equipment, power conversion system equipment, power control system and balance of system. No forecast was provided for fixed O&M costs. There are a wide variety of O&M agreements and capacity maintenance agreements which are sometimes rolled into upfront capital costs or combined as a single O&M agreement. There is not currently a uniform or industry acceptable methodology for quantifying variable O&M.

Based on the information provided in the study, the Company selected Li-Ion and Flow batteries to use in the PaR model and developed the following special escalation rates for battery energy storage. Li-Ion escalation rates are based on an average of the technologies presented in the study. The data indicates that Li-Ion batteries with higher power-to-energy ratios (also known as high power batteries) have lower de-escalation rates than high energy Li-Ion batteries. However, high energy flow batteries have higher de-escalation rates than high energy flow batteries. Larger scale battery energy storage systems are expected to have the same escalation rates as smaller systems with the same power-to-energy ratio.

The battery storage special escalation rates are provided and reported in Table 6.10.

Table 6.10 - Battery Energy Storage Special Escalation Rates

	Li-Ion Storage			Flow Storage		
MW	1	1	8	1	1	8
MWh	1	4	32	1	4	32
2017	-7.77%	-9.79%	-9.79%	-5.98%	-5.41%	-5.41%
2018	-7.00%	-9.15%	-9.15%	-5.37%	-4.59%	-4.59%
2019	-6.05%	-7.80%	-7.80%	-4.48%	-3.81%	-3.81%
2020	-5.21%	-7.05%	-7.05%	-4.03%	-3.51%	-3.51%
2021	-4.35%	-6.03%	-6.03%	-2.98%	-2.59%	-2.59%
2022	-3.63%	-4.84%	-4.84%	-2.11%	-1.71%	-1.71%
2023	-3.04%	-4.37%	-4.37%	-1.80%	-1.21%	-1.21%
2024	-2.43%	-3.47%	-3.47%	-1.36%	-1.03%	-1.03%
2025	-1.85%	-2.45%	-2.45%	-0.84%	-0.72%	-0.72%
2026	-1.31%	-1.48%	-1.48%	-0.51%	-0.19%	-0.19%

Another new subject covered in this study is Utility Applications and Value Stream. The applicability of each technology and the relative potential for generating economic value were studied for the following benefit cases within the Company's service territory during the next 20 years. Potential uses include:

- Electric Energy Time Shift
- Electric Supply Capacity
- Regulation
- Spinning, Non-Spinning and Supplemental Reserves
- Voltage Support
- Load Following/Ramping Support for Renewables
- Frequency Response
- Transmission and Distribution Congestion Relief

Bulk Energy Storage Study

The Bulk Energy Storage Study (available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/Black_Veatch_PacifiCorp_Bulk_Storage_IRP_Study_Report-final_20160819.pdf) provides an update to engineering estimates for the cost and performance of utility scale bulk energy storage technologies.

The bulk energy storage technologies identified for updates include the technologies identified below. PacifiCorp has no affiliation or partnership with any of these projects. They are considered to be in a medium stage of development and are representative of what is available to PacifiCorp for these types of energy storage systems. Other projects may become available such as the Banks Lake project. The study provides an updated project status, description and schedule. Various levels of detail were provided for each project:

- Pumped Hydro (PH)
- Swan Lake North

- JD Pool
- Seminoe (previously Black Canyon)
- Compressed Air Energy Storage (CAES)
- Western Energy Hub
- Norton Energy Storage
- PG&E Kern County CAES
- Adele CAES
- APEX Bethel Energy Center

Case-by-Case Analysis of Energy Storage Solutions

In 2015, PacifiCorp hired B&V to develop a cost estimating model for BESS's. The modeled was vetted against information in the DOE Energy Storage Database and will be updated using the information provided in this year's battery energy storage study. Estimating the value cases of ESS's is still under development. PNNL recently developed the Battery Storage Evaluation Tool (BSET) which models up to four stacked use cases in using actual load data. PacifiCorp is also participating in EPRI's Energy Storage Integration Council (ESIC) on the development of a new model called StorageVET which recently underwent alpha and beta testing. StorageVET appears to combine aspects of earlier models.

While these models are being evaluated, more work is needed to accurately model the value of potential energy storage projects. Each project needs to have different values applied to the applicable use cases. Additionally, in a dynamic market those values may change over time, especially as more of the service is introduced to the market. The Company will continue to work with organizations like ESIC to further develop storage valuation modeling.

Nuclear

PacifiCorp revisited two of the nuclear options presented in the 2015 IRP: 1) the AP 1000 plant being developed by Blue Castle Holdings in Green River, Utah rated at 2,234 MW and 2) the 570 MW NuScale Small Modular Reactor (SMR) being developed for construction at the Idaho National Lab site. PacifiCorp participated in in-depth discussions with Blue Castle Holdings (BCH) and NuScale regarding the expected levelized cost of energy (LCOE) of each plant. The data used from BCH and NuScale in this IRP is publicly available.

BCH provided a detailed cost analysis of the Vogtle plant construction and eliminated unexpected costs which would not apply to the Green River site such as geotechnical problems encountered at the Vogtle site. The Vogtle plant was a first of a kind (FOAK) plant but the Green River plant will be an Nth of a kind (NOAK) plant based on the Vogtle plant AP 1000 design. PacifiCorp added a 3.7% delay cost to BCH's capital cost estimate for potential unforeseen problems not encountered on the Vogtle project. Details of the BCH project can be found at www.bluecastleproject.com/.

NuScale is developed an advanced reactor design in the small modular reactor (SMR) category. Although it is an FOAK technology, the design has inherent safety features which support reduced capital costs and operating cost estimates. PacifiCorp has a seat on the NuScale advisory board, however PacifiCorp has no monetary interest in NuScale or the SMR project being developed for the Idaho National Lab site. PacifiCorp added 5% contingency and 10% delay costs due to the project being FOAK. Details of NuScale's SMR can be found at http://www.nuscalepower.com/.

PacifiCorp's capital cost estimates include a 10.36% owner's cost for the BCH and NuScale projects. Despite the cost improvements due to the learning curve associated with the AP-1000' previous installations or the NuScale SMR's simplified design attributes, nuclear generation is still expected to have a high LCOE relative to other generation options.

Coal

Potential coal resources are shown in the supply-side resource options table (Table 6.1) as supercritical pulverized coal boilers (PC) and integrated gasification combined cycle (IGCC), located in both Utah and Wyoming. Both resource types include carbon dioxide capture and compression needed for sequestration.

Supercritical technology is considered the standard design technology compared to subcritical technology for pulverized coal. Increasing coal costs make the added efficiency of the supercritical technology more 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 also have better load following capability, faster ramp rates, use less water and require less steel for construction. The costs shown in Table 6.1 for a supercritical PC facility reflect the cost of adding a new unit at an existing site.

The requirement for CO_2 capture and sequestration (CCS) represents a significant cost for both new and existing coal resources. In order for a coal-fueled generating facility to meet the Federal New Source Performance Standards for Greenhouse Gases (NSPS-GHG) carbon dioxide emissions limit of 1,100 lbs per megawatt-hour would require CO_2 capture and permanent sequestration. Based on this requirement, only coal resource options that include carbon capture are included in the Supply Side Resource Table.

Two major utility-scale CCS retrofit projects have been recently constructed and have entered commercial operation on pulverized coal plants in North America. SaskPower's 115 MW (net) $1.24 billion Boundary Dam project entered commercial operation in October 2014. In July, 2016, the plant reached a major milestone when it had demonstrated that over 1,100,000 tons of CO_2 had been captured. In January, 2017, NRG's Petra Nova project went into commercial operation. Both of these projects have CO_2 capture rates in excess of 90%; sequestration is accomplished through enhanced oil recovery (EOR). Both of these projects utilize amine-based systems for carbon dioxide capture.

The Petra Nova project is especially meaningful in that the project entailed a retrofit of an existing coal-fueled plant using an amine based system and captures approximately 5,000 tons per day from the 240 MWe equivalent flue gas slipstream from NRG's W.A. Parish unit 8. Captured CO_2 is transported through an 81-mile pipeline and used for EOR at the West Ranch Oilfield, located on the Gulf Coast of Texas. It is the largest retrofit of a carbon capture technology of a pulverized coal plant in the world. The project was constructed and commissioned on schedule. No major cost increases have been reported; material cost increases and schedule delays have been the prevailing characteristic of a number of recent clean coal projects. Petra Nova is a 50-50 joint venture by NRG and JX Nippon. The United States Department of Energy (DOE) is providing up to $190 million in grants as part of the Clean Coal Power Initiative program (CCPI), a cost-shared collaboration between the federal government and private industry. Managed and executed in the U.S., the capture system is based on Mitsubishi's proprietary KM CDR Process® and uses its KS-1™ amine solvent.

MHIA formed a consortium with TIC (The Industrial Company) to construct the project on a full turnkey basis. The consortium began construction in September 2014 and completed the performance tests in December 2016.

PacifiCorp continues to monitor these CO_2 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. An option to capture CO_2 at an existing coal-fired unit has been included in the supply side resource tables. Currently there are only a limited number of large-scale sequestration projects in operation around the world; most of these have been installed in conjunction with enhanced oil recovery. Given the high capital cost of implementing CCS on coal fired generation (either on a retrofit basis or for new resources) CCS is not considered a viable option before 2025. Factors contributing to this position include capital cost risk uncertainty, the availability of commercial sequestration (non-EOR) sites, and the uncertainty regarding long term liabilities for underground sequestration.

To address the availability of commercial sequestration, three PacifiCorp power plants are participating in new federally funded research into carbon capture and storage. A grant from the U.S. Department of Energy to the University of Wyoming will be used to assess the storage of carbon dioxide in the Rock Springs Uplift, a geologic formation located adjacent to the Jim Bridger Plant in southwest Wyoming. Similar funding will allow the University of Utah to study the feasibility of long-term carbon dioxide storage in the San Rafael Swell near the Hunter and Huntington plants in central Utah. Both of these projects were selected based on the proximity to the geologic formations and the plants, which are major sources of carbon dioxide.

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 CO_2 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. These projects have been constructed with significant federal funding. One large, utility-scale IGCC plant with carbon capture capability recently went into service. Southern Company's 582 MWnet $6.8 billion Kemper County project includes carbon capture (65% capture) and sequestration (for EOR). The plant is expected to enter commercial operation on coal-fuel based syn-gas in the first quarter of 2017.

The Texas Clean Energy Project is a second IGCC project which also includes carbon dioxide capture and is currently in an advanced stage of development. This project anticipates using Siemens gasification technology with CO_2 capture being used for both EOR purposes and urea production. However, it is uncertain at this stage if this project will progress to construction given recent de-funding announcements by the US DOE.

The costs presented in the supply-side resource option tables for new IGCC resources are based on 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.

Other than the Texas Clean Power Project, which is the only current coal-fueled IGCC project in development in the United States, a consortium of Japanese firms received orders on December 1, 2016 for two 540 MW IGCC plants to be constructed in Japan based on Mitsubishi's IGCC technology that was tested at the Nakoso Power Station from 2007 through 2013. A number of countries, including Dubai, India, Kenya, Philippines and Malaysia have recently announced plans to construct new conventional coal-fueled electric generating resources.

No new cost studies were performed for coal-fueled generation options in 2016. Updated capital and O&M costs for coal-fuel generation options were based on escalating costs used in the 2015 IRP.

<u>Coal Plant Efficiency Improvements</u>

Fuel efficiency gains for existing coal plants, which manifest 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. Turbine upgrades can 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. Currently the Company has no plans to make any major steam turbine or generator upgrades over the next 10 years.

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 2017 IRP were derived from the Demand-side Resource Potential Assessment for 2017-2036 (DSM Potential Study) conducted by Applied Energy Group (AEG). This study provided a broad estimate of the size, type, location and cost of demand-side resources.[1] 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 (i.e. capacity-focused 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, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (products and quantities) based on each resource's competitiveness against alternative resource options. At the time of preparation for the 2017 IRP, the Company had established DSM acquisition targets and funding levels and had begun acquiring savings for calendar year 2017. To ensure that the 2017 IRP analysis is consistent with those planned Class 2 DSM acquisition levels, expected DSM savings in each state were fixed for calendar year 2017. Beyond 2017, the model optimized DSM selections.

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 in terms of 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 of the planning period;
- Persistence of resource savings; for example, Class 2 DSM (energy-focused) resource measure lives;
- Seasonal availability and hours available (Class 1 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 Class 1 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.

[1] The 2017 DSM potential study is available on PacifiCorp's demand-side management web page. http://www.pacificorp.com/es/dsm.html

Class 1 DSM Capacity Supply Curves

The potentials and costs for Class 1 DSM products were provided at the state level, with impacts specified separately for summer and winter peak periods. Resource price differences between states for similar resources reflect 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 Oregon is more expensive than Utah on a unitized or dollar-per-kilowatt-year basis due to climatic differences that result in a lower load impact per installed switch

Table 6.11 and Table 6.12 show the summary level Class 1 DSM resource supply curve information, by control area. For additional detail on Class 1 DSM resource assumptions used to develop these supply curves, see Volume 3 of the 2017 DSM Potential Study.[2] Potential shown is incremental to the existing Class 1 DSM resources identified in Table 5.12. For existing program offerings, it is assumed that the Company could begin acquiring incremental potential in 2017. For resources representing new product offerings, it is assumed the Company could begin acquiring potential in 2019, accounting for the time required for program design, regulatory approval, vendor selection, etc.

[2] http://www.pacificorp.com/es/dsm.html

Table 6.11 - Class 1 DSM Program Attributes West Control Area

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
Residential and Small Commercial Air Conditioning and Water Heating	58	$71 - $104	25[1]	$198 - $248
Residential and Small Commercial Space Heating	n/a	n/a	117	$40 - $51
Residential Room Air Conditioners	3	$238 - $404	n/a	n/a
Residential Smart Thermostats	21	$65 - $100	51	$34 - $39
Residential Smart Appliances	5	$256 - $263	5	$256 - $263
Residential Electric Vehicle Charging	11	$236 - $241	11	$236 - $241
Irrigation Direct Load Control	27	$80 - $81	n/a	n/a
Commercial/Industrial Curtailment	49	$85 - $89	44	$96 - $123
Ice Energy Storage	7	$199 - $204	n/a	n/a

[1] For consistency in modeling, water heating potential for both seasons is included with the central air conditioning product.

Table 6.12 - Class 1 DSM Program Attributes East Control Area

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
Residential and Small Commercial Air Conditioning and Water Heating	108	$43 - $102	20[1]	$302 - $661
Residential and Small Commercial Space Heating	n/a	n/a	82	$34 - $43
Residential Room Air Conditioners	5	$185 - $264	n/a	n/a
Residential Smart Thermostats	46	$45 - $93	21	$39 - $125
Residential Smart Appliances	9	$266 - $278	9	$266 - $278
Residential Electric Vehicle Charging	10	$244 - $250	10	$244 - $250
Irrigation Direct Load Control	31	$58 - $82	n/a	n/a
Commercial/Industrial Curtailment	134	$90 - $108	108	$92 - $121
Ice Energy Storage	8	$206 - $217	n/a	n/a

[1] For consistency in modeling, water heating potential for both seasons is included with the central air conditioning product.

Class 2 DSM, Energy Supply Curves

The 2017 DSM potential study provided the information to fully assess the potential contribution from Class 2 DSM resources over the IRP planning horizon accounting for known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics 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 DSM potential study provided Class 2 DSM resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming[3]
- **Measure:**
  - 83 residential measures
  - 109 commercial measures
  - 99 industrial measures
  - 22 irrigation measures
  - 11 street lighting measures

- **Facility type[4]:**
  - Six residential facility types
  - 28 commercial facility types
  - 30 industrial facility types
  - Two irrigation facility type
  - Four street lighting types

The 2017 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 11.2 million MWh.[5] 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 an achievable technical potential for modeling consideration of 9.5 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 33,000 separate permutations or distinct measures that could be modeled using the supply curve methodology. 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 range of measure costs in each of

[3] Oregon's Class 2 DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.
[4] Facility type includes such attributes as existing or new construction, single or multi-family, etc. Facility types are more fully described in Chapter 4 of Volume 2 of the 2015 DSM potential study; pages 4-3 for residential, pages 4-5 for commercial, and pages 4-8 for industrial.
[5] 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.

the 27 bundles used in the development of the Class 2 DSM supply curves for the 2017 IRP are the same as those developed for the 2015 IRP.

Bundle development began with the Class 2 DSM technical potential identified by the 2017 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 Power and Conservation Council's aggressive[6] regional planning assumptions, it was assumed that 85 percent of the technical potential for discretionary (retrofit) resources and 73 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.

The 2015 DSM potential study applied market ramp rates on top of measure ramp rates to reflect state-specific considerations affecting acquisition rates, such as age of programs, small and rural markets, and current delivery infrastructure. This mechanism was used solely in the Wyoming industrial sector to reflect that program momentum is still building. The current assessment utilizes the same "Emerging" market ramp rate used in the 2017 assessment for Wyoming's industrial sector. [7]

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 2017 DSM Potential study and the ETO's resource assessment, see Appendix E in Volume 4 of the 2015 DSM potential study report. Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the Class 2 DSM supply curves used in the development of the 2017 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles were available across six states (including Oregon), which equates to 189 Class 2 DSM supply curves. Table 6.13 shows the 20-year MWh potential for Class 2 DSM cost bundles, designated by ranges of $/MWh. Table 6.14 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 $13.56/kW-year
- Stochastic risk reduction credit of $5.03/MWh[8]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[9]

[6] 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.
[7] The Wyoming industrial market ramp rate is provided in Table E-1 of Volume 4 of the 2017 DSM potential study report.
[8] PacifiCorp developed this credit from two sets of production dispatch simulations of a given resource portfolio, and each set has two runs with and without DSM. One simulation is on deterministic basis and another on stochastic basis. Differences in production costs between the two sets of simulations determine the dollar per MWh stochastic risk reduction credit.

The bundle price is the average levelized cost for the group of measures in the cost range, weighted by the potential of the measures. In specifying the bundle cost breakpoints, narrow cost ranges were defined for the lower-cost resources to ensure cost accuracy for the bundles considered more likely to be selected during the resource selection phase of the IRP.

Table 6.13 - Class 2 DSM MWh Potential by Cost Bundle

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	27,146	91,695	610,445	972,850	118,725	211,694
10 - 20	8,772	37,868	186,280	869,625	43,968	91,745
20 - 30	10,126	45,728	688,346	588,821	79,553	131,056
30 – 40	14,956	38,417	334,064	411,008	52,584	342,310
40 – 50	9,775	52,426	229,316	483,287	65,569	193,275
50 - 60	4,341	36,941	77,508	530,396	87,588	151,994
60 – 70	17,388	15,456	5,469	455,608	61,885	64,025
70 – 80	9,417	25,123	134,301	220,392	42,658	107,615
80 – 90	5,154	10,915	100,947	108,222	26,837	49,829
90 – 100	10,254	16,337	326,823	73,579	34,445	23,983
100 – 110	11,845	15,402	123,499	73,895	40,142	83,812
110 – 120	5,672	5,813	84,733	81,351	25,457	20,135
120 – 130	2,185	1,895	31,830	135,611	13,624	8,299
130 – 140	1,180	2,936	243	96,048	12,904	7,132
140 – 150	3,650	9,583	8,074	102,483	20,565	19,236
150 - 160	5,327	13,075	5,370	171,330	1,751	12,537
160 – 170	2,948	2,079	11,767	79,327	11,433	31,246
170 – 180	1,553	21,250	123,068	20,376	27,385	13,435
180 – 190	2,420	4,429	21,219	72,989	24,746	2,655
190 – 200	1,461	1,412	-	8,995	28,040	7,011
200 – 250	20,293	20,386	13,612	51,139	28,980	33,316
250 – 300	1,173	4,187	24,169	30,894	11,539	7,536
300 – 400	3,750	6,470	30,240	174,195	16,937	12,491
400 – 500	1,627	3,338	57,170	154,893	13,614	10,608
500 – 750	7,154	9,940	4,520	87,716	16,628	20,803
750 – 1,000	1,954	4,118	4,553	36,122	7,967	4,789
> 1,000	2,418	7,107	124,020	55,743	11,637	19,268

[9] The formula for calculating the $/MWh credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

Table 6.14 - Class 2 DSM Adjusted Prices by Cost Bundle

Bundle	Levelized Bundle Price after Adjustments ($/Mwh)					
	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	-	-	-	-	-	-
10 - 20	1.04	4.42	4.56	3.70	-	5.97
20 - 30	15.07	13.79	15.89	14.08	10.80	14.82
30 – 40	25.06	23.38	24.11	22.54	19.79	26.55
40 – 50	35.33	35.92	34.35	32.63	28.52	34.14
50 - 60	44.56	43.51	43.79	43.37	39.65	43.13
60 – 70	53.97	53.08	53.99	53.38	48.50	53.14
70 – 80	66.15	62.16	66.16	62.65	59.46	63.16
80 – 90	74.24	75.16	75.49	73.77	70.66	73.55
90 – 100	83.35	84.80	87.00	82.02	79.51	84.48
100 – 110	93.40	95.42	95.49	93.16	89.22	92.62
110 – 120	105.98	103.19	107.87	106.22	97.34	102.72
120 – 130	115.81	115.56	112.39	112.17	108.30	114.16
130 – 140	122.24	121.79	125.21	121.67	121.26	123.01
140 – 150	131.05	131.36	131.26	134.06	133.12	130.60
150 - 160	146.61	147.08	141.70	140.69	135.46	144.93
160 – 170	157.27	152.80	152.24	152.46	149.59	157.21
170 – 180	163.12	160.40	164.32	162.74	160.37	163.00
180 – 190	176.04	175.68	168.19	175.32	171.99	176.14
190 – 200	183.28	181.78	-	183.84	179.57	181.80
200 – 250	209.42	210.12	210.55	210.61	204.00	212.39
250 – 300	256.32	247.66	270.22	258.92	263.51	261.11
300 – 400	342.64	334.27	338.95	321.47	329.59	337.62
400 – 500	430.66	423.50	451.01	441.33	458.62	422.80
500 – 750	660.71	664.18	677.89	599.56	662.05	642.42
750 – 1,000	880.50	877.28	947.88	868.86	840.77	848.36
> 1,000	31,152.34	22,647.63	1,315.61	43,789.06	43,421.09	24,325.48

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.

Distribution Efficiency

The Company continues to evaluate distribution energy efficiency. The Company's recent efforts in distribution efficiency are expected to show tangible results in three areas. The first is streetlight efficiency. In 2017, the Company is endeavoring to replace approximately 1,420 company owned streetlights system-wide, equal to ten percent of existing inventory. Older mercury vapor, metal halide and incandescent streetlights will be replaced with more efficient lights (high pressure sodium or LED).

The second area is software focused. The Company recently transitioned its power flow application from ABB FeederAll® to CYME CYMDIST®. The new CYME power flow application allows the evaluation of many complex real world scenarios, and will help ensure that future planning efforts and project definitions are as accurate as possible. As application proficiency and model accuracy evolve, CYME will further enhance the Company's ability to develop renewable resources and private generation.

The third area touches the key areas of efficiency, capital deferral and customer service. The Company evaluated a VAR (Volt Ampere Reactive) optimization project as a possible solution to respond efficiently to a proposed system change while maintaining reliability and safe operation of the system. In 2016, efforts in the Yakima, Washington area addressed conductor thermal capacity and low voltage risks associated with a customer load addition. The strategy implemented a complex voltage and reactive power control scheme utilizing voltage regulators, fixed capacitor banks and switched capacitor banks. Additional monitoring will be performed to ensure proper off-peak operation and to identify any power quality issues or increased maintenance costs.

The distribution energy efficiency efforts described above have not been modeled as potential resources in this IRP, as the savings associated with these measures is difficult to determine and expected to be very small.

Transmission Resources

For the 2017 IRP, the Company selects generation resource portfolios with a pre-determined transmission topology based on transmission rights that are owned by the Company and contracted with third parties. Potential transmission resource additions are examined prior to generation resource selection. Sensitivities are also developed to test various transmission build-out scenarios. Additionally, in order to determine the appropriate placement and timing of generation resources, generic assumptions on transmission integration costs are included in the costs of potential resources. These costs are associated with improvements needed to transfer the generation to load centers and/or markets and maintain the reliability and stability of the transmission system.

Costs of transmission integration vary discretely based on size of the resources added. Table 6.15 provides an illustrative example how the transmission integration costs at a location may be structured based on the size of the resource additions.

Table 6.15 - Example of Transmission Integration Costs by Size of Resource Additions

Size of the Resources Addition	Transmission Integration Costs
Up to 500 MW	$0 million
500 MW to 1,500 MW	$350 million
1,500 MW to 2,500 MW	$700 million
2,500 MW to 3,000 MW	$1,000 million

For any initial resource additions up to 500 MW there would not be incremental transmission costs as there is capacity currently available. However, if a resource added is in any size between 500 MW and 1,500 MW, the transmission integration costs would be $350 million. If a second resource added subsequently at the same location and total capacity between the two resources does not exceed 1,500 MW, there would not be transmission integration costs for this second resource.

In addition, if a comparable resource is selected immediately after a unit retires, there may not need to be costs to reinforce the existing transmission resource in the area; otherwise, additional costs would be incurred to maintain reliability of the transmission system. To accurately reflect the impact of transmission costs of the resource portfolios, the generic assumptions are later revised based on specific size, timing, location, and sequence of resources added in each portfolio.

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 on-going 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 super peak (hours ending 13 through 20) and typically rely on standard enabling agreements as a contracting vehicle. FOT prices are determined at the time of the transaction, usually via an exchange or third party broker, and are based on 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, however, most transactions made to balance PacifiCorp's system are made on a balance of month, day-ahead, hour-ahead, or intra-hour basis. Annual transactions can be available 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.

Three FOT types were included for portfolio analysis in the 2017 IRP: an annual flat product, a HLH July for summer, and a HLH December for winter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. The HLH transactions represent purchases received 16 hours per day, six days per week for July and December. Table 6.16 shows the FOT resources included in the IRP models, identifying the market hub, product type, annual megawatt capacity limit, and availability. PacifiCorp develops its FOT limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and market depth, and with consideration of regional resource supply (see Volume II, Appendix J for an assessment of western resource adequacy). 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, as applicable. Additional discussion of how FOTs are modeled during the resource portfolio development process of the IRP is included in Chapter 7 (Modeling and Portfolio Evaluation Approach).

Table 6.16 - Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type Available over Study Period	Megawatt Limit and Availability (MW)	
	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	400	400
Heavy Load Hour ("6X16")	375	375
California Oregon Border (COB)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	400	400
Nevada Oregon Border (NOB)		
Heavy Load Hour ("6X16")	100	100
Mona		
Heavy Load Hour ("6X16")	300	300

CHAPTER 7 – MODELING AND PORTFOLIO EVALUATION APPROACH

CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios. The 2017 IRP modeling and evaluation approach consists of three screening stages used to select a preferred portfolio, including Regional Haze screening, eligible portfolio screening, and final screening.
- PacifiCorp uses System Optimizer (SO) to produce unique resource portfolios across a range of different planning assumptions. Informed by the public input process, PacifiCorp ultimately produced and evaluated 43 different SO portfolios for its 2017 IRP.
- PacifiCorp uses Planning and Risk (PaR) to perform stochastic risk analysis of the portfolios produced by SO. For each SO portfolio, PaR studies are developed for three natural gas price scenarios (low, base, and high) and two carbon dioxide (CO_2) emissions limit assumptions, which together form six price-emissions scenarios.[1] The resulting cost and risk metrics are then used to compare portfolio alternatives and inform selection of the preferred portfolio.
- Taking into consideration stakeholder comments received during the public input process, PacifiCorp also developed 24 sensitivity cases designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. Six of the sensitivities developed over the course of the 2017 IRP were considered for the preferred portfolio.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from PaR, comparing resource portfolios on the basis of expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions and other criteria.

Introduction

IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting a target planning reserve margin. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

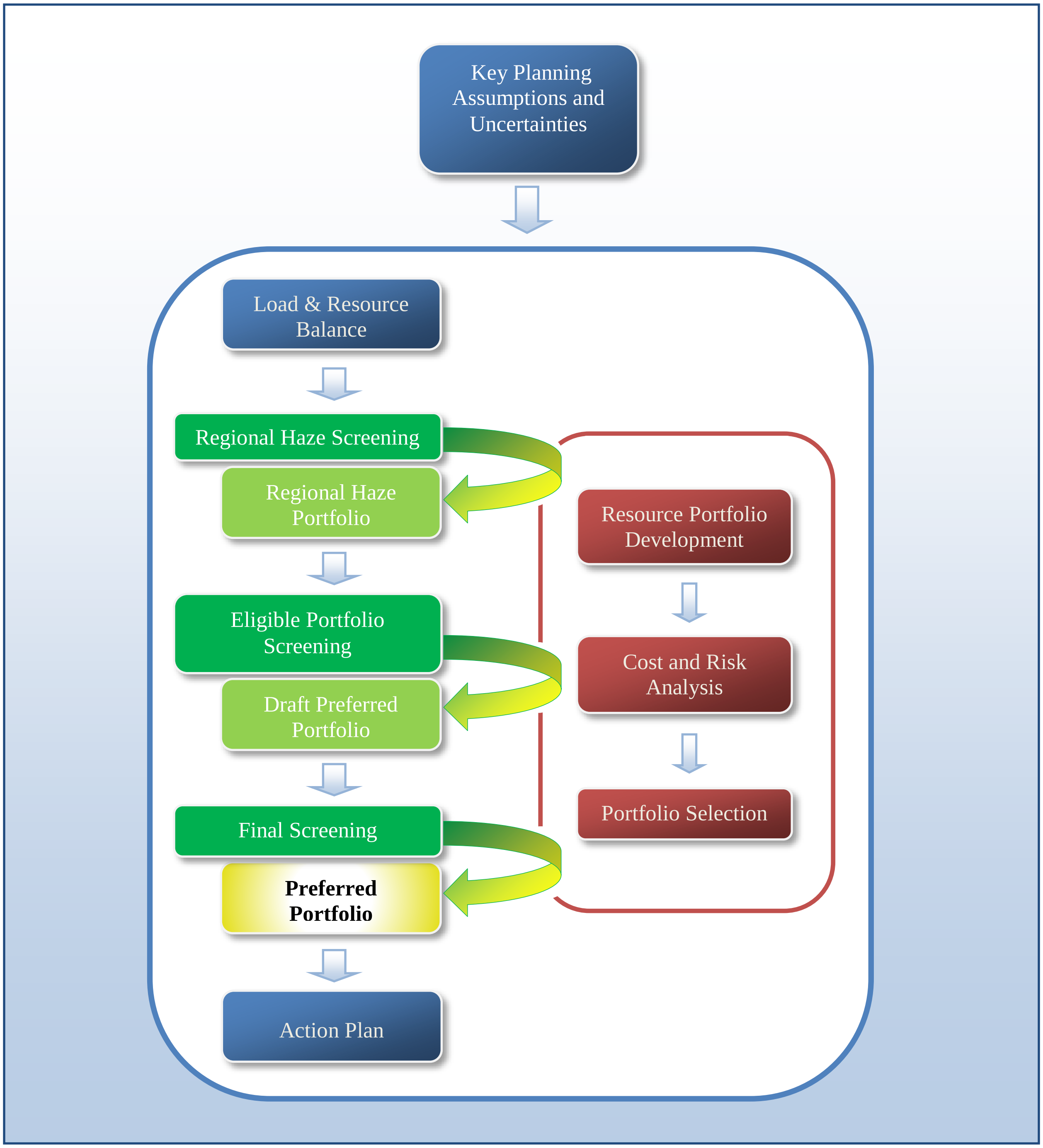
The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each screening stage, including Regional Haze cases, core cases, and sensitivity cases. The results of PacifiCorp's modeling and portfolio analysis are summarized in Chapter 8.

[1] In select instances only, the base price assumptions are modeled to evaluate a sensitivity case; these exceptions are described in Volume I, Chapter 8: Modeling and Portfolio Selection Results.

Modeling and Evaluation Steps

Figure 7.1 summarizes the portfolio evaluation steps used in the 2017 IRP, with three screening stages highlighted in green. The three stages are (1) Regional Haze screening, (2) eligible portfolio screening, and (3) the final portfolio screening. The result of the final screening stage is the preferred portfolio.

Figure 7.1 – Portfolio Evaluation Steps within the IRP Process



For each screening stage, PacifiCorp developed unique resource portfolios, analyzed cost and stochastic risk metrics for each portfolio, and selected, based on comparative cost and risk metrics, the specific portfolios considered in the next screening stage. The outcomes of each can inform the need for additional studies to test or refine assumptions in a subsequent screening analysis. The basic portfolio evaluation steps within each screening stage are highlighted in red in Figure 7.1 above and include:

- Resource Portfolio Development
  All IRP models are configured and loaded with the best available information at the time a commitment must be made for the model run. This information is fed into SO, which is used to produce resource portfolios with sufficient capacity to achieve a target planning reserve margin. Each resource portfolio is uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system over time.

- Cost and Risk Analysis
  Resource portfolios developed with SO are simulated in PaR to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed using Monte Carlo sampling of stochastic variables across the 20-year study horizon, which include load, natural gas and wholesale electricity prices, hydro generation, and unplanned thermal outages.

- Portfolio Selection
  The portfolio selection process in each screening stage is based upon modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the present value revenue requirement (PVRR) of system costs, assessed across six price-emissions scenarios on an expected-value basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the expected value PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other supplemental modeling results, including reliability and CO_2 emissions data.

Resource Portfolio Development

Resource expansion plan modeling, performed with SO, is used to produce resource portfolios with sufficient capacity to achieve a target planning reserve margin over the 20-year study horizon. Each resource portfolio is uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as environmental and tax policies, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, and new resource cost and performance data. Changes to these input variables cause changes to the resource mix.

System Optimizer (SO)

The SO model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and capacity constraints (summer peak loads, winter peak loads, plus a target planning reserve margin for each load area represented in the model). In the event that an early retirement of an existing generating resource is assumed for a given planning scenario, SO will select additional resources as required to meet summer and winter peak loads inclusive of the target planning reserve margin.

To accomplish these optimization objectives, SO performs a time-of-day least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new demand side management (DSM) alternatives within PacifiCorp's transmission system. Resource 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, and the model scales output results to the number of days in the month and then the number of months in the year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, spot market purchase costs, spot market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, and amortized capital costs for existing coal resources and potential new resources.

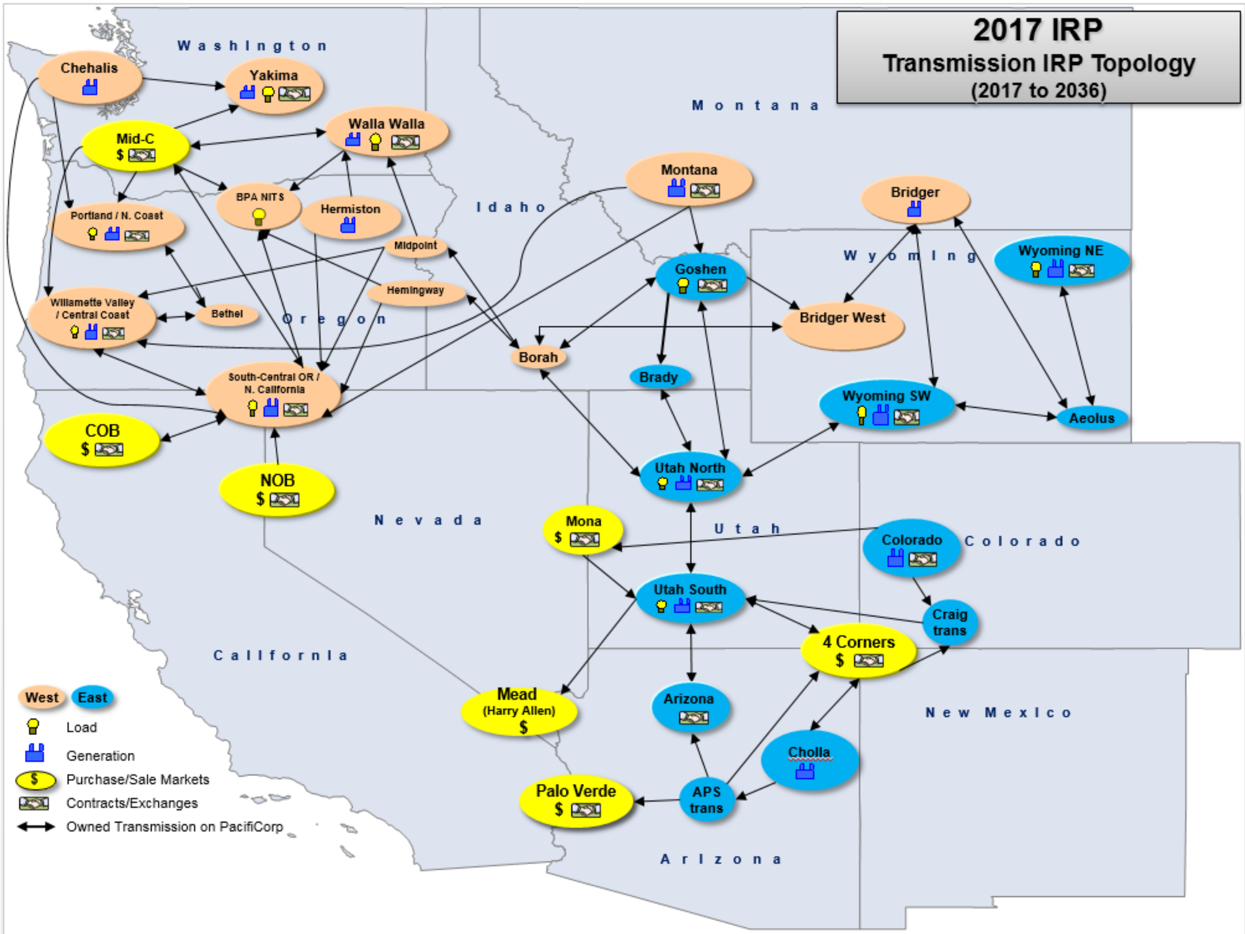
Transmission System

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths. Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers. Figure 7.2 shows the 2017 IRP transmission system model topology.

Transmission Costs

In developing resource portfolios for the 2017 IRP, PacifiCorp includes estimated transmission integration and transmission reinforcement costs specific to each resource portfolio. These costs are influenced by the type, timing, and location of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

Figure 7.2 – Transmission System Model Topology



Resource Adequacy

Resource adequacy is modeled in the portfolio development process by ensuring each portfolio meets a target planning reserve margin. In its 2017 IRP, PacifiCorp continues to apply a 13 percent target planning reserve margin. The planning reserve margin, which influences the need for new resources, is applied to PacifiCorp's coincident system peak load forecast net of offsetting "load resources" such as energy efficiency capacity. Planning to achieve a 13 percent planning reserve margin ensures that PacifiCorp has sufficient resources to meet peak loads, recognizing that there is a possibility for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves. Volume II, Appendix I of this report summarizes PacifiCorp's updated planning reserve margin study that supports selection of a 13 percent target planning reserve margin in the 2017 IRP.

New Resource Options

Dispatchable Thermal Resources

SO performs time-of-day least cost dispatch of existing and potential new thermal resources to meet load while minimizing costs. Dispatch costs applicable to thermal resources include fuel costs, non-fuel variable operations & maintenance (VOM) costs, and the cost of emissions, as applicable. For existing and potential new dispatchable thermal resources, System Optimizer uses generator specific inputs for fuel costs, VOM, heat rates, emission rates, and any applicable price for emissions to establish the dispatch cost of each generating unit for each dispatch interval. Thermal resources are dispatched by least cost merit order. The power produced by these resources can be used to meet load or to make off-system sales at times when resource dispatch costs fall below market prices. Conversely, at times when dispatch costs exceed market prices, off-system purchases can displace dispatchable thermal generation to minimize system energy costs. Dispatch of thermal resources reflects any applicable transmission constraints connecting generating resources with both load and market bubbles as defined in the transmission topology for the model.

Front Office Transactions

Front office transactions (FOTs) represent short-term firm market purchases for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., prompt month forward, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or the exchange provides the service of providing a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all of the short-term firm physical power products, which differ by delivery pattern and delivery period, that are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the capacity contribution of short-term firm market purchases are accounted for in the resource portfolio development process. For capacity optimization modeling, short-term firm forward transactions are represented as FOTs and configured in SO with either an annual flat, summer-on-peak (July), or winter on-peak (December) delivery pattern in every year of the twenty-year planning horizon. As configured in SO, FOTs contribute capacity toward meeting the 2017 IRP's 13 percent target planning reserve margin and supply system energy consistent with the assumed FOT delivery pattern.

Unlike FOTs, system balancing transactions do not contribute capacity toward meeting the 13 percent target planning reserve margin. System balancing transactions include hourly off-system sales and hourly off-system purchases, representing market activities that minimize system energy costs as part of the economic dispatch of system resources, including energy from any FOTs included in a resource portfolio.

A description of FOT limits assumed in the 2017 IRP is included in Chapter 6, Resource Options. PacifiCorp's evaluation of resource adequacy in the western power markets is summarized in Volume II, Appendix J.

Demand Side Management

SO can select incremental DSM resources during the portfolio optimization development step of each screening stage. Selection of DSM resources is made from supply curves that define how much of a DSM resource can be acquired at a given cost point.

Class 2 DSM resources, representing energy savings from energy efficiency programs, are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measure specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the Class 2 DSM supply curve specifies the aggregate energy savings profile of all measures included in the cost bundle, with a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with PacifiCorp's coincident system peak load.

Class 1 DSM resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). SO evaluates Class 1 DSM resources by considering capacity contribution, cost, and operating characteristics. Operating characteristics include variables such as total number of hours and number of hours per event that the Class 1 DSM resource is available in a given year. Additional discussion of DSM resources modeled in the 2017 IRP is included in Chapter 6 and in Volume II, Appendix D.

<u>Wind and Solar Resources</u>
Wind and solar resources are modeled as non-dispatchable, must-run resources using fixed energy profiles varying 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.

The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. The capacity contribution of new and existing wind resources in PacifiCorp's east and west balancing authority areas (BAAs) is set to 15.8 percent and 11.8 percent, respectively. The capacity contribution of new and existing fixed tilt solar photovoltaic resources in PacifiCorp's east and west BAAs is set to 37.9 percent and 53.9 percent, respectively. New single axis tracking solar photovoltaic capacity contribution values in PacifiCorp's east and west BAAs are set to 59.7 percent and 64.8 percent, respectively. Volume II, Appendix N of this report summarizes PacifiCorp's updated wind and solar capacity contribution study used to derive these values.

<u>Energy Storage Resources</u>
Energy storage resources are distinguished from other resources by the following three attributes:

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

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. SO 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, SO accounts for conventional generation system performance and cost characteristics of the storage resource, including capital cost, size of the storage and time to fill the storage, heat rate (if fuel is used), operating and maintenance cost, minimum capacity, and maximum capacity.

Capital Costs and End-Effects

SO uses annual capital recovery factors to convert capital dollars into real levelized revenue requirement costs to address end-effects that arise with capital-intensive projects 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 for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. 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 2017 IRP, the PVRR is calculated inclusive of real levelized capital revenue requirement through the end of the 2036 planning period.

General Assumptions

<u>Study Period and Date Conventions</u>

PacifiCorp executes its 2017 IRP models for a 20-year period beginning January 1, 2017 and ending December 31, 2036. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, with the exception of coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period.

<u>Inflation Rates</u>

The 2017 IRP model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.22 percent is assumed. The annual escalation rate reflects the average of annual inflation rate projections for the period 2017 through 2036, using PacifiCorp's September 2016 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product (GDP) inflator and the Consumer Price Index (CPI).

<u>Discount Factor</u>

The discount rate used in present value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2017 IRP is 6.57 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.[2] PVRR figures reported in the 2017 IRP are reported in January 1, 2017 dollars.

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

Environmental Policy and Price Scenarios

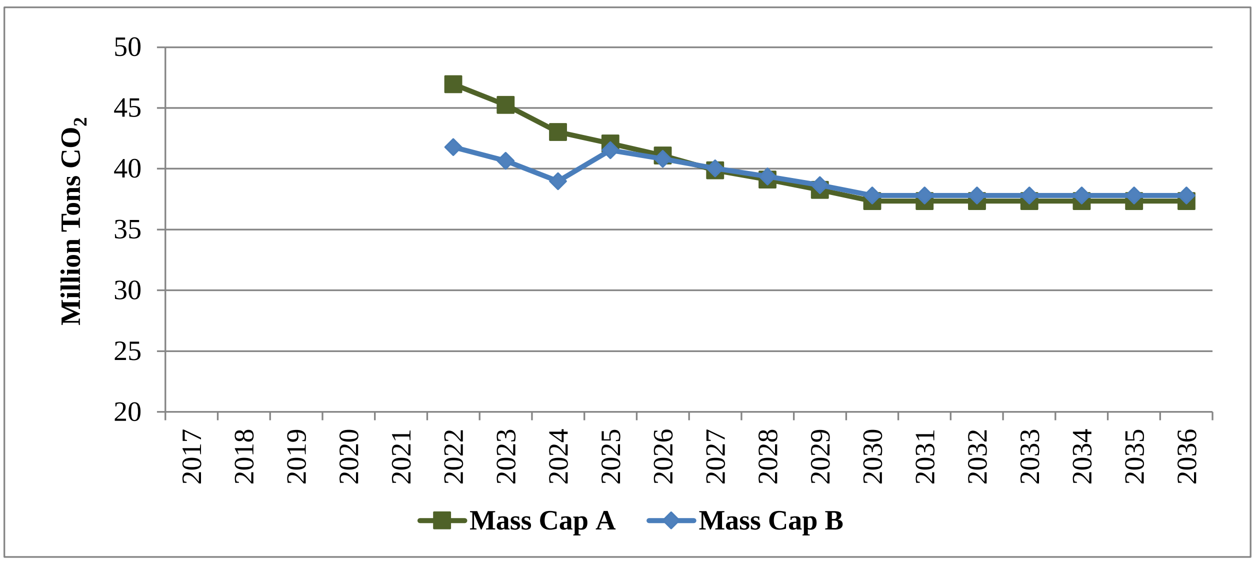
Six price-emissions scenarios are defined for the 2017 IRP, representing combinations of two emissions policy scenarios multiplied by three natural gas price scenarios (low, base, and high).

<u>Emissions Policy Scenarios</u>
The two CO_2 emissions policy scenarios are defined by two differing interpretations of the Environmental Protection Agency's (EPA) Clean Power Plan (CPP).

- CPP(a) (or Mass Cap A): Mass-based compliance approach with pro-rata allowance allocation to PacifiCorp based on historical generation with no set-asides and no new source complement.
- CPP(b) (or Mass Cap B): Mass-based compliance approach with pro-rata allowance allocation to PacifiCorp based on historical generation with new source complement allowances allocated on a pro-rata basis, ***less*** the Clean Energy Incentive Program (CEIP), renewable and output-based set-asides. It is assumed that PacifiCorp does not receive any of these set-asides.

Figure 7.3 shows the assumed CO_2 mass cap scenarios applicable to emissions for affected units on PacifiCorp's system. Consistent with the underlying assumptions used to develop these two scenarios, new combined cycle combustion turbine (CCCT) natural gas plants fall under the Mass Cap B scenario, but are not subject to emission limits under the Mass Cap A scenario.

Figure 7.3 - PacifiCorp System Mass Cap A & Mass Cap B Assumptions



<u>Price Scenario Development</u>
Natural gas price forecasts are based upon a review of third-party expert projections. The expert forecasts are a key input to Aurora, the production cost dispatch model used by PacifiCorp to generate a long-term wholesale power price forecast for each natural gas price scenario. Aurora is also configured with CPP assumptions that align with scenarios developed for the 2017 IRP (CPP(a) and CPP(b)). The end result yields a unique and consistent set of natural gas price and wholesale power price scenarios for alternative CPP and natural gas price assumptions.

Table 7.1 – Price-Emissions Scenarios

Scenario	Clean Power Plan (CPP) Case	CPP Attributes	Natural Gas	Power
CPP(b) Base	U.S. WECC* Mass Cap B total allocation cap	New source complement included; generic combine cycles subject to constraint	Oct. 2016 OFPC (72-months market; 12-months blend; followed by base gas)	Oct. 2016 OFPC (72-months market; 12-months blend; followed by fundamentals per Aurora©)
CPP(b) Low	U.S. WECC* Mass Cap B total allocation cap	New source complement included; generic combine cycles subject to constraint	Low gas	Fundamental price forecast per Aurora©
CPP(b) High	U.S. WECC* Mass Cap B total allocation cap	New source complement included; generic combine cycles subject to constraint	High gas	Fundamental price forecast per Aurora©
CPP(a) Base	U.S. WECC* Mass Cap A total allocation cap	No new source complement included; generic combine cycles not subject to constraint	Base gas	Fundamental price forecast per Aurora©
CPP(a) Low	U.S. WECC* Mass Cap A total allocation cap	No new source complement included; generic combine cycles not subject to constraint	Low gas	Fundamental price forecast per Aurora©
CPP(a) High	U.S. WECC* Mass Cap A total allocation cap	No new source complement included; generic combine cycles not subject to constraint	High gas	Fundamental price forecast per Aurora©

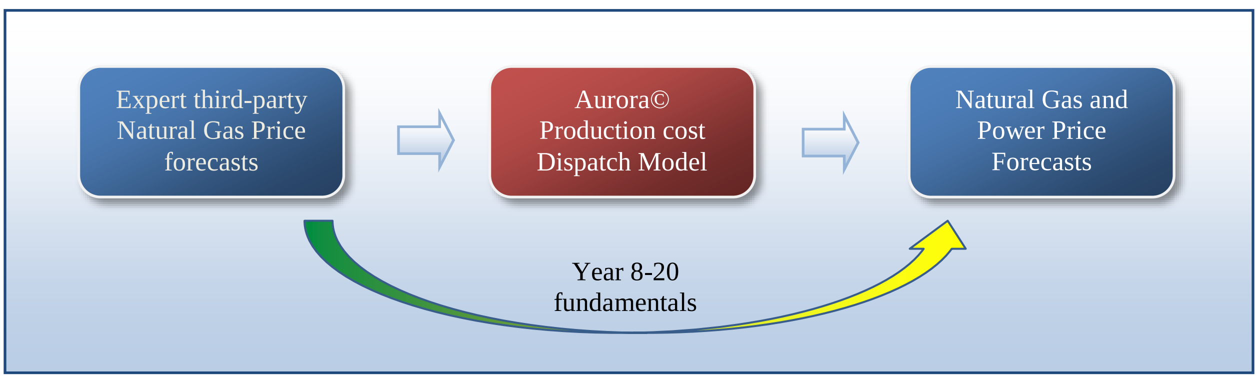
Table 7.1 Notes

- OFPC – Official Forward Price Curve
- California is modeled using a CO_2 tax as a proxy for its cap-and-trade program established pursuant to the California Global Warming Solutions Act of 2006. As such, it is not modeled as being subject to the CPP limits.

Wholesale Electricity and Natural Gas Forward Prices

For 2017 IRP modeling purposes, seven electricity price forecasts were generated: the official forward price curve (OFPC) and six scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents the Company's official price outlook. It is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast. Figure 7.4 depicts the process used by PacifiCorp to develop its price curve scenarios.

Figure 7.4 - Price Scenario Modeling



At the time PacifiCorp's 2017 IRP modeling was initiated, the most current OFPC was produced in October 2016. For both gas and electricity, the front 72 months of the OFPC reflects market forwards at the close of the markets on a given trading day. For the October 2016 OFPC, prices over the front 72-months are based on market forwards as of October 12, 2016. The blending period (months 73 through 84) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp (Aurora), a WECC-wide market model.[3] Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp reviews third party natural gas price forecasts each quarter for the OFPC, and as a corollary, the electricity OFPC is also updated. Scenarios, unlike the OFPC, do not incorporate market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, both electricity and natural gas price scenarios are fundamentals-based forecasts.

PacifiCorp's OFPC for electricity and each of its six scenarios were developed from one of three (low, base, high) underlying expert third-party natural gas price forecasts in conjunction with one of three CO_2 compliance designs tied to the CPP. PacifiCorp's base CO_2 compliance design, Mass Cap B, assumes a WECC-wide (excluding California) yearly CO_2 tonnage cap using EPA's allocation of state-specified allowances, with new source complement.[4] As such, Mass Cap B applies to both targeted existing and new-build resources. Mass Cap B assumes states receive their full allocation of allowances, based on historical generation, as promulgated in the CPP emission guidelines. When only modeling PacifiCorp's system, such as in the 2017 IRP, set-asides for the Clean Energy Incentive Program, output-based set-asides, and renewable set-asides were subtracted from the overall cap as part of Mass Cap B. However, when developing WECC-wide price forecasts, PacifiCorp did not subtract set-asides, assuming they would be allocated somewhere in the region. California was not modeled as part of the CPP since it was already modeled to meet clean air targets established under the (more stringent) California Global Warming Solutions Act (Assembly Bill 32). The October 12, 2016 OFPC was developed using Mass Cap B assumptions in conjunction with base natural gas prices. Two alternative electricity price scenarios, assuming low and high natural gas prices, were also produced under Mass Cap B assumptions.

Another three electricity price scenarios were generated by Aurora with Mass Cap A assumptions—an alternative CPP compliance view. As such, each of the three underlying expert third-party natural gas price forecasts were modeled in Aurora using Mass Cap A compliance targets. Mass Cap A differs from Mass Cap B only in that it does not include the new source complement. Finally a CO_2 price scenario was produced that combined the underlying base natural gas price forecast with a plausible CO_2 price assumption as an alternative to the CPP. Thus, in total, seven (including the OFPC) wholesale electricity price forecasts were produced using three natural gas price forecasts in conjunction with different CO_2 compliance paradigms.

Figure 7.5 summarizes the seven wholesale electricity price forecasts and three natural gas price forecasts used in core and sensitivity cases for the 2017 IRP. By the end of the 20-year planning horizon, wholesale power prices range from just below $48/MWh to over $93/MWh and Henry Hub natural gas prices range from $4.75/MMBtu to over $10.00/MMBtu.

---

[3] AURORAxmp is a production cost simulation model, developed by EPIS, LLC.

[4] Plausible allocation designs are based on EPA's Clean Power Plan, as finalized August 3, 2016 and authorized by §111(d) of the Clean Air Act.

Figure 7.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios

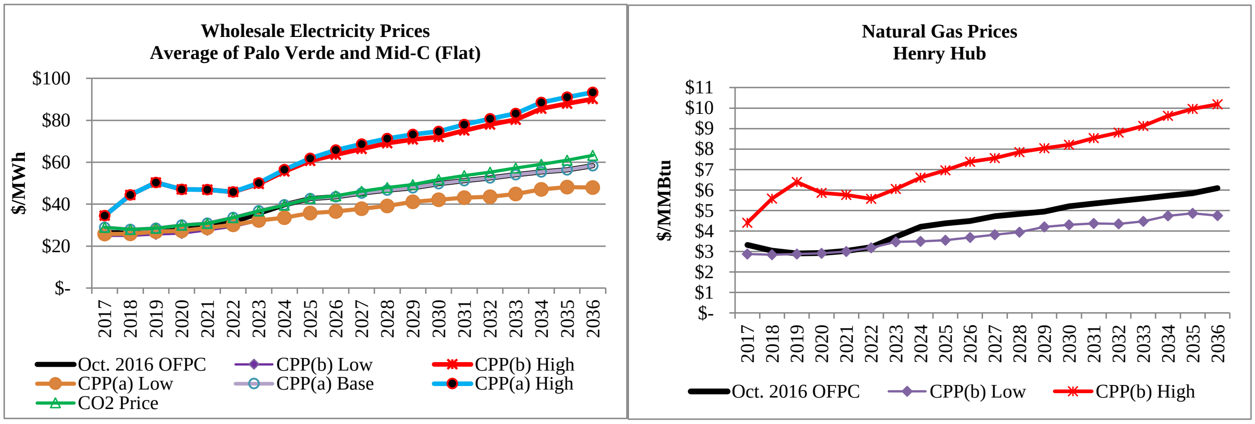


Figure 7.6 through Figure 7.8 illustrate the CPP constraints in relation to regional emissions from the price curve development process discussed above. The CPP does not constrain emissions except in the high as price scenarios, indicating that under base natural gas and low natural gas futures, regional emission targets will be lower than those required by the CPP.

Figure 7.6 – U.S.WECC CO_2 Emissions, Base Natural Gas Prices

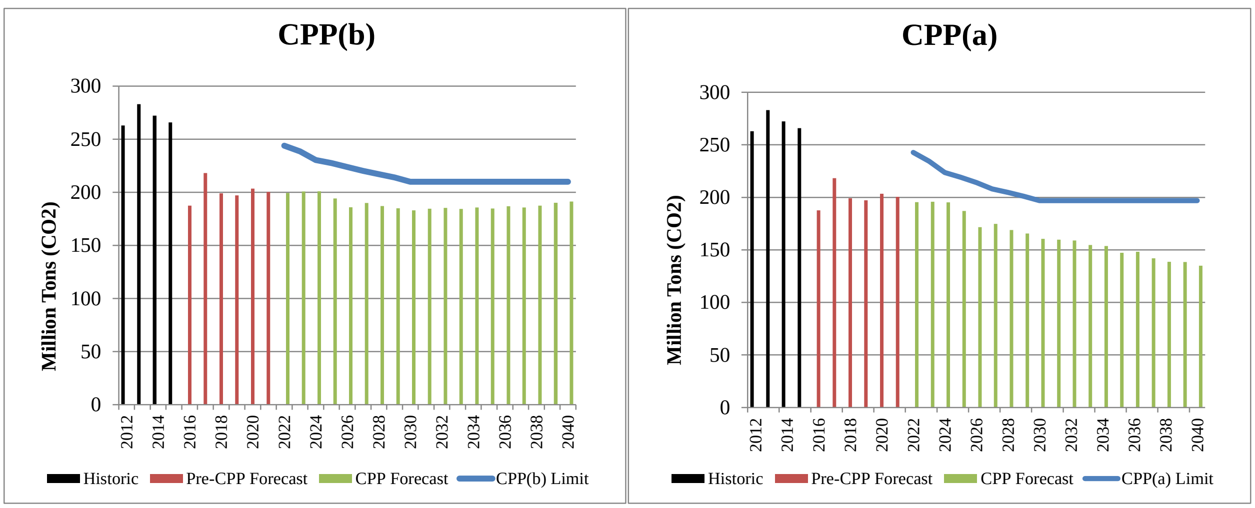


Figure 7.7 – U.S.WECC CO_2 Emissions, Low Natural Gas Prices

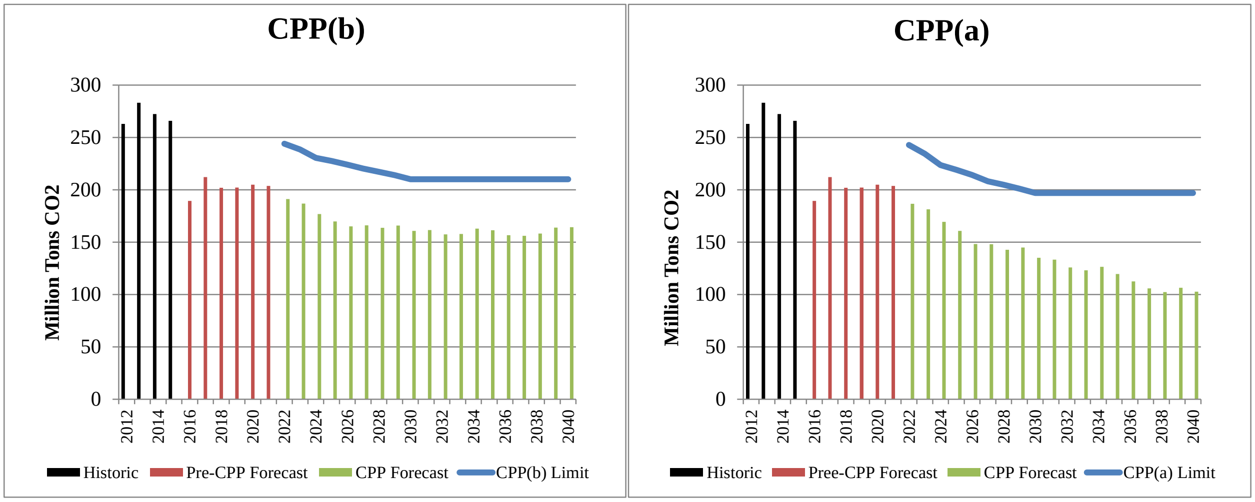
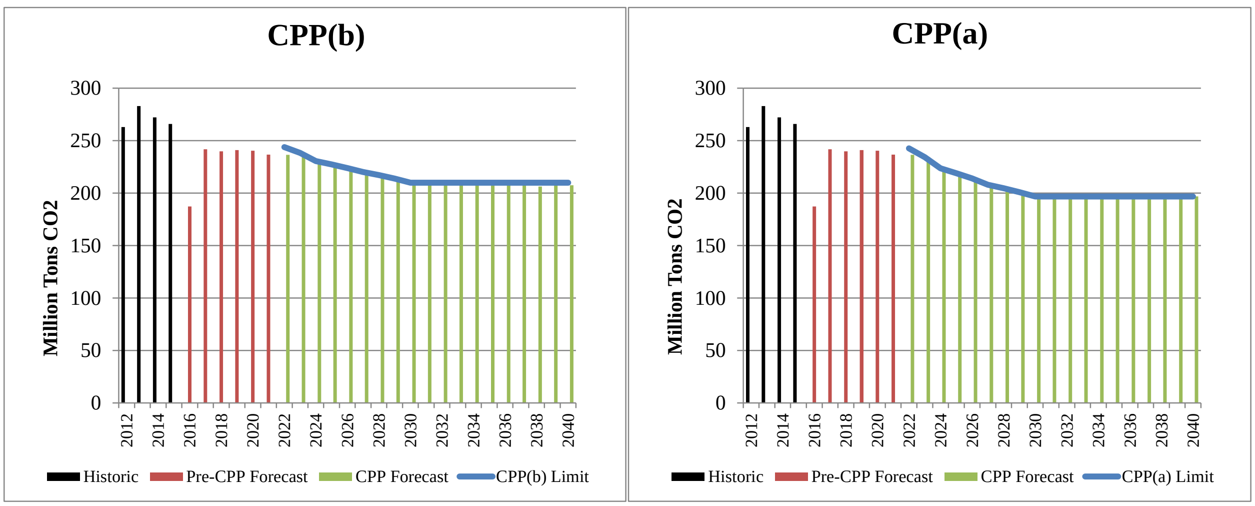


Figure 7.8 - U.S. WECC CO_2 Emissions, High Natural Gas Prices



PacifiCorp System CPP Shadow Prices

During the Regional Haze portfolio screening stage, the selected Regional Haze portfolio is run through each of the six price-emissions scenarios, producing six sets of outcomes for analysis. The results of these studies established CO_2 shadow prices representing the marginal cost, measured in dollars per ton, to achieve the CPP (Mass Cap A and Mass Cap B) emission caps applied to PacifiCorp's system for each price wholesale market price scenario (low, base and high). Thus, CO_2 shadow prices were developed for each of the six price-emissions scenarios. These shadow price results were used in stochastic model optimizations (see Cost and Risk section below) as a cost-driver designed to avoid exceeding relevant emission caps when analyzing each portfolio in PaR.

Particulate Matter Emissions

The Washington Utilities and Transportation Commission (WUTC) requested that investor-owned utilities in Washington start incorporating the non-energy benefits of fine particular matter ($PM_{2.5}$) emissions in conservation and energy planning calculations going forward, including incorporating these benefits into the IRP. In further discussion with WUTC staff to clarify this request, it became clear that staff was requesting a broad health impacts analysis (and potentially other societal impacts) of PacifiCorp's generating resources. Following further clarification and conversation with WUTC staff, both staff and PacifiCorp agreed that it would not be feasible to conduct such an analysis for this IRP (either focused on $PM_{2.5}$ or other emissions), but that this issue may be raised in future IRPs. Generally, PacifiCorp considers health assessments and other societal externalities to be outside the scope of the IRP, which focuses on the economic costs of various resource decisions including direct costs to serve our customers.

Cost and Risk Analysis

Planning and Risk (PaR)

PaR uses the same common input assumptions described for SO with additional data provided by the SO outcomes (e.g., CO_2 shadow prices and the selected resource portfolio). While SO supplies a capacity view basis for determination of optimized portfolios for each case, PaR is able to bring the advantages of stochastic-driven risk metrics to the evaluation of the studies. While PaR cost-risk metrics are ultimately used in the preferred portfolio selection, SO results remain valuable and informative, especially in their role as a magnitude and direction indicator to compare to PaR outcomes.

Cost and Risk Analysis

Once unique resource portfolios are developed using SO, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed with PaR.

The stochastic simulation in PaR produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The PaR simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.[5] Wind and solar generation is not modeled with stochastic parameters; however, the incremental reserve requirements associated with uncertainty and variability in wind generation, as determined in the updated flexible reserve study, are captured in the stochastic simulations. PacifiCorp's updated flexible reserve study is provided in Volume II, Appendix F (Flexible Reserve Study).

The stochastic parameters used in PaR for the 2017 IRP are developed with a short-run mean reverting process, whereby mean reversion represents a rate at which a disturbed variable returns to its expected value. Stochastic variables may have log-normal or normal distribution as appropriate. The log-normal distribution is often used to describe prices because such distribution is bounded on the low end by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average. Unlike prices, load generally does not have such skewed distribution and is generally better described by a normal distribution. Volatility and

[5] FOTs included in resource portfolios developed using System Optimizer are subject to the Monte Carlo random sampling of wholesale electricity prices in PaR.

mean reversion parameters are used for modeling the volatilities of the variables, while accounting for seasonal effects. Correlation measures how much the random variables tend to move together.

Stochastic Model Parameter Estimation

Stochastic 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. The stochastic parameters are used to drive the stochastic processes of the following variables:

- Representative natural gas prices for PacifiCorp's east and west BAAs;
- Electricity market prices for Mid-C, COB, Four Corners, and Palo Verde;
- Loads for California, Idaho, Oregon, Utah, Washington and Wyoming regions; and
- Hydro generation.

Volume II, Appendix H of this report discusses the methodology on how the stochastic parameters for the 2017 IRP were developed.

For unplanned thermal outages, PacifiCorp assumes a uniform distribution around an expected rate. For existing units, the expected unplanned outage rates by unit are based on its historical performance during the 4-year period ended December 2015. For new resources, the unplanned outage rates are as specified for those resources as listed in the supply side resource table in Chapter 6.

Table 7.2 – Short Term Load Stochastic Parameters

Short-term Volatility	CA/OR without Portland	Portland	ID	UT	WA	WY
Winter 2017 IRP	0.044	0.033	0.031	0.022	0.049	0.017
Spring 2017 IRP	0.034	0.029	0.052	0.029	0.038	0.016
Summer 2017 IRP	0.038	0.039	0.048	0.045	0.048	0.016
Fall 2017 IRP	0.041	0.034	0.049	0.033	0.044	0.017
Short-term Mean Reversion	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2017 IRP	0.21	0.237	0.175	0.4	0.202	0.263
Spring 2017 IRP	0.278	0.204	0.097	0.398	0.25	0.271
Summer 2017 IRP	0.197	0.294	0.101	0.211	0.184	0.316
Fall 2017 IRP	0.218	0.268	0.21	0.287	0.184	0.192

Table 7.3 - Short Term Gas Price Parameters

Short-Term Volatility	East Natural Gas	West Natural Gas
Winter 2017 IRP	0.132	0.14
Spring 2017 IRP	0.104	0.1
Summer 2017 IRP	0.027	0.042
Fall 2017 IRP	0.028	0.06
Short-term Mean Reversion	**East Natural Gas**	**West Natural Gas**
Winter 2017 IRP	0.219	0.197
Spring 2017 IRP	0.652	0.537
Summer 2017 IRP	0.068	0.125
Fall 2017 IRP	0.06	0.157

Table 7.4 - Short Term Electricity Price Parameters

Short-Term Volatility	Four Corners	COB	Mid- Columbia	Palo Verde
Winter 2017 IRP	0.106	0.136	0.162	0.106
Spring 2017 IRP	0.087	0.229	0.42	0.058
Summer 2017 IRP	0.105	0.235	0.383	0.088
Fall 2017 IRP	0.066	0.074	0.079	0.05
Short-term Mean Reversion	**Four Corners**	**COB**	**Mid- Columbia**	**Palo Verde**
Winter 2017 IRP	0.129	0.135	0.138	0.16
Spring 2017 IRP	0.466	0.435	0.51	0.308
Summer 2017 IRP	0.27	0.39	0.91	0.252
Fall 2017 IRP	0.372	0.227	0.188	0.247

Table 7.5 - Winter Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1					
Four Corners	0.531	1				
COB	0.271	0.538	1			
Mid - Columbia	0.268	0.528	0.965	1		
Palo Verde	0.521	0.785	0.714	0.684	1	
Natural Gas West	0.919	0.46	0.28	0.275	0.451	1

Table 7.6 - Spring Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1					
Four Corners	0.131	1				
COB	0.085	0.421	1			
Mid - Columbia	0.057	0.347	0.862	1		
Palo Verde	0.18	0.639	0.456	0.328	1	
Natural Gas West	0.874	0.118	0.09	0.059	0.144	1

Table 7.7 - Summer Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1					
Four Corners	0.074	1				
COB	0.104	0.449	1			
Mid - Columbia	0.055	0.345	0.661	1		
Palo Verde	0.109	0.841	0.525	0.369	1	
Natural Gas West	0.563	0.097	0.131	0.054	0.132	1

Table 7.8 - Fall Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1					
Four Corners	0.137	1				
COB	0.072	0.452	1			
Mid - Columbia	0.041	0.376	0.853	1		
Palo Verde	0.166	0.734	0.501	0.368	1	
Natural Gas West	0.347	0.063	0.027	0.043	0.006	1

Table 7.9 - Hydro Short Term Stochastic

	Short-term Volatility	Short-Term Mean Reversion
Winter 2017 IRP	0.208	0.806
Spring 2017 IRP	0.134	0.373
Summer 2017 IRP	0.149	1.436
Fall 2017 IRP	0.28	1.056

Figure 7.9 and Figure 7.10 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for Mid-C and Palo Verde market hubs based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Mid-C electricity prices, differences between the first and 99th percentiles range from \$4.69/MWh to \$10.69/MWh during the 20-year study period. For Palo Verde electricity prices, the difference between the first and 99th percentiles range from \$2.72/MWh to \$3.88/MWh.

Figure 7.9 - Simulated Annual Mid-C Electricity Market Prices

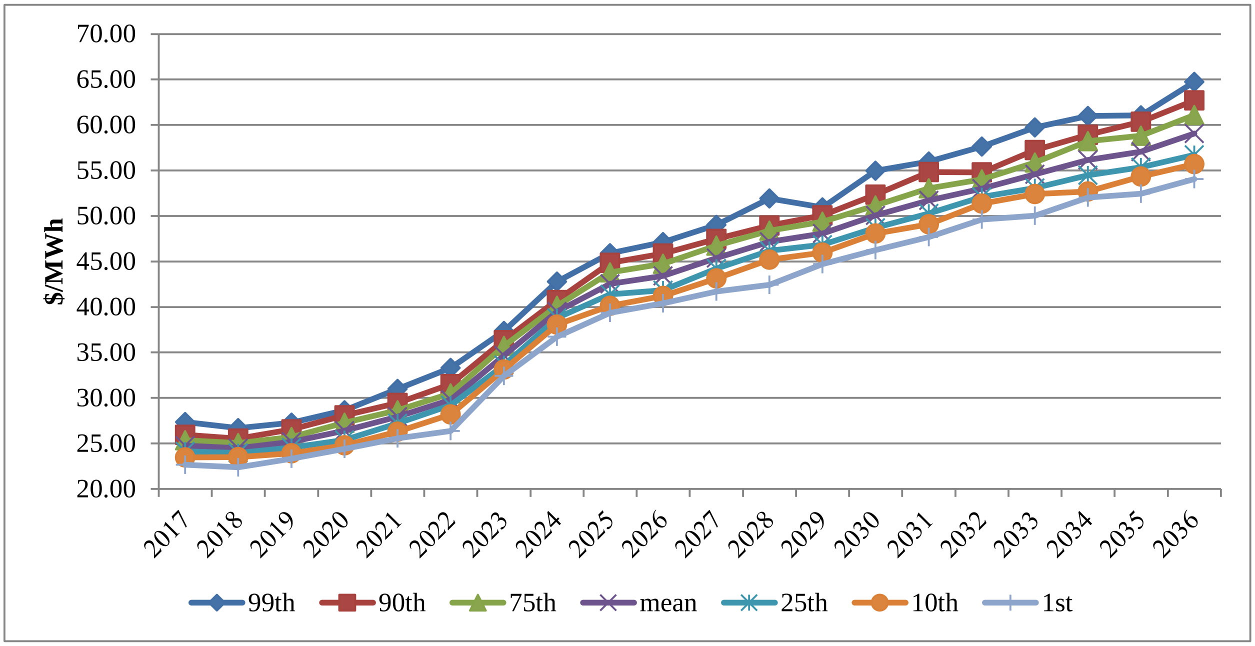


Figure 7.10 - Simulated Annual Palo Verde Electricity Market Prices

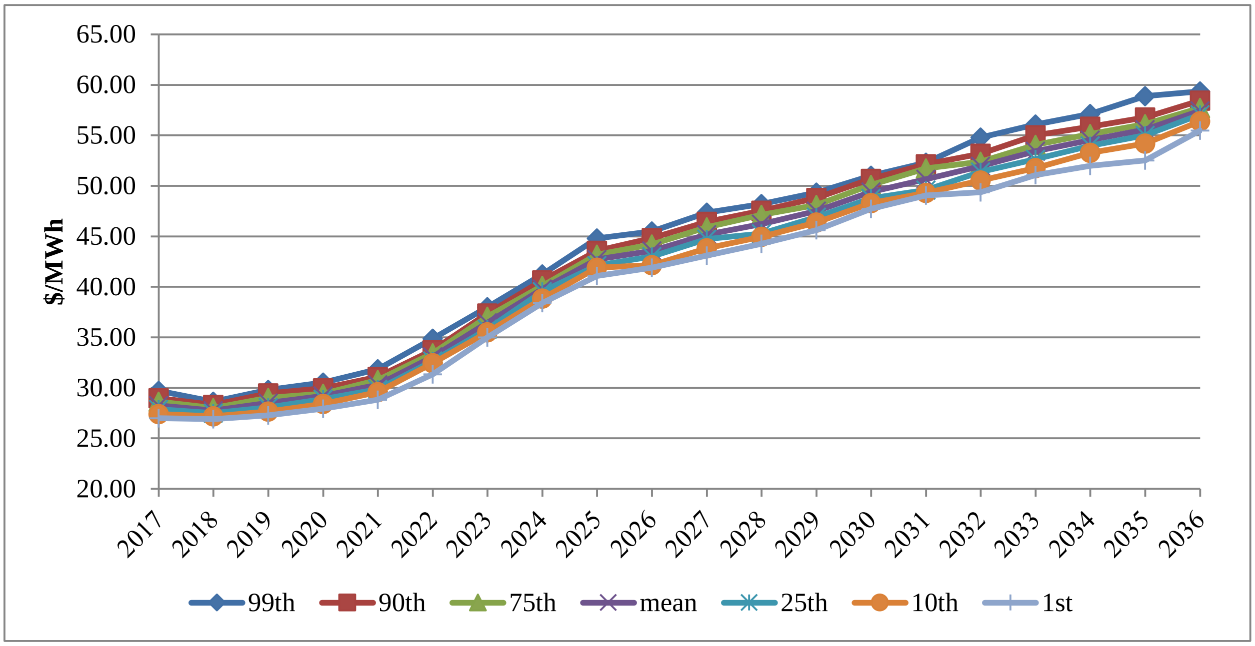


Figure 7.11 and Figure 7.12 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for west and east natural gas prices. For west natural gas prices, differences between the first and 99th percentiles range from \$0.22/MMBtu to \$0.48/MMBtu during the 20-year study period. For east natural gas prices, differences between the first and 99th percentiles range from \$0.27/MMBtu to \$0.53/MMBtu.

Figure 7.11 - Simulated Annual Western Natural Gas Market Prices

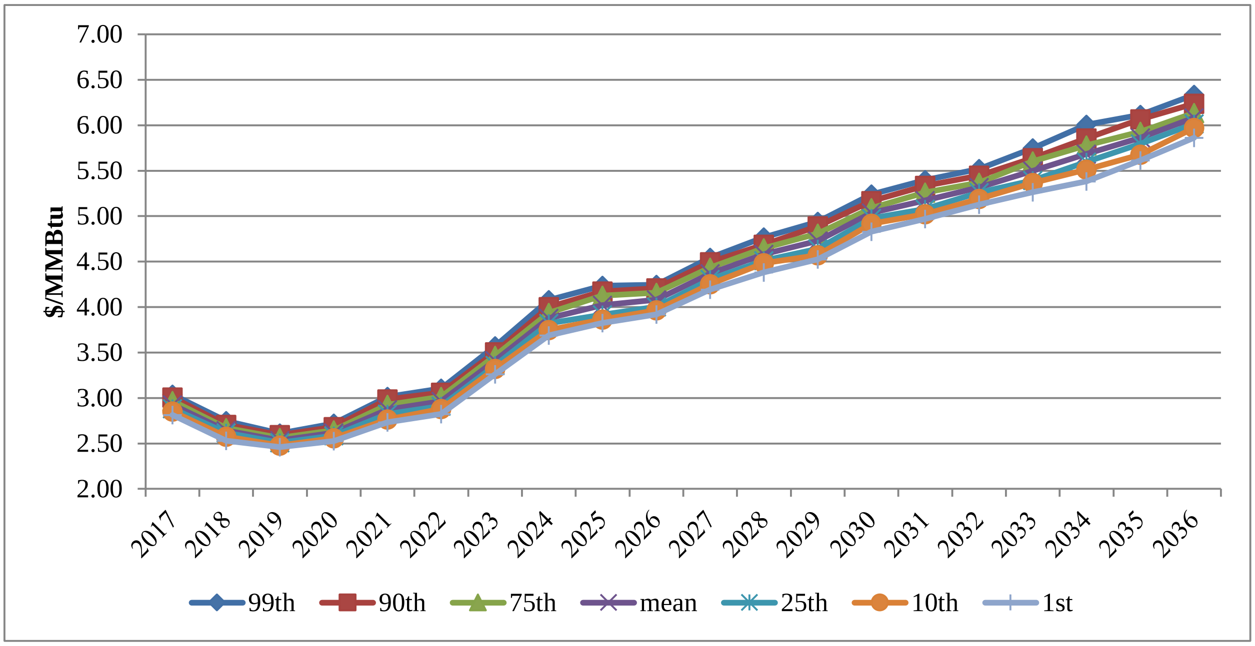


Figure 7.12 - Simulated Annual Eastern Natural Gas Market Prices

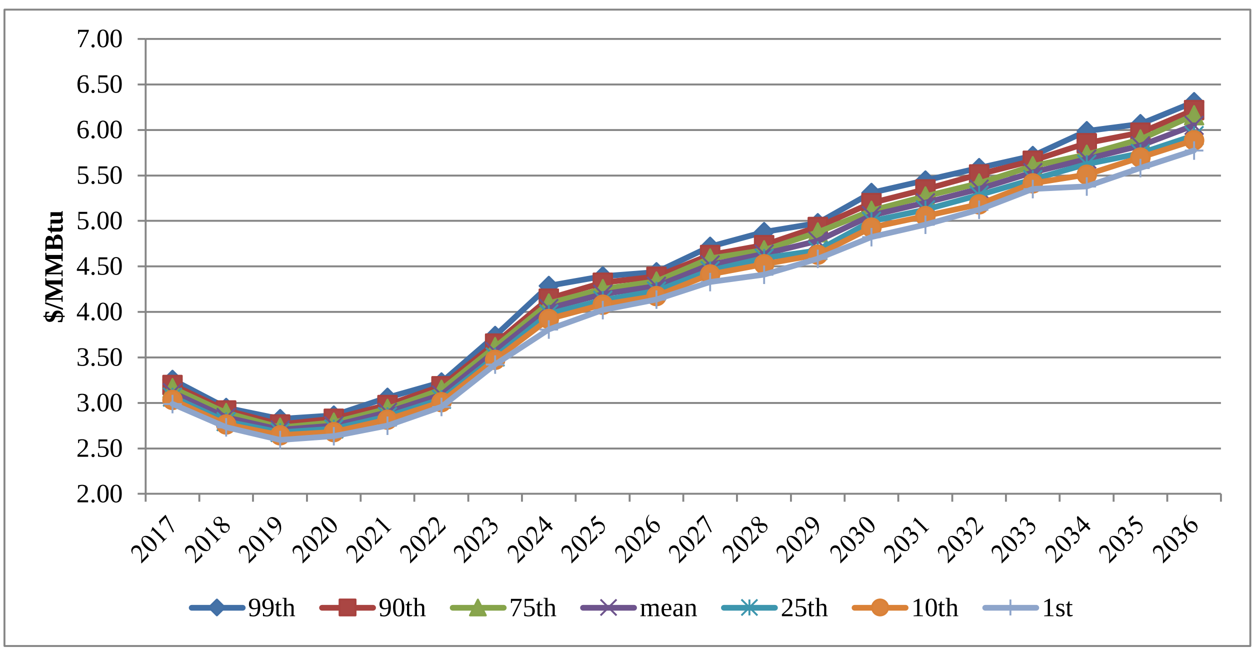


Figure 7.13 through Figure 7.18 show annual loads by load area and for PacifiCorp's system at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Idaho (Goshen) load, the annual differences between the first and 99th percentiles range from 184 GWh to 382 GWh. For Utah load, the annual difference ranges from 1,408 GWh to 2,683 GWh. For Wyoming load, the annual difference range from 139 GWh to 279 GWh. For Oregon/California load, annual differences range from 895 GWh to 1,551 GWh. For Washington load, the annual difference ranges from 233 GWh to 473 GWh. For PacifiCorp's system load, the annual difference ranges from 2,110 GWh to 4,643 GWh.

Figure 7.13 - Simulated Annual Idaho (Goshen) Load

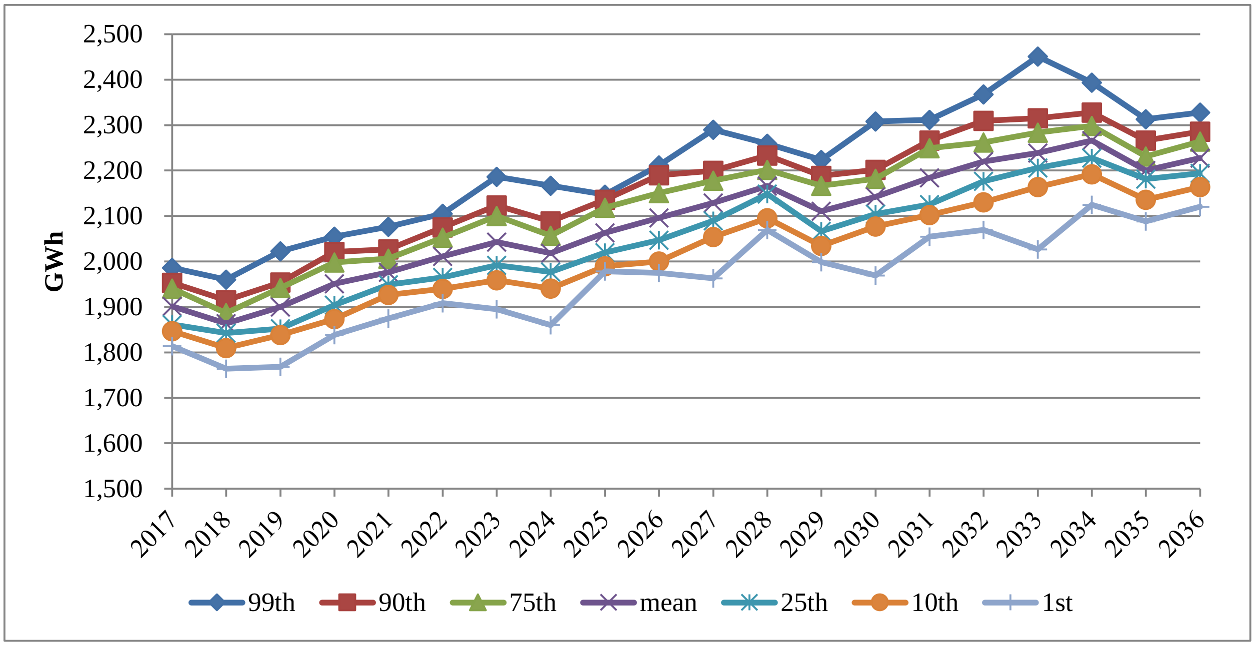


Figure 7.14 - Simulated Annual Utah Load

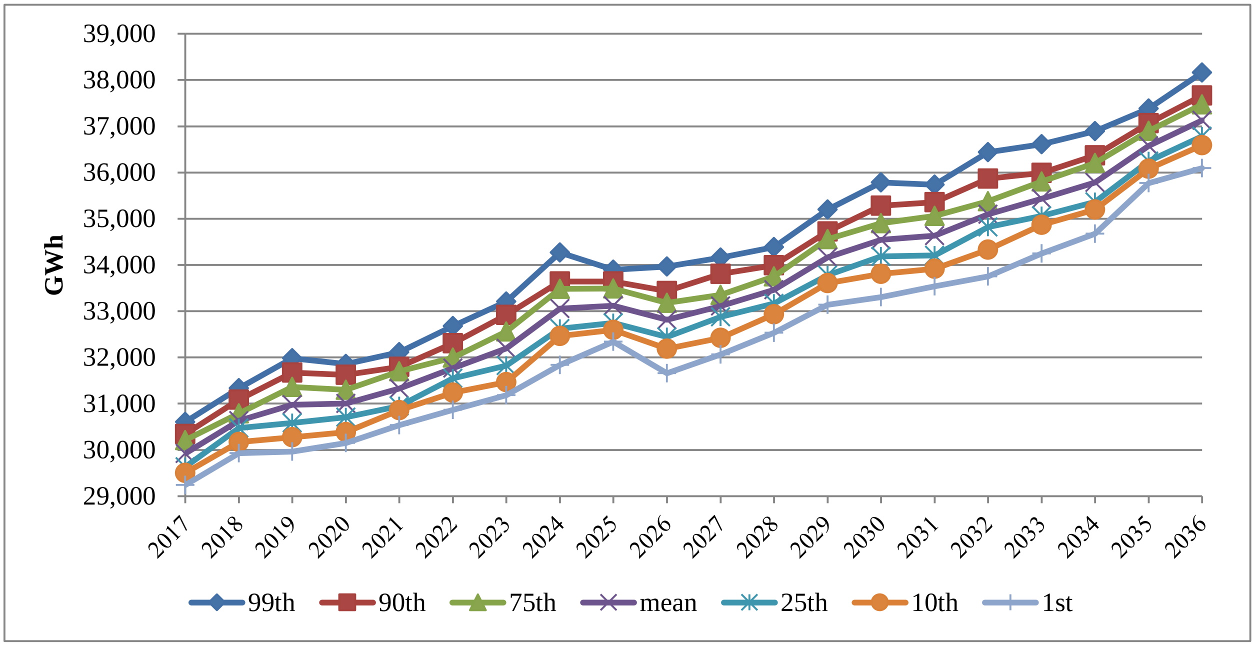


Figure 7.15 - Simulated Annual Wyoming Load

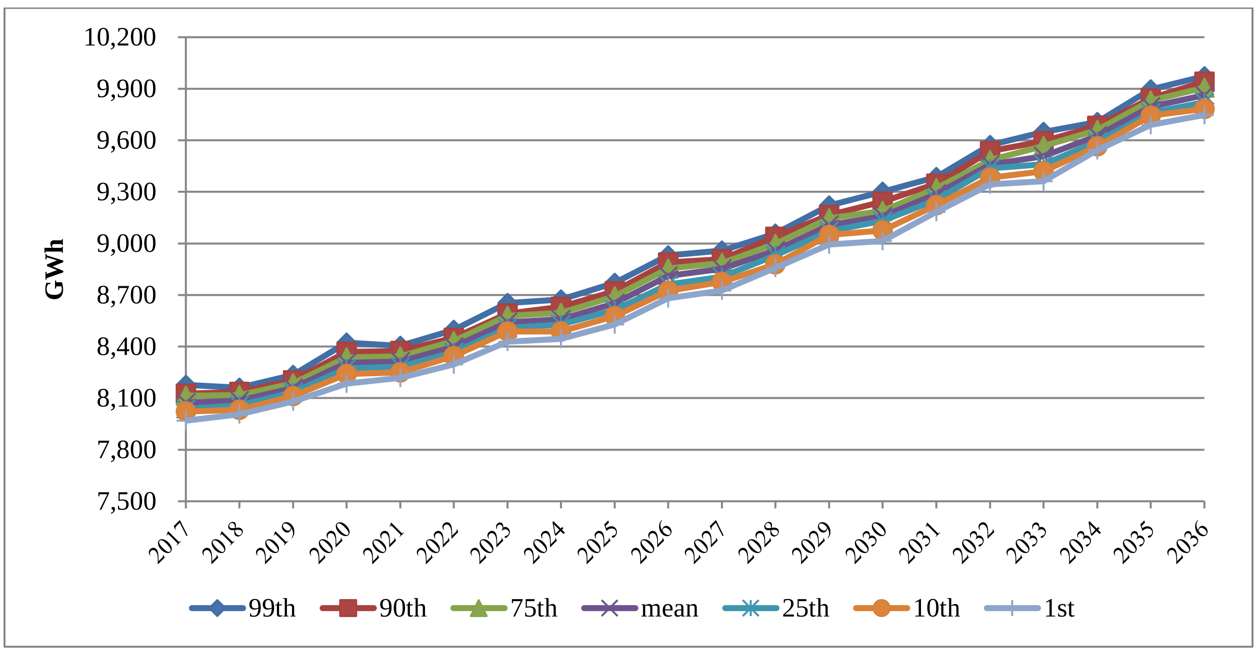


Figure 7.16 - Simulated Annual Oregon/California Load

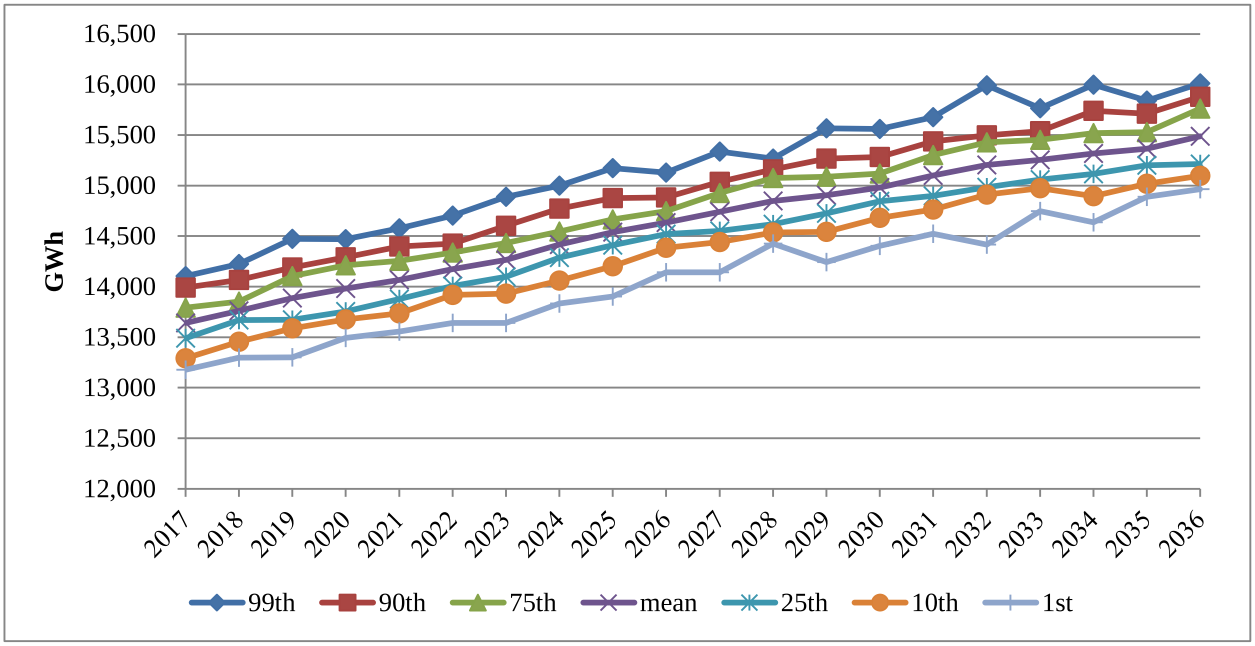


Figure 7.17 - Simulated Annual Washington Load

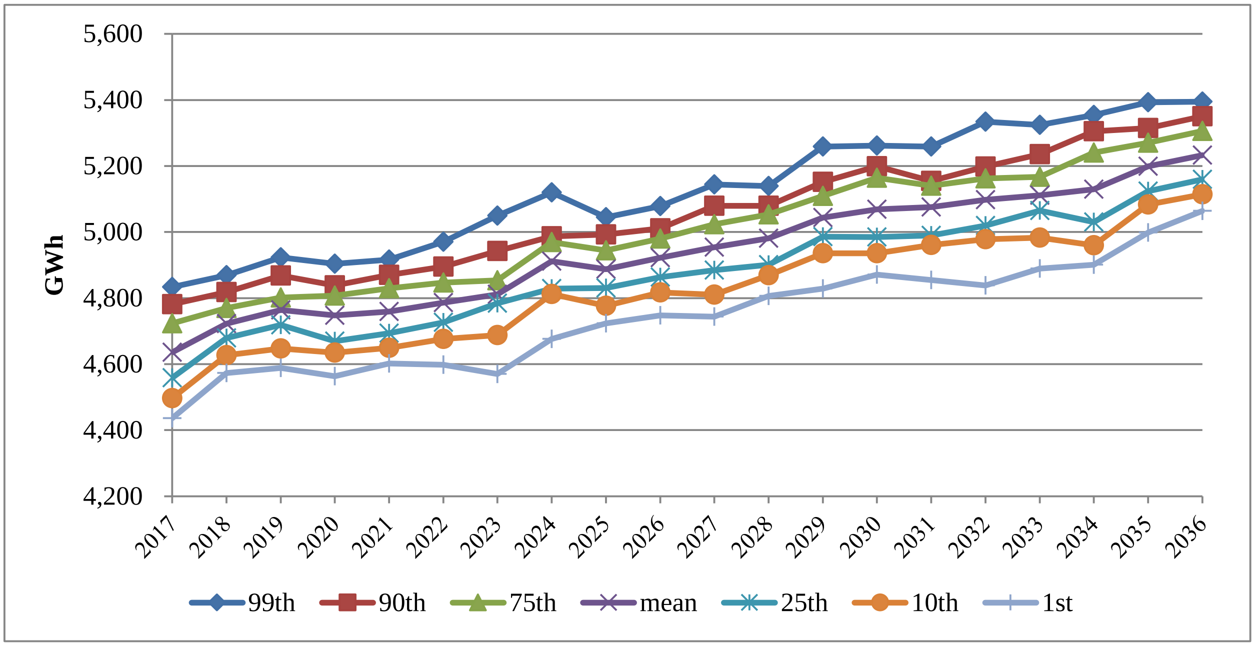


Figure 7.18 - Simulated Annual System Load

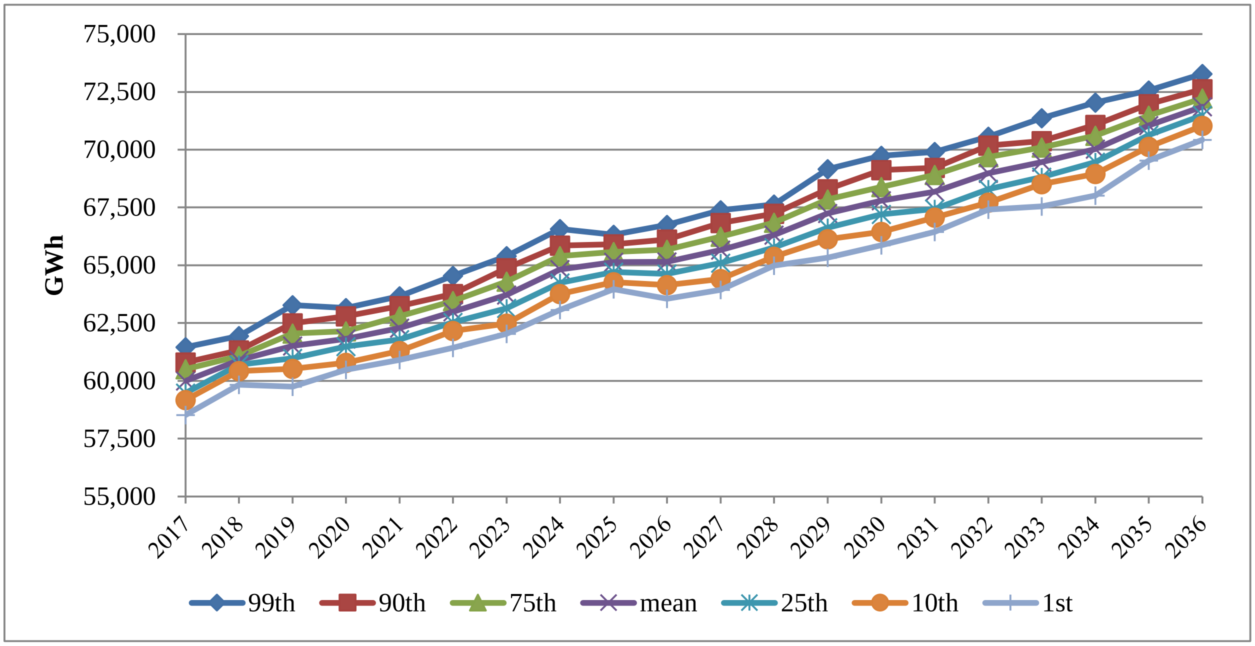
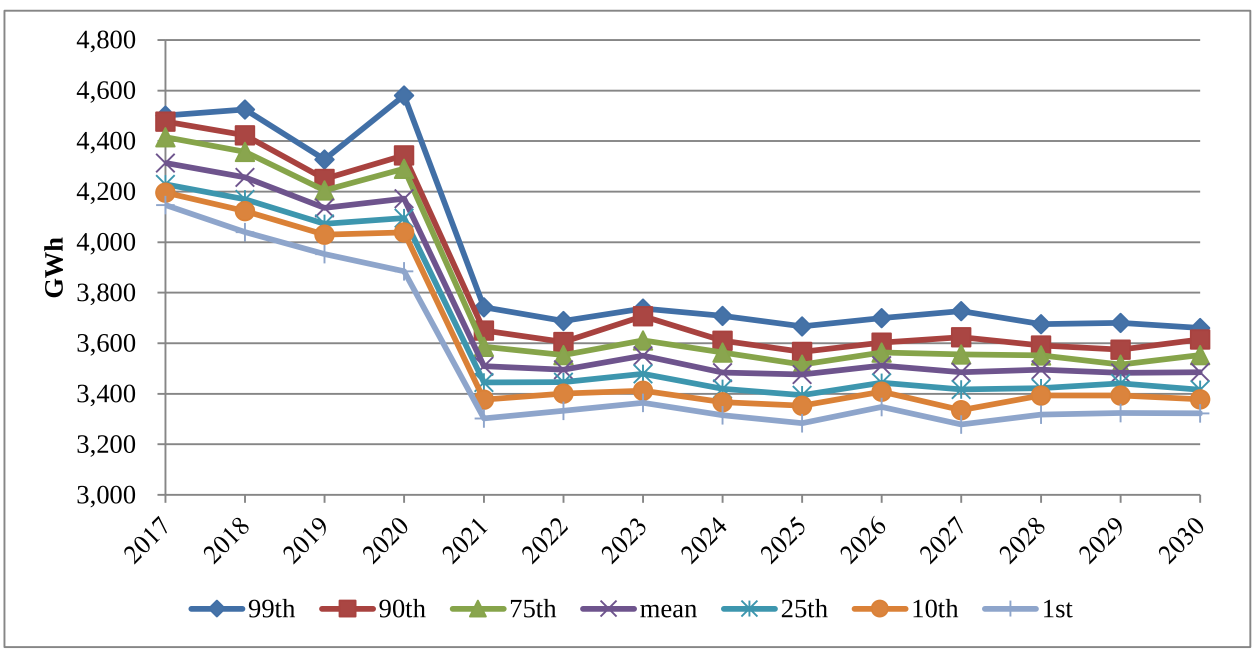


Figure 7.19 shows hydro generation at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. PacifiCorp can dispatch its hydro generation on a limited basis to meet load and reserve obligations. The parameters developed for the hydro stochastic process approximate the volatility of hydro conditions as opposed to variations due to dispatch. The drop in 2021 is due to the assumed decommissioning of the Klamath River projects. Annual differences in hydro generation between the first and 99th percentiles range from 286 GWh to 634 GWh.

Figure 7.19 - Simulated Annual Hydro Generation



Monte Carlo Simulation

During model execution, the PaR model makes time-path-dependent Monte Carlo draws for each stochastic variable based on input parameters. The Monte Carlo draws are percentage deviations from the expected forward value of each variable. The Monte Carlo draws of the stochastic variables among all resource portfolios modeled are the same, which allows for a direct comparison of stochastic results among all of the resource portfolios being analyzed. 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.

For the 2017 IRP, PaR is configured to conduct 50 Monte Carlo iterations for the 20-year study period. For each of the 50 Monte Carlo iterations, PaR generates a set of natural gas prices, electricity prices, loads, hydroelectric generation and thermal outages. Then, the model optimizes resource dispatch to minimize costs while meeting load and wholesale sale obligations subject to operating and physical constraints. In a 50-iteration simulation, the resource portfolio is fixed. The end result of the Monte Carlo simulation is 50 production cost figures for the 20-year study period reflecting a wide range of cost outcomes for the portfolio.

The expected values of the Monte Carlo simulation are the average result of all 50 iterations. Results from subsets of the 50 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, which are described below.

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from PaR include:

- Stochastic mean PVRR;
- Risk-adjusted mean PVRR;
- Upper-tail Mean PVRR;
- 5^{th} and 95^{th} percentile PVRR;
- Average annual mean and upper-tail energy not served (ENS);
- Loss of load probability; and
- Cumulative CO_2 emissions.

Stochastic Mean PVRR

The stochastic mean PVRR is the average of system net variable operating costs among 50 iterations, combined with the real levelized capital costs and fixed costs taken from SO for any given resource portfolio.[6] The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, unit start-up, market contracts, system balancing market purchases expenses and sales revenues, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources, taken from SO, are calculated on an escalated real-levelized basis. Other components in the stochastic mean

[6] Fixed costs are not affected by stochastic variables, and therefore, do not change across the 50 PaR iterations.

PVRR include fixed costs for new DSM resources in the portfolio, also taken from SO, and CO_2 emission costs for any scenarios that include a CO_2 price assumption.

Risk-Adjusted PVRR
The risk-adjusted PVRR incorporates the expected-value cost of low-probability, high cost outcomes. This measure is calculated as the PVRR of stochastic mean system variable costs plus five percent of system variable costs from the 95th percentile. The PVRR of system fixed costs, taken from SO, are then added to this system variable cost metric. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on 50 Monte Carlo simulations for each resource portfolio. 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.

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 three highest production costs on a net present value basis. The portfolio's real levelized fixed costs, taken from SO, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

95th and 5th Percentile PVRR
The 5th and 95th percentile PVRRs are also reported from the 50 Monte Carlo iterations. 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 mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation
To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 50 Monte Carlo iterations. The production cost is expressed as a net present value of annual costs over the period 2017 through 2036. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Average and Upper-Tail Energy Not Served
Certain iterations of a stochastic simulation will have ENS, a condition where there are insufficient resources, inclusive of system balancing purchases, available to meet load or operating reserve requirements because of physical constraints. This occurs when Monte Carlo draws of stochastic variables result in a load obligation that is higher than the capability of the available resources in the portfolio. For example, this might occur in Monte Carlo draws with large load shocks concurrent with a random unplanned plant outage event. Consequently, ENS, when averaged across all 50 iterations, serves as a measure of reliability that can be compared among resource portfolios. PacifiCorp calculates an average annual value over the 2017 through 2036 planning horizon, reported in gigawatt-hours, as well as the upper-tail ENS (average of the three iterations with the highest ENS). In the 2017 IRP, ENS is priced at $1,000/MWh.

Loss of Load Probability
Loss of load probability (LOLP) reports the probability and extent that available resources of a portfolio cannot serve load during the peak-load period of July in the 20-year period. PacifiCorp reports LOLP statistics, which are calculated from ENS events that exceed threshold levels.

Cumulative CO_2 Emissions
Annual CO_2 emissions from each portfolio are reported from PaR and summed for the twenty year planning period. Comparison of total CO_2 emissions is used to identify potential outliers among resource portfolios that might otherwise be comparable with regard to expected cost, upper-tail cost risk, and/or ENS.

Forward Price Curve Scenarios

Each of the unique resource portfolios developed with SO during the resource portfolio development process are analyzed in PaR among the six price-emissions scenarios. The price curve scenarios include PacifiCorp's October 2016 OFPC along with price curves developed assuming low and high natural gas price assumptions. PaR results using each of these scenarios inform selection of the preferred portfolio.

Price assumptions for each of these scenarios are subject to short-term volatility and mean reversion stochastic parameters when used in PaR. The approach for producing wholesale electricity and natural gas price scenarios used for PaR simulations is identical to the approach used to develop price scenarios for the resource portfolio development process.

Other PaR Modeling Methods and Assumptions

Transmission System
The transmission topology used for SO, shown in Figure 7.2, is identical to the transmission topology used for PaR simulations.

Resource Adequacy
The resource portfolio developed with SO, which meets an assumed 13 percent target planning reserve margin, is fixed in all PaR simulations. With fixed resources, the unit commitment and dispatch logic in PaR accounts for operating reserve requirements. These reserve requirements include contingency reserves, which are calculated as 3 percent of load and 3 percent of generation. In addition, PaR reserve requirements account for regulation reserves. PacifiCorp's regulation reserve assumptions are outlined in PacifiCorp's flexible reserve study, provided in Volume II, Appendix F.

Energy Storage Resources
PaR unit commitment is implemented 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.

General Assumptions
The general assumptions applied in SO for the study period (20-years beginning 2017) annual inflation rates (2.22 percent), and discount rates (6.57 percent) are also applied in PaR.

Other Cost and Risk Considerations

In addition to reviewing stochastic PVRR, ENS, and CO_2 emissions data from PaR, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity

PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, DSM resources and FOTs.

Customer Rate Impacts

To derive a rate impact measure, PacifiCorp computes the percentage change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the stochastic production cost results from PaR and capital costs reported by SO on a real levelized basis. The real levelized capital costs are adjusted to nominal dollars based on the timing of when new resources are added to the portfolio. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

Portfolio Selection

The final step in the evaluation process within each screening stage is portfolio selection. In the first screening stage portfolio selection step, the least-cost least-risk Regional Haze case is selected. In the second screening stage, the draft preferred portfolio is selected from among the cases eligible for consideration. In the final screening stage, the preferred portfolio is selected.

Within each screening stage, each portfolio under examination is compared on the basis of cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include the mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean ENS, upper-tail ENS, and emissions. The comparisons of outcomes are detailed, ranked, plotted and assessed in the next chapter (Volume I, Chapter 8: Modeling and Portfolio Selection Results).

Final Screening Stage and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final screening stage is the last opportunity to consider not only the draft preferred portfolio, but also significant indicators from all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps.

During the final screening process, the results of any further resource portfolio developments are ranked by risk-adjusted mean PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the low, base, and high price curve scenarios under both CPP scenarios. The average portfolio rank among each of the price curve scenarios is also produced. Resource portfolios with the lowest risk-adjusted mean PVRR receive the highest rank. Final screening also considers system cost PVRR data from SO and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional stochastic metrics from PaR looking to identify if expected and upper-tail ENS results and CO_2 emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted mean PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio during the resource portfolio development step of each screening stage. Regional Haze cases provide a range of compliance alternatives detailing coal unit retirement strategies. Core cases include combinations of alternative assumptions tailored to target specific resource technologies and that promotes resource diversity. Sensitivity cases isolate the impact to resource portfolio and system costs when modifying a single assumption. The resource portfolio and system cost data from sensitivity cases are compared to a benchmark case portfolio appropriate to the timing and needs of the sensitivity.

Regional Haze Case Definitions

Seven Regional Haze compliance scenarios were developed for planning purposes (the 'reference' case plus Regional Haze cases 1 through 6). In addition to analyzing known and prospective Regional Haze compliance requirements, PacifiCorp's portfolio development process incorporates compliance cost assumptions related to the Mercury and Air Toxics Standard (MATS), coal combustion residuals (CCR), effluent limit guidelines (ELG), and cooling water intake structures as may be required under the Clean Water Act (CWA).

Each Regional Haze case considered in the portfolio development process drives the timing and magnitude of run-rate capital and operations and maintenance costs for each individual coal unit in PacifiCorp's fleet. For instance, if a specific Regional Haze case assumes an early retirement for a given coal unit as part of a compliance plan, the run-rate operating costs for that unit are customized to reflect the assumed early closure date. This can include changes to the timing of planned maintenance throughout the twenty year planning horizon and avoidance of future costs related to known or assumed MATS, CCR, ELG or CWA compliance requirements, as applicable. If it poses a reasonable scenario, a given coal plant may continue operating until end-of-life, retire in an earlier year, convert to gas plant operations, or undergo a selective catalytic reduction (SCR) refit to continue operations with reduced emissions.

Regional Haze Case 6 is an endogenous retirement case, created in response to stakeholder feedback received during the public input process. The endogenous retirement case differs in approach from the designated retirement strategies embodied in the reference case and Regional Haze cases 1 through 5. Specifically, under Regional Haze Case 6:

- SO is configured to choose early retirement or SCR installation as competitive compliance outcomes.
- Cost impacts of early retirement alternatives are approximated for the following coal units: Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1, and Jim Bridger 2.
- Cost impacts assume that early retirement, if chosen by SO, occurs at the end of the month prior to the month SCR equipment would otherwise be installed.

Individual unit outcomes under any Regional Haze compliance case will ultimately be determined by ongoing rulemaking, results of litigation, and future negotiations with state and federal agencies, partner plant owners, and other vested stakeholders. While the Regional Haze case definitions represent a range of strategic paths to be evaluated, no individual unit commitments are being made at this time.

Table 7.10 summarizes Regional Haze case key assumptions for the seven compliance scenarios. The 2015 IRP Update assumptions are also included for reference.

Table 7.10 - Regional Haze Case Assumptions

Plant	2015 IRP Update (Pref. Port.)	2017 IRP (Ref. Case)	2017 IRP (Alt. Case RH-1)	2017 IRP (Alt. Case RH-2)	2017 IRP (Alt. Case RH-3)	2017 IRP (Alt. Case RH-4)	2017 IRP (Alt. Case RH-5)	2017 IRP (Alt. Case RH-6)
Hunter 1	SCR 2021 Ret. 2042	SCR 2021 Ret. 2042	No SCR;NO_X+ 2021 Ret. 2042	No SCR Ret. 2031	No SCR;NO_X+ 2026 Ret. 2042	SCR 2021[1] Ret. 2042	RH-1	SCR 8/4/2021 Ret 7/31/2021
Hunter 2	No SCR Ret. 2032	SCR 2021 Ret. 2042	No SCR;NO_X+ 2021 Ret. 2042	No SCR Ret. 2031	No SCR;NO_X+ 2027 Ret. 2042	No SCR;NO_X+ 2027[1] Ret. 2042	RH-1	SCR 8/4/2021 Ret 7/31/2021
Huntington 1	SCR 2022 Ret. 2036	SCR 2021 Ret. 2036	No SCR Ret. 2036	No SCR Ret. 2036	No SCR;NO_X+ 2026 Ret. 2036	SCR 2021[2] Ret. 2036	RH-1	SCR 8/4/2021 Ret 7/31/2021
Huntington 2	No SCR Ret. 2029	SCR 2021 Ret. 2036	No SCR Ret. 2036	No SCR Ret. 2036	No SCR;NO_X+ 2027 Ret. 2036	No SCR;NO_X+ 2027[2] Ret. 2036	RH-1	SCR 8/4/2021 Ret 7/31/2021
Jim Bridger 1	SCR 2022 Ret. 2037	SCR 2022 Ret. 2037	No SCR Ret. 2032	No SCR Ret. 2024	No SCR Ret. 2028	No SCR;NO_X+ 2022[1] Ret. 2032	RH-3	SCR 12/31/2022 Ret 12/30/2022
Jim Bridger 2	SCR 2021 Ret. 2037	SCR 2021 Ret. 2037	No SCR Ret. 2035	No SCR Ret. 2028	No SCR Ret. 2032	SCR 2021[1] Ret. 2037	RH-3	SCR 12/31/2021 Ret 12/30/2021
Naughton 3	No Gas Conv. Ret. 2017	Gas Conv. 2019[3] Ret. 2029	No Gas Conv. Ret. 2017	Gas Conv. 2019[3] Ret. 2029	No Gas Conv. Ret. 2017	Gas Conv. 2019[3] Ret. 2029	RH-2	No Gas Conv. Ret. 2017
Cholla 4	No Gas Conv. Ret. Apr-2025	Gas Conv. 2025 Ret. 2042	No Gas Conv. Ret. Apr-2025	No Gas Conv. Ret. 2020	No Gas Conv. Ret. Apr-2025	No Gas Conv. Ret. Apr-2025	RH-2	No Gas Conv. Ret. Apr-2025
Craig 1	SCR 2021 Ret. 2034	No SCR Ret. 2025	No SCR Ret. 2025	Gas Conv. 2023[4] Ret. 2034	No SCR Ret. 2025	No SCR Ret. 2025	RH-1	No SCR Ret. 2025

1 The Alternative Regional Haze cases for Hunter units 1 and 2 and Jim Bridger units 1 and 2 have been developed for analysis purposes only with consideration given to the fact that the emissions profiles for the units are effectively identical in the Regional Haze context. The compliance actions in this scenario could effectively be swapped and provide the same Regional Haze compliance outcome. The matrix presentation of different compliance actions between the units is necessary for analysis data preparation, but does not dictate or represent pre-determined individual partner plant owner strategies or preferences or individual unit strategies or preferences.

2 The Alternative Regional Haze cases for Huntington 1 and 2 have been developed for analysis purposes only with consideration given to the fact that the emissions profiles for the units are effectively identical in the Regional Haze context. The compliance actions for the units in this scenario could effectively be swapped and provide the same Regional Haze compliance outcome. The matrix presentation of different compliance actions between the units is necessary for analysis data preparation, but does not dictate or represent pre-determined individual unit strategies or preferences.

3 Naughton 3 will cease coal fueled operation by year-end 2017, under this scenario.

4 Craig 1 will cease coal fueled operation by end of August 2023, under this scenario.

Core Case Definitions

PacifiCorp defined six core cases to be modeled and examined as part of the second screening stage (eligible portfolios) of the 2017 IRP process. Informed by the public input process from current and prior IRP cycles, core cases target specific types of resources, promoting portfolio diversity and eliminating the need for deterministic risk analysis. Resources having operating characteristics not valued in SO are also analyzed in PaR during the cost and risk analysis phase of the portfolio development process. Doing so allows resources that may have been neglected due to the limitations of SO, the opportunity to take advantage of PaR model capabilities and stochastics-driven cost-risk metrics. The core case definitions reflect multiple combinations of planning assumptions.

Table 7.11 provides the core case definitions for this IRP, which are described in more detail in Chapter 8. Core case refinements and additions were modeled on the basis of outcomes and stakeholder feedback in the 2017 IRP public input process.

Table 7.11 - Core Case Definitions

Resource Class	Case 1 OP-1	Case 2 FR-1	Case 3 FR-2	Case 4 RE-1a	Case 4 RE-1b	Case 4 RE-1c	Case 5 RE-2	Case 6 DLC-1
Flexible Resources	Optimized	10% of Incremental L&R balance	20% of Incremental L&R balance	Optimized	Optimized	Optimized	Optimized	Optimized
Renewable Resources	Optimized	Optimized	Optimized	Just-in-Time Physical RPS Compliance (OR)	Just-in-Time Physical RPS Compliance (WA)	Just-in-Time Physical RPS Compliance (OR and WA)	Early Physical Compliance	Just-in-Time Physical RPS Compliance (OR and WA)
Class 1 DSM Resources	Optimized	Optimized	Optimized	Optimized	Optimized	5% of Incremental L&R balance	Optimized	5% of Incremental L&R balance
All other Resources	Optimized	Optimized	Optimized	Optimized	Optimized	Optimized	Optimized	Optimized

Case 1: Optimized Portfolio (OP-1)
This case is the least-cost-least-risk Regional Haze case emerging from screening stage 1. The Regional Haze case with the best cost-risk metrics is promoted to become core case 1, and serves as the basis for further studies, including the remaining core cases and sensitivities. Therefore, as with the underlying Regional Haze case, all resources have been optimized (selected endogenously by SO), and analyzed in PaR.

Case 2: Flexible Resources (FR-1)
Fast ramp resources are added with a capacity of at least 10 percent of the system L&R need. Fast-ramp resources available for selection include: SCCT Aero (i.e., LM6000); Intercooled SCCT Aero (i.e., LMS100); IC Reciprocating Engines; pumped storage, compressed air energy storage, and battery storage.

Case 3: Flexible Resources (FR-2)
As with FR-1, fast ramp resources are added but with a capacity of at least 20 percent of the system L&R need.

Case 4: Renewable Energy (RE-1)
Endogenous renewables from core case 1 (OP-1) are retained. Additional renewables are added to physically comply with projected Oregon and Washington renewable portfolio standard (RPS) requirements, with additions made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance).

Case 5: Renewable Energy (RE-2)
As with RE-1, endogenous renewables from core case 1 (OP-1) are retained. Additional renewables are added to physically comply with projected Oregon RPS requirements, with additions are made in 2021 (proxy for year-end 2020) to meet requirements throughout the planning period (early compliance).

Case 6: Direct Load Control (DLC-1)
Additional Direct Load Control (DLC) is added to core case 1 (OP-1) in the first year (2021), with a capacity of at least 5 percent of the system load & resource balance need. Renewable resource assumptions are taken from core case 4 (RE-1).

Additional details on core cases can be found in Appendix M: Case Study Fact Sheets.

Sensitivity Case Definitions

PacifiCorp initially identified 16 sensitivities based on prior IRP cycle experience, stakeholder feedback, and anticipated areas of interest. Additional sensitivities were identified during the 2017 IRP cycle, and are described in Volume I, Chapter 8. Each sensitivity is designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. Note that some sensitivities are considered eligible for preferred portfolio selection in screening stages 2 and 3 of the IRP process. Other sensitivities are for informational purposes and serve to illustrate how the system behaves under a variety of conditions that may be theoretically possible but which cannot be supported on the basis of cost-risk metrics (e.g., the 1-in-20 load sensitivity).

Table 7.12 - Sensitivity Definitions

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway
RH2a	Regional Haze	OP-1	Base	Base	Mass Cap B	Base	None
LD-1	1 in 20 Loads	OP-1	1 in 20	Base	Mass Cap B	Base	None
LD-2	Low Load	OP-1	Low	Base	Mass Cap B	Base	None
LD-3	High Load	OP-1	High	Base	Mass Cap B	Base	None
PG-1	Low Private Gen	OP-1	Base	Low	Mass Cap B	Base	None
PG-2	High Private Gen	OP-1	Base	High	Mass Cap B	Base	None
CPP-C	CPP Mass Cap C	OP-1	Base	Base	Mass Cap C	Base	None
CPP-D	CPP Mass Cap D	OP-1	Base	Base	Mass Cap D	Base	None
FOT-1	Limited FOT	OP-1	Base	Base	Mass Cap B	Restricted	None
CO2-1	CO_2 Price	OP-1	Base	Base	Tax, No CPP	Base	None
NO-CO2	No CO_2	OP-NT3	Base	Base	No Tax, No CPP	Base	None
BP	Business Plan	OP-NT3	Base	Base	Mass Cap D	Base	None
GW1	Gateway 1	OP-NT3	Base	Base	Mass Cap B	Base	Segment D
GW2	Gateway 2	OP-NT3	Base	Base	Mass Cap B	Base	Segment F
GW3	Gateway 3	OP-NT3	Base	Base	Mass Cap B	Base	Segment D&F
GW4	Gateway 4	OP-NT3	Base	Base	Mass Cap B	Base	Segment D2
Battery	Battery Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2
CAES	CAES Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2
WCA	WCA	FS-REP	Base	Base	Mass Cap B	Base	None
WCA-RPS	WCA RPS	FS-REP	Base	Base	Mass Cap B	Base	None

Additional details on the sensitivity cases can be found in Volume II, Appendix M: Case Study Fact Sheets.

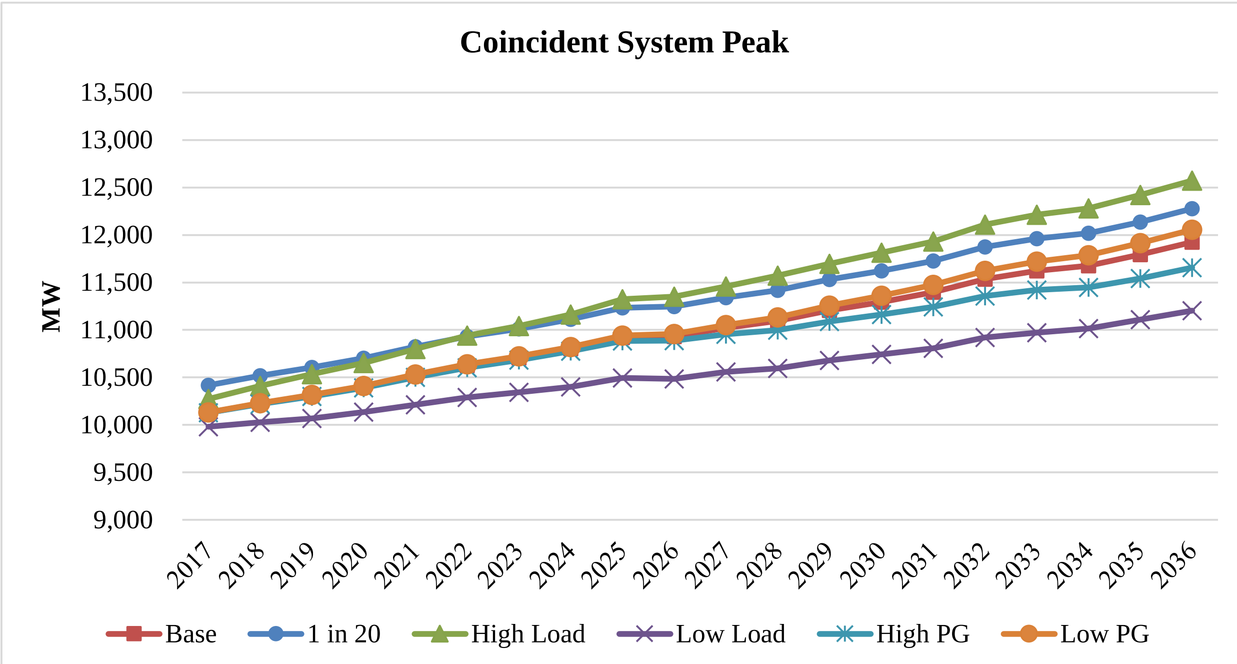
Regional Haze Sensitivities

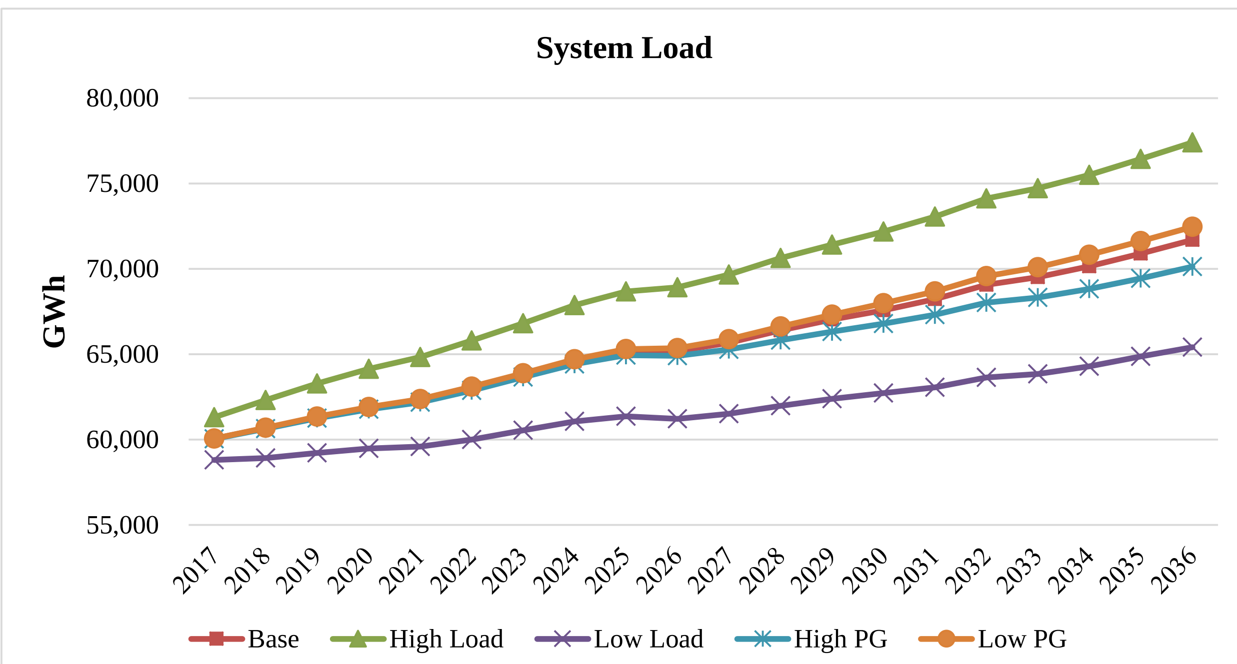
An additional sensitivity (RH-2a) was performed relevant to Region Haze case 2 (RH-2) in response to stakeholder feedback at the PacifiCorp IRP January 26-27, 2017 public input meeting. As a result, the selected Regional Haze case (RH-5) was modified and re-optimized, becoming RH-5a. Both additional cases are described in Volume 1, Chapter 8.

Load Sensitivities

PacifiCorp includes three different load forecast sensitivities. The low load forecast sensitivity reflects pessimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The high load forecast sensitivity reflects optimistic economic growth assumptions from IHS Global Insight and high Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The low and high industrial load forecast is taken from 5^{th} and 95^{th} percentile. The third load forecast sensitivity is a 1-in-20 (5 percent probability) extreme weather scenario. The 1-in-20 peak weather scenario is defined as the year for which the peak has the chance of occurring once in 20 years. This sensitivity is based on 1-in-20 peak weather for July in each state. Figure 7.20 compares the low, high, and 1-in-20 load sensitivities, net of base case distributed generation penetration levels, alongside the base case load forecast.

Figure 7.20 - Load Sensitivity Assumptions

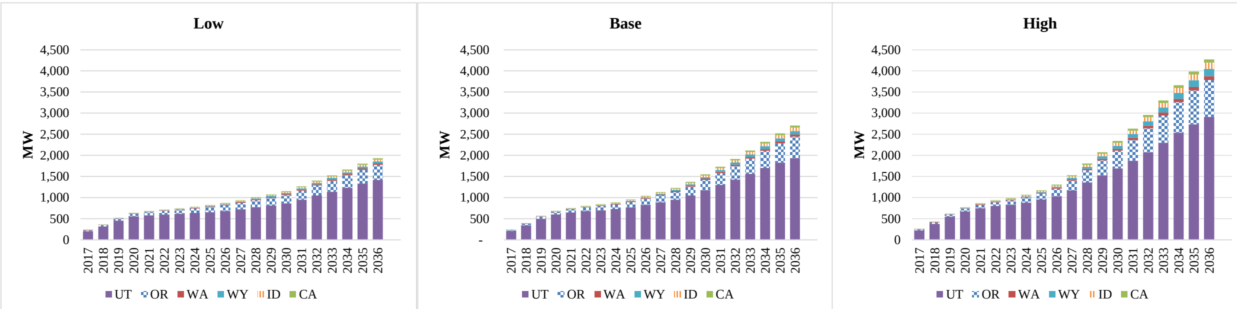




Private Generation Sensitivities

Two private generation sensitivities are analyzed. As compared to base private generation penetration levels that incorporated annual reductions in technology costs, the low private generation sensitivity reflects reduced reductions in technology costs, reduced technology performance levels, and lower retail electricity rates. In contrast, the high private generation sensitivity reflects more aggressive technology cost reduction assumptions, higher technology performance levels, and higher retail electricity rates. Figure 7.21 summarizes private generation penetration levels for the low and high sensitivities alongside the base case.

Figure 7.21 - Private Generation Sensitivity Assumptions



CPP Mass Cap C

CPP Mass Cap C: Mass-based compliance approach with pro-rata allowance allocation to PacifiCorp based on historical generation with no new source complement ***less*** the CEIP, renewable and output-based set-asides. It is assumed that PacifiCorp does not receive any of these set-asides.

CPP Mass Cap D

Mass Cap D: CPP with no set-aside program and with new source complement. The new source compliment assumes that the mass-based limit grows to accommodate new resources that are needed to meet load growth.

Limited Availability of FOTs

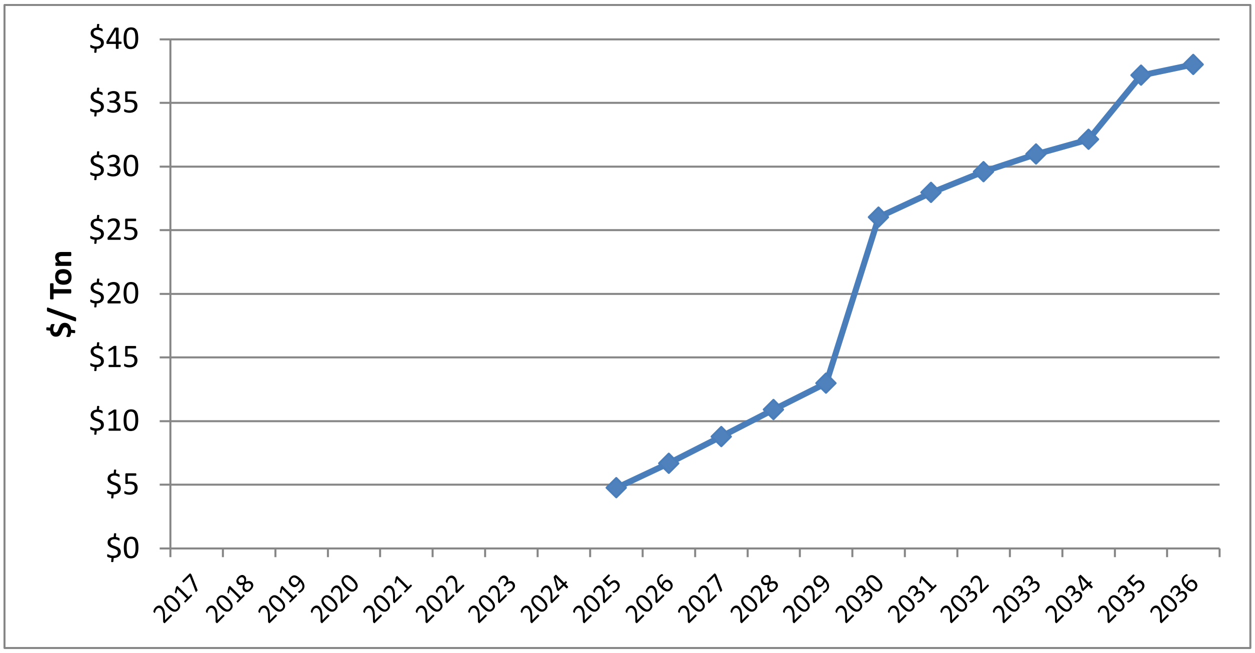
As noted in Chapter 6, PacifiCorp develops FOT limits based on its active participation in wholesale power markets; its view of physical delivery constraints, market liquidity, and market depth; and with consideration of regional resource supply. Alternative FOT limit assumptions applied during the portfolio development process eliminates the availability of FOTs at the NOB (100 MW) and Mona (300 MW) market hubs in summer and winter beginning 2021.

CO_2 Price

With the introduction of EPA's CPP, PacifiCorp has reflected how future regulations targeting CO_2 emission reductions in the electric sector might influence its resource plan. The CPP is reflected in all Regional Haze, core cases and sensitivities in the emissions-price scenarios. The CO_2 Price sensitivity examines the impact of replacing the CPP with a CO_2 price proxy beginning in the year 2025, based on the possibility that even if the CPP is not in effect, there will be some type of carbon-based policy in place by this time. An additional "No CO_2" sensitivity was added in response to stakeholder feedback late in the 2017 IRP cycle. This additional study is described as part of Volume I, Chapter 8.

Figure 7.22 shows CO_2 price assumptions used in the 2017 IRP CO_2 sensitivity case. Prices are applied to each ton of CO_2 emissions from new and existing resources, beginning in 2025 at $4.75/ton and reaching $38.02/ton by 2036.

Figure 7.22 – Nominal CO2 Price Assumptions for the CO2 Sensitivity



No CO_2 Policy

An additional sensitivity was performed in response to stakeholder feedback, representing the PacifiCorp system in the absence of a CO_2 policy. The development and results of this sensitivity are presented in Volume I, Chapter 8.

Business Plan Sensitivity

This sensitivity complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's Fall 2016 Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with the draft preferred portfolio selected from the second screening stage. All other resources are optimized. Note that initially, these assumptions were expected to align with core case 1. Due to the timing of this sensitivity, the study was modeled based on the outcome of a later screening stage. This serves to make the business plan sensitivity closer to the preferred portfolio, and therefore a more indicative comparison.

Energy Gateway Sensitivities

PacifiCorp modeled four Energy Gateway transmission sensitivities, expanding on scenarios defined in the 2013 and 2015 IRP cycles. Incremental to the base case, the Energy Gateway sensitivities are as follows:

Table 7.13 - Energy Gateway Sensitivities

Gateway Study	Transmission Segment	Description
Gateway 1	Segment D	Windstar to Anticline (assumed in-service 2022)
Gateway 2	Segment F	Windstar to Mona / Clover (assumed in-service 2023)
Gateway 3	Segment D&F	Windstar to Anticline and Aeolus to Mona / Clover (assumed in-service 2022 and 2023, respectively)
Gateway 4	Segment D2	Aeolus to Anticline (assumed in-service year-end 2020)

Energy Storage

PacifiCorp includes two energy storage sensitivities. Both force large scale energy storage resources into the resource portfolio, but allow the models to optimize their usage. The first storage sensitivity forces 80 MW of battery storage capacity in PacifiCorp's east BAA (Wyoming). The second storage sensitivity forces an 80 MW compressed air storage plant (CAES) sited in PacifiCorp's east BAA (Utah South). The sites selected were based on a qualitative assessment of locations best suited for storage to provide support for added renewables, in the expectation that storage plants have the ability to mitigate the non-dispatchable nature of wind and solar energy production.

East/West Split

As required by the Washington Utilities and Transportation Commission, PacifiCorp's 2017 IRP includes a sensitivity that produces standalone resource portfolios for the west control area (WCA) compared to operation as part of PacifiCorp's integrated system. This sensitivity required different assumptions for the west BAA model and for the WCA break-out from the base model results, summarized below. An additional sensitivity (WCA-RPS) examines the impact of assuming a physical renewable portfolio standard (RPS) compliance strategy in the WCA break-out.

WCA Assumptions

- Maintains 13 percent target planning reserve margin, applicable to summer and winter peak
- Class 2 DSM capacity contribution values are updated to align with summer and winter peak;
- All of Jim Bridger is included in the west BAA
- Colstrip is included in the west BAA up to transmission limits

CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Using a range of cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio reflecting a cost-conscious plan to transition to a cleaner energy future with near-term investments in both existing and new renewable resources, new transmission infrastructure, and energy efficiency programs. More than 200 Planning and Risk (PaR) studies were performed over three portfolio screening stages to inform selection of the preferred portfolio. Considering each PaR study includes 50 iterations of system performance, this equates to over 10,000 simulations of potential 20-year system dispatch outcomes.
- The preferred portfolio includes 1,100 MW of new Wyoming wind resources that will connect to a new 140-mile transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger Plant. This time-sensitive project requires that the new wind and transmission assets achieve commercial operation by the end of 2020 to maximize wind production tax credit (PTC) benefits.
- Repowering 905 MW of existing wind resources by the end of 2020 will re-qualify these zero-emission resources to receive the full value of PTCs for an additional ten years. With the installation of modern technology and improved control systems, the repowered wind facilities will produce more energy for a longer period of time at reduced operating costs—saving customers hundreds of millions of dollars.
- Energy efficiency continues to play a key role in PacifiCorp's resource mix. Over the first ten years of the planning horizon, accumulated acquisition of incremental energy efficiency resources meets 88 percent of forecasted load growth (up from 86 percent in the 2015 IRP). Over the longer term, direct load control programs play an increasing role in PacifiCorp's transitioning resource mix.
- The preferred portfolio does not include the installation of any incremental selective catalytic reduction equipment for coal generation. Avoiding installation of this equipment will save customers hundreds of millions of dollars and retain compliance-planning flexibility for the Clean Power Plan or other potential state and environmental policies. By the end of the planning horizon, PacifiCorp assumes 3,650 MW of existing coal generation will be retired.
- Natural gas-fired resources do not appear in the preferred portfolio until 2029 (one year later than in the 2015 IRP). By the end of the planning horizon, naturalgas-fired capacity totals 1,313 MW, a reduction of 1,540 MW relative to the 2015 IRP preferred portfolio. PacifiCorp will continue to evaluate potential long-term supply alternatives, including the potential penetration of energy storage, through its on-going resource planning efforts.
- The preferred portfolio reflects PacifiCorp's on-going efforts to provide clean energy solutions for our customers. As compared to the 2015 IRP, projected carbon dioxide (CO_2) emissions are down by 21 percent over the first ten years of the planning horizon. By the end of the planning period, system CO_2 emissions are project to fall by 24.5 percent.

Introduction

This chapter reports modeling and performance evaluation results for the resource portfolios developed with a broad range of input assumptions using System Optimizer (SO) and simulated with PaR. Using model data from the portfolio development process and subsequent cost and risk analysis of unique portfolio alternatives, PacifiCorp steps through its preferred portfolio selection process and presents the 2017 IRP preferred portfolio.

The chapter is organized around the three screening stages identified in the previous chapter: (1) Regional Haze case screening; (2) eligible case screening; and (3) final screening for preferred portfolio selection. The final preferred portfolio screening stage is informed by all relevant case results and incorporates additional updates and sensitivities indicated by preceding results, recent relevant events and stakeholder feedback. This chapter also presents modeling results for additional 2017 IRP sensitivity cases that, while informative, were not considered for selection as the preferred portfolio.

Results of resource portfolio cost and risk analysis from each screening stage are presented as PacifiCorp steps through the following discussion of its portfolio evaluation processes. Stochastic modeling results from PaR are also summarized in Volume II, Appendix L (Stochastic Simulation Results).

Regional Haze Portfolio Screening

Resource Portfolio Development

Aligning with the screening methodology described in Chapter 7, the seven Regional Haze cases assume differing sets of retirement assumptions, which together comprise a range of compliance strategies for modeling and comparative analysis. Each Regional Haze scenario considers the timing and magnitude of run-rate capital and operations and maintenance costs for individual coal units in PacifiCorp's fleet. For instance, if a specific Regional Haze scenario assumes an early retirement for a given coal unit as part of a Regional Haze compliance solution, the run-rate operating costs for that unit are customized to reflect the assumed early closure date. This can include changes to the timing of planned maintenance throughout the 20-year planning horizon and avoidance of future costs related to known or assumed environmental compliance costs as described in Chapter 7 Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

Figure 8.1 summarizes the cumulative capacity of new resources and the cumulative reduction in existing resources through 2036, as optimized by SO under the reference Regional Haze scenario. Figure 8.2 through Figure 8.7 present corresponding summary results for resource portfolios developed under Regional Haze cases 1 through 6.

Each case is driven by key retirement strategy assumptions as presented in the previous chapter. In nearly every case, PTCs drive the addition of roughly 300 MW of renewable wind capacity in Wyoming, constrained by available transmission.

Detailed resource portfolio results for each core case, showing new resource capacity and changes to existing resource capacity by year, are contained in Volume II, Appendix K (Capacity

Expansion Results Detail). Summary portfolio results are also shown in the case fact sheets presented in Volume II, Appendix M (Case Study Fact Sheets).

Figure 8.1 – Cumulative Capacity through 2036, Regional Haze Reference Case

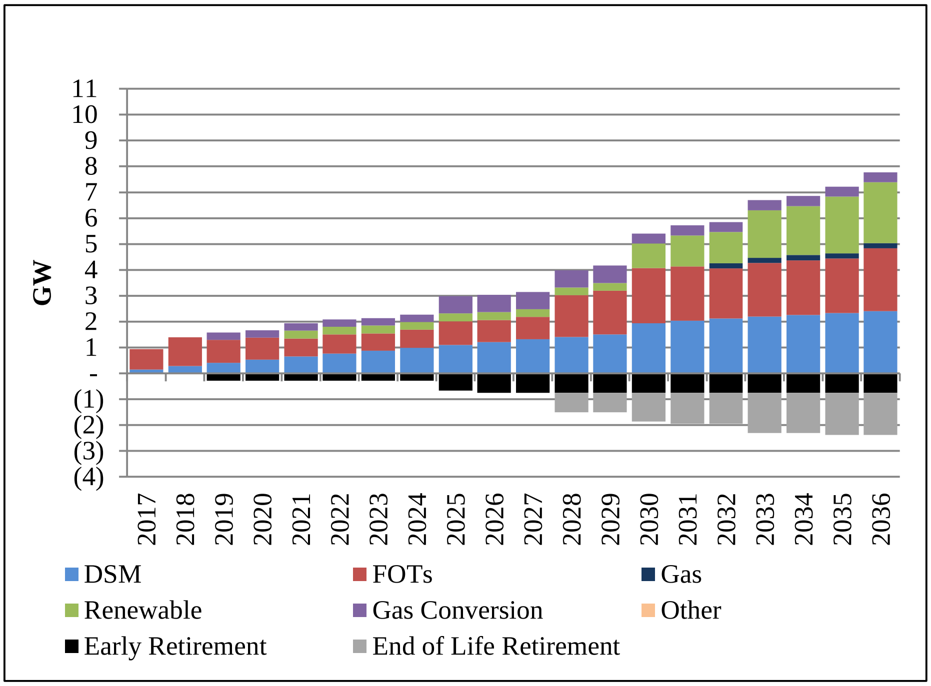


Figure 8.2 – Cumulative Capacity through 2036, Regional Haze Case 1

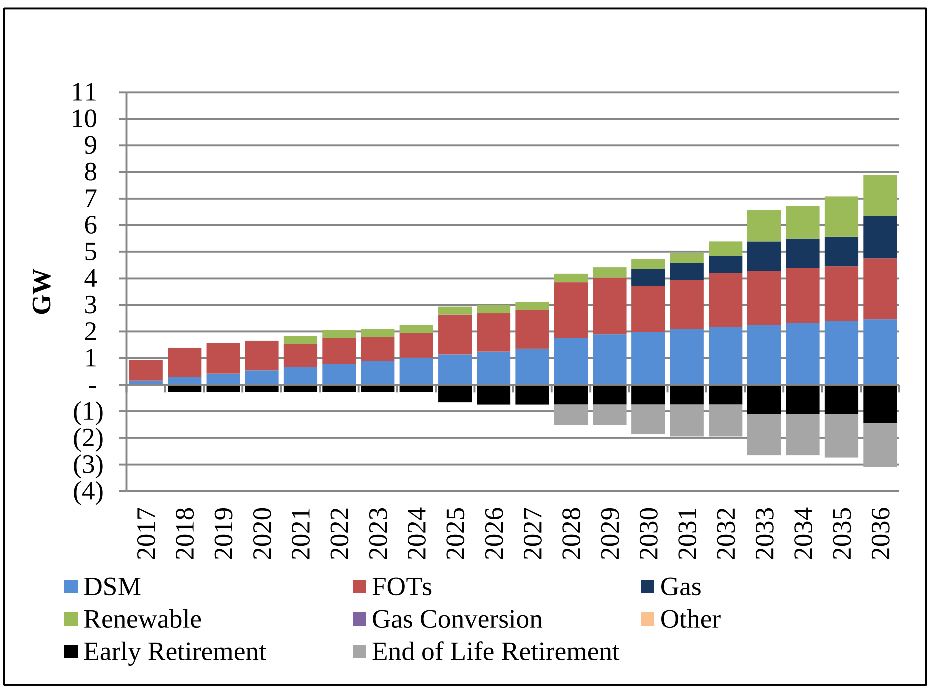


Figure 8.3 – Cumulative Capacity through 2036, Regional Haze Case 2

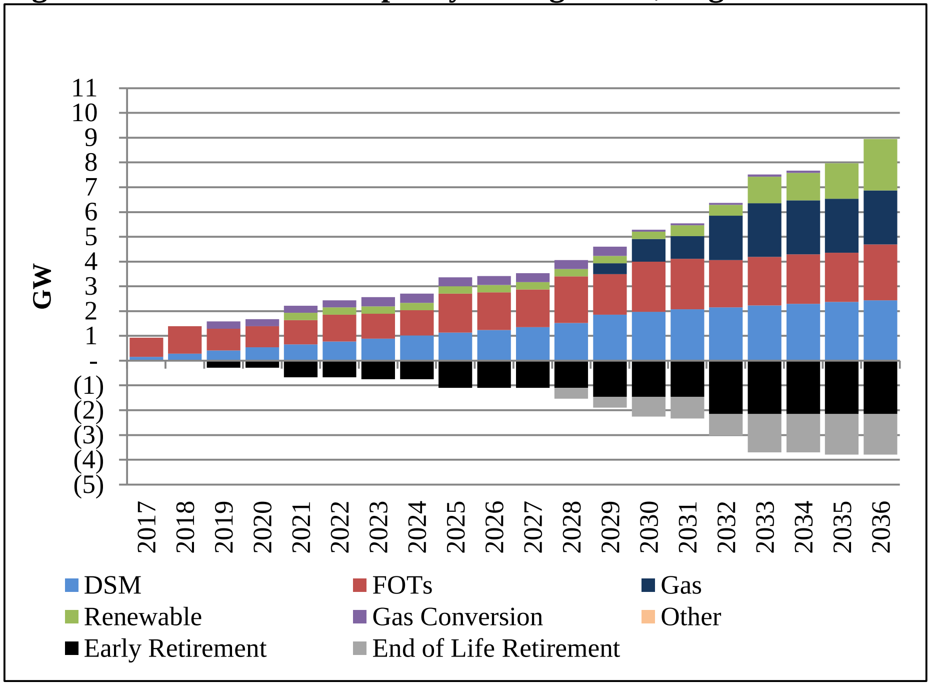


Figure 8.4 – Cumulative Capacity through 2036, Regional Haze Case 3

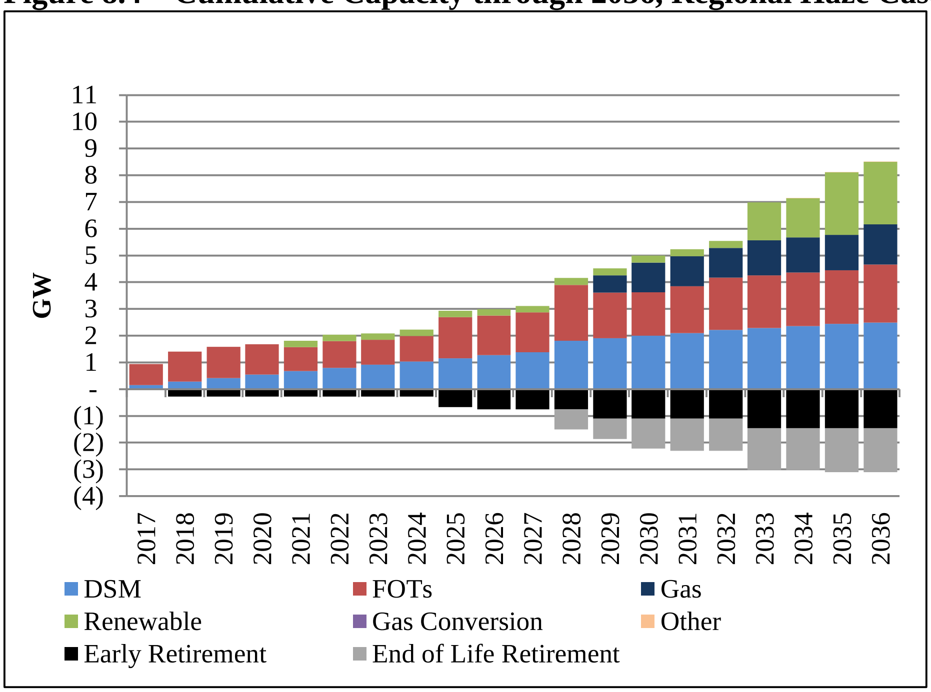


Figure 8.5 – Cumulative Capacity through 2036, Regional Haze Case 4

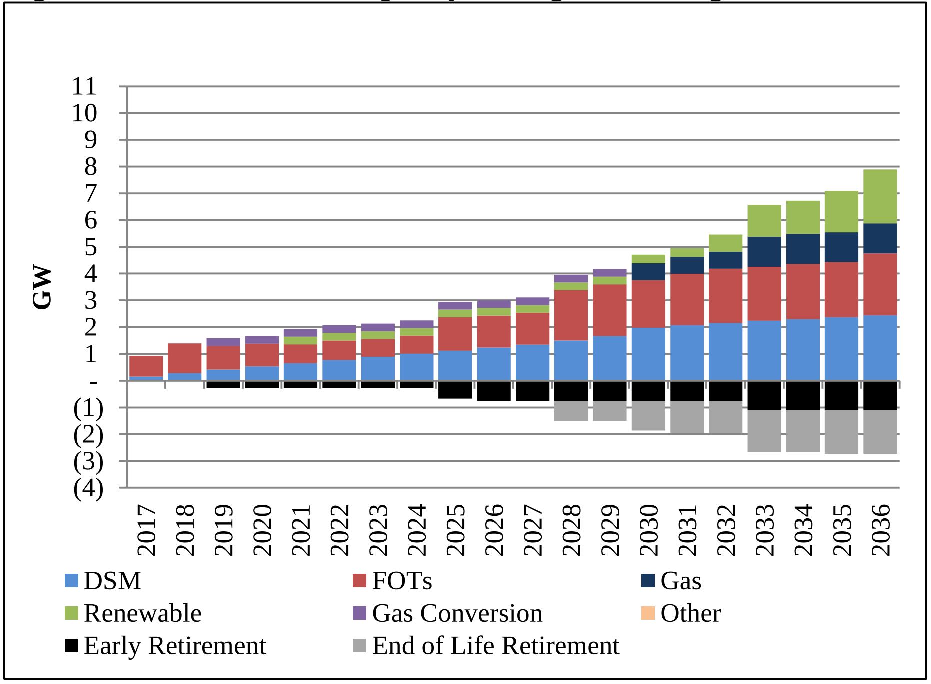


Figure 8.6 – Cumulative Capacity through 2036, Regional Haze Case 5

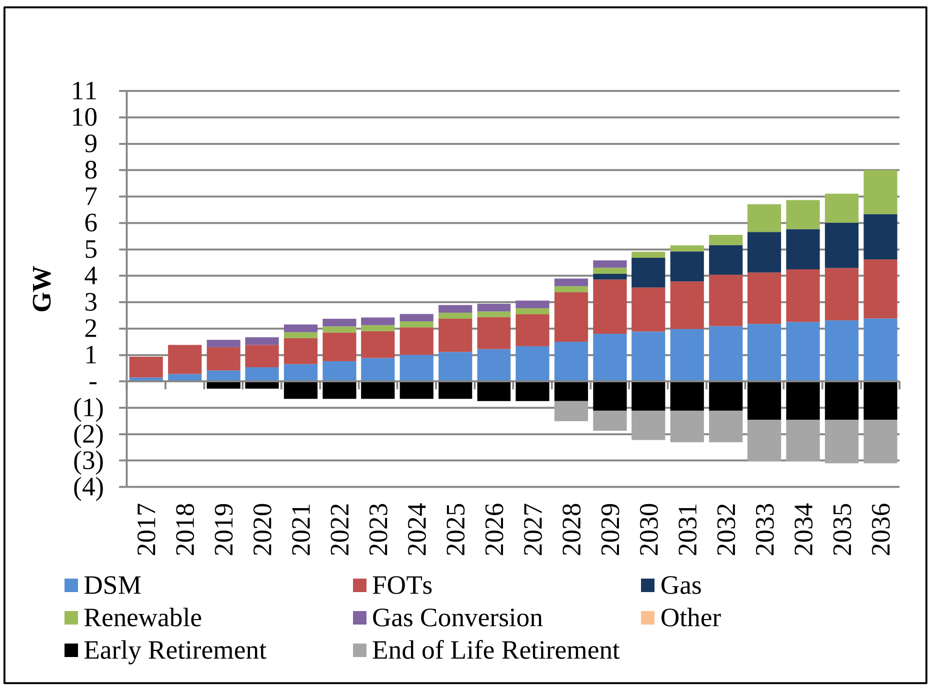
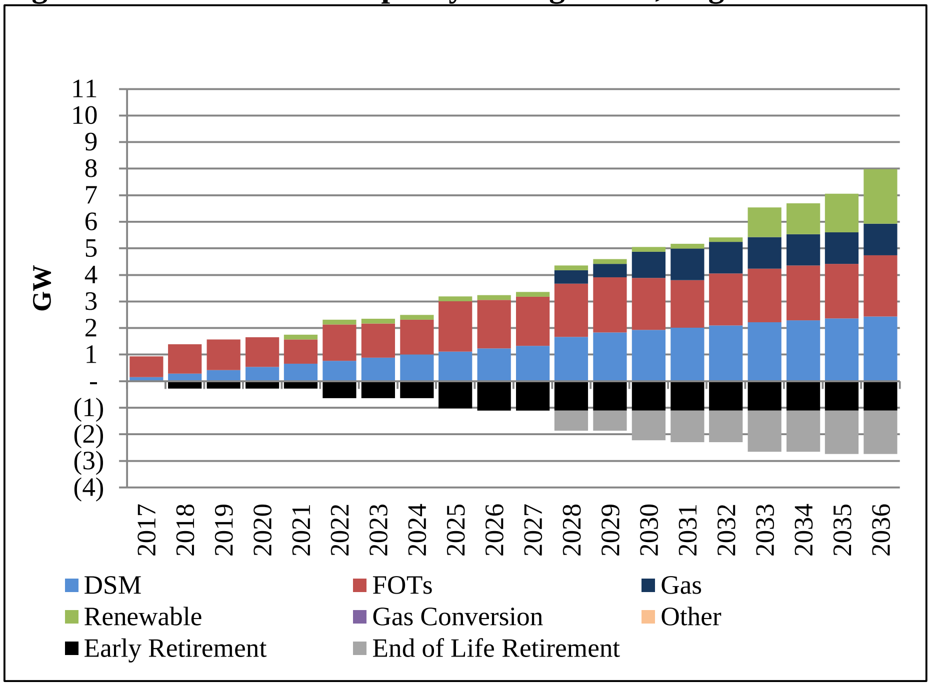


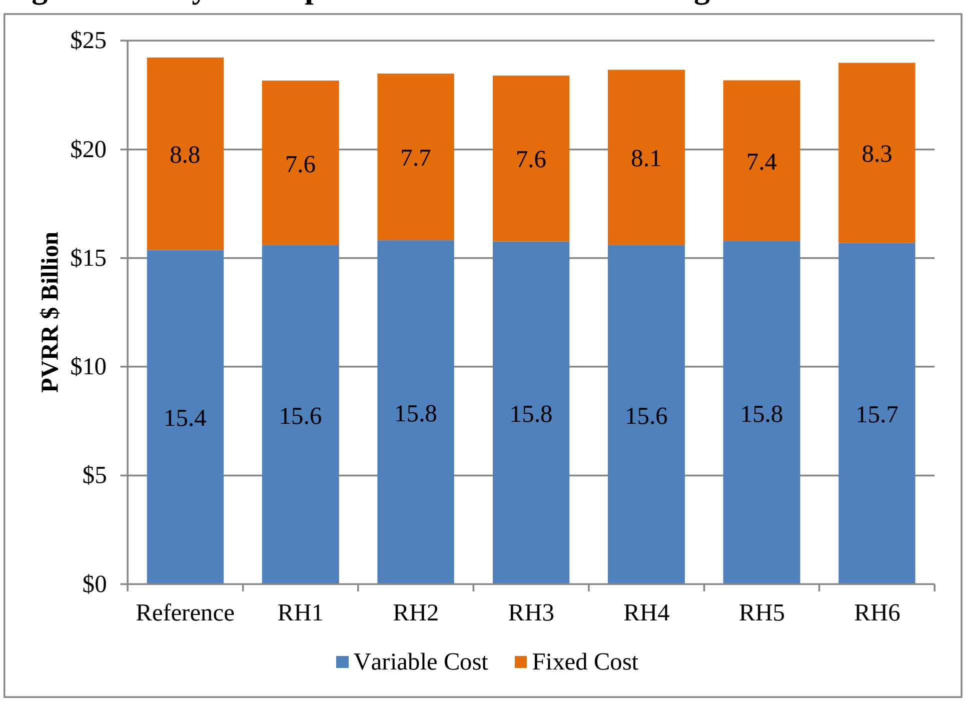
Figure 8.7 – Cumulative Capacity through 2036, Regional Haze Case 6



System Costs

Figure 8.8 shows the present value revenue requirement (PVRR) of system costs among resource portfolios developed under reference Regional Haze compliance assumptions and under Regional Haze cases 1 through 6.

Figure 8.8 – System Optimizer PVRR Costs for Regional Haze Cases



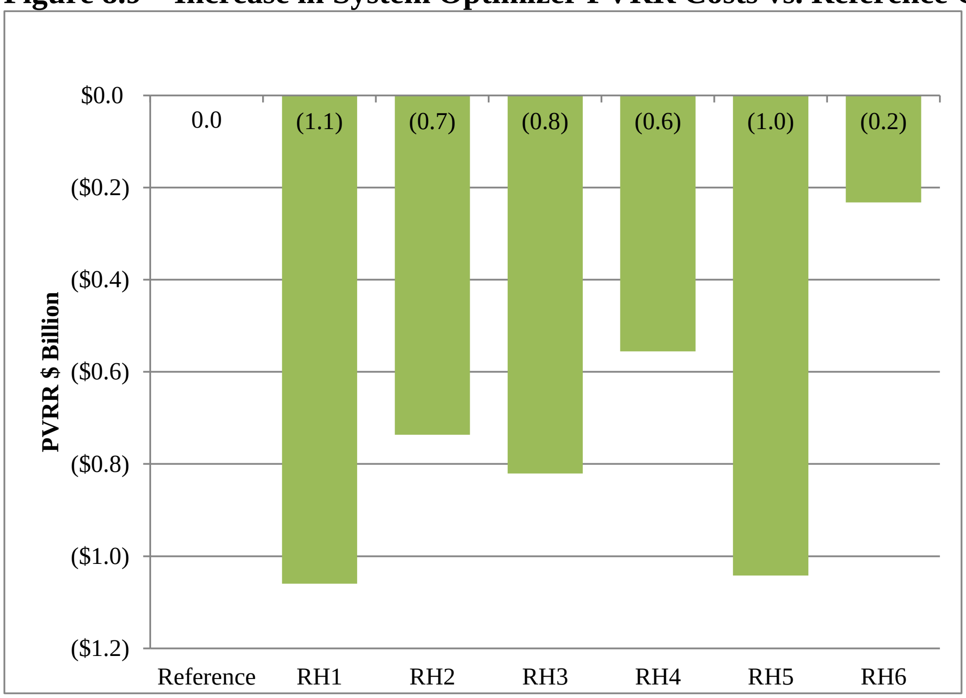
Based upon the System Optimizer PVRR, Regional Haze cases 1 and 5 provide the lowest net system costs, which are notably lower than the system costs from all other cases developed assuming medium natural gas prices and Clean Power Plan (CPP) CO_2 emission limits as defined under the Mass Cap B scenario.

When enabling endogenous early retirements (Regional Haze case 6), net system costs are reduced relative to the Reference Case, but net costs are higher relative to other Regional Haze compliance cases that reflect a range of potential negotiated compliance alternatives. Regional Haze case 6 produced the following key Regional Haze outcomes:

- Jim Bridger Unit 2 retires year-end 2021
- Selective catalytic reduction (SCR) equipment was installed on Hunter Units 1 & 2, Huntington Units 1 & 2, and Jim Bridger Unit 1

Figure 8.9 summarizes the comparative difference in PVRR system costs for each Regional Haze case relative to the system costs from the Reference Case. Detailed portfolio cost results, showing system cost line items by year, are included in Volume II, Appendix K (Capacity Expansion Results Detail). Summary portfolio costs are also shown in the case fact sheets presented in Volume II, Appendix M (Case Study Fact Sheets).

Figure 8.9 – Increase in System Optimizer PVRR Costs vs. Reference Case



Regional Haze Cost and Risk Analysis

PaR Configuration and Metrics

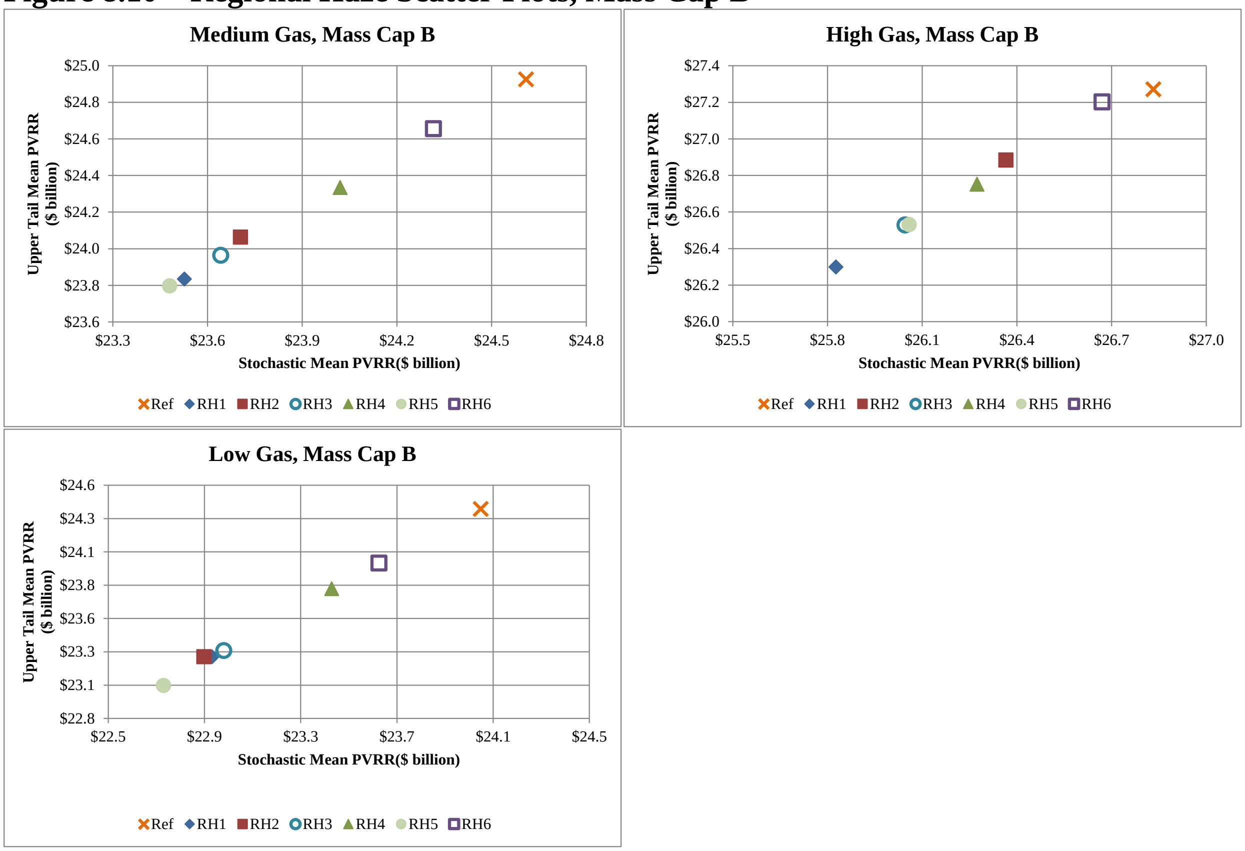
PaR model results are used to develop portfolio ranking metrics, which include the mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean Energy Not Served (ENS), upper-tail ENS, and CO_2 emissions. PaR is configured to calculate 50-iterations of 12 sample weeks representing the months of each study year (2017 through 2036). Sample weeks capture the peak load week for each month.

Each of the 50 iterations applies varying stochastic shocks to loads, gas and power prices, thermal outages and hydro inputs. Fifty iterations have been demonstrated to provide practical performance and are sufficient to ensure convergence of stochastic draws.

CO_2 shadow prices from SO are input into PaR to influence thermal dispatch, as required, to achieve CPP mass cap emission limits. The resulting CO_2 costs reported by PaR represent the opportunity cost of the CPP, but are not real expenses, and thus they are removed in the final PVRR reporting.

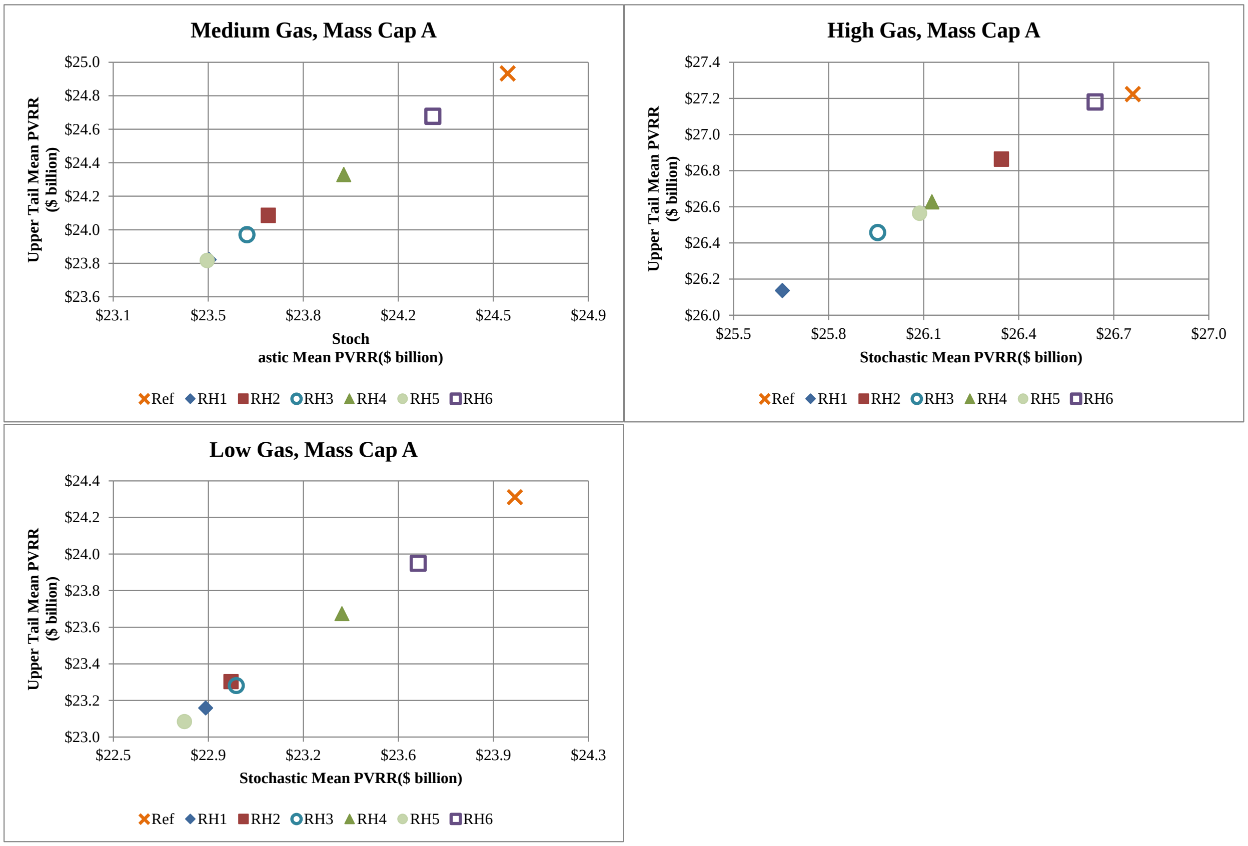
Scatter plots, shown in Figure 8.10 and Figure 8.11, present the mean PVRR of each unique Regional Haze case portfolio on the horizontal axis and the upper-tail mean PVRR on the vertical axis. Portfolios toward the left-bottom corner of each scatter plot contain the least-cost, least-risk mix of resources, while portfolios toward the upper-right corner contain the highest-cost and highest-risk mix of resources.

Figure 8.10 – Regional Haze Scatter Plots, Mass Cap B



With fixed costs included in the upper-tail mean, which does not change among stochastic iterations, the mean PVRR cost and the upper-tail mean PVRR risk metrics are highly correlated. Case RH-5 is least cost, least risk under both medium and low natural gas price scenarios. While RH-5 is a close competitor in the high gas price scenario, RH-1 provides the most favorable cost and risk results when high natural gas prices are assumed.

Figure 8.11 – Regional Haze Scatter Plots, Mass Cap A

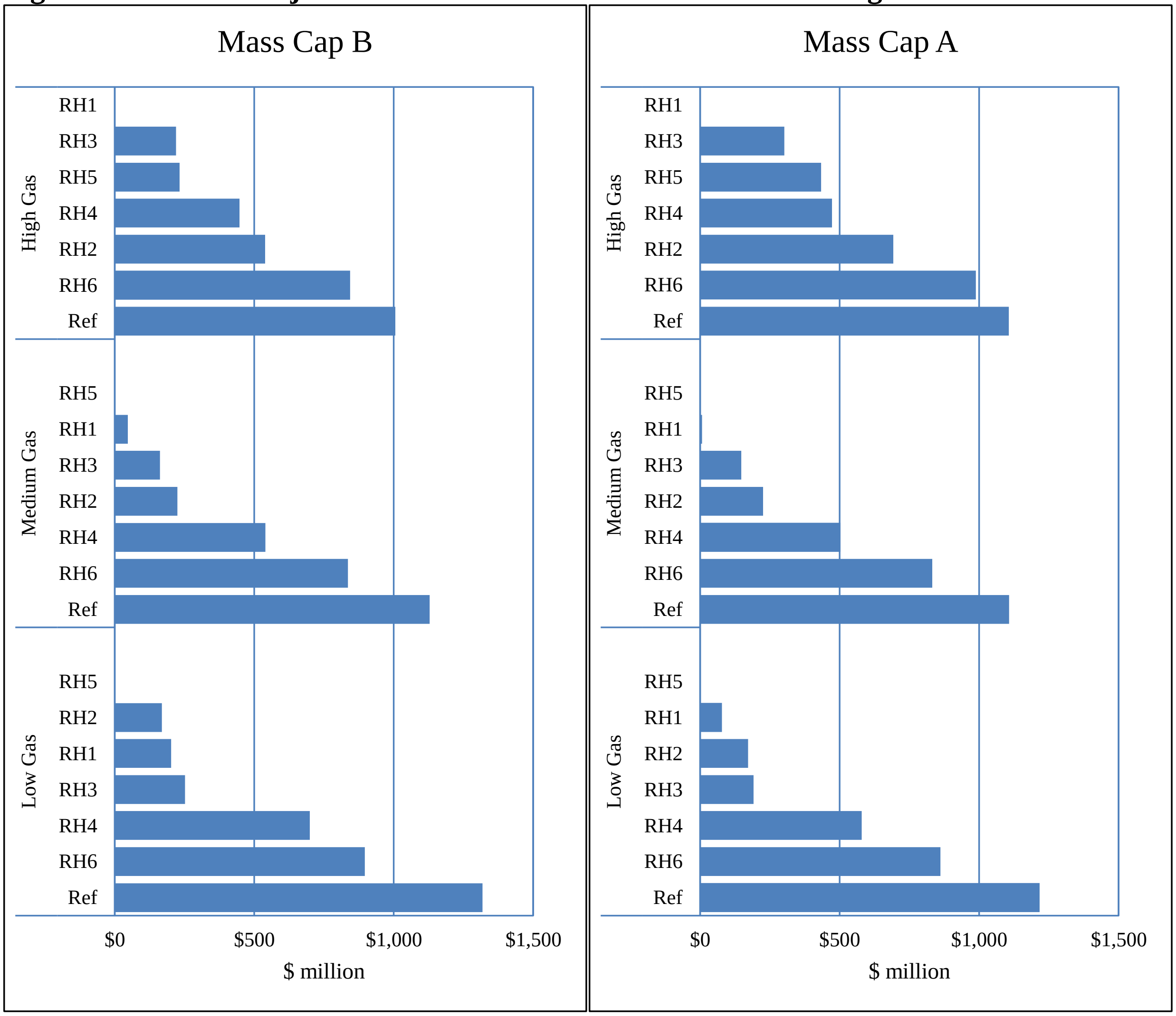


With fixed costs included in the upper-tail mean, which does not change among stochastic iterations, cost and risk are highly correlated. RH-5 is least-cost, least-risk under both medium and low natural gas price scenarios. RH-1 is least-cost, least-risk when high natural gas prices are assumed. The degree of distribution between cases is similar to Mass Cap B.

Risk-Adjusted PVRR

Figure 8.12 shows the stochastic mean PVRR of each Regional Haze case ranked against the best performing case in each price-emission scenario. In this view, Regional Haze case 5 (RH-5) produces the lowest risk-adjusted PVRR in four out of the six price scenarios. The Reference Case and case RH-6 consistently produce the highest risk-adjusted PVRR among all Regional Haze cases.

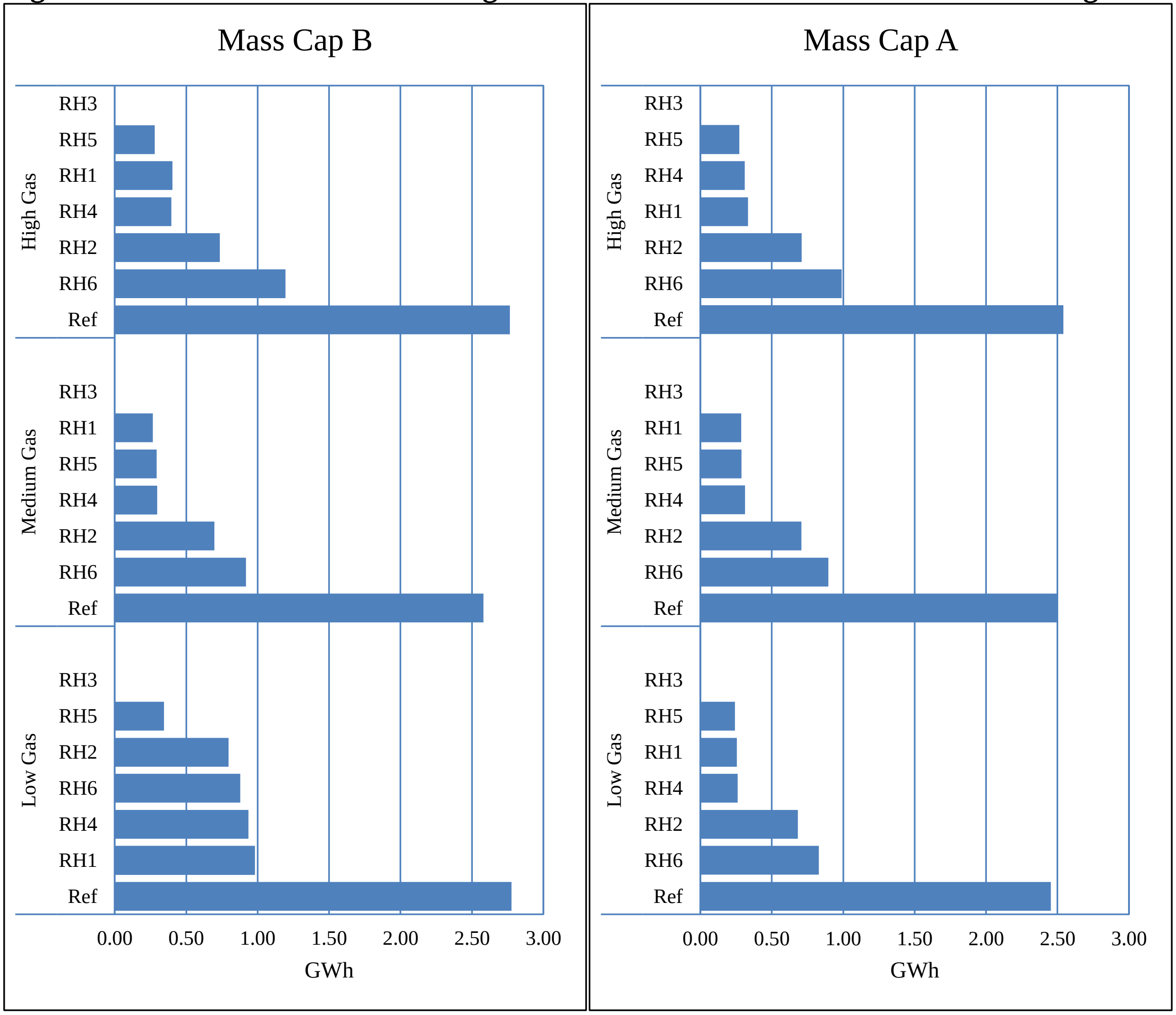
Figure 8.12 – Risk-Adjusted PVRR Relative to the Lowest Cost Regional Haze Case



Average Energy Not Served (ENS)

Figure 8.13 presents the stochastic mean average annual ENS of each Regional Haze case ranked against the best performing case in each price-emission scenario. In this view, all cases have mean ENS levels that are a fraction of total load (annual mean ENS ranges between 10.8 and 14.9 GWh), signaling that all of the cases would be expected to provide reliable service. Relative to other cases, RH-3 consistently produces the lowest mean ENS levels. The Reference Case consistently produces the highest mean ENS levels.

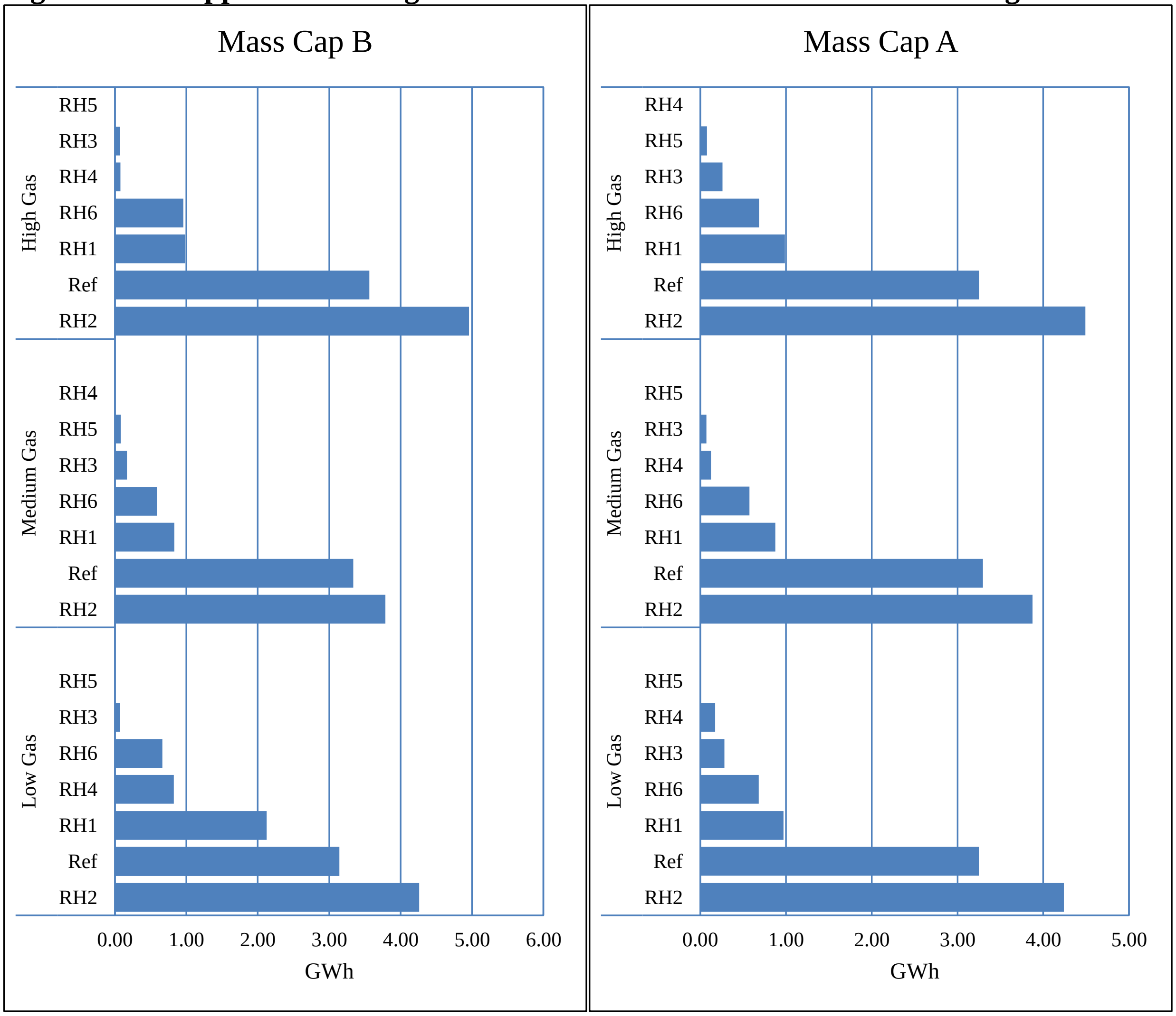
Figure 8.13 – Stochastic Mean Average Annual ENS Relative to the Best Performing Case



Upper-tail Average ENS

Figure 8.14 shows the upper-tail average annual ENS of each Regional Haze case ranked against the best performing case in each price-emission scenario. As is the case for mean ENS metrics, all cases have upper-tail ENS levels that are a fraction of total load (upper-tail annual ENS ranges between 30.1 and 35.8 GWh), signaling that all of the cases would be expected to provide reliable service. Relative to other cases, RH-5 and RH-4 consistently produce the lowest upper-tail ENS levels. RH-2 and the Reference Case consistently produce the highest upper-tail ENS levels.

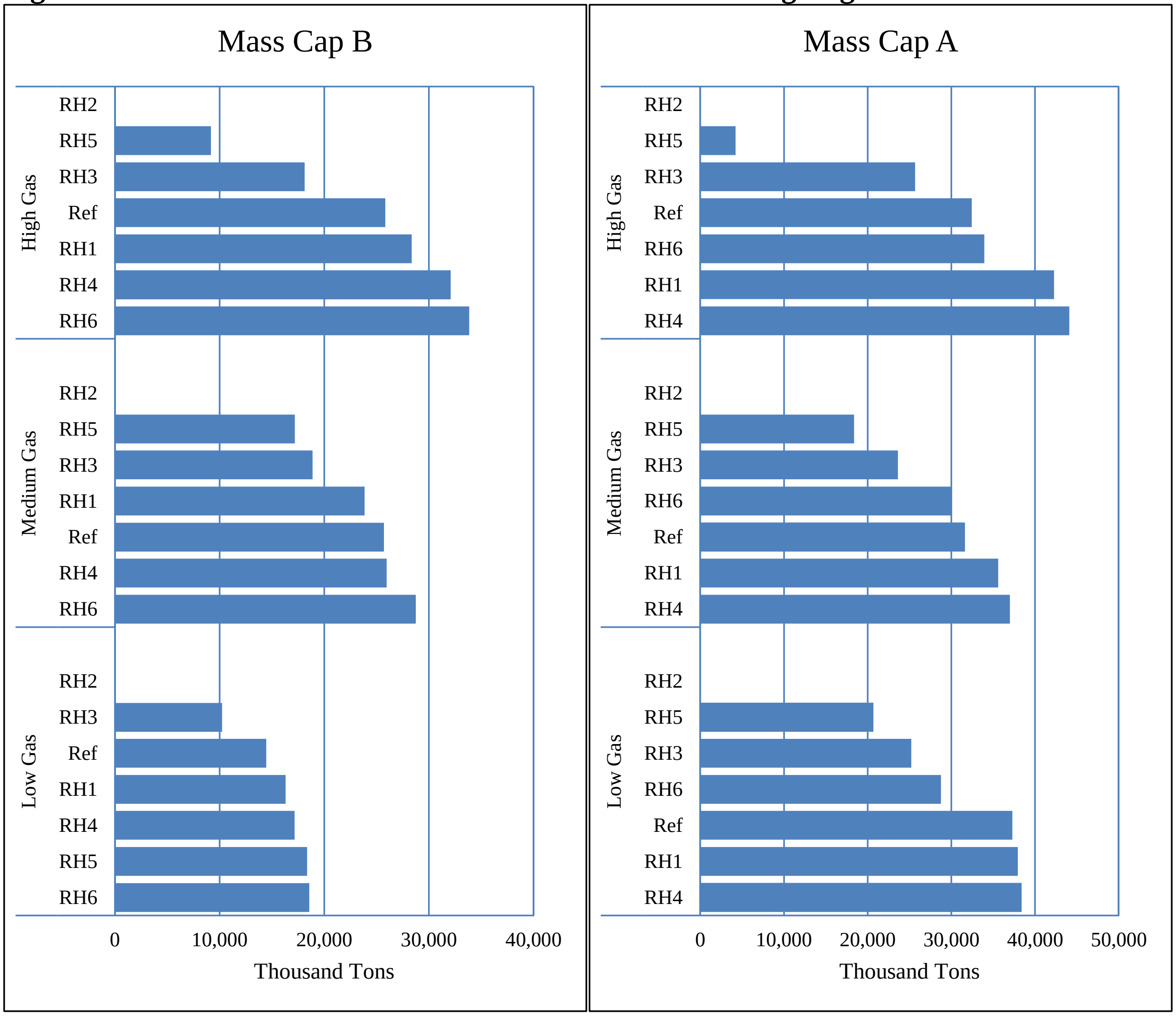
Figure 8.14 – Upper-tail Average Annual ENS Relative to the Best Performing Case



CO_2 Emissions

Figure 8.15 shows total CO_2 emissions of each Regional Haze case relative to the best performing case in each price-emission scenario. RH-2, with the earliest coal unit retirement assumptions, consistently yields the lowest emissions among all Regional Haze cases. Case RH-5 yields comparatively low emissions relative to most cases. Case RH-4, with the latest coal unit retirement assumptions, consistently yields emissions that are higher than other Regional Haze cases.

Figure 8.15 – CO2 Emissions Relative to the Best Performing Regional Haze Case



Shadow Prices

CPP emission limits are enforced in PaR by a CO_2 shadow price, which is an output from SO. The CO_2 shadow price represents the incremental system cost, expressed in dollars per ton, of meeting CPP mass cap emission limit assumptions. This represents a modeling improvement relative to the 2015 IRP, where a shadow price could not be derived from SO, and therefore, not enforced when evaluating portfolios in PaR. Exceedances under the CPP Mass Cap A and Mass Cap B scenarios are rare (less than six percent of iterations among all cases and price curve scenarios). For the state of Washington, the Clean Air Rule (CAR) limit is used to restrict emissions at PacifiCorp's Chehalis plant, the only fossil-fired resource PacifiCorp owns in the state. Washington CAR exceedances occur in greater frequency and volume relative to the CPP; however, CAR allows for use of emission reduction units (ERUs). Without an ERU market, RECs can be converted to ERUs. Figure 8.16 and Figure 8.17 show the range in shadow prices, which varies among each Regional Haze case portfolio and price-emission scenario.

Figure 8.16 – Range in CO2 Shadow Prices, Mass Cap B

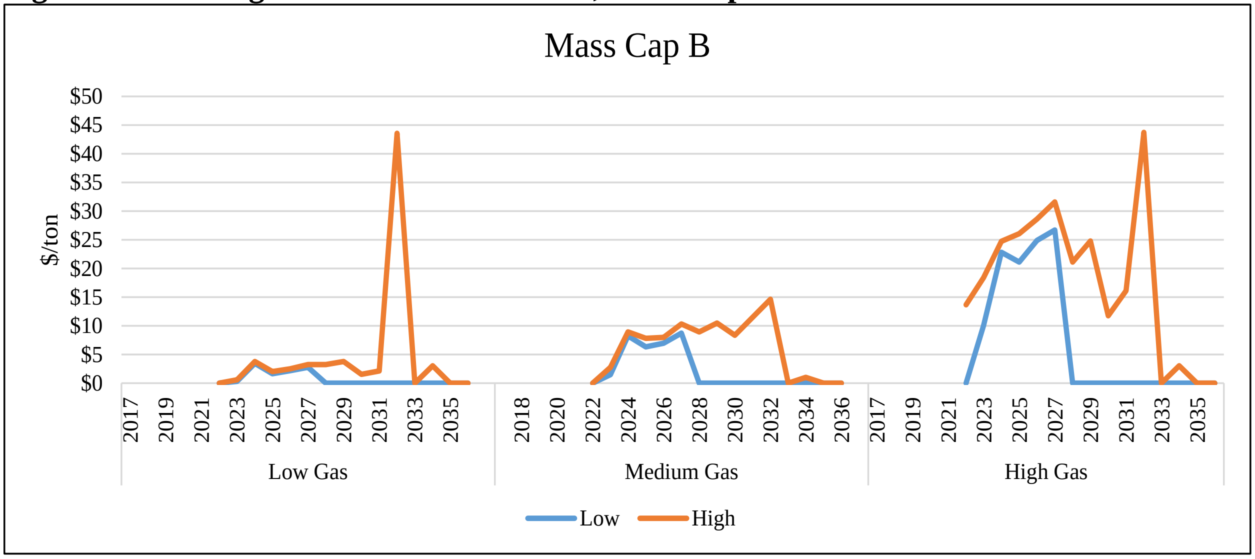
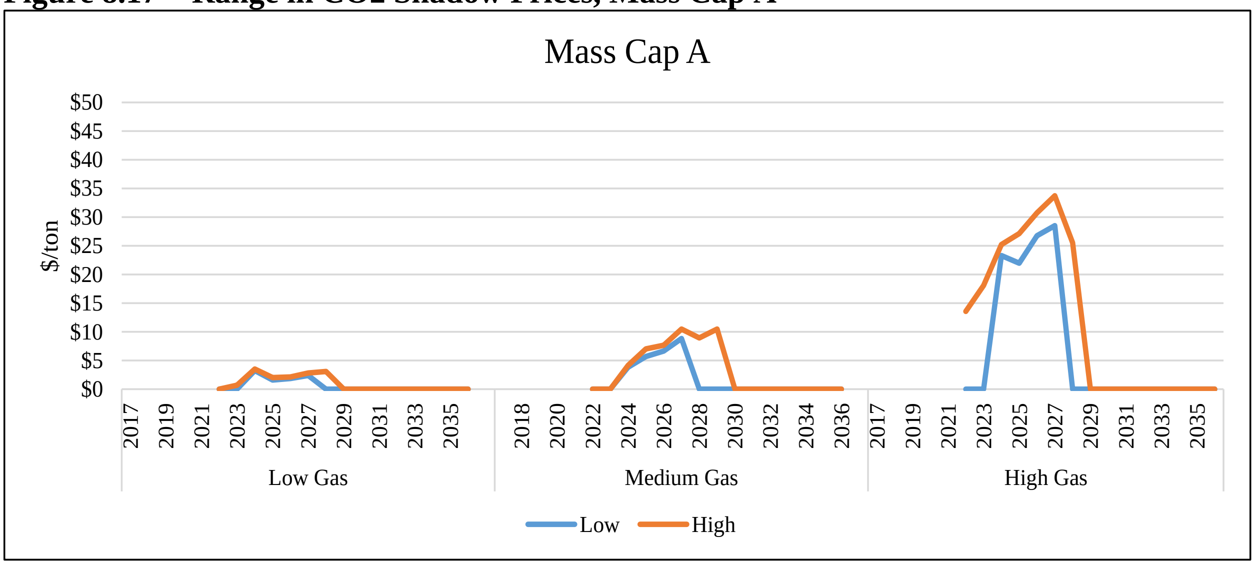


Figure 8.17 – Range in CO2 Shadow Prices, Mass Cap A



Shadow prices under Mass Cap B persist longer. This is because the Mass Cap B limit applies to new combined cycle combustion turbine (CCCT) resources per the new resource compliment interpretation of the policy. Under Mass Cap B, annual prices are influenced by timing of coal unit retirements among cases and timing of new CCCT additions. For example, Regional Haze case 1 (RH-1) has more coal operating in 2032 when CCCTs are added, driving the seemingly anomalous price spike. Overall, higher gas prices, which tend to increase coal dispatch, produce higher CO_2 shadow prices.

Regional Haze Case Portfolio Selection

On the basis of cost-risk metrics, PacifiCorp selected Regional Haze case 5 (RH-5) as the top performing portfolio in this phase of the portfolio selection process. However, stakeholder input received by PacifiCorp during the public input process influenced a change to the configuration of RH-5. To present a complete picture of the Regional Haze case final selection, this section begins with a review of the initial outcomes, followed by a full assessment of the enhancement to RH-5 and the impact this enhancement had on cost-risk metrics.

Initial Results and Conclusions

The metrics described in the cost and risk analysis are condensed into a comparative summary as outlined in Table 8.1. Across the various measures, RH-5 is consistently a top performer. It should also be emphasized that the rankings, while indicative of relative rankings among portfolios, tend to obscure how close some of the outcomes are in terms of absolute measures (e.g., total CO_2 emissions).

Table 8.1 -- Risk-adjusted PVRR among Top Performing Portfolios, Phase One

	Risk Adjusted[1]			ENS Scenario Average			ENS Upper Tail Average			CO_2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2017-2036 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Ref	26,395	$1,146	7	14.1	2.6	7	33.7	3.3	6	786,334	27,895	4
RH1	25,249	$0	1	11.9	0.4	4	31.5	1.1	5	789,172	30,732	6
RH2	25,544	$295	4	12.2	0.7	5	34.7	4.2	7	758,440	0	1
RH3	25,414	$165	3	11.5	0.0	1	30.6	0.1	2	778,734	20,294	3
RH4	25,757	$508	5	11.9	0.4	3	30.6	0.2	3	790,896	32,456	7
RH5	25,307	$58	2	11.7	0.3	2	30.4	0.0	1	773,115	14,676	2
RH6	26,111	$862	6	12.4	1.0	6	31.1	0.7	4	787,410	28,971	5

[1] Based on average of 6 price-emissions scenarios

PacifiCorp identified case RH-5 as the top performing Regional Haze case based on the following observations communicated with stakeholders during the public input process:

- Case RH-5 produces the lowest risk-adjusted PVRR in four out of six price scenarios and is among the top three cases in the other two price scenarios.
- Case RH-5 is consistently among the top performing portfolios when ranked on mean and upper-tail ENS.
- Case RH-5 is among the top two portfolios when ranked on CO_2 emissions in five out of six price scenarios.
- Case RH-5 produces a notably lower risk adjusted PVRR than the top performing emissions portfolio (RH-2).
- Emission differences between cases are closely bunched in the remaining price scenario.
- Case RH-5 produces a low PVRR relative to other Regional Haze cases based on the PVRR from SO.
- Case RH-5 and RH-1 are very close when evaluating the PVRR from SO, but case RH-1 only exhibits the lowest risk-adjusted PVRR in the high natural gas price scenarios when evaluated in PaR.
- Case RH-5 is a blend of Cases RH-1, RH-2, and RH-3, and is a balanced representation of potential Regional Haze outcomes.

Regional Haze Case 5 Enhancement

In response to stakeholder feedback, PacifiCorp performed an additional sensitivity, designated as case RH-2a, to examine the impact of a Naughton Unit 3 retirement at year-end 2017 and a Craig 1 retirement at year-end 2025 as an alternative to the gas conversions assumed in case RH-2.

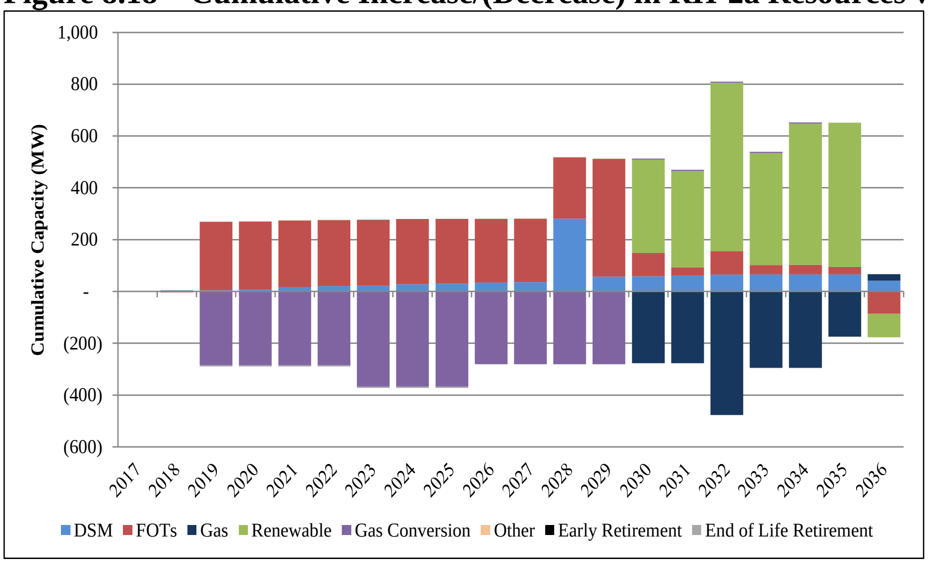
<u>Sensitivity RH-2a</u>

Table 8.2 shows the impacts of the RH-2a modifications when compared to the RH-2 and RH-5 results. As compared to case RH-2, system costs are reduced when Naughton 3 and Craig 1 are assumed to retire instead of converting to natural gas. These cost savings do not surpass the system cost benefits from RH-5, and therefore do not support adopting RH-2a as the selected Regional Haze case.

Table 8.2 – PVRR Cost/(Benefit) of RH-2a vs. RH-2

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean	PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B			Mass B	
	Medium Gas			Medium Gas	
Change from RH-2	($79)	($112)	Change from RH-5	$227	$112

Figure 8.18 – Cumulative Increase/(Decrease) in RH-2a Resources vs. RH-2



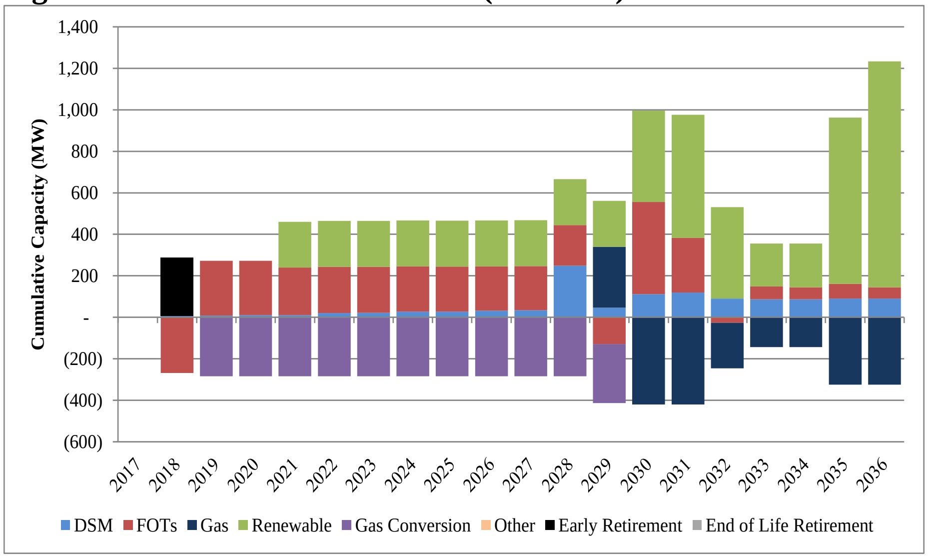
<u>Sensitivity RH-5a</u>

While the RH-2a results did not suggest replacing RH-5 as the selected Regional Haze case, the favorable impacts were sufficient to justify an additional sensitivity as a variant to case RH-5. Case RH-5a assumes Naughton 3 continues to operate as a coal-fired facility through the end of 2018, reflecting changes in its operating permit, and then is retired. This is a variant of case RH-5, where Naughton 3 was assumed to cease coal-fired operation in 2017, convert to natural gas in 2019, and retire at the end of 2029. Table 8.3 shows the impacts of the RH-5a modifications when compared to case RH-5.

Table 8.3 – PVRR Cost/(Benefit) of RH-5a vs. RH-5

PVRR(d) Cost/(Benefit) ($ million)	SO	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Med Gas	Low Gas	Med Gas	High Gas	Low Gas	Med Gas	High Gas
Change from RH-5	($125)	($2)	($39)	($372)	($5)	($43)	($337)

Figure 8.19 – Cumulative Increase/(Decrease) in RH-5a Resources vs. RH-5



Final Regional Haze Portfolio Selection

Case RH-5a yields lower costs relative to case RH-5 in all price-emission scenarios. Cost reductions are most significant with high natural gas price assumptions. Based on these results, PacifiCorp adopted Regional Haze compliance assumptions from case RH-5a for use in subsequent core case and sensitivity case studies being considered for the preferred portfolio.

In summary, Regional Haze compliance assumptions coming out of case RH-5a are as follows:

- No incremental selective catalytic reduction (SCR) emission control installations.
- Assumed coal unit retirements (there are no natural gas conversions):
- Naughton Unit 3 (Retired 2018)
- Cholla Unit 4 (Retired 2020)
- Craig Unit 1 (Retired 2025)
- Dave Johnston Plant (Retired 2027, end-of-life)
- Jim Bridger Unit 1 (Retired 2028)
- Naughton Units 1 & 2 (Retired 2029, end-of-life)
- Hayden Units 1 & 2 (Retired 2030, end-of-life)
- Jim Bridger Unit 2 (Retired 2032)
- Craig Unit 2 (Retired 2034, end-of-life)

- Huntington Plant (Retired 2036, end-of-life)

The selected Regional Haze case becomes core case 1 in the following screening stage of eligible portfolios, and serves as the basis of subsequent studies in that stage. RH-5a is therefore referred to in following sections of this chapter as core case 1 with the abbreviation OP-NT3 in reference to the change in the assumed Naughton Unit 3 retirement versus gas conversion assumptions.

Eligible Portfolio Screening

Eligible Portfolio Development

Eligible portfolios are those portfolios deemed eligible to be considered for preferred portfolio selection. The eligible set of portfolios is a combination of the six identified core cases plus a set of select sensitivity cases. For all eligible portfolios, Regional Haze compliance assumptions are based on Regional Haze case RH-5a (referred to as OP-NT3 throughout the rest of this chapter). The use of OP-NT3 in this IRP as the common basis for further screening stages addresses 2015 IRP stakeholder feedback recommending that cases considered for selection as the preferred portfolio be compared among common Regional Haze assumptions. The following discussion begins with an examination of the core cases and subsequent sensitivity cases considered for selection as the preferred portfolio.

Core Case Portfolio Development

Core case 4 (RE-1) has been expanded in this view to represent the additional modeling necessary for a full examination of just-in-time physical renewable portfolio standard (RPS) compliance. Case RE-1a is modeled to show the impacts of just-in-time physical compliance meeting Oregon RPS requirements. RE-1b is modeled to show the impacts of just-in-time physical compliance meeting Washington RPS requirements. Finally, RE-1c is modeled to show the impacts of just-in-time physical compliance meeting both Oregon and Washington physical RPS requirements concurrently. Table 8.4 lists the names and key characteristics of the core cases examined in screening stage two.

Table 8.4 – Core Cases

Resource Class	Case 1 OP-NT3	Case 2 FR-1	Case 3 FR-2	Case 4 RE-1a	Case 4 RE-1b	Case 4 RE-1c	Case 5 RE-2	Case 6 DLC-1
Flexible Resources	Optimized	10% of Incremental L&R balance	20% of Incremental L&R balance	Optimized	Optimized	Optimized	Optimized	Optimized
Renewable Resources	Optimized	Optimized	Optimized	Just-in-Time Physical RPS Compliance (OR)	Just-in-Time Physical RPS Compliance (WA)	Just-in-Time Physical RPS Compliance (OR and WA)	Early Physical Compliance	Just-in-Time Physical RPS Compliance (OR and WA)
Class 1 DSM Resources	Optimized	Optimized	Optimized	Optimized	Optimized	5% of Incremental L&R balance	Optimized	5% of Incremental L&R balance
All other Resources	Optimized	Optimized	Optimized	Optimized	Optimized	Optimized	Optimized	Optimized

The following tables and figures present portfolio additions and system costs for the core cases. Additional information is provided specific to the merits of each case, including situs-assigned renewable additions for the renewables core cases, RE-1 through RE-1c and RE-2. Detailed resource portfolio results for each core case, showing new resource capacity and changes to existing resource capacity by year, are contained in Volume II, Appendix K (Capacity Expansion Results Detail). Summary portfolio results are also shown in the case fact sheets presented in Volume II, Appendix M (Case Study Fact Sheets).

Cumulative Additional Resource Capacity

Figure 8.20 through Figure 8.27 summarize the cumulative capacity of new resources and the cumulative reduction in existing resources through 2036, as developed for the core cases in SO. As with the Regional Haze cases, in nearly every core case the availability of PTCs drive the addition of roughly 300 MW of renewable wind capacity in Wyoming.

Figure 8.20 – Cumulative Capacity through 2036, Core Case OP-NT3

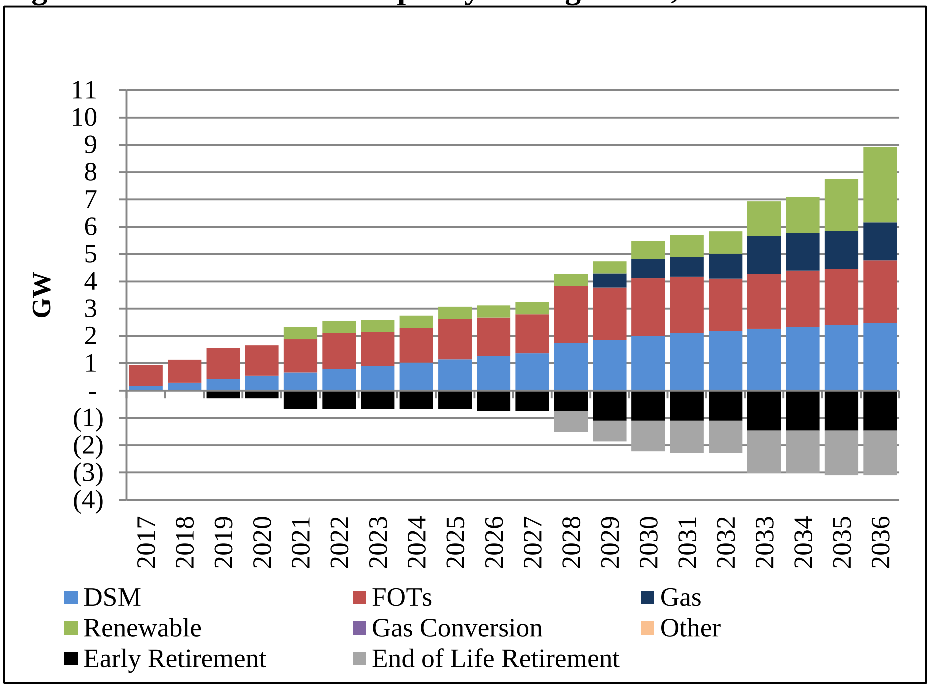


Figure 8.21 – Cumulative Capacity through 2036, Core Case FR-1

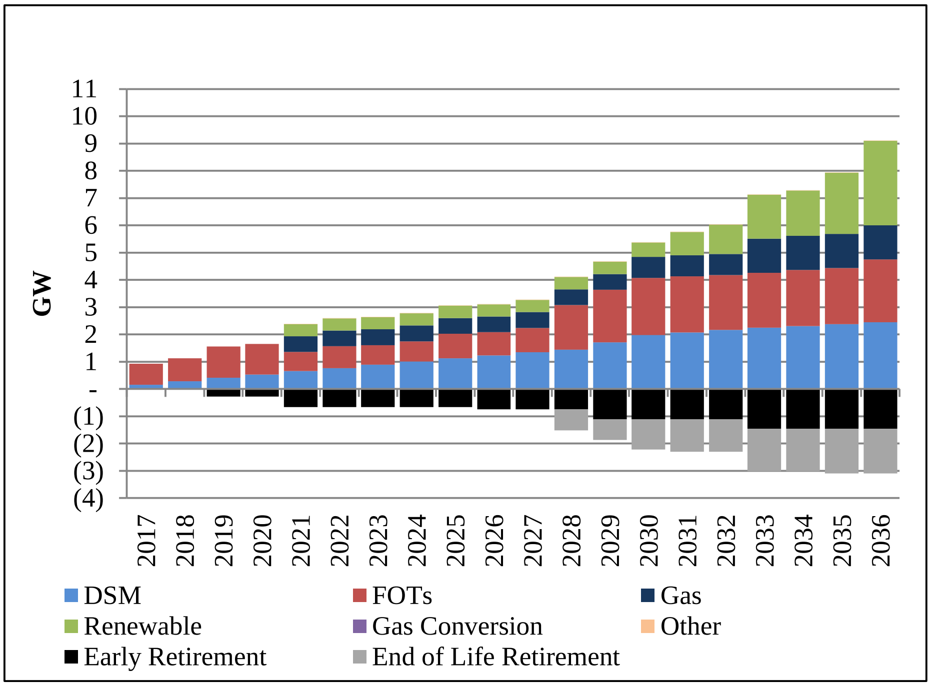


Figure 8.22 – Cumulative Capacity through 2036, Core Case FR-2

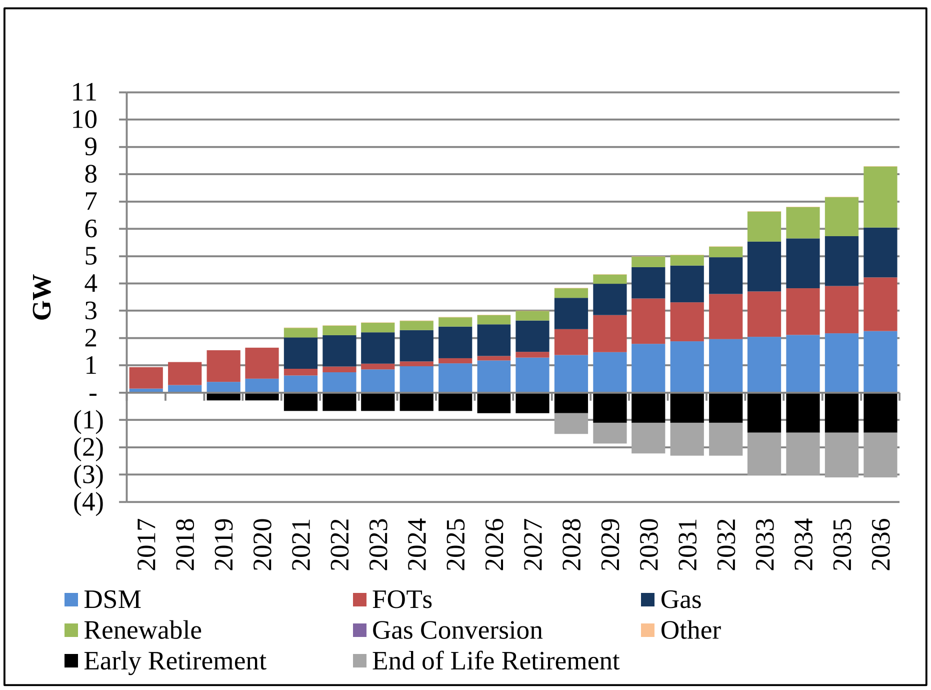


Figure 8.23 – Cumulative Capacity through 2036, Core Case RE-1a

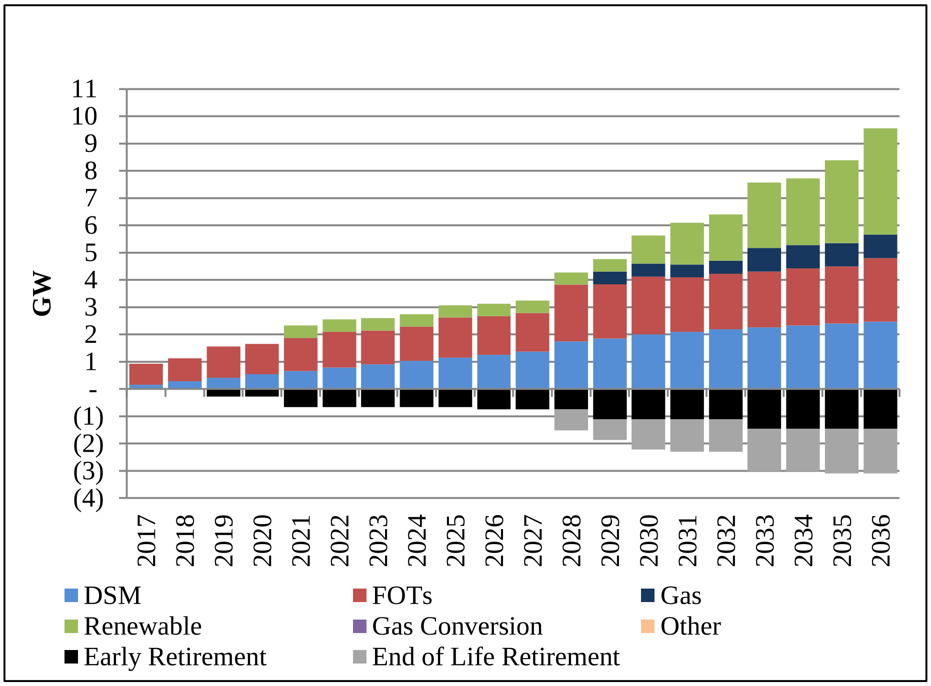


Figure 8.24 – Cumulative Capacity through 2036, Core Case RE-1b

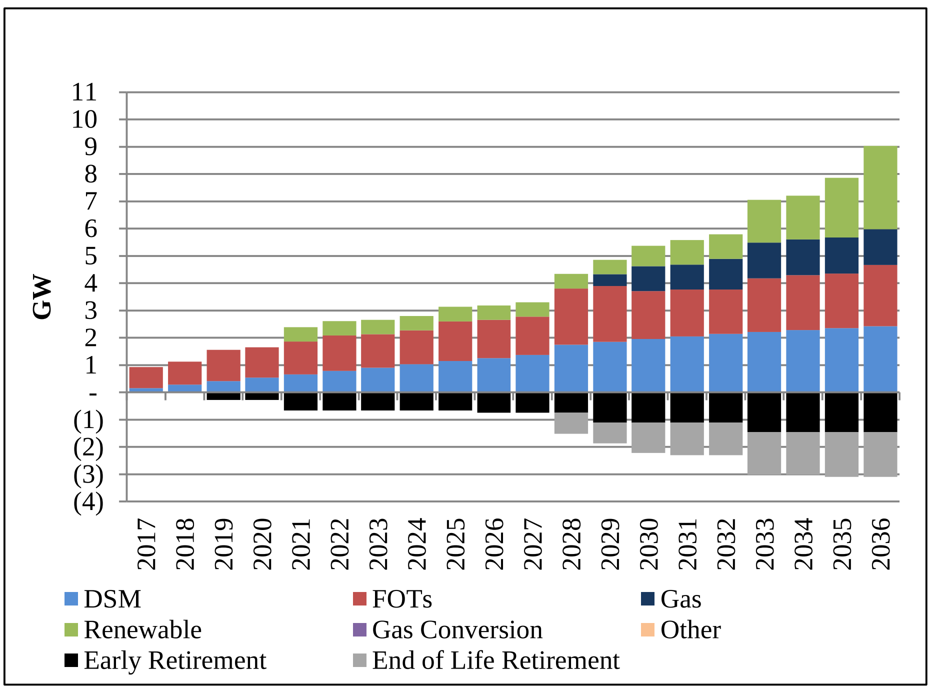


Figure 8.25 – Cumulative Capacity through 2036, Core Case RE-1c

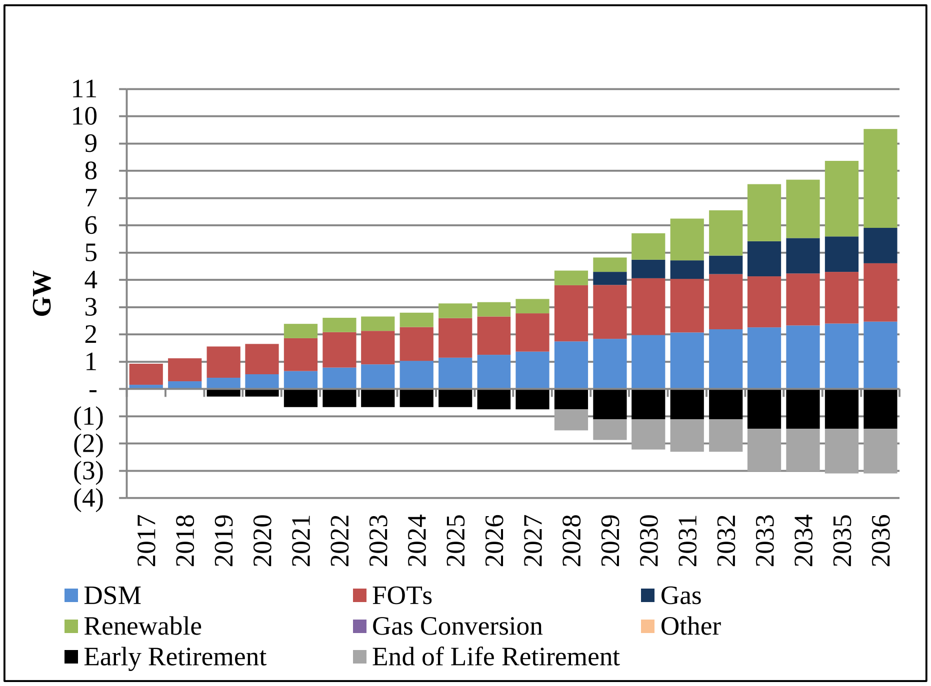


Figure 8.26 – Cumulative Capacity through 2036, Core Case RE-2

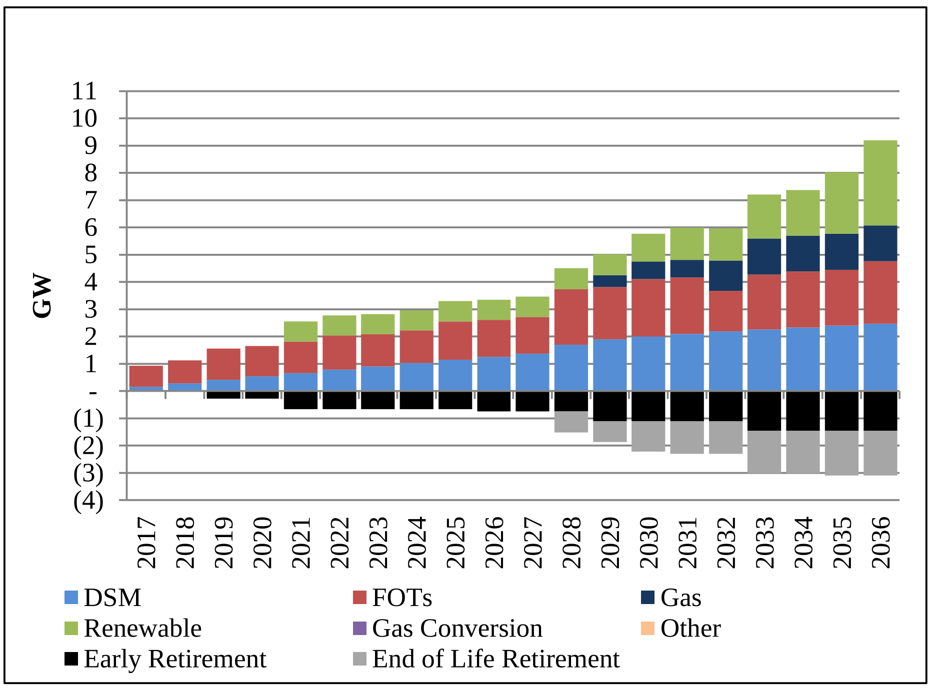
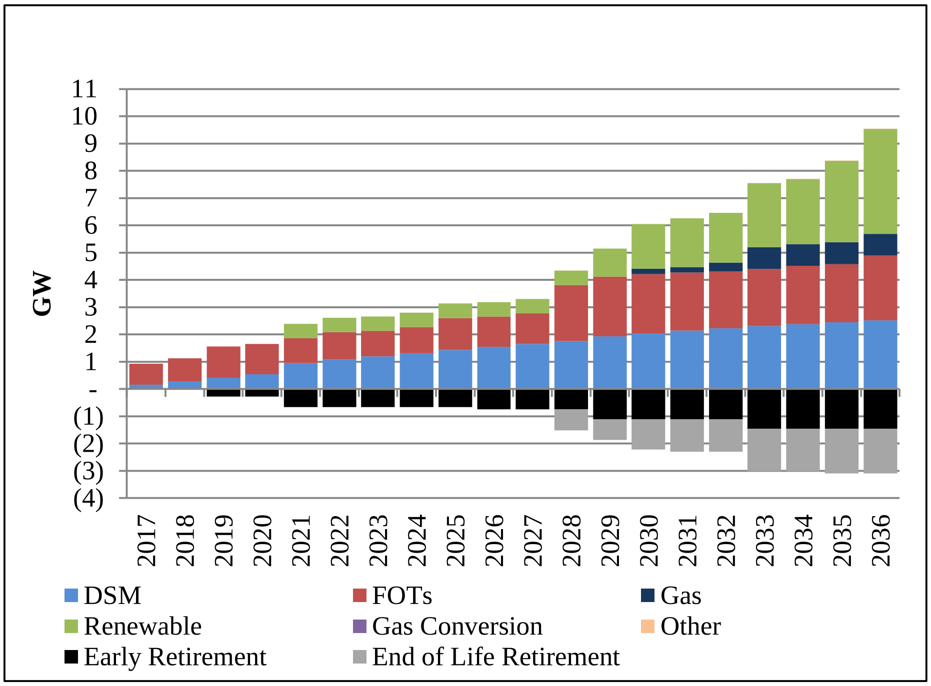


Figure 8.27 – Cumulative Capacity through 2036, Core Case DLC-1



Situs-Assigned Renewable Resources

Renewables core cases RE-1a, RE-1b, RE-1c and RE-2, assume physical RPS compliance to meet incremental requirements specific to each case, assuming system renewable resources from OP-NT3 are retained.

Just-in-Time Compliance

In cases RE-1a, RE-1b and RE-1c, additional renewables are added to physically comply with Oregon and Washington RPS:

- RE1a – Oregon
- RE1b – Washington (West Control Area renewable resources only)
- RE1c – Oregon and Washington (West Control Area renewable resources for Washington)

In each of these cases, renewable resource additions are made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance), after accounting for the system renewable resources included in case OP-NT3. Figure 8.28 through Figure 8.30 show the physical resource additions needed to meet RPS requirements for just-in-time compliance in each of the three cases (RE1a, RE1b, and RE1c). The total capacity of situs-assigned renewable resources in Figure 8.30 (Oregon and Washington) is less than the sum of situs-assigned renewable resources in Figure 8.28 (Oregon) and Figure 8.29 (Washington). When optimizing renewable energy targets for both states simultaneously, SO selects a higher proportion of wind vs. solar resources. Wind resource capacity factors are higher than the solar resource capacity factors, based on the resource selections from SO, and therefore, there is a reduction in total situs-assigned resource capacity in case RE-1c when compared to the sum of situs-assigned renewable resource capacity in cases RE-1a and RE-1b.

Figure 8.28 – Cumulative Situs Renewable Capacity, Core Case RE-1a (Oregon RPS)

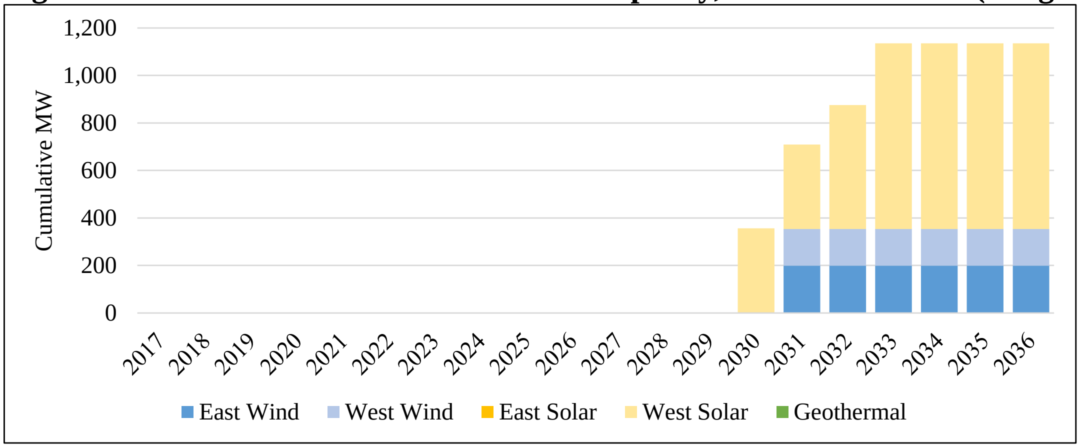


Figure 8.29 – Cumulative Situs Renewable Capacity, Core Case RE-1b (Washington RPS)

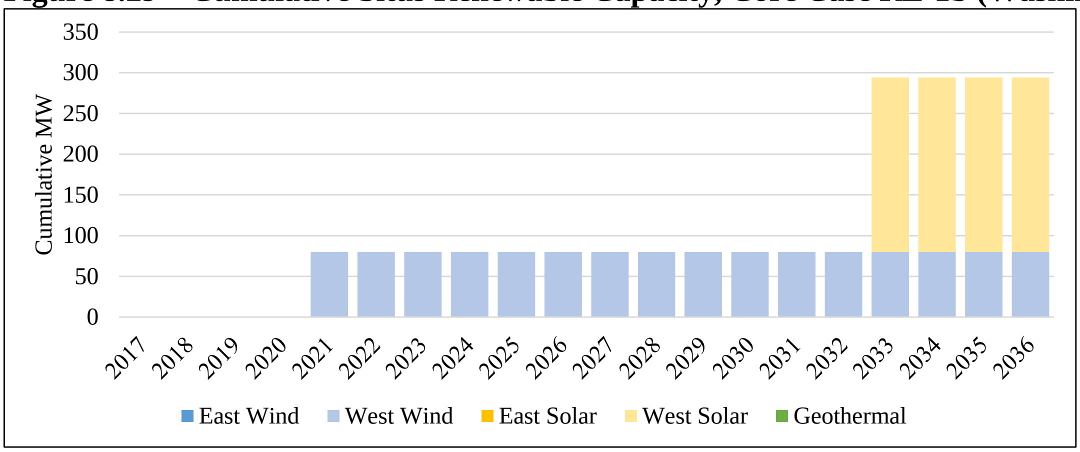
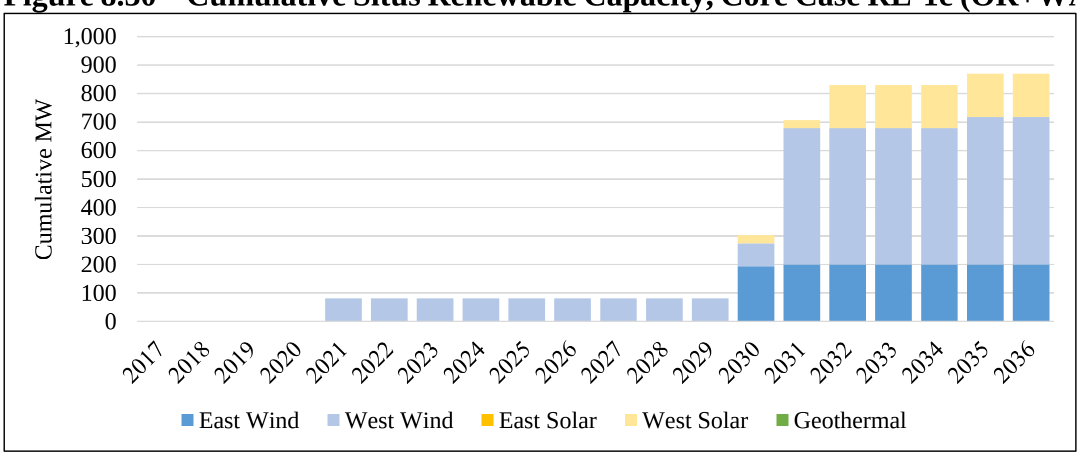


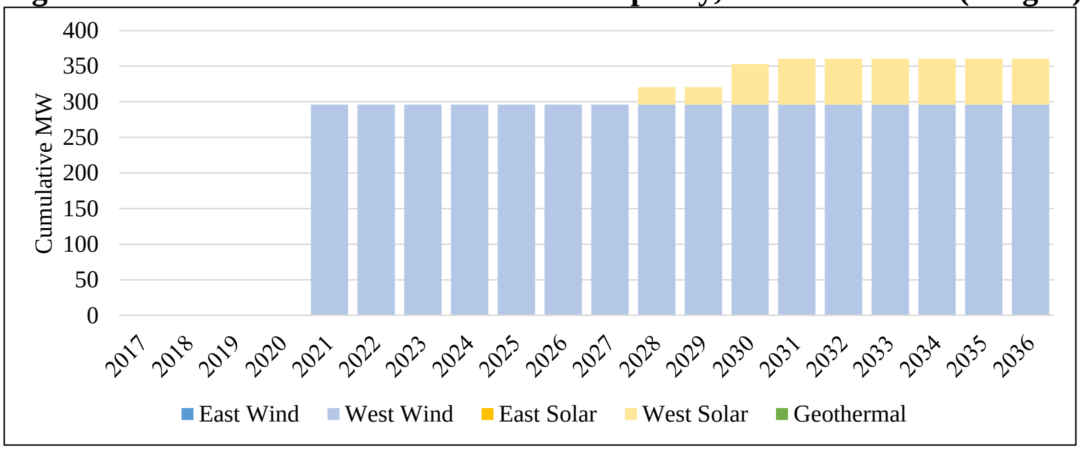
Figure 8.30 – Cumulative Situs Renewable Capacity, Core Case RE-1c (OR+WA Combined)



Early RPS Compliance Strategy

In the early compliance strategy, additional renewables are added to physically comply with projected Oregon RPS beginning 2021 (proxy for year-end 2020) to meet requirements throughout the planning period (early compliance). This strategy tests whether the benefits of early compliance (higher production tax credits and earlier availability of capacity to the system) make this option competitive with other eligible portfolios. Figure 8.31 shows the renewable Oregon situs resource additions resulting from this strategy. Washington cannot significantly benefit from the early compliance strategy due to the comparatively restricted banking rules for RECs as applied to the RPS requirement (one year REC persistence), and thus only Oregon RPS targets are considered in core case RE-2.

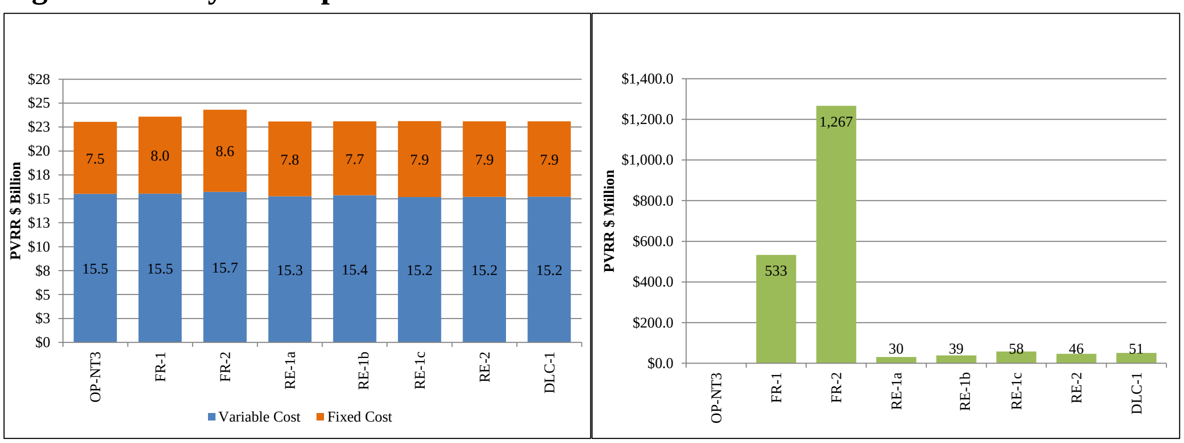
Figure 8.31 – Cumulative Situs Renewable Capacity, Core Case RE-2 (Oregon)



SO System Costs

SO provides a least-cost resource portfolio optimization. While preferred portfolio selection considers PaR measures, SO results provide an additional indicator and support for the subsequent PaR stochastic results. Among the core cases studied in SO, case OP-NT3 reports the lowest PVRR, while flexible resource cases (cases FR-1 and FR-2) report the highest PVRRs.

Figure 8.32 – System Optimizer PVRR Costs for Core Cases



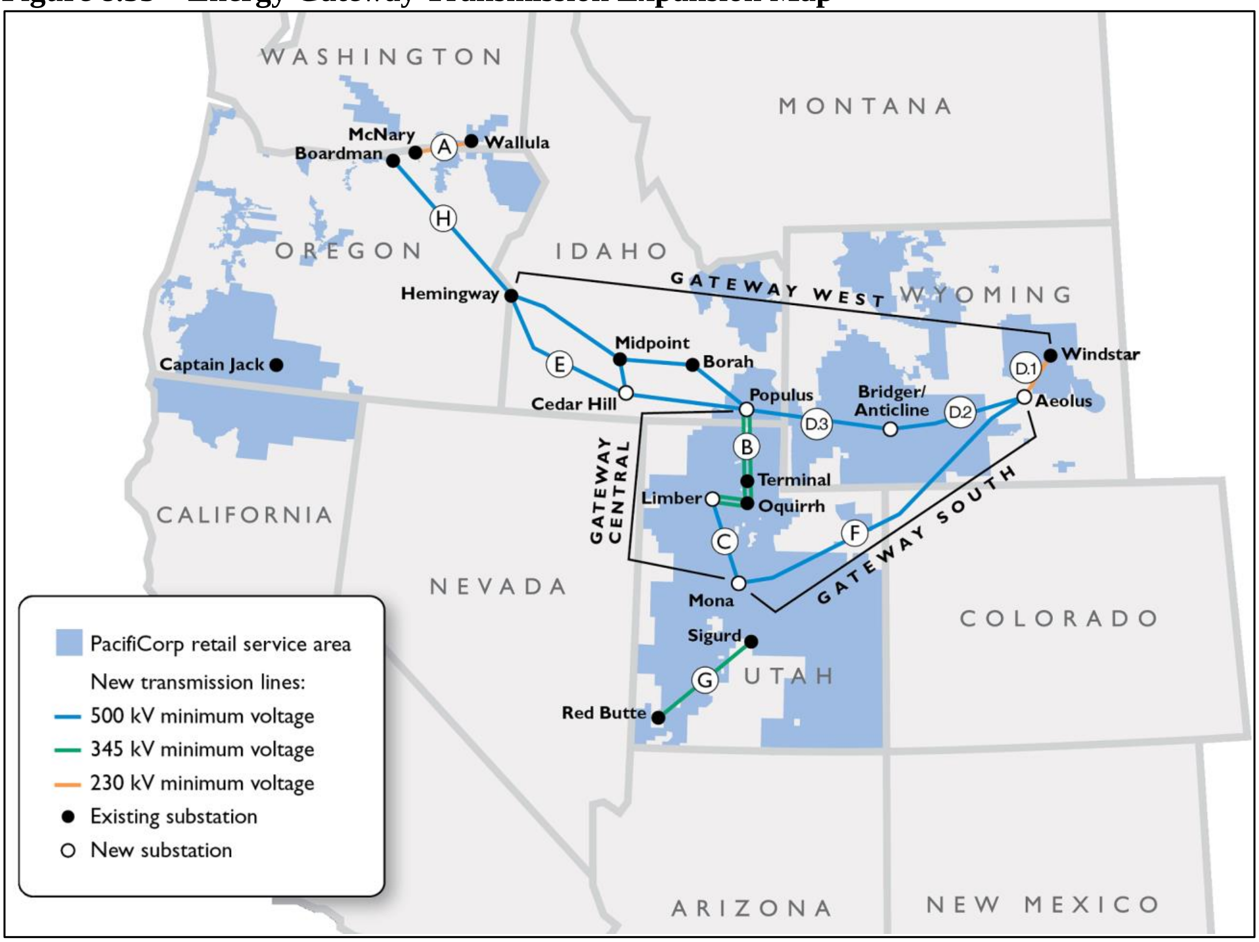
Eligible Sensitivity Portfolio Development

Table 8.5 lists the names and key characteristics of the wind repower and Energy Gateway transmission sensitivity cases considered for preferred portfolio consideration in screening stage two. Each case is benchmarked against OP-NT3, the selected Regional Haze case which emerged as least-cost, least-risk in screening stage one. The OP-REP case was added as a sensitivity to evaluate, in the context of the IRP, the economic benefits of PacifiCorp's December 2016 safe-harbor wind-turbine-generator (WTG) equipment purchase, securing the option to repower existing wind facilities and re-qualifying the repower projects for PTC benefits over a 10-year period. The OP-GW4 case was added to study the cumulative impacts of layering the most favorable Energy Gateway scenario on top of the Wind Repower case. Figure 8.33 provides a high-level map of the Energy Gateway segments under consideration.

Table 8.5 – Sensitivities Considered for the Preferred Portfolio

Sensitivity	Short Name	Gateway
Wind Repower	OP-REP	Base
Gateway 1	GW1	D
Gateway 2	GW2	F
Gateway 3	GW3	D & F
Gateway 4	GW4	D2
Gateway Repower	OP-GW4	D2

Figure 8.33 – Energy Gateway Transmission Expansion Map



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

Resource Capacity Impacts and PVRR Results

Figure 8.34 through Figure 8.39 summarize the resource capacity impacts of new resources and reductions in existing resources through 2036, as developed for the eligible sensitivity cases in SO. As with the Regional Haze and core cases, PTCs drive the addition of wind capacity in Wyoming.

Wind Repower (OP-REP)

PacifiCorp successfully executed WTG equipment purchases in December 2016 with General Electric and Vestas. These safe-harbor equipment purchases support repowering of the Wyoming wind fleet (Glenrock, Rolling Hills, Seven Mile Hill, High Plains, McFadden Ridge, and Dunlap), the Marengo project in Washington, and the Leaning Juniper project in Oregon by the end of 2020, enabling the projects to qualify for 100 percent of PTCs. Repowering of other projects in PacifiCorp's fleet may be feasible (i.e., Foote Creek and Goodnoe Hills).

Repowered WTGs must meet the Internal Revenue Service 80/20 test, meaning that the retrofitted WTG qualifies for PTCs if the fair market value of the retained property (i.e., tower and foundation) is no more than 20 percent of the facility's total value after installation of the new property (i.e., nacelle and blades).

Wind repowering has many benefits, including the ability to capture an additional ten years of PTCs for the full output of each repowered facility. These savings are passed through to customers. Modern technology and longer blade lengths increase annual energy production by an estimated 14 to 32 percent, depending upon the project. Existing foundations and towers are used, resulting in minimal environmental impact and permitting requirements. Also, new equipment reduces future operating costs and extends the project life by approximately ten years. The wind repower sensitivity (OP-REP) represents the fulfillment of this significant opportunity.

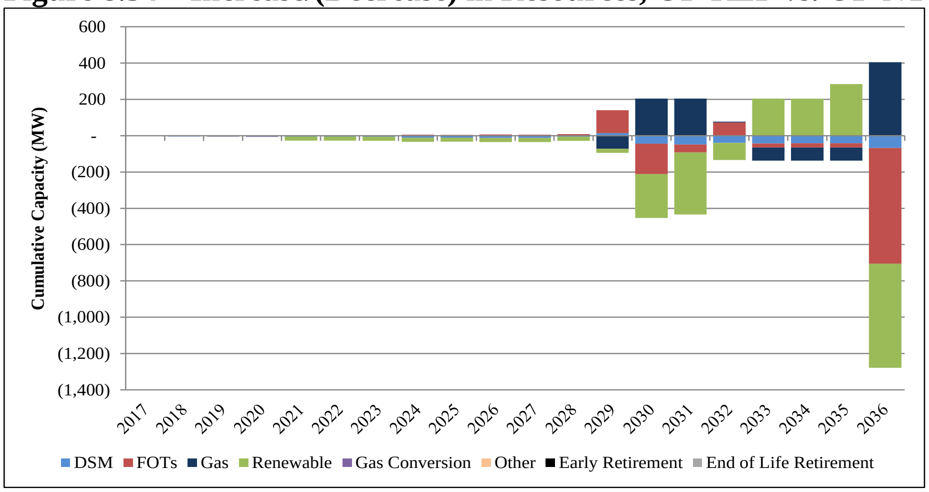
The OP-REP sensitivity assumes 905 MW of existing wind resources are repowered by the end of 2020 (Glenrock, Rolling Hills, Seven Mile Hill, High Plains, McFadden Ridge, Dunlap, Marengo, and Leaning Juniper). The repowering of wind projects across the fleet provides significant customer benefits in all market price and CPP scenarios.

Due to the extended life of repowered wind units, there are large known benefits extending beyond 2036 through 2050. The increased energy expected from the repowered wind facilities increases the full output of each repowered plant over the period when the life is extended. Over the existing life of the repowered projects, incremental annual energy production is in excess of 500 GWh. Incremental annual energy production beyond the current existing life (just beyond the IRP planning horizon) exceeds 3,100 GWh. Table 8.6 presents PVRR values through 2036 and through 2050. Capturing the benefits of the extended life increases customer benefits significantly. However, even when truncating the value of the wind repower project at year 2036, results are notably favorable to the benchmark non-repower case (OP-NT3).

Table 8.6 - PVRR Cost/(Benefit) of OP-REP vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3 (2036)	($66)	($51)	($66)	($152)	($48)	($64)	($143)
Change from OP-NT3 (2050)	($412)	($340)	($387)	($639)	($333)	($381)	($609)

Figure 8.34 – Increase/(Decrease) in Resources, OP-REP vs. OP-NT3



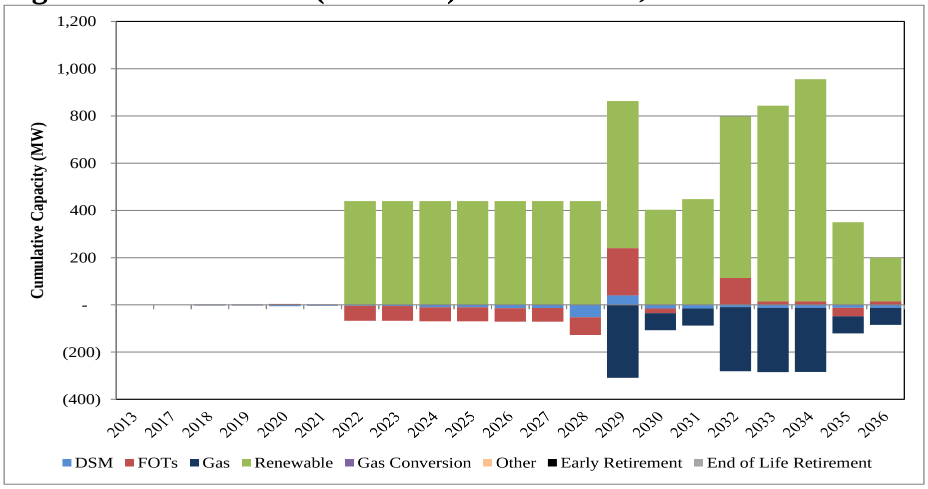
<u>Gateway 1 (GW1)</u>

Energy Gateway 1 assumes the addition of Energy Gateway segment D – Windstar to Anticline (assumed in-service date in 2022). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 440 MW of Wyoming wind additions in 2022. The PVRR results indicate an overall increase to system costs, with improving benefits under high natural gas price assumptions.

Table 8.7 – PVRR Cost/(Benefit) of GW1 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3	$541	$560	$483	$125	$559	$479	$124

Figure 8.35 – Increase/(Decrease) in Resources, GW1 vs. OP-NT3



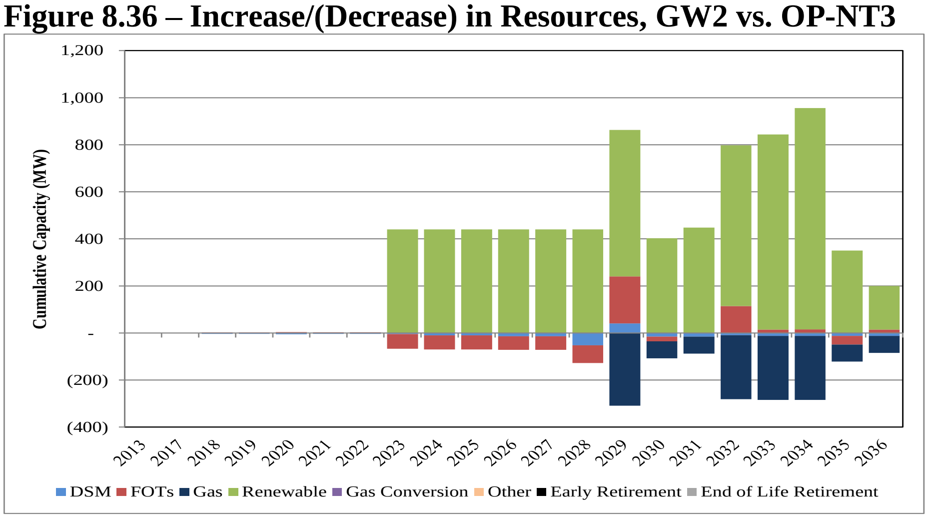
Gateway 2 (GW2)

Energy Gateway 2 assumes the addition of transmission segment F – Windstar to Mona/Clover (assumed in-service date in 2023). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 440 MW of Wyoming wind additions in 2023. The PVRR results indicate an overall increase to system costs, higher than case GW1, with improving benefits under high natural gas price assumptions.

Table 8.8 – PVRR Cost/(Benefit) of GW2 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3	$874	$906	$829	$478	$904	$824	$477

Figure 8.36 – Increase/(Decrease) in Resources, GW2 vs. OP-NT3



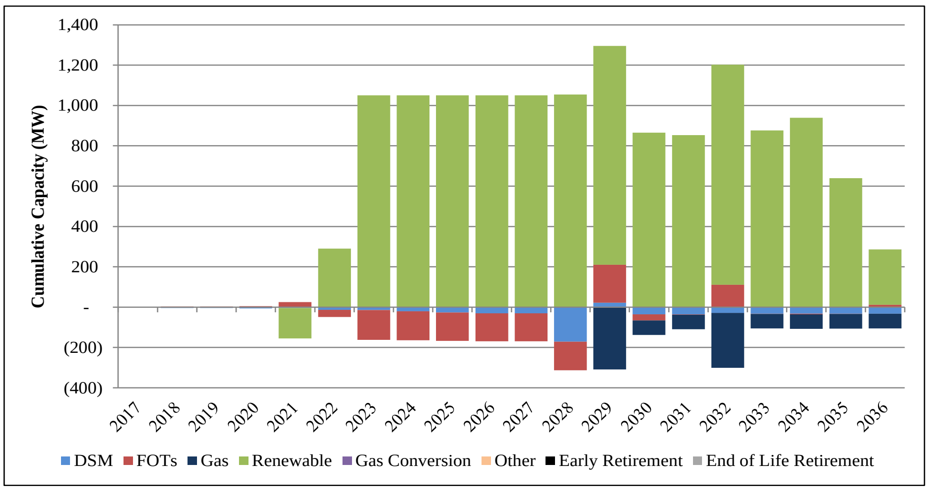
Gateway 3 (GW3)

Energy Gateway 3 assumes the addition of transmission segments D & F – Windstar to Anticline and Aeolus to Mona/Clover (assumed in-service dates in 2022 and 2023, respectively). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 440 MW of Wyoming wind additions in 2022 and 760 MW in 2023. In 2021, 150 MW of Goshen wind is eliminated. The PVRR results indicate an overall increase to system costs, higher than cases GW1 and GW2, with improving benefits under high natural gas price assumptions.

Table 8.9 – PVRR Cost/(Benefit) of GW3 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3	$1,363	$1,453	$1,316	$724	$1,452	$1,308	$726

Figure 8.37 – Increase/(Decrease) in Resources, GW3 vs. OP-NT3



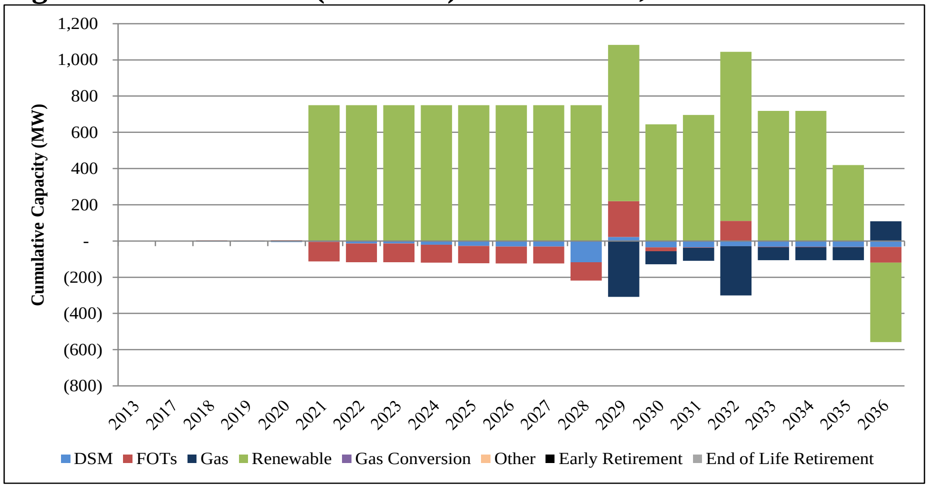
Gateway 4 (GW4)

Energy Gateway 4 assumes the addition of transmission segment D2 – Aeolus to Bridger/Anticline (assumed in service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 900 MW of Wyoming wind additions in 2021 (proxy for year-end 2020). In 2021, 150 MW of Goshen wind is eliminated. This sensitivity shows improved economics relative to cases GW1, GW2, and GW3, with favorable benefits under high natural gas price assumptions.

Table 8.10 - PVRR Cost/(Benefit) of GW4 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3	$107	$295	$205	($236)	$295	$199	($234)

Figure 8.38 – Increase/(Decrease) in Resources, GW4 vs. OP-NT3



Gateway Repower (OP-GW4)

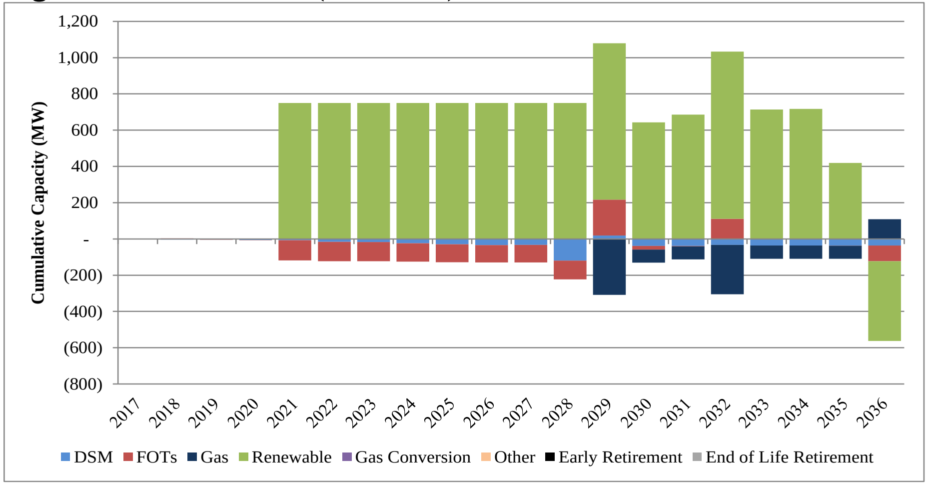
Considering the overwhelmingly favorable result of the Wind Repower sensitivity (OP-REP) and the encouraging Gateway 4 results showing favorable PVRR results in the high gas price scenarios, PacifiCorp conducted an additional Energy Gateway sensitivity. The Gateway Repower (OP-GW4) sensitivity assumes the addition of the Aeolus to Bridger/Anticline transmission segment D2 (assumed in service year-end 2020), as well as 905 MW of wind repowering represented in the OP-REP Wind Repower sensitivity.

Incremental to the 300 MW of Wyoming wind in core case OP-NT3, the increased transmission enables 900 MW of Wyoming wind additions in 2021 (proxy for year-end 2020). Compared to OP-NT3, 150 MW of Goshen wind is eliminated in 2021. This sensitivity yields improved economics relative to cases GW1, GW2, GW3, and GW4, with increasingly favorable benefits under high natural gas price assumptions.

Table 8.11 - PVRR Cost/(Benefit) of OP-GW4 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3	$71	$309	$201	($315)	$310	$196	($310)
Change from OP-NT3 (2050)	($275)	$19	($119)	($803)	$26	($120)	($775)

Figure 8.39 – Increase/(Decrease) in Resources, OP-GW4 vs. OP-NT3[1]



SO System Costs

Figure 8.40 and Figure 8.41 add sensitivities eligible for consideration to the core case results previously presented in Figure 8.32. Among the eligible cases studied in SO, the OP-REP and OP-GW4 cases produces the lowest system PVRRs. Cases FR-2 and GW3 report the highest system PVRRs. The results for the OP-REP and OP-GW4 cases include benefits for the wind repower project through 2050, accounting for the significant incremental energy benefits beyond the IRP planning period when the life of repowered wind resources is extended. During the public input process, PacifiCorp received feedback from stakeholders that including these long-term incremental benefits may distort comparisons with portfolios that do not include the wind repower project. Stakeholders requested that PacifiCorp address these concerns by including the wind repower project as part of the RE-1c and RE-2 cases. In response to these comments, PacifiCorp considered these additional sensitivity cases during the final portfolio screening stage.

[1] While Figure 8.39 is visually similar to Figure 8.38, there are differences in DSM and FOTs that are not visible at this resolution

Figure 8.40 – System Optimizer PVRR Costs for Eligible Core Cases and Sensitivities

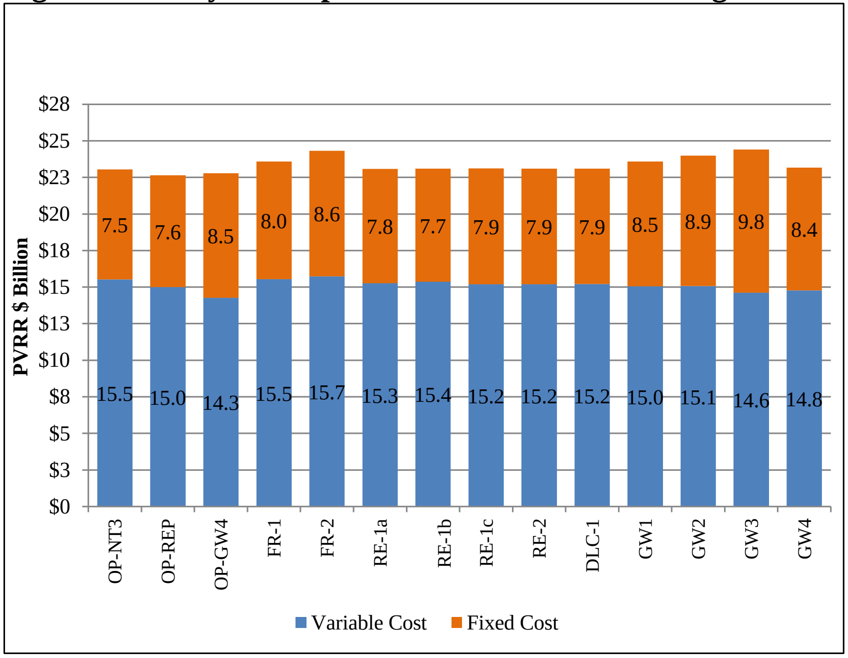
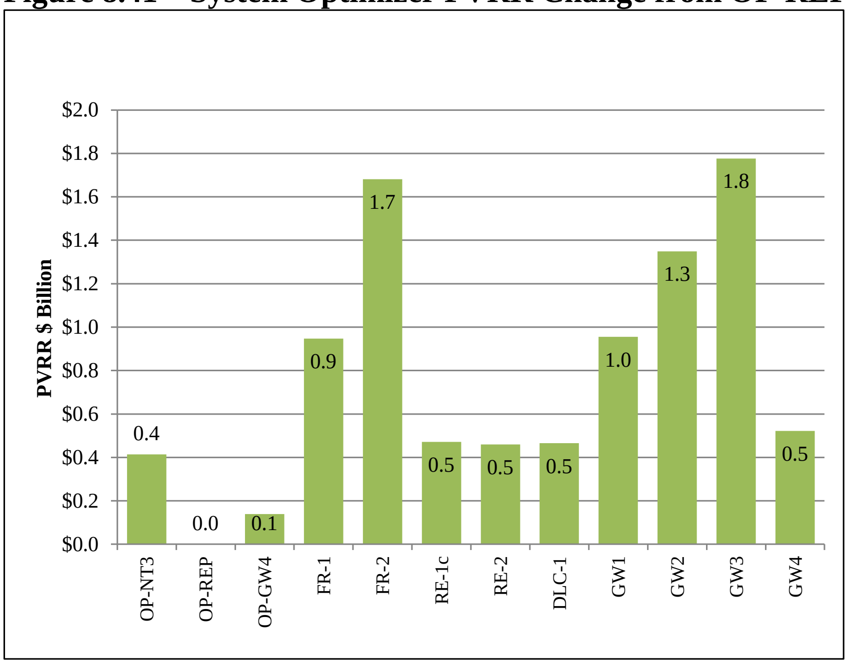


Figure 8.41 – System Optimizer PVRR Change from OP-REP



Eligible Portfolio Cost and Risk Analysis

PaR Configuration and Metrics

The PaR portfolio ranking metrics, which include mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean ENS, upper-tail ENS, and emissions, are fundamentally alike for each screening stage. As in the Regional Haze screening stage, CO_2 shadow prices from SO are input into PaR to reduce thermal dispatch, as required, and achieve mass cap emission limits. The resulting CO_2

costs reported by PaR represent the opportunity cost of the CPP, but are not real expenses, and thus they are removed in the final PVRR reporting.

Scatter plots present the mean PVRR of each unique core case and eligible sensitivity portfolio on the horizontal axis, and the upper-tail mean PVRR on the vertical axis. Portfolios toward the left-bottom corner of each scatter plot contain the least-cost, least-risk mix of resources, while portfolios toward the upper-right corner contain the highest-cost and highest-risk mix of resources. Figure 8.42 and

Figure 8.43 show the scatter plot results for eligible cases under both the Mass Cap A and Mass Cap B scenarios. As observed in the Regional Haze case results, cost and risk in the upper-tail mean are highly correlated. The OP-REP case is least-cost, least-risk under the low and medium price scenarios, and ranks second in the high gas price scenario. OP-GW4 is least-cost, least-risk in the high gas scenario. GW3 produces the highest cost and risk under each price-emission scenario, with the exception of high natural gas price scenarios, where FR-2 produces the highest- cost, highest-risk results.

Figure 8.42 – Eligible Portfolio Scatter Plots, Mass Cap B

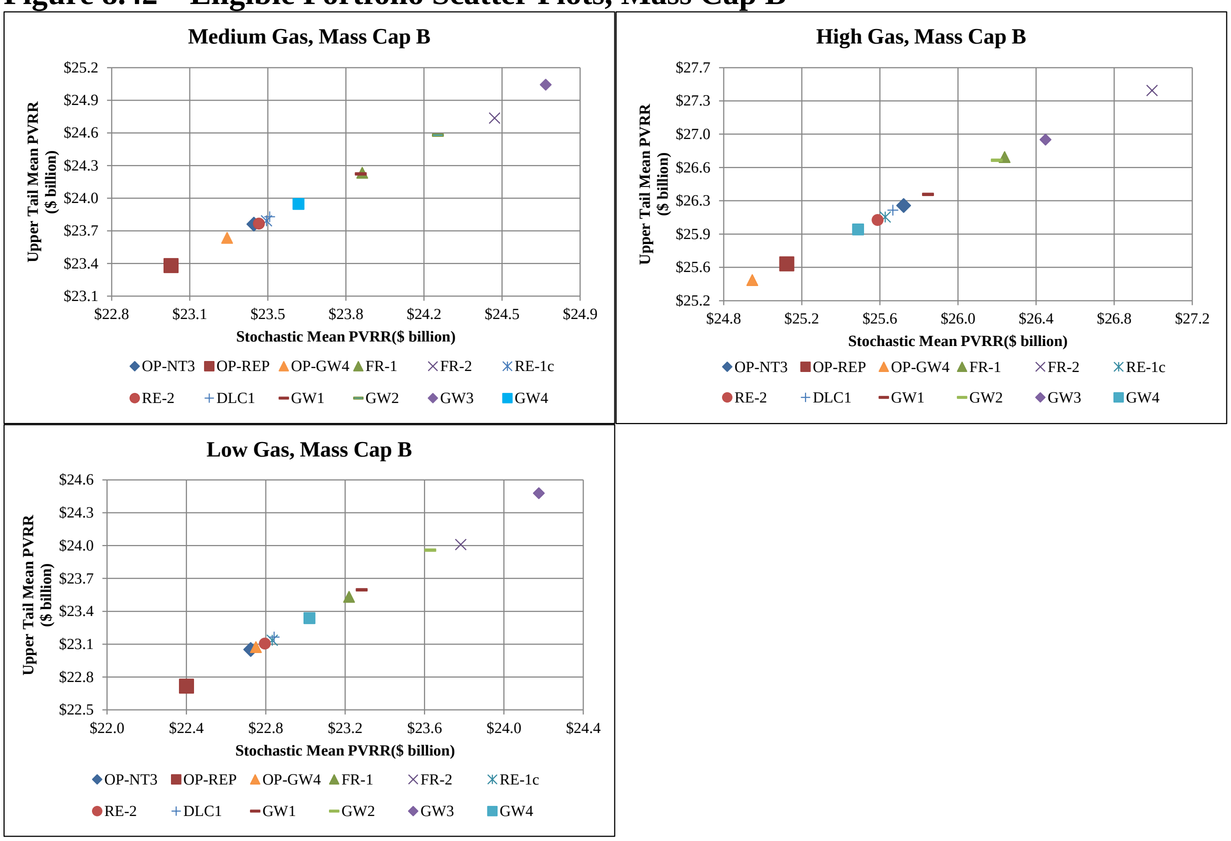
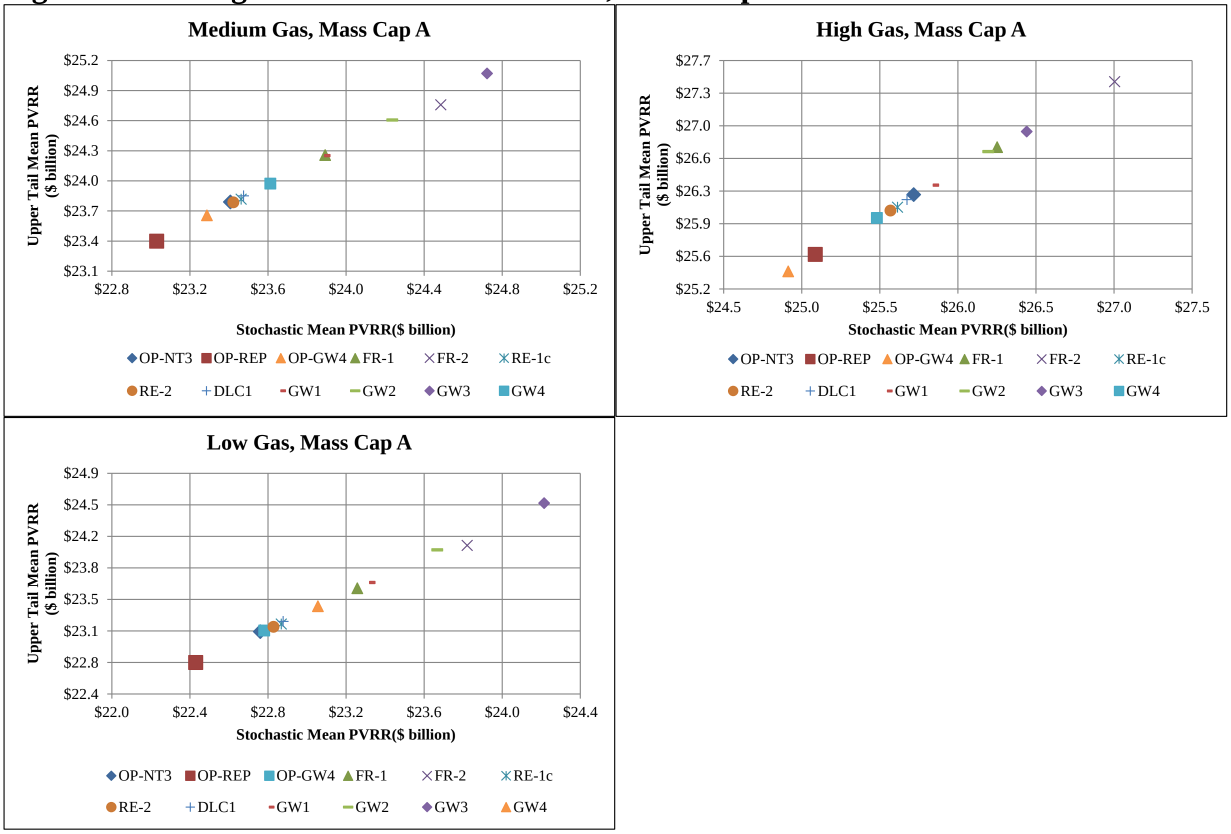


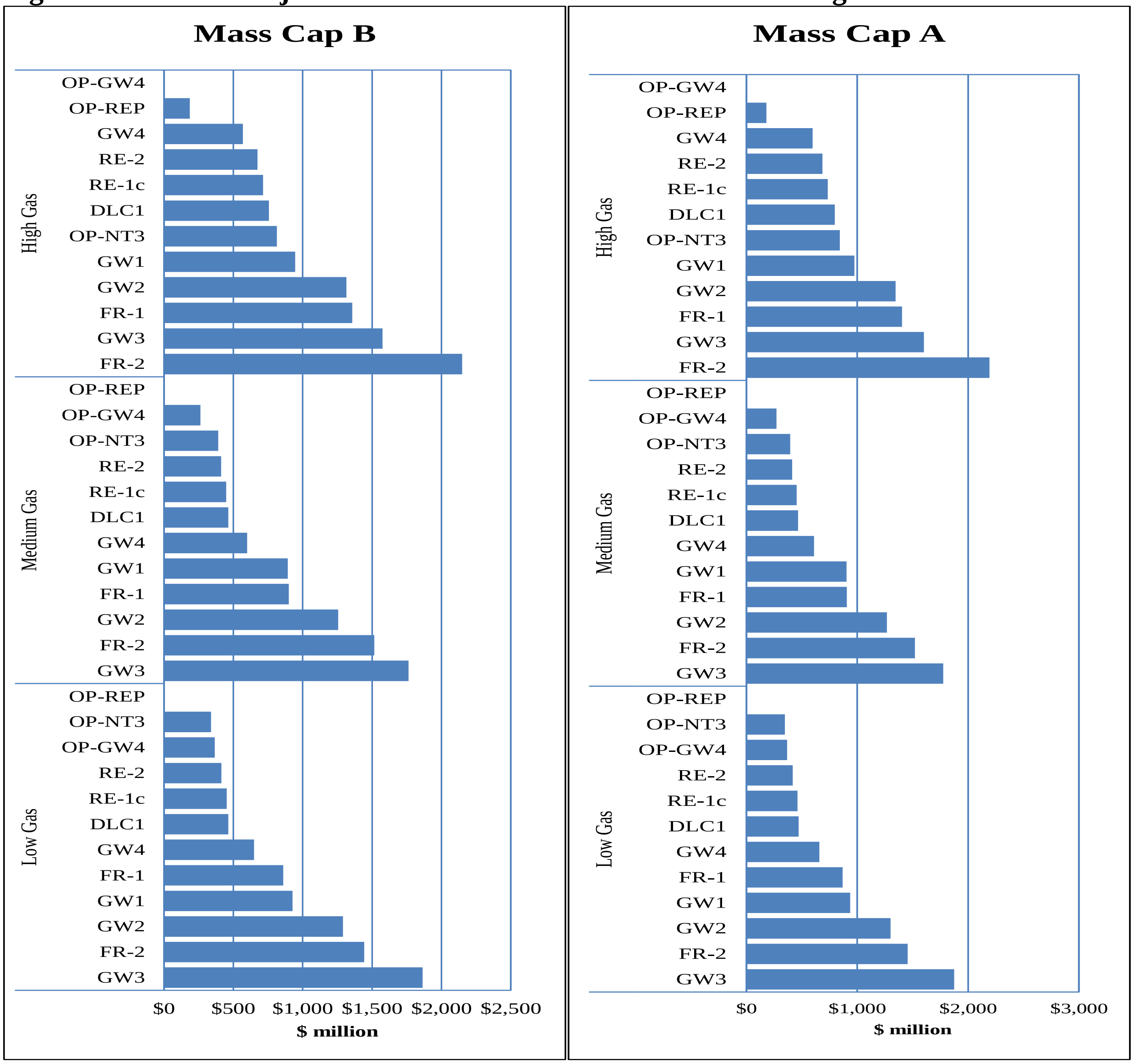
Figure 8.43 – Eligible Portfolio Scatter Plots, Mass Cap A



Risk-Adjusted PVRR

Figure 8.44 shows the stochastic mean PVRR of each case ranked against the best performing case in each price-emission scenario. OP-REP produces the lowest risk-adjusted PVRR in four out of the six price scenarios. OP-GW4 produces the most favorable risk-adjusted PVRR in the high gas price scenarios. Cases GW3 and FR-2 consistently have the highest risk-adjusted PVRR.

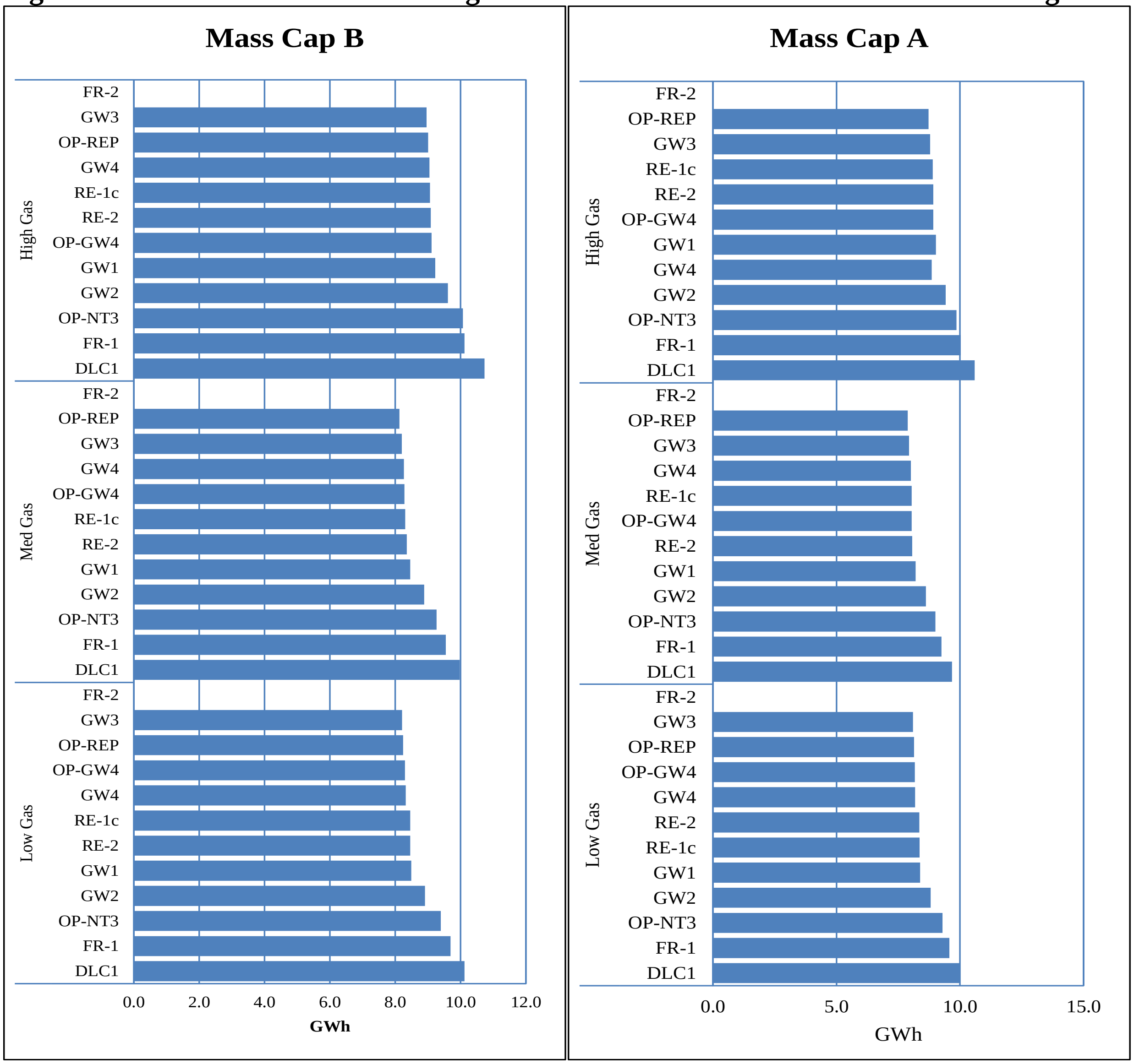
Figure 8.44 – Risk-Adjusted PVRR Relative to the Best Performing Case



Average Energy Not Served (ENS)

Figure 8.45 presents the stochastic mean average annual ENS of each eligible case ranked against the best performing case in each price-emission scenario. All cases have mean ENS levels that are a fraction of total load (annual mean ENS ranges between 2.8 and 13.8 GWh). Relative to other cases, FR-2, with incremental peaking capacity, consistently produces the lowest mean ENS levels (between 2.8 and 3.1 GWh).

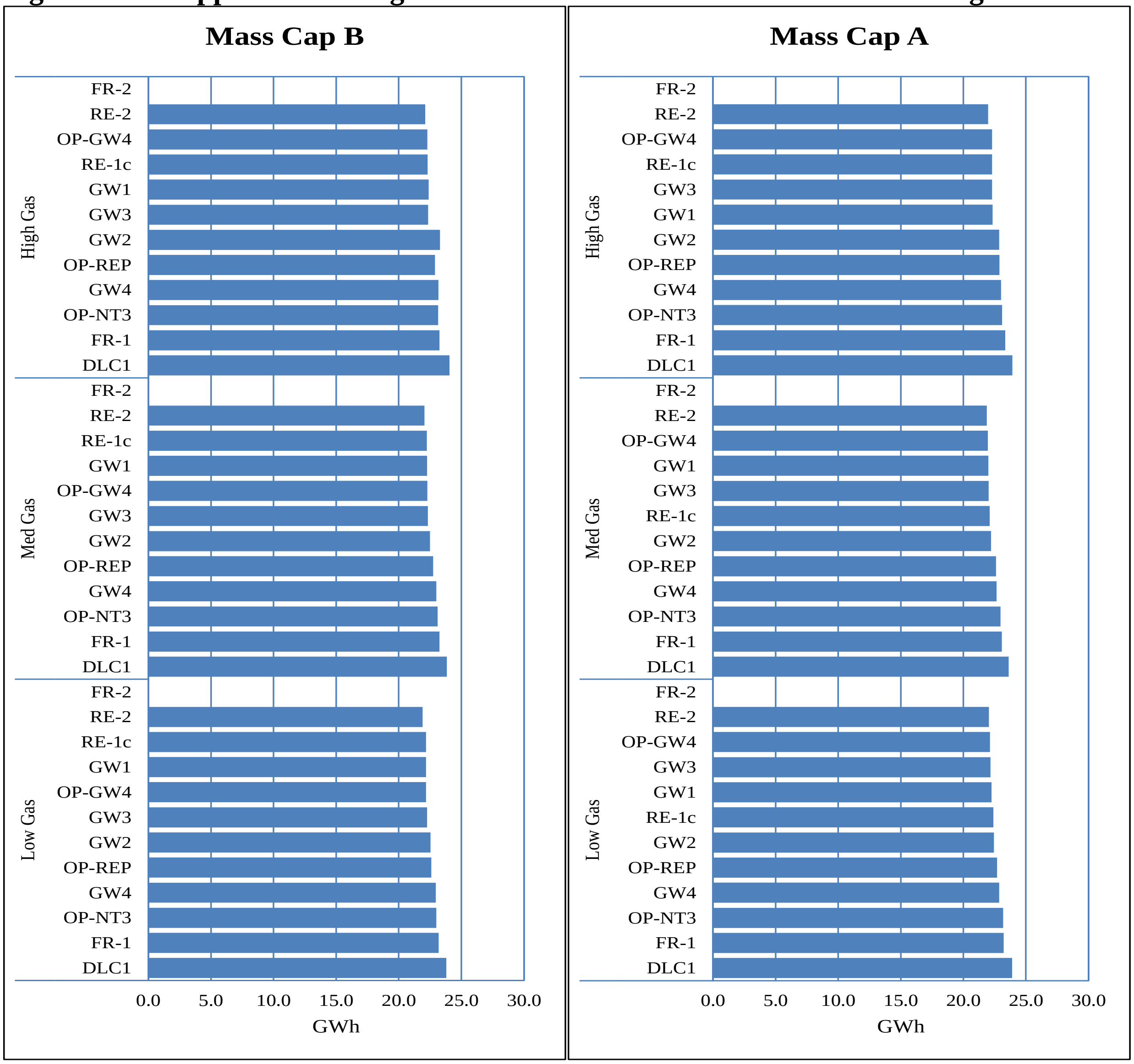
Figure 8.45 – Stochastic Mean Average Annual ENS Relative to the Best Performing Case



Upper-tail Average Energy Not Served (ENS)

Figure 8.46 shows the upper-tail average annual ENS of each eligible case ranked against the best performing case in each price-emission scenario. All cases have upper-tail ENS levels that are a fraction of total load. As with the mean ENS metric, relative to other cases, FR-2, with incremental peaking capacity, consistently produces very low upper-tail ENS levels.

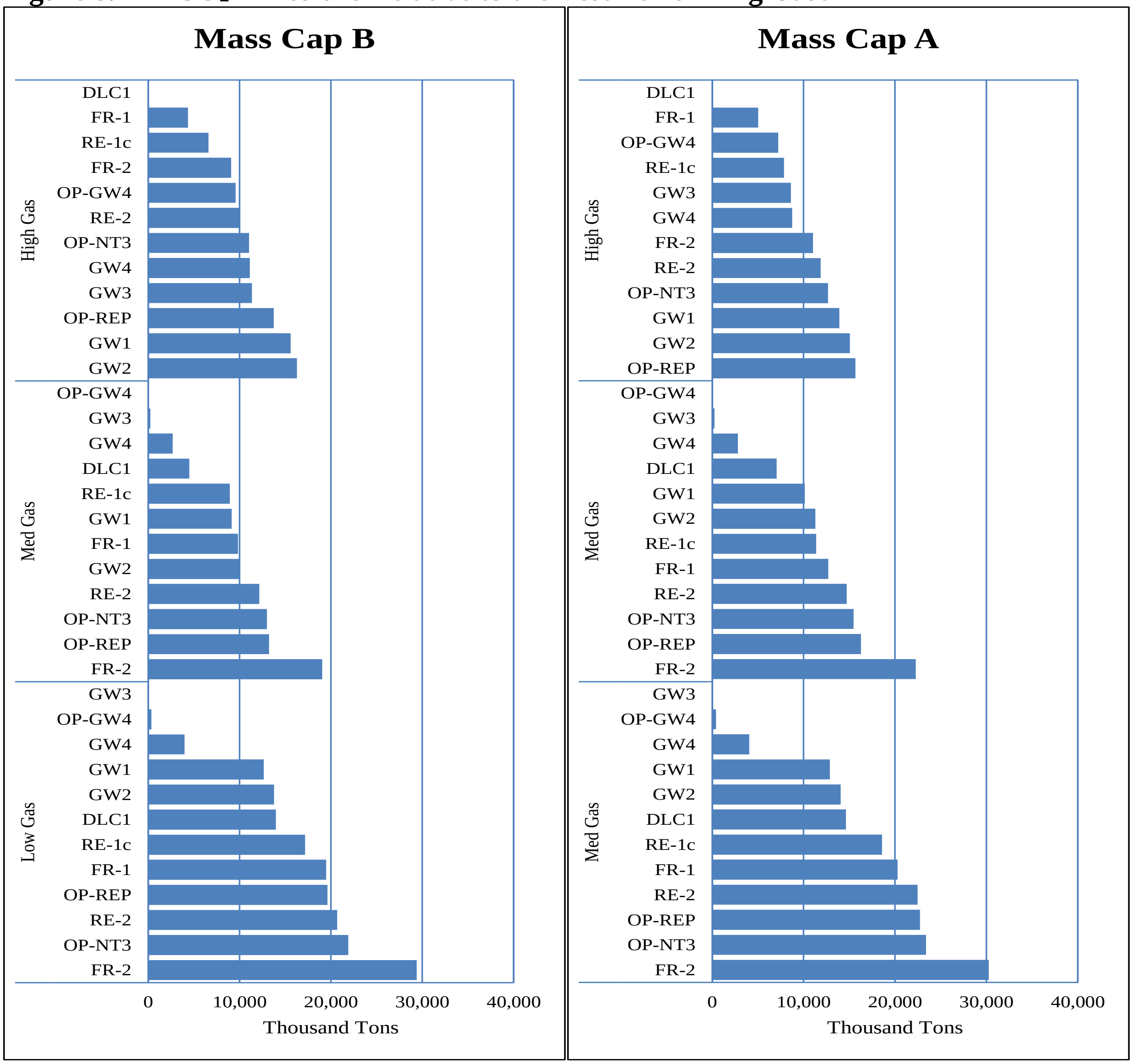
Figure 8.46 – Upper-tail Average Annual ENS Relative to the Best Performing Case



CO_2 Emissions

Figure 8.47 shows total CO_2 emissions of each eligible case ranked against the best performing case in each price-emission scenario. Case GW3 and OP-GW4, which contain the highest level of renewable resources among the cases, consistently yield the lowest emissions levels. The DLC-1 case performed most favorably in the high gas price scenarios. Case OP-REP yields mid-to-high emissions relative to other cases.

Figure 8.47 – CO_2 Emissions Relative to the Best Performing Case



Eligible Portfolio Selection

The metrics described in the cost and risk analysis are condensed into Table 8.12. The OP-REP case ranks first in the risk adjusted PVRR metric, second in the average ENS metric, eighth in the upper-tail ENS metric, and eleventh on emissions. The rankings, while indicative of order, tend to obscure how close some of the outcomes are in terms of raw measures (e.g., total CO_2 emissions). Case OP-REP performs very well in comparison to other top candidates eligible for consideration as the preferred portfolio.

Table 8.12 - Risk-adjusted PVRR among Top Performing Portfolios, Phase Two

	Risk Adjusted[1]			ENS Scenario Average			ENS Upper Tail Average			CO_2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2017-2036 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
OP-NT3	25,167	$461	4	12.5	9.5	10	31.4	23.1	10	770,651	13,323	10
OP-REP	24,706	$0	1	11.3	8.4	2	31.0	22.7	8	771,283	13,956	11
OP-GW4	24,857	$150	2	11.5	8.5	5	30.5	22.2	3	757,327	0	1
FR-1	25,695	$988	9	12.7	9.7	11	31.5	23.2	11	766,344	9,017	6
FR-2	26,358	$1,652	11	3.0	0.0	1	8.3	0.0	1	774,577	17,250	12
RE-1c	25,189	$483	5	11.5	8.5	6	30.5	22.3	6	766,154	8,827	5
RE-2	25,148	$441	3	11.5	8.5	7	30.3	22.0	2	769,738	12,411	9
DLC1	25,215	$509	6	13.2	10.2	12	32.1	23.9	12	761,095	3,768	4
GW1	25,575	$869	8	11.6	8.6	8	30.5	22.2	4	766,789	9,461	7
GW2	25,941	$1,234	10	12.0	9.0	9	30.9	22.6	7	767,825	10,498	8
GW3	26,388	$1,681	12	11.4	8.4	3	30.5	22.2	5	757,806	479	2
GW4	25,259	$553	7	11.4	8.4	4	31.2	22.9	9	759,964	2,636	3

[1]Based on average of 6 emissions/price scenarios

PacifiCorp identified case OP-REP as the top performing case for phase two of the portfolio selection process. This selection is based on the following observations:

- Case OP-REP produces the lowest risk-adjusted PVRR in four out of six price scenarios and is among the top two cases in the other two price scenarios.
- All cases produce low ENS levels; case OP-REP is consistently among the top performing portfolios when ranked on mean ENS.
- All cases show similar levels of CO_2 emissions; the relative differences among cases does not warrant using the CO_2 emissions metric to select a higher-cost, higher-risk portfolio.
- Case OP-REP produces a low PVRR relative to other eligible cases based on the PVRR from SO.
- Case OP-REP and OP-GW4 are very close when evaluating the PVRR from SO, but case OP-GW4 only exhibits the lowest risk-adjusted PVRR in the high natural gas price scenarios when evaluated in PaR.

Final Portfolio Screening

Final Portfolio Development

In screening stages one and two, PacifiCorp evaluated nine Regional Haze cases (including the additional RH-2a and RH-5a Naughton Unit 3 retirement sensitivities), eight core cases (including the expanded examination of RE-1a, RE-1b and RE-1c), and six sensitivities eligible for preferred portfolio consideration (OP-REP, GW1, GW2, GW3, GW4, and OP-GW4).

In the final portfolio screening stage, PacifiCorp conducted additional studies informed by the analysis performed during the prior screening stage. The initial results for the GW4 and OP-GW4 sensitivity cases suggest there may be potential for a time-limited opportunity to align development of Energy Gateway sub-segment D2 with wind projects that can qualify for the full value of PTCs. In the final screening stage, PacifiCorp has quantified additional benefits reasonably expected from the new transmission line, assessed how more current near-term assumptions for project capital costs and wind capacity factors affect the analysis, and completed power flow and dynamic stability analysis to refine transmission assumptions. In response to stakeholder feedback, PacifiCorp also re-evaluated the RE-1c and RE-2 cases to include the wind repower project and updated Energy Gateway sub-segment D2 transmission assumptions. This ensures final selection is performed on portfolios developed with comparable assumptions as informed by analysis completed in stage two of the screening process. Final screening portfolios receive an "FS-" designation to indicate that they are distinct from prior screening versions of cases having the same name. Table 8.13 summarizes the portfolios considered for final screening in the 2017 IRP cycle.

Table 8.13 – Final Screening Portfolios

Resource Class	Wind Repower (FS-REP)	Gateway 4 (FS-GW4)	Renewable Energy (FS-RE-1c)	Renewable Energy (FS-RE-2)
Flexible Resources	Optimized	Optimized	Optimized	Optimized
Renewable Resources	Optimized	Optimized	Just-in-Time Physical RPS Compliance (OR and WA)	Early Physical Compliance (OR)
Class 1 DSM Resources	Optimized	Optimized	Optimized	Optimized
All other Resources	Optimized	Optimized	Optimized	Optimized
Gateway 4	No	Yes	Yes	Yes

Wind Repower (FS-REP) Portfolio

After completing the original OP-REP core case studies, PacifiCorp received monthly shaping profiles for the incremental annual energy output expected for the repowered wind plants. These updated monthly profiles, which show the increased annual production associated with installing more modern equipment is higher during the summer months, when wind speeds are lower, than in the winter months, when wind speeds are higher. These monthly profiles were incorporated into the updated repower case (FS-REP) and subsequently used in all final screening portfolio studies.

Energy Gateway 4 (FS-GW4) Portfolio

At the end of screening stage two, the preferred-portfolio-eligible Gateway studies indicated potential for a time-limited opportunity to align the development of Energy Gateway sub-segment D2 with wind projects that can qualify for the full value of PTCs. During the public input process, PacifiCorp indicated its intention to further evaluate its assumptions for case OP-GW4. Since the last public input meeting, PacifiCorp completed power flow and dynamic stability analysis to support updated transmission assumptions, updated its transmission capital cost assumptions, assessed wind cost and performance assumptions, and quantified incremental cost and benefit drivers associated with the Energy Gateway sub-segment D2 transmission line. These updates, summarized below, are used in PacifiCorp's final screening portfolio studies.

Energy Gateway Sub-Segment D2 Assumptions

Power flow and dynamic stability analysis confirmed that the Energy Gateway sub-segment D2 transmission line can accommodate new and existing wind resource interconnections at levels at or above those assumed in PacifiCorp's original OP-GW4 sensitivity case. This analysis further supports an increase in the transfer capability from 650 MW, as assumed in the original sensitivity case, to 750 MW as assumed in the updated analysis. PacifiCorp also completed a detailed review of its assumed cost to build the new transmission line. The results of this review support reducing the originally assumed capital cost of the transmission line by approximately $113m. The updated transfer capability and reduced capital costs directionally improve the economics of the transmission project.

Wind Cost and Performance Assumptions

Considering the potential to expand new wind resource capacity with addition of the transmission line, PacifiCorp reviewed the Wyoming wind cost and performance assumptions adopted for the 2017 IRP with a more detailed review of potential wind projects located in Wyoming, taking into consideration equipment costs, interconnection costs, and potential development fees. This analysis supports reducing nominal wind capital cost assumptions included in the original sensitivity case of $1,834/kW by 10.7 percent to $1,637/kW. Directionally, the updated wind capital cost assumptions improve the economics of the updated sensitivity case.

In its review of updated wind capital cost assumptions, PacifiCorp also assessed projected Wyoming wind resource capacity factors for potential projects that might connect to the new transmission line. This review supports reducing the 43.0 percent capacity factor assumed for proxy Wyoming wind resources in the 2017 IRP to 41.2 percent. Directionally, the updated wind capacity factor assumptions increase the cost of the updated sensitivity case.

Additional Cost/Benefit Drivers

The qualifying facility (QF) pricing methodology used in Wyoming includes two price streams—one with and one without incremental transmission upgrades. PacifiCorp reviewed existing qualifying facility (QF) contracts located in constrained areas of the transmission system in Wyoming to estimate the potential change to contract pricing that might be triggered by the new transmission line. Directionally, accounting for changes in QF contract pricing assumptions increases the cost of the updated sensitivity case.

A new transmission line in parallel with existing lines reduces resistance and therefore reduces line losses. With reduced line losses, an additional 12 aMW of incremental annual energy is expected to flow out of eastern Wyoming. The potential value of reduced line losses was calculated using a production cost model simulation to capture the value of this energy specific to the location on PacifiCorp's system where line loss savings would occur. Directionally, accounting for reduced line losses improves the economics of the updated sensitivity case.

A new transmission line also provides reliability benefits by reducing transmission de-rates associated with outages of transmission system elements that would not occur with the addition of the Energy Gateway sub-segment D2 line. Avoided average transmission path de-rates are estimated at 146 MW. Incremental reliability benefits were calculated using a production cost model simulation to capture the avoided transmission de-rates that account for estimated outage days for affected transmission system elements. Directionally, accounting for reduced transmission de-rates improves the economics of the updated sensitivity case.

Finally, the new transmission line is expected to provide incremental benefits in the energy imbalance market (EIM). In the EIM, power flows across the system are able to take advantage of within-the-hour available transmission of the participating EIM entities due to unscheduled or unused transmission capacity. The EIM currently includes NV Energy, Arizona Public Service Company, Puget Sound Energy, and the California Independent System Operator Corporation. The EIM is expected to include Idaho Power Company and Portland General Electric Company, which provides a significant amount of transmission capacity across the west to move power more efficiently. Due to the large number of entities in the EIM with participating transmission, there is an ability to move additional energy from Wyoming to offset higher priced generators in the PacifiCorp system both in the east and the west, or make a sale to an EIM participant. EIM benefits were estimated by simulating incremental transfer capabilities from the east to the west using a production cost simulation model, thereby capturing the incremental benefits of moving additional energy out of Wyoming to the west. Directionally, taking into consideration the ability to move low-cost energy from Wyoming to a larger market improves the economics of the updated sensitivity case.

Summary of Updated Assumptions

Table 8.14 summarizes the incremental adjustments applied to capture the impacts of updated assumptions on the net cost of the FS-GW4 sensitivity case.[2] In aggregate, the updated analysis reflects a net economic improvement ranging between $181m and $209m.

Table 8.14 – Gateway 4 Quantifiable Benefits

Gateway 4 ($ millions)	System Optimizer	PaR	PaR	PaR	PaR	PaR	PaR
Natural Gas Price Scenario	**Base**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
Clean Power Plan Scenario	**Mass B**	**Mass B**	**Mass B**	**Mass B**	**Mass A**	**Mass A**	**Mass A**
Wind QF PPA Price Increase	$3	$3	$3	$3	$3	$3	$3
Wind CF Adjustment	$29	$24	$28	$45	$24	$27	$45
Wind CapEx Adjustment	($84)	($84)	($84)	($84)	($84)	($84)	($84)
Transmission CapEx Adjustment	($71)	($71)	($71)	($71)	($71)	($71)	($71)
Line Loss Value Adjustment	($22)	($19)	($22)	($37)	($19)	($22)	($36)
Reliability Value Adjustment	($17)	($14)	($17)	($27)	($14)	($16)	($27)
EIM Value Adjustment	($24)	($20)	($24)	($39)	($20)	($24)	($39)
Total Adjustments	($185)	($181)	($186)	($209)	($181)	($186)	($209)

[2] The increased transfer capability assumed in the updated analysis is captured in the SO and PaR simulations and not quantified as a specific adjustment here.

Renewable Energy (FS-R1c and FS-R2) Portfolios

Based on analysis from the prior screening stage and stakeholder feedback, PacifiCorp recognized that cases RE-1c and RE-2 should be considered for final selection when studied with comparable wind repower and Energy Gateway assumptions. Adding the wind repowering project and comparable Energy Gateway and new wind resources to these cases significantly reduces the base RPS shortfall relative to RE-1c and RE-2.

Cumulative Additional Resource Capacity

Figure 8.48 through Figure 8.51 summarize the cumulative capacity of new resources and the cumulative reduction in existing resources through 2036, as developed for the final screening cases in SO.

Figure 8.48 – Cumulative Capacity through 2036, Final Screening Case FS-REP

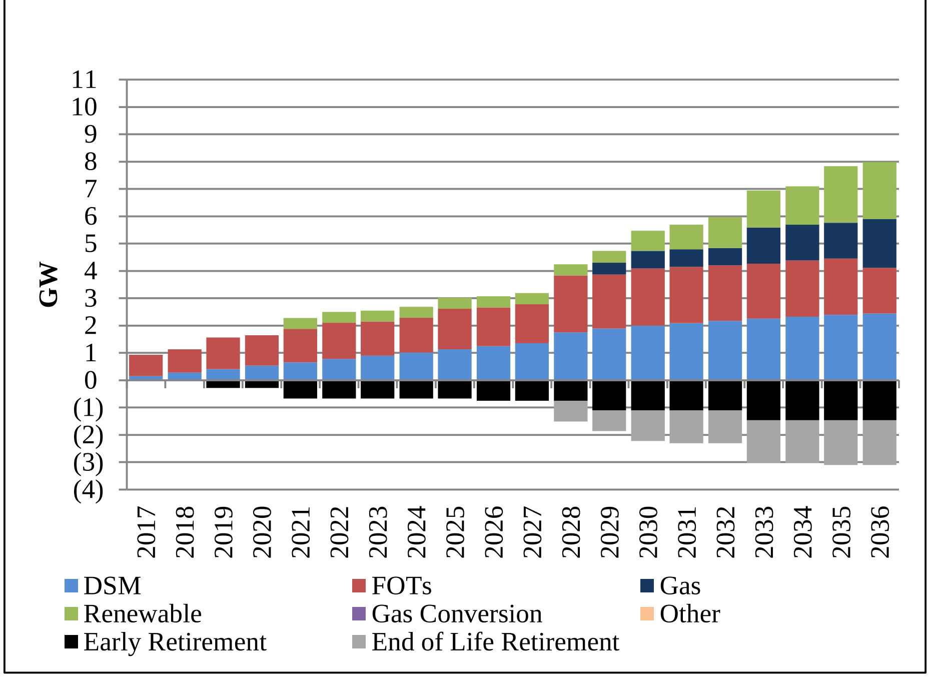


Figure 8.49 – Cumulative Capacity through 2036, Final Screening Case FS-GW4

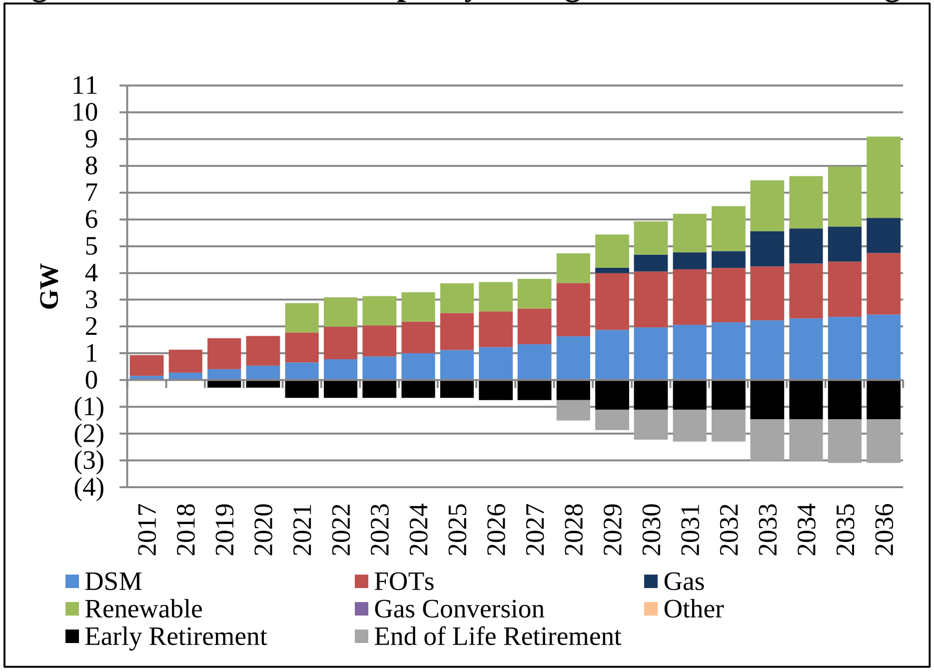


Figure 8.50 – Cumulative Capacity through 2036, Final Screening Case FS-R1c

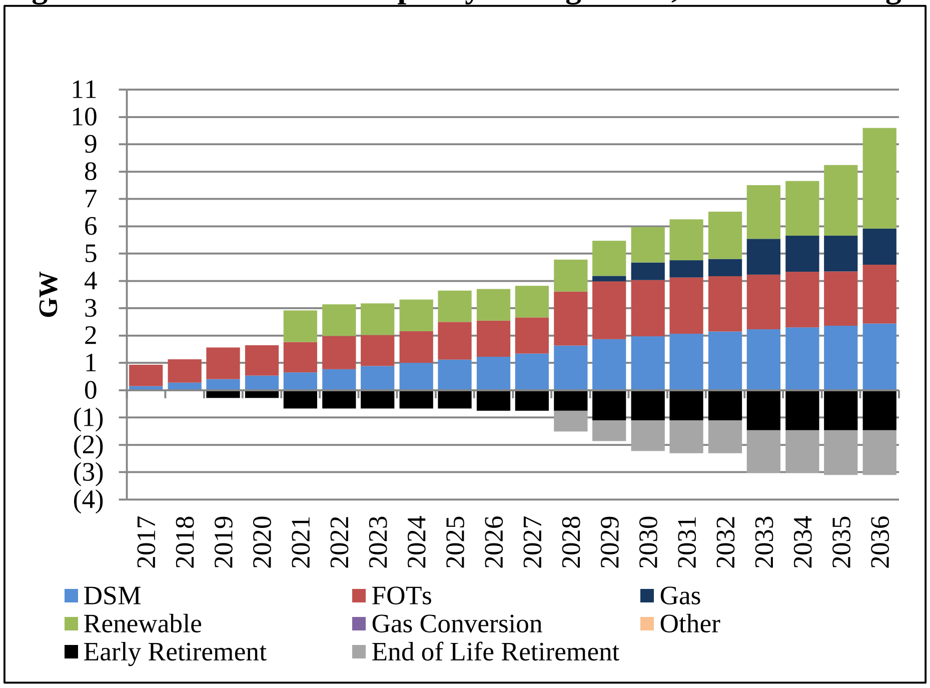
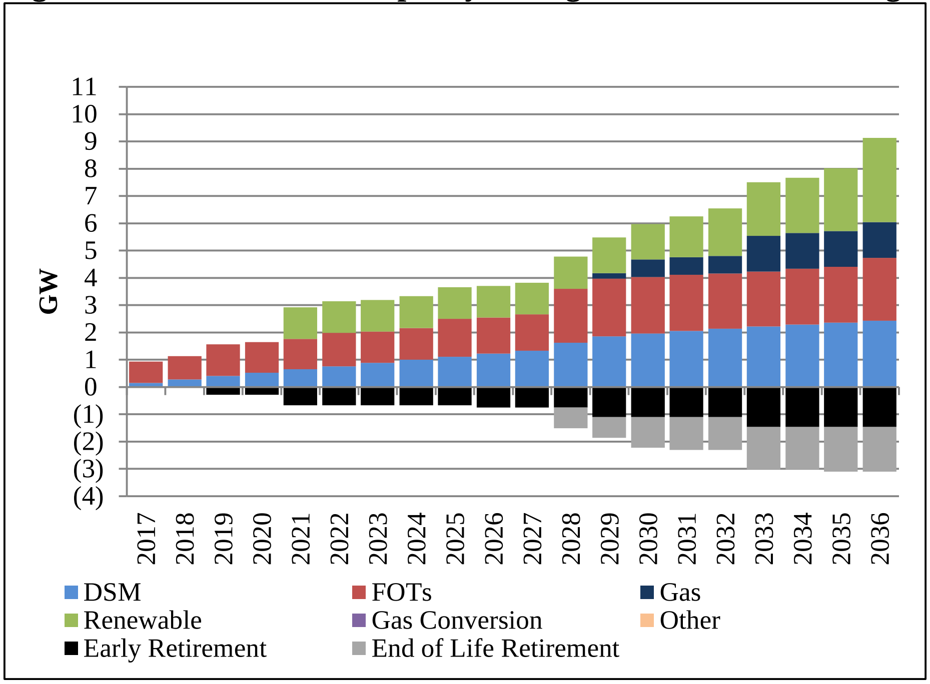


Figure 8.51 – Cumulative Capacity through 2036, Final Screening Case FS-R2



SO System Costs

Figure 8.52 and Figure 8.53 report SO system PVRR results for the final screening portfolios. In this stage of the analysis, wind repower benefits through 2050 are reported in the total PVRRs for all four cases to account for extended operational life benefits. Among the final cases studied in SO, FS-GW4 reports the lowest total PVRR, while case FS-REP reported the least favorable PVRR. The SO result for FS-GW4, representing optimum resource expansion on a capacity basis for the Gateway 4 scenario, shows a benefit $52.2m favorable compared to FS-REP.

Figure 8.52 – System Optimizer PVRR Costs for Final Cases

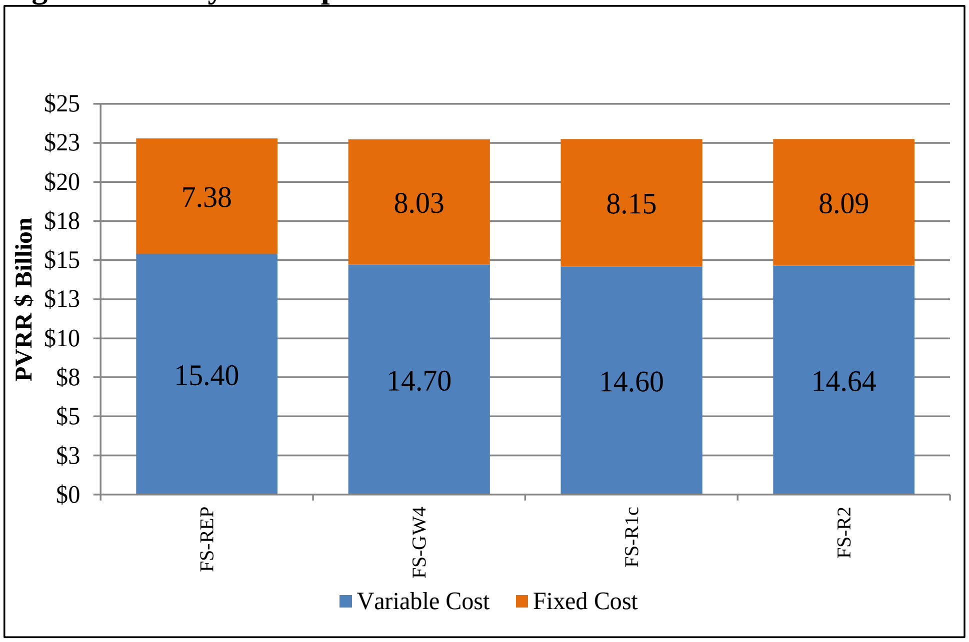


Figure 8.53 – System Optimizer PVRR Change from FS-REP for Final Cases

Final Portfolio Cost and Risk Analysis

PaR Configuration and Metrics

The PaR portfolio ranking metrics, which include mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean ENS, upper-tail ENS, and emissions, are fundamentally alike for each screening stage. As in the previous screening stages, CO_2 shadow prices from SO are input into PaR to affect thermal dispatch in a way that achieves assumed CPP mass cap emission limits. The resulting CO_2 costs reported by PaR represent the opportunity cost of the CPP, but are not real expenses, and thus they are removed in the final PVRR reporting.

Scatter plots present the mean PVRR of each unique final screening portfolio on the horizontal axis, and the upper-tail mean PVRR on the vertical axis. Portfolios toward the left-bottom corner of each scatter plot contain the least-cost, least-risk mix of resources, while portfolios toward the upper-right corner contain the highest-risk and highest-cost mix of resources. Figure 8.54 and

Figure 8.55 show the scatter plot results for eligible cases under both the Mass Cap A and Mass Cap B scenarios. As observed in the previous screening stages, cost and risk metrics are highly correlated. FS-REP is least-cost, least-risk portfolio under the low price scenario, while FS-R2 is least least-cost, least-risk portfolio under the medium and high gas price scenarios. FS-GW4 is second least-cost, least-risk portfolio under all scenarios. The difference in costs among the four cases is very small.

Figure 8.54 – Final Portfolio Scatter Plots, Mass Cap B

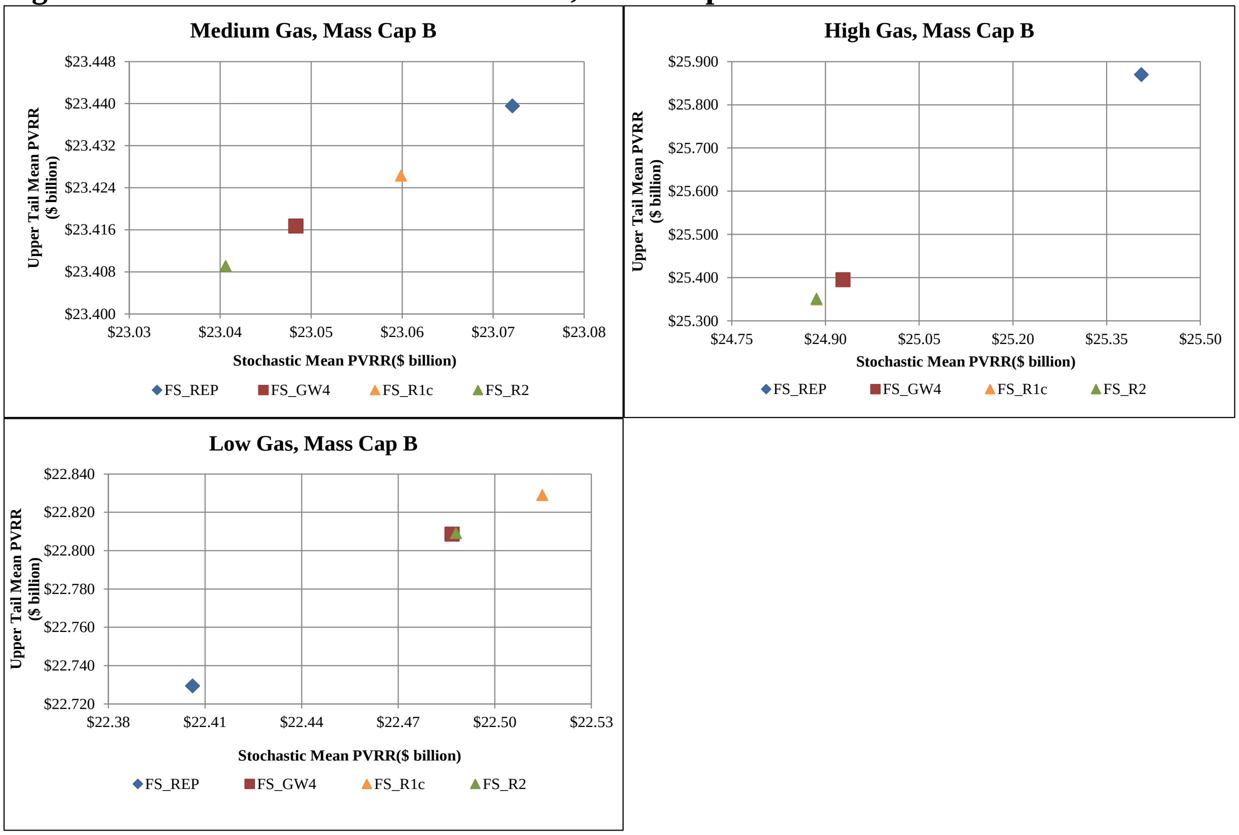
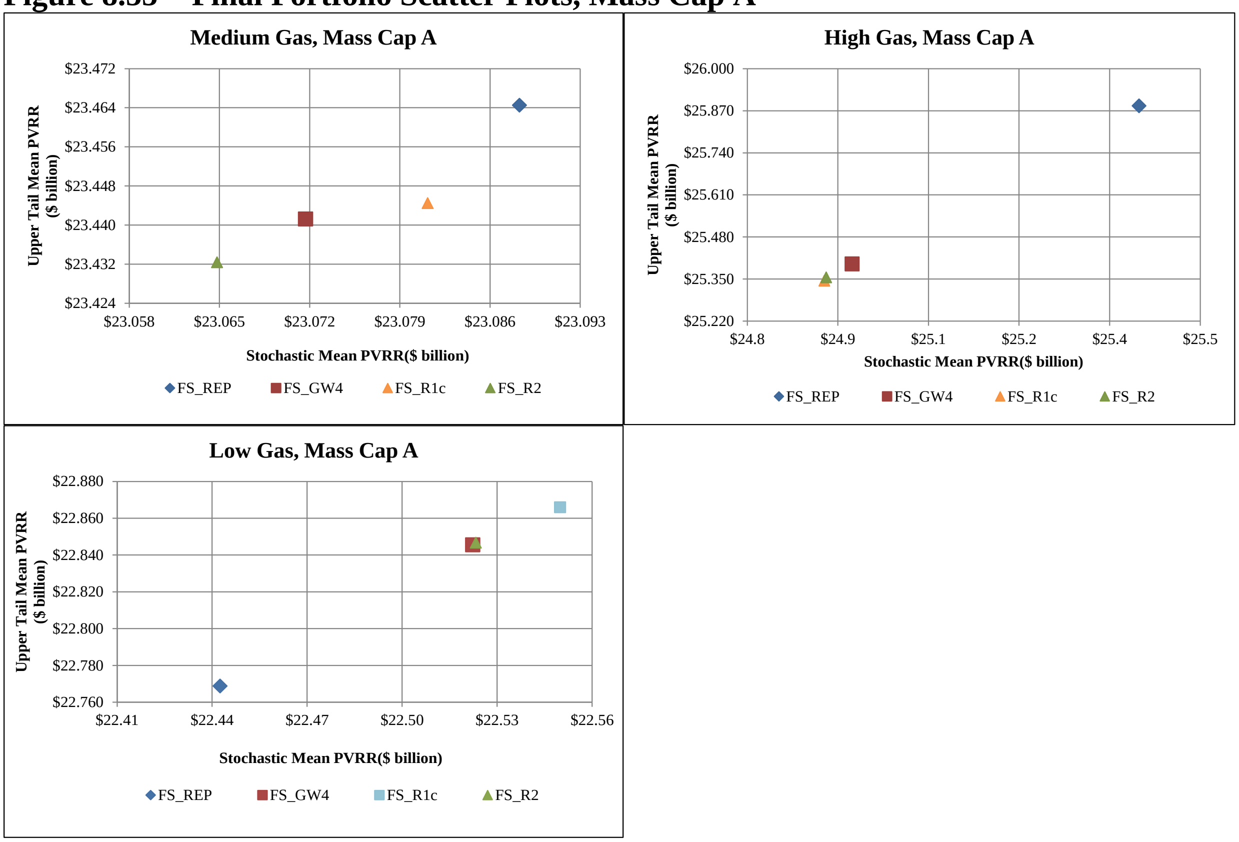


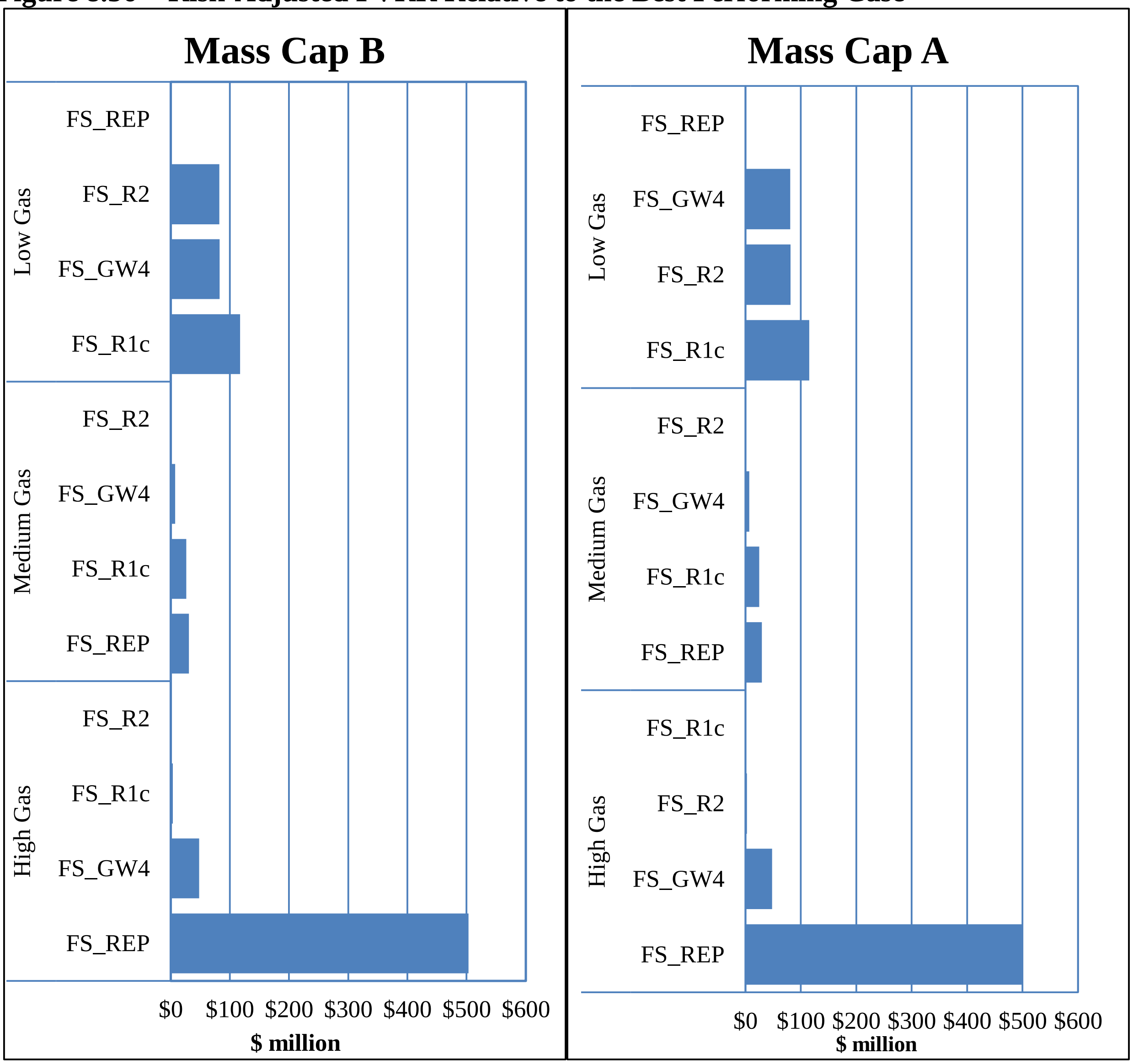
Figure 8.55 – Final Portfolio Scatter Plots, Mass Cap A



Risk-Adjusted PVRR

Figure 8.56 shows the stochastic risk-adjusted PVRR of each final screening portfolio ranked against the best performing case in each price-emission scenario. FS-REP performs the best in low natural gas price scenarios, followed by a nearly indiscernible difference between cases FS-R2 and FS-GW4. FS-R2 produces the lowest risk-adjusted PVRR in the medium natural gas price scenario, with a nearly indiscernible difference relative to case FS-GW4. Under high natural gas price scenarios, FS-R2 and FS-R1c produce slightly lower risk-adjusted PVRRs relative to FS-GW4.

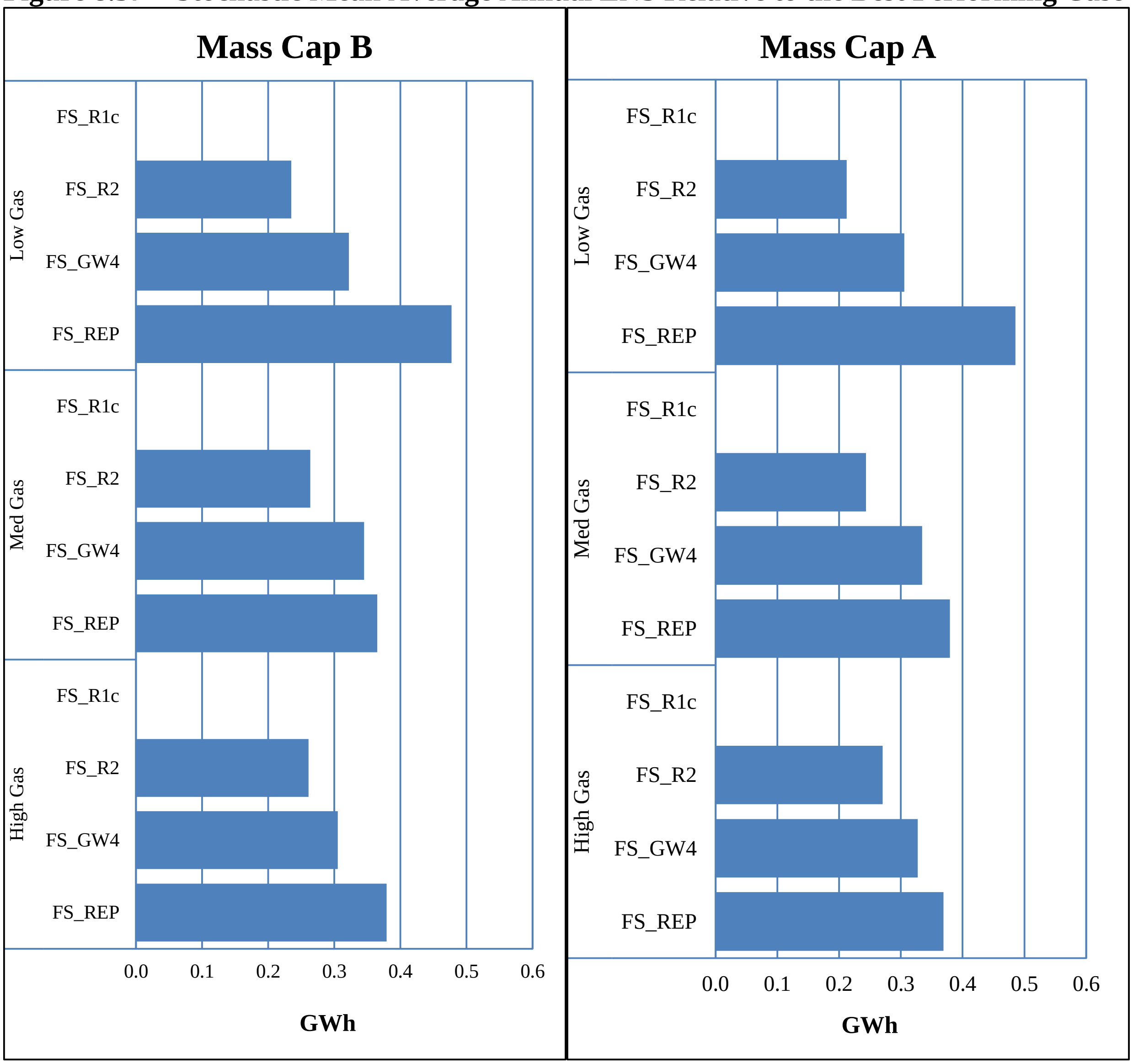
Figure 8.56 – Risk-Adjusted PVRR Relative to the Best Performing Case



Average Energy Not Served (ENS)

Figure 8.57 presents the stochastic mean average annual ENS of each final screening portfolios relative to the best performing case in each price-emission scenario. All cases have mean ENS levels that are a fraction of total load (annual mean ENS ranges between 2.8 and 13.8 GWh). Relative to other cases, FS-R1c, with additional renewables to meet RPS, consistently produces the lowest mean ENS levels (between 0.2 and 0.5 GWh).

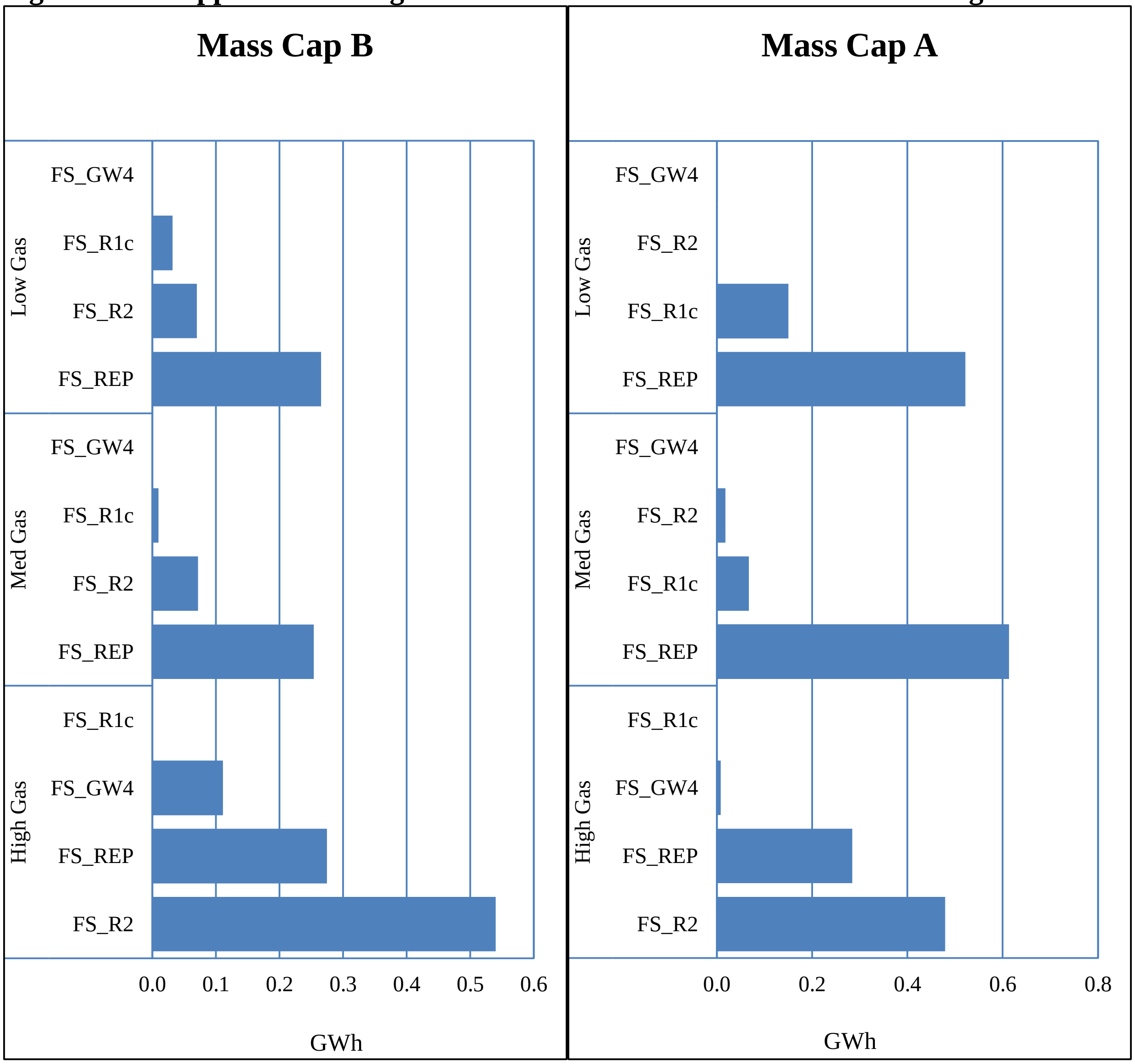
Figure 8.57 – Stochastic Mean Average Annual ENS Relative to the Best Performing Case



Upper-tail Average Energy Not Served (ENS)

Figure 8.58 shows the upper-tail average annual ENS of each final screening portfolio relative to the best performing case in each price-emission scenario. All cases have upper-tail ENS levels that are a fraction of total load. Relative to other cases, FS-GW4 consistently produces the lowest upper-tail ENS levels, except under high gas price scenarios.

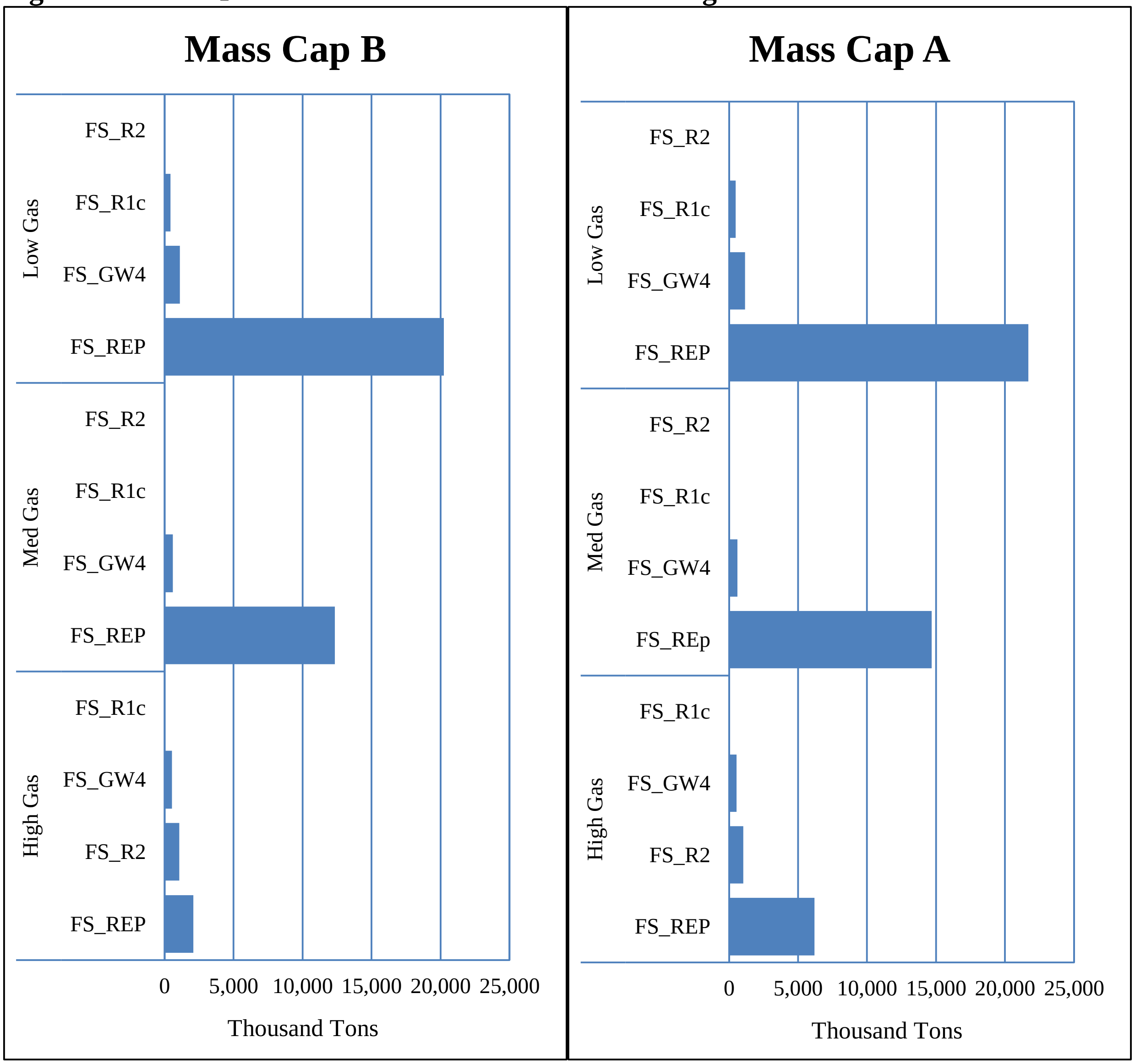
Figure 8.58 – Upper-tail Average Annual ENS Relative to the Best Performing Case



CO_2 Emissions

Figure 8.59 shows total CO_2 emissions of each final screening portfolio relative to the best performing case in each price-emission scenario. Cases FS-R2 and FS-R1c consistently yield the lowest emissions among all portfolios. Case FS-R1c performed most favorably in the high gas price scenarios. Case FS-REP yields higher emissions due to lower renewables relative to other cases.

Figure 8.59 – CO_2 Emissions Relative to Best Performing Case

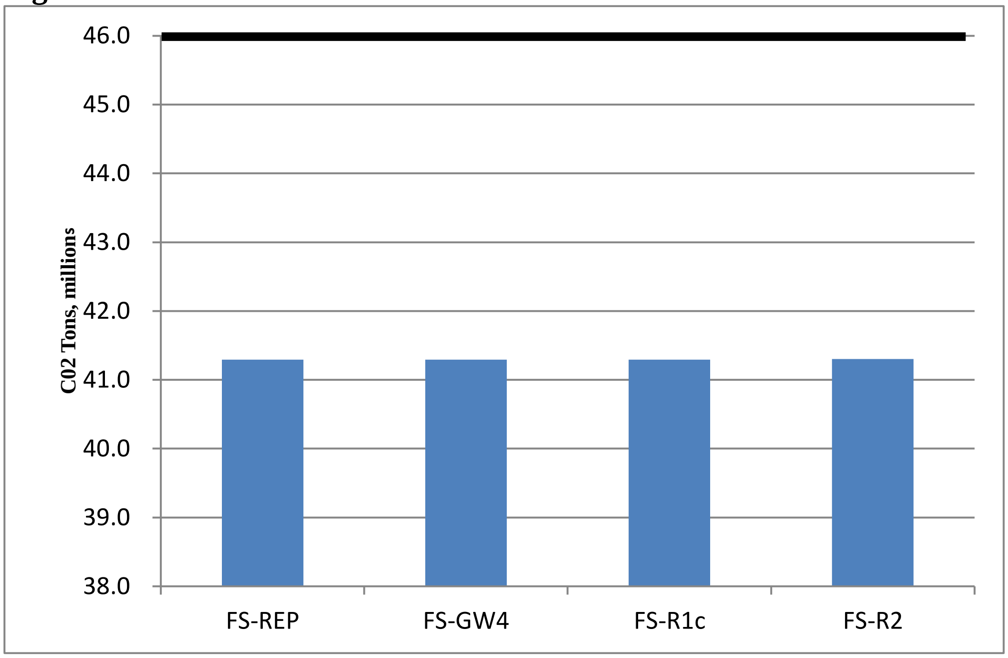


Each of these cases achieves emission goals in Oregon and Washington, which rely on 1990 emissions as a benchmark.[3] For PacifiCorp's system, the 1990 emission level was approximately

[3] Washington has a goal to reduce emissions to 1990 levels by 2020. Oregon has a goal to reduce emissions to ten percent below 1990 levels by 2020.

46 million tons. As seen in Figure 8.60, all final screening portfolios show 2020 emissions that fall well below 1990 emission levels.

Figure 8.60 – 2020 Forecast CO_2 emissions versus 1990 Estimated Emission Levels



Final Preferred Portfolio Selection

The metrics described in the cost and risk analysis are condensed into Table 8.15. FS-R2 ranks first in the risk adjusted PVRR metric, while FS-R1c ranks first in average ENS, and FS-GW4 ranks first in upper-tail ENS. The rankings, while indicative of order, tend to obscure how close some of the outcomes are in terms of raw measures. The separation among the three Energy Gateway cases on the average risk-adjusted PVRR metric is $20m, which is just 0.08 percent of the system PVRR, suggesting that these cases are essentially equivalent. All three of the Energy Gateway cases (FS-GW4, FS-R1c, and FS-R2) yield a risk-adjusted PVRR that is notably favorable to the FS-REP case.

Table 8.15 - Risk-adjusted PVRR among Top Performing Portfolios

	Risk Adjusted[1]			ENS Scenario Average			ENS Upper Tail Average			CO_2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2017-2036 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
FS_REP	23,939	$150	4	11.8	0.4	4	30.6	0.3	4	770,886	12,720	4
FS_GW4	23,808	$18	2	11.7	0.3	3	30.3	0.0	1	758,774	607	3
FS_R1c	23,810	$20	3	11.4	0.0	1	30.3	0.0	2	758,167	0	1
FS_R2	23,790	$0	1	11.6	0.2	2	30.4	0.2	3	758,361	194	2

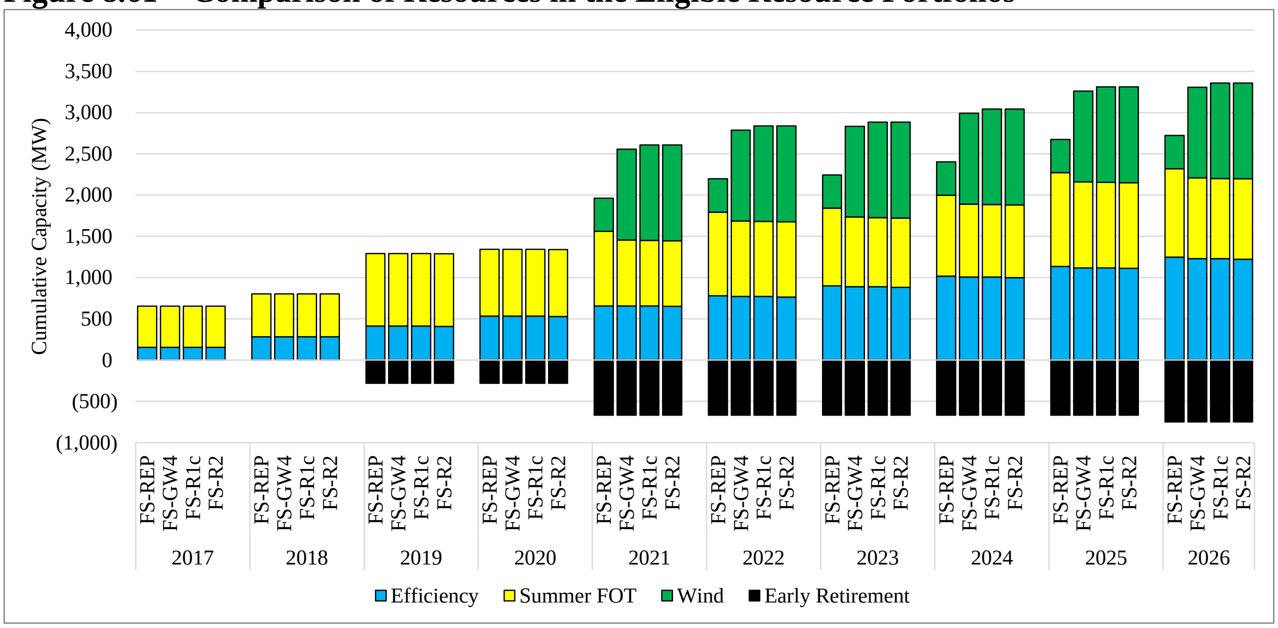
[1] Based on average of 6 emissions/price scenarios

Fuel Source Diversity

Figure 8.61 summarizes the nameplate capacity of cumulative resource selection through 2026 among the portfolios considered for final selection. This figure illustrates the similarity among the top performing portfolios through the first ten years of the planning period, when differences among portfolios are most likely to influence PacifiCorp's action plan. The FS-REP portfolio, without Energy Gateway transmission, contains less wind and more front-office transactions (FOTs). All of the Energy Gateway portfolios have nearly identical levels of energy efficiency, FOTs, and new wind resources.

The modest difference in new wind resource additions in 2021 in the FS-R1c case (57 MW of additional west-side wind) is driven by the Washington RPS program.[4] Considering banking restrictions in the Washington RPS program, the addition of this incremental 2021 west-side wind resource contributes to over-compliance for the Washington RPS later in the planning horizon when system renewable resources located in the Washington Utilities and Transportation Commission (WUTC) West Control Area (WCA) are added to the resource mix. In the FS-R2 case, an additional 61 MW of Idaho wind is added to the portfolio to offset a potential Oregon RPS shortfall that would otherwise occur beyond 2034, once accounting for system renewable resources already included in the resource mix.

Figure 8.61 – Comparison of Resources in the Eligible Resource Portfolios

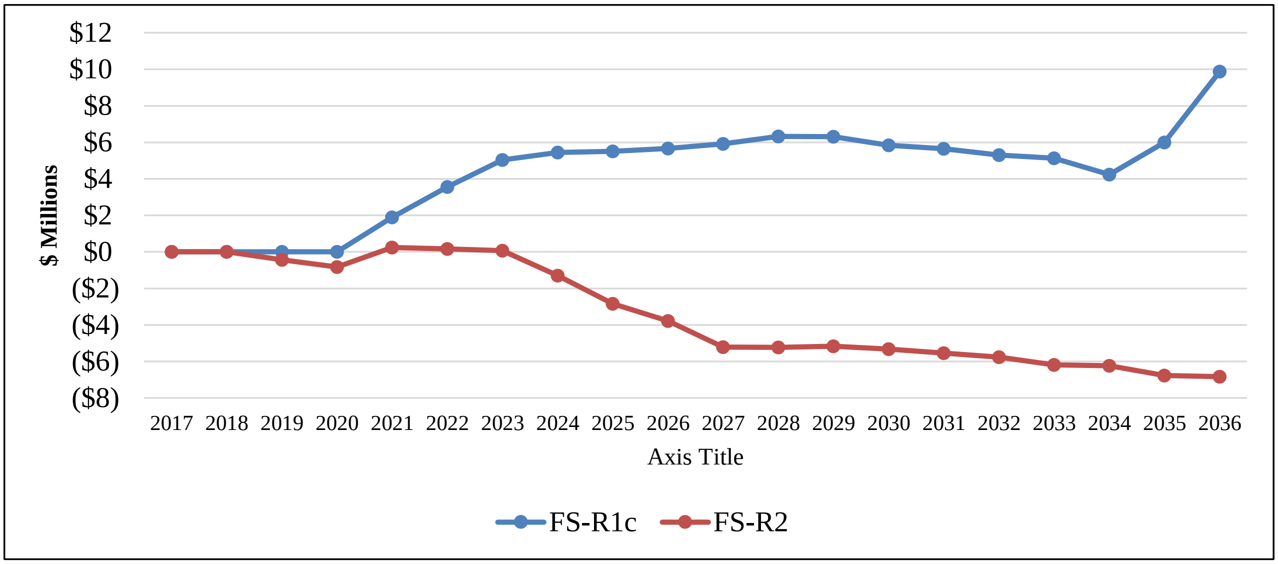


Customer Rate Impacts

Figure 8.62 shows the difference in cumulative PVRR between FS-R1c and FS-R2 relative to case FS-GW4 under base case emissions-price assumptions. Through year 2023, FS-R2 tracks closely with FS-GW4, while FS-R1c reports a higher, albeit relative small, and escalating cost. After 2023, FS-R2 improves while FS-R1c continues to be unfavorable. FS-R1c sees a spike in unfavorable PVRR in the final two years, coinciding with the addition of incremental west-side wind needed to achieve RPS requirements. Over the 20-year study horizon, FS-R2 yields a small aggregate cumulative benefit relative to FS-GW4 (~$7m PVRR, a 0.029 percent reduction relative to FS-GW4). As this benefit occurs farther out the curve, it is not only small but is also more speculative.

[4] Under FS-R1c and FS-R2, system renewable resources in the portfolio eliminate any need for incremental renewable resources in the front ten years of the planning period.

Figure 8.62 – Change in the Cumulative PVRR relative to FS-GW4



Preferred Portfolio Selection

Informed by all of the analysis used to compare resource portfolios throughout the three-stage screening process, PacifiCorp has selected case FS-GW4 as the preferred portfolio for its 2017 IRP. PacifiCorp's preferred portfolio selection is based on the following:

- The preferred portfolio reflects Regional Haze compliance assumptions consistent with least-cost, least-risk comparative analysis performed in the first screening stage of the selection process.
- The preferred portfolio incorporates the wind repowering project as supported by additional core case and sensitivity analysis performed during the second screening stage of the selection process.
- The preferred portfolio includes Energy Gateway sub-segment D2, with associated incremental new Wyoming wind resources, based on updated analysis performed during the final screening stage of the selection process.
- The risk-adjusted PVRR and other stochastic metrics among portfolios that include the Energy Gateway sub-segment D2 transmission line in the final screening stage of the planning process are closely grouped, with an average variation in the risk-adjusted PVRR that is just 0.08 percent of the average system risk-adjusted PVRR.
    - Among these cases, case FS-GW4 produces the lowest system PVRR when analyzed in SO.
    - Variations in resources among these cases within the first ten years of the planning period would not alter PacifiCorp's 2017 IRP action plan.
    - Among these cases, case FS-GW4 mitigates near-term customer rate impacts caused by Oregon and Washington state RPS programs that result in situs-assigned costs for customers in these states.

The 2017 IRP Preferred Portfolio

The 2017 IRP preferred portfolio reflects a cost-conscious transition to a cleaner energy future. Table 8.16 shows that PacifiCorp's resource needs will be met with new renewable resources, demand side management (DSM) resources, and short-term firm market purchases (labeled as front-office transactions or FOTs) through 2028. Over the 20-year planning horizon, the preferred portfolio includes 1,959 MW of new wind resources, 905 MW of upgraded ("repowered") wind resources, 1,040 MW of new solar resources, 2,077 MW of incremental energy efficiency resources, and 365 MW of new direct load control capacity.

Notably, PacifiCorp's analysis demonstrates that—by 2020 and with all-in economic savings for customers—the company can add 905 MW of repowered wind resources, 1,100 MW of new wind resources, and a new 140-mile 500 kV transmission line in Wyoming to access the new wind resources and relieve congestion for existing capacity. The preferred portfolio also assumes existing owned coal capacity will be reduced by 3,650 MW through the end of 2036 (including assumed coal retirements at the end of 2036 not shown below). The first new natural gas resource is added in 2029, one year later when compared to PacifiCorp's 2015 IRP preferred portfolio, subject to technology and IRP reassessments over the next decade.

Table 8.16 – 2017 IRP Preferred Portfolio Summary (Nameplate MW)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
New Resources																					
Summer FOT	500	521	878	807	799	916	844	885	1,042	978	1,040	1,575	1,575	1,566	1,575	1,575	1,575	1,575	1,575	1,539	n/a
Winter FOT	281	332	273	307	319	308	306	287	348	351	297	412	551	516	490	451	437	477	479	766	n/a
DSM - Energy Efficiency	154	128	131	122	123	114	118	118	112	111	109	102	96	95	96	83	75	65	63	63	2,077
DSM - Load Control	0	0	0	0	0	0	0	0	0	0	0	193	140	5	3	3	3	4	3	12	365
Wind	0	0	0	0	1,100	0	0	0	0	0	0	0	0	0	85	0	0	0	0	774	1,959
Solar	0	0	0	0	0	0	0	0	0	0	0	11	97	0	118	237	226	48	291	13	1,040
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	30	0	0	0	0	0	0	0	30
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	200	436	0	0	677	0	0	0	1,313
Existing Resources																					
Reduced Coal Capacity	0	0	(280)	0	(387)	0	0	0	0	(82)	0	(762)	(354)	(357)	(78)	0	(359)	0	(82)	0	(2,741)
Reduced Gas Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(358)	0	0	0	(358)
Repowered Wind Capacity	0	0	794	111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	905

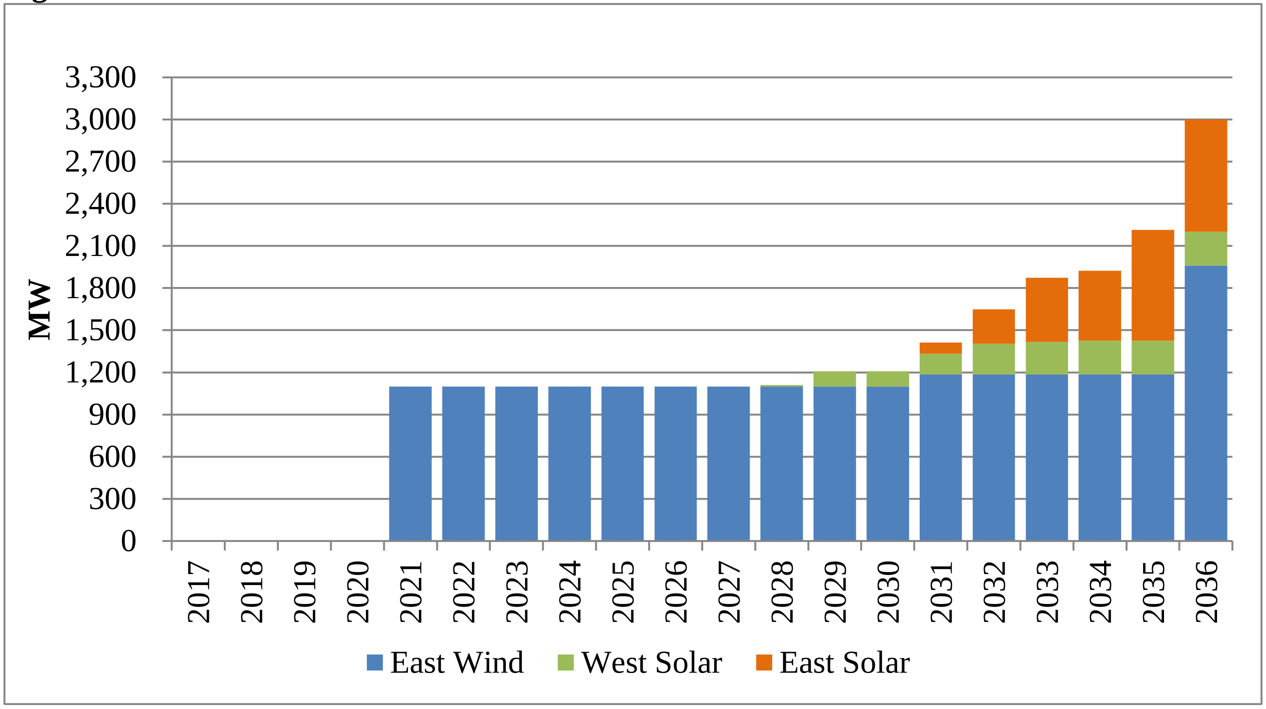
*Note: Energy efficiency resource capacity reflects projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply side resource. FOTs are short-term firm market purchases delivered only in the year shown. Reductions in existing coal and natural gas capacity are shown in the year after the assumed year-end retirement date (909 MW of existing coal capacity is assumed to retire year-end 2036, which would be reflected beginning 2037). Repowered wind capacity reports the amount of existing wind capacity assumed to be repowered in the preferred portfolio.

New Renewable Resources and Transmission

Figure 8.63 reports the cumulative renewables additions across the 20-year study horizon. The 2017 IRP preferred portfolio advances PacifiCorp's commitment to low-cost clean energy with plans to add 1,100 MW of new Wyoming wind resources by the end of 2020. These new zero-emission wind facilities will connect to a new 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This time-sensitive project requires that the new wind and transmission assets achieve commercial operation by the end of 2020 to maximize PTC benefits. In addition to providing significant economic benefits for PacifiCorp's customers, the wind and transmission project will provide extraordinary economic development benefits to the state of Wyoming.

Beyond 2020, the preferred portfolio includes an additional 859 MW of new wind coming on line—85 MW of Wyoming wind in 2031, and 774 MW of Idaho wind in 2036. New solar resource additions totaling 1,040 MW come on-line over the 2028 to 2036 timeframe. Approximately 77 percent of the new solar is located in Utah (beginning 2031) and the remaining 23 percent is located in the west side of PacifiCorp's system (beginning 2028).

Figure 8.63 – 2017 IRP Preferred Portfolio - Cumulative Renewable Resources



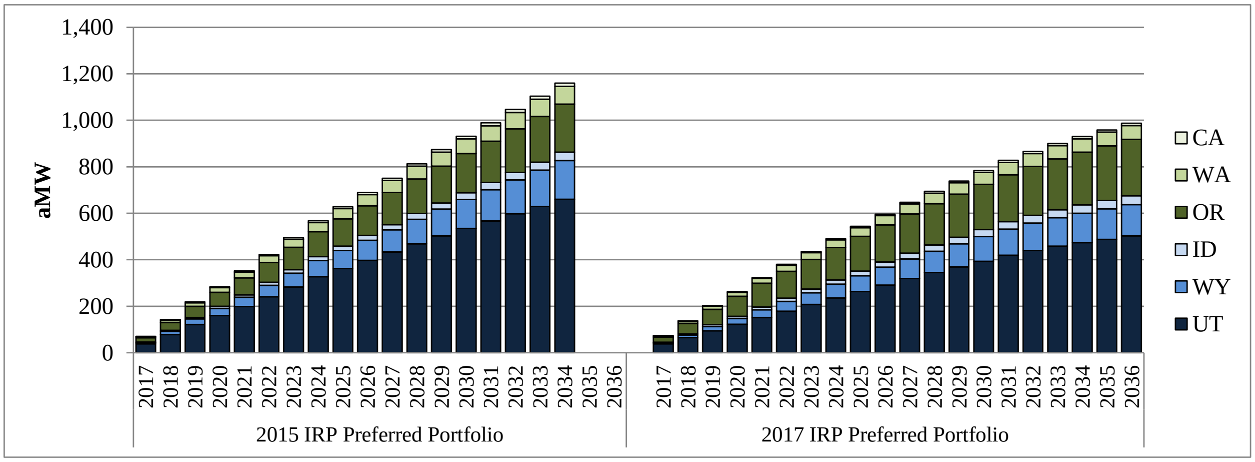
Wind Repowering

PacifiCorp WTG equipment purchases in December 2016 preserve the option to repower existing wind generation facilities and maximize PTC benefits for customers. Analysis performed in the 2017 IRP supports repowering 905 MW of existing wind resources by the end of 2020 and demonstrates that this exciting project will save customers hundreds of millions of dollars. The scope of the repowering project involves installing new nacelles and longer blades. With the installation of modern technology and improved control systems, the repowered wind facilities will produce more zero-emission energy for a longer period of time at reduced operating costs. Existing towers and foundations will remain in place, resulting in minimal environmental impact and permitting requirements.

Demand Side Management

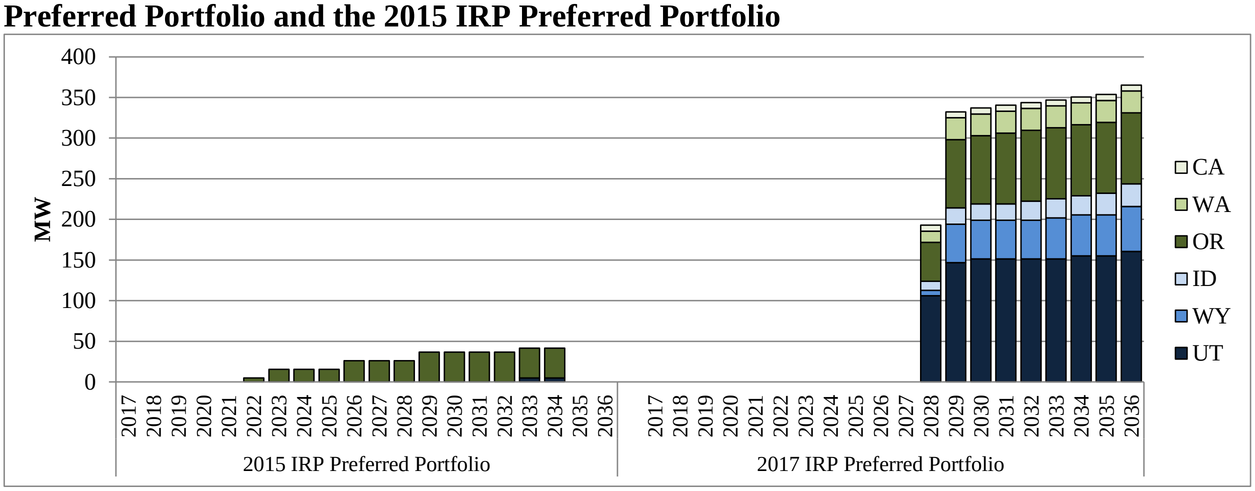
DSM resources continue to play a key role in PacifiCorp's resource mix. Over the first ten years of the planning horizon, accumulated acquisition of incremental energy efficiency resources meets 88 percent of forecasted load growth from 2017 through 2026 (up from 86 percent in the 2015 IRP). Figure 8.64 compares total energy efficiency savings by state in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. Decreased selection of energy efficiency resources relative to the 2015 IRP is driven by reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives.

Figure 8.64 – Comparison of Total Energy Efficiency Savings between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



In addition to continued investment in energy efficiency programs, the preferred portfolio identifies an increasing role for direct load control programs with total capacity reaching 365 MW by the end of the planning period. Figure 8.65 compares total incremental direct load control program capacity by state in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. The significant increase in direct load control capacity and expansion of programs among states is coincident with assumed coal unit retirements, signaling the importance of these capacity-based programs in PacifiCorp's transitioning resource mix.

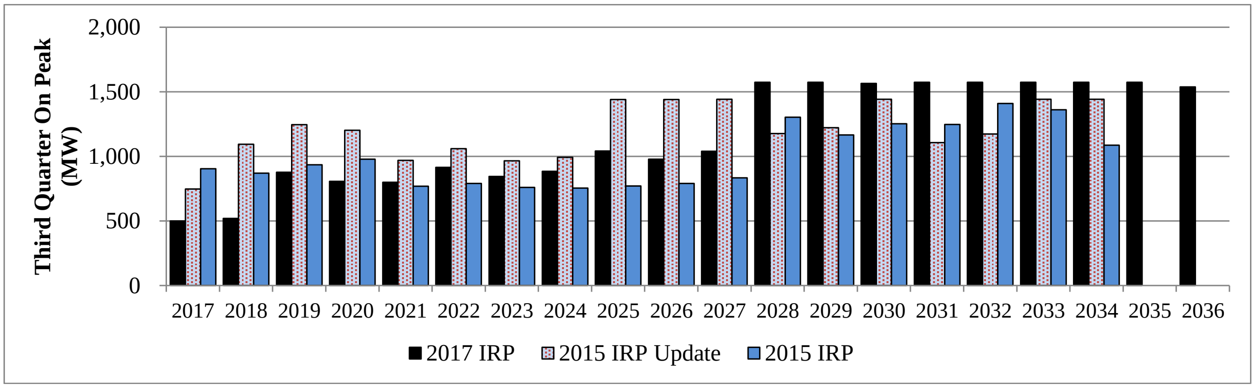
Figure 8.65 – Comparison of Total Direct Load Control Capacity between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



Wholesale Power Market Purchases

Figure 8.66 compares wholesale market firm purchases from the 2017 IRP preferred portfolio to the market purchases included in the preferred portfolio of recent IRPs. While market conditions for firm wholesale power purchases are favorable, reduced loads and continued investment in energy efficiency programs reduce the need for wholesale power purchases relative to the 2015 IRP Update through 2027. Over this period, average annual wholesale power purchases are down by 27 percent relative to the 2015 IRP Update and on par with wholesale power purchases projected in the 2015 IRP. Longer term, wholesale power purchases increase coincident with assumed coal unit retirements. In this 2017 IRP, PacifiCorp has evaluated regional resource adequacy and believes its wholesale power purchase limits are reasonable. PacifiCorp will continue to monitor potential shortfalls in regional supply through its on-going planning process.

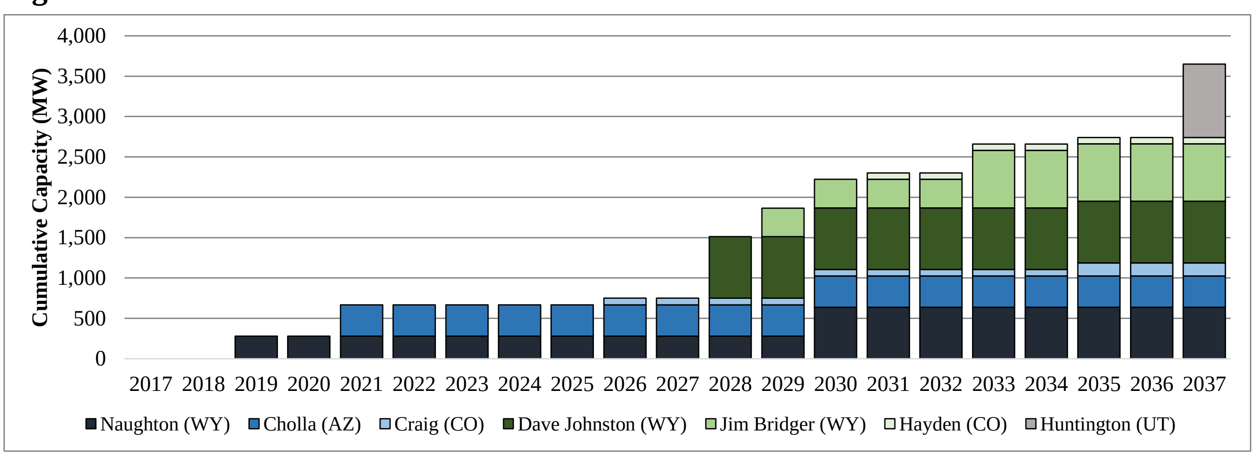
Figure 8.66 – Comparison of Summer Market Purchases among Recent IRPs



Existing Coal Resources

Supported by analysis of potential Regional Haze compliance alternatives, the 2017 IRP preferred portfolio does not include any incremental SCR equipment throughout the planning horizon. Avoiding installation of this equipment will save customers hundreds of millions of dollars and retain compliance-planning flexibility associated with the CPP or other potential state and federal environmental policies. As in past IRPs, the 2017 IRP studies a range of Regional Haze compliance scenarios, reflecting potential bookend alternatives that consider early retirement outcomes as a means to avoid installation of expensive SCR equipment. The individual unit-specific outcomes assumed in the 2017 IRP preferred portfolio will ultimately be determined by on-going rulemaking, results of litigation, and future negotiations with state and federal agencies, partner plant owners, and other vested stakeholders. Consequently, individual unit retirements reflected in the preferred portfolio, while reasonable for planning purposes, are not firm commitments for early unit closures. Figure 8.67 summarizes coal unit retirements assumed in the preferred portfolio. By the end of the planning horizon, PacifiCorp assumes 3,650 MW of existing coal capacity will be retired.

Figure 8.67 – 2017 IRP Preferred Portfolio Coal Unit Retirements



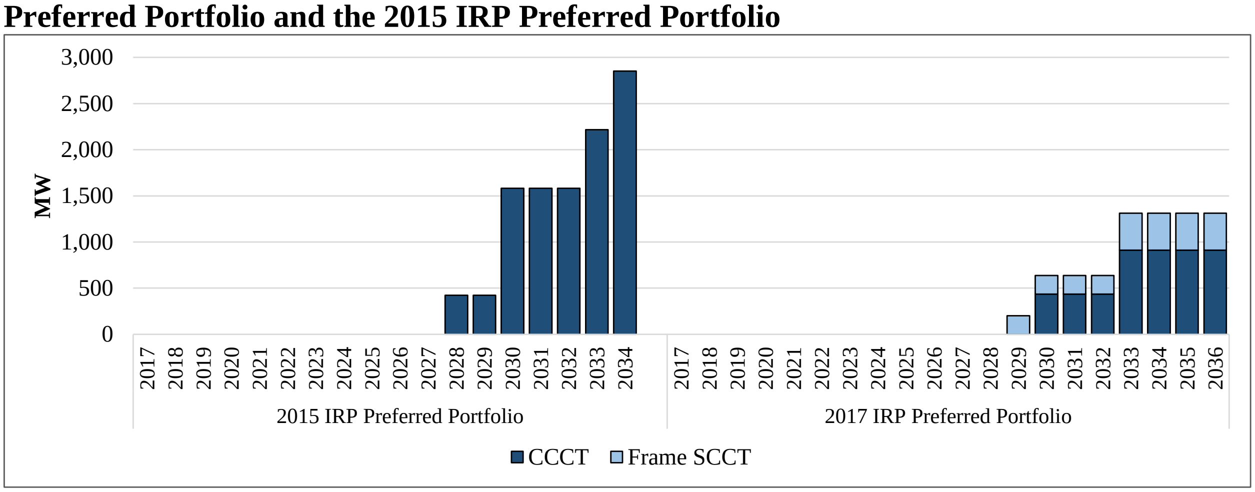
*Note: Retired capacity is reported in the first year in which the unit is no longer available to meet summer coincident peak load.

Reflecting an updated operating permit from the state of Wyoming, PacifiCorp assumes Naughton Unit 3 retires at the end of 2018—one year later than in the 2015 IRP Update. PacifiCorp will continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2018 if proven to be cost effective for customers. PacifiCorp's analysis also assumes Cholla Unit 4 retires at the end of 2020. This early closure assumption was considered in PacifiCorp's Regional Haze compliance analysis to account for changes in market conditions, characterized by reduced loads and wholesale power prices. As with Naughton Unit 3, PacifiCorp will continue to analyze potential early closure scenarios for Cholla Unit 4 as part of its on-going planning process. Longer term, the preferred portfolio reflects an early retirement of Craig Unit 1 at the end of 2025, Jim Bridger Unit 1 at the end of 2028, and Jim Bridger Unit 2 at the end of 2032. Assumed end-of-life retirements include four units at the Dave Johnston plant at the end of 2027, Naughton Units 1 and 2 at the end of 2029, Hayden at the end of 2030, Craig Unit 2 at the end of 2034, and two units at the Huntington plant at the end of 2036.

Natural Gas Resources

Figure 8.68 compares total new natural gas-fired resource capacity in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. The first natural gas resource, a 200 MW frame simple cycle combustion turbine (SCCT), is added to the portfolio in 2029—one year later than the first natural gas resource in the 2015 IRP. The first CCCT, a 436 MW G-class 1x1, is added to the system in 2030—two years later than the first CCCT in the 2015 IRP. In aggregate, the 2017 IRP preferred portfolio includes 1,313 MW of new natural gas-fired capacity, a reduction of 1,540 MW of natural gas resources relative to the 2015 IRP preferred portfolio. Reduced loads, on-going investment in energy efficiency programs, and increased renewables reduce the need for new natural gas resources in the 2017 IRP. Recognizing the long time horizon before the first natural gas plant is added, PacifiCorp will continue to evaluate potential long-term supply alternatives, including the potential penetration of energy storage, through its on-going resource planning efforts.

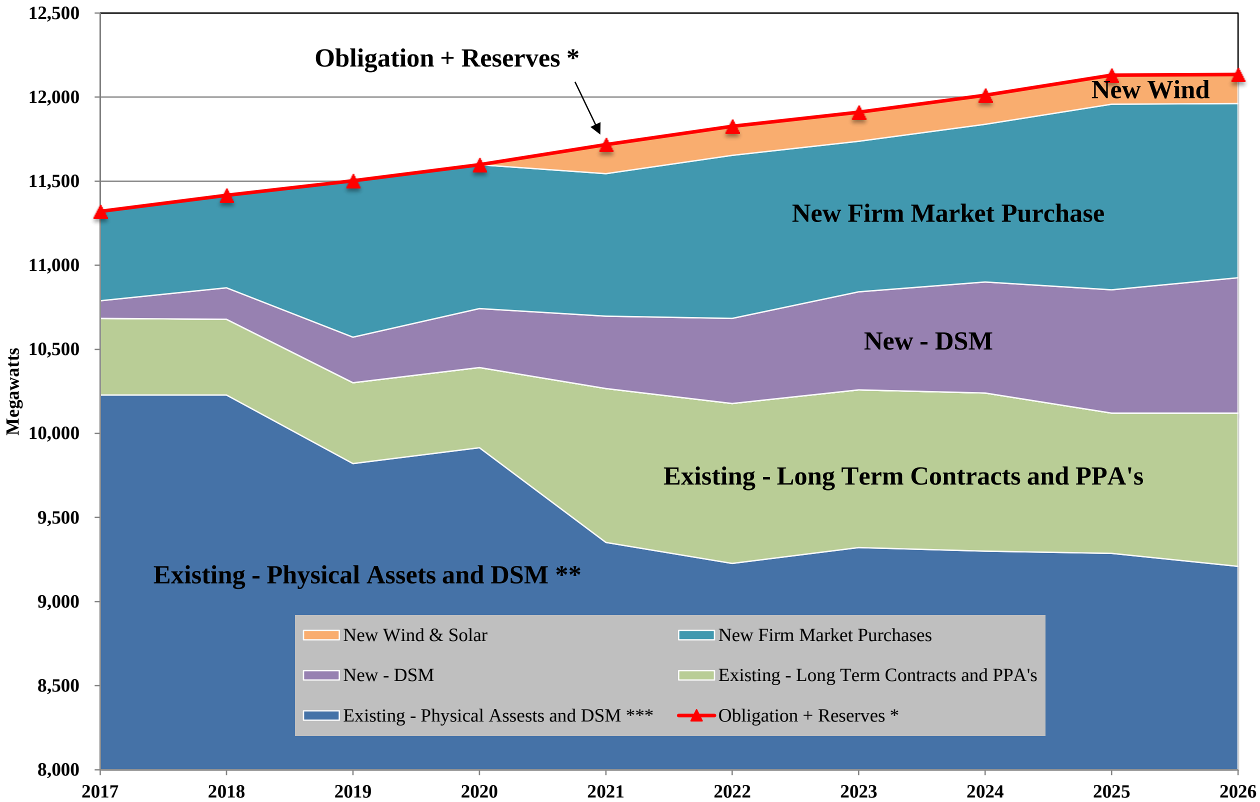
Figure 8.68 – Comparison of Total New Natural Gas Resources between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



Capacity and Energy

Figure 8.69 graphically displays how preferred portfolio resources meet PacifiCorp's capacity needs over time. Through 2026, PacifiCorp meets its capacity needs, including a 13 percent target planning reserve margin, through incremental acquisition of new DSM and wind resources and through wholesale power market purchases.

Figure 8.69 – Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources



* Includes 13% Planning Reserves, Sales and Non-Owned Reserves
** Includes retirements, and gas repower. DSM includes both Class 1 and 2.

Figure 8.70 and Figure 8.71 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[5] On an energy basis, coal generation drops below 50 percent by 2025, falls to 38 percent by 2030, and declines to 32 percent by the end of the planning period. On a capacity basis, coal resources drop

[5]The projected PacifiCorp 2017 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2017 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

to 31 percent by 2025, fall to 21 percent by 2030, and decline to 16 percent by the end of the planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable resources, DSM resources, and longer-term, new natural gas resources.

Figure 8.70 – Projected Energy Mix with Preferred Portfolio Resources

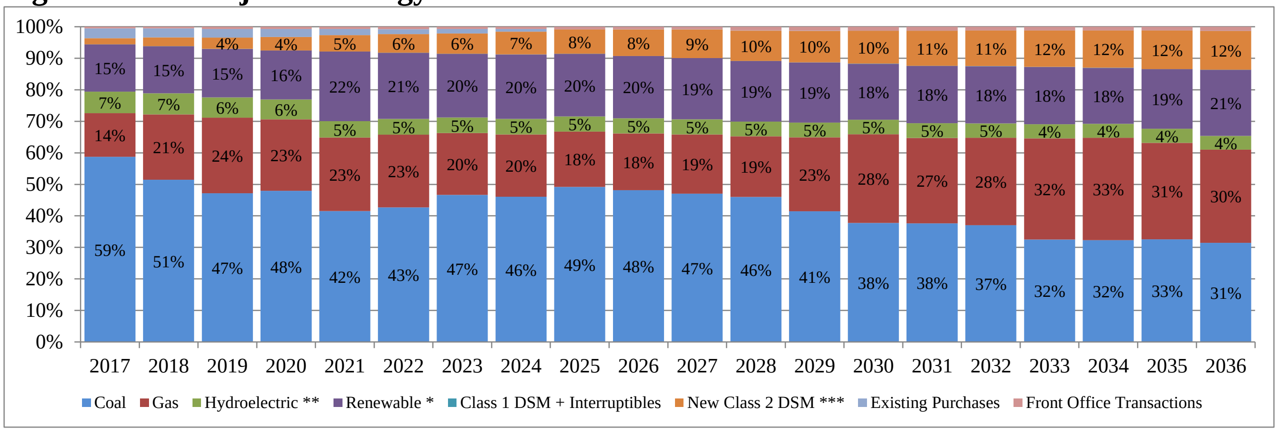
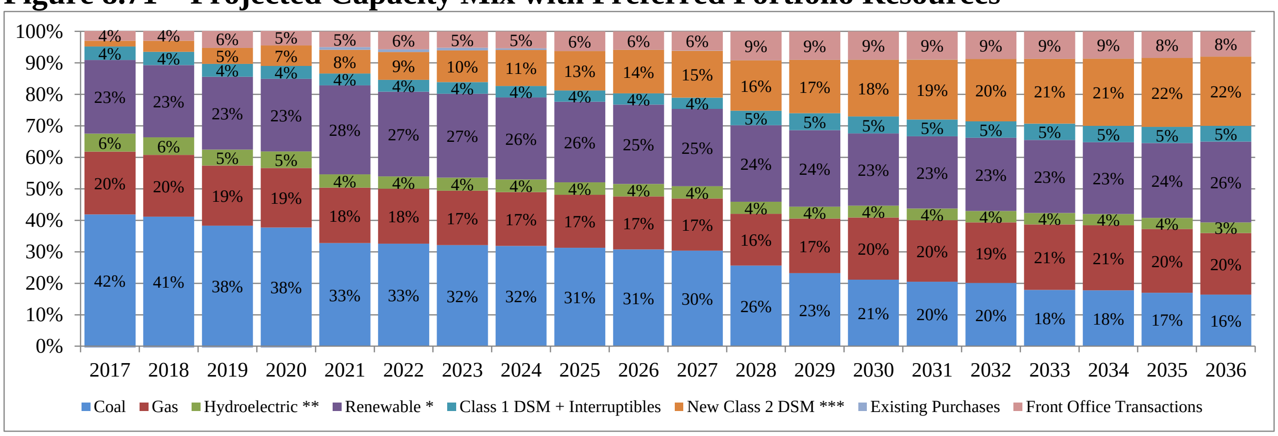


Figure 8.71 – Projected Capacity Mix with Preferred Portfolio Resources



Renewable Portfolio Standards

Figure 8.72 shows PacifiCorp's RPS compliance forecast for California, Oregon, and Washington after accounting for the wind repower project and new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources, they also contribute to meeting RPS targets in PacifiCorp's western states.

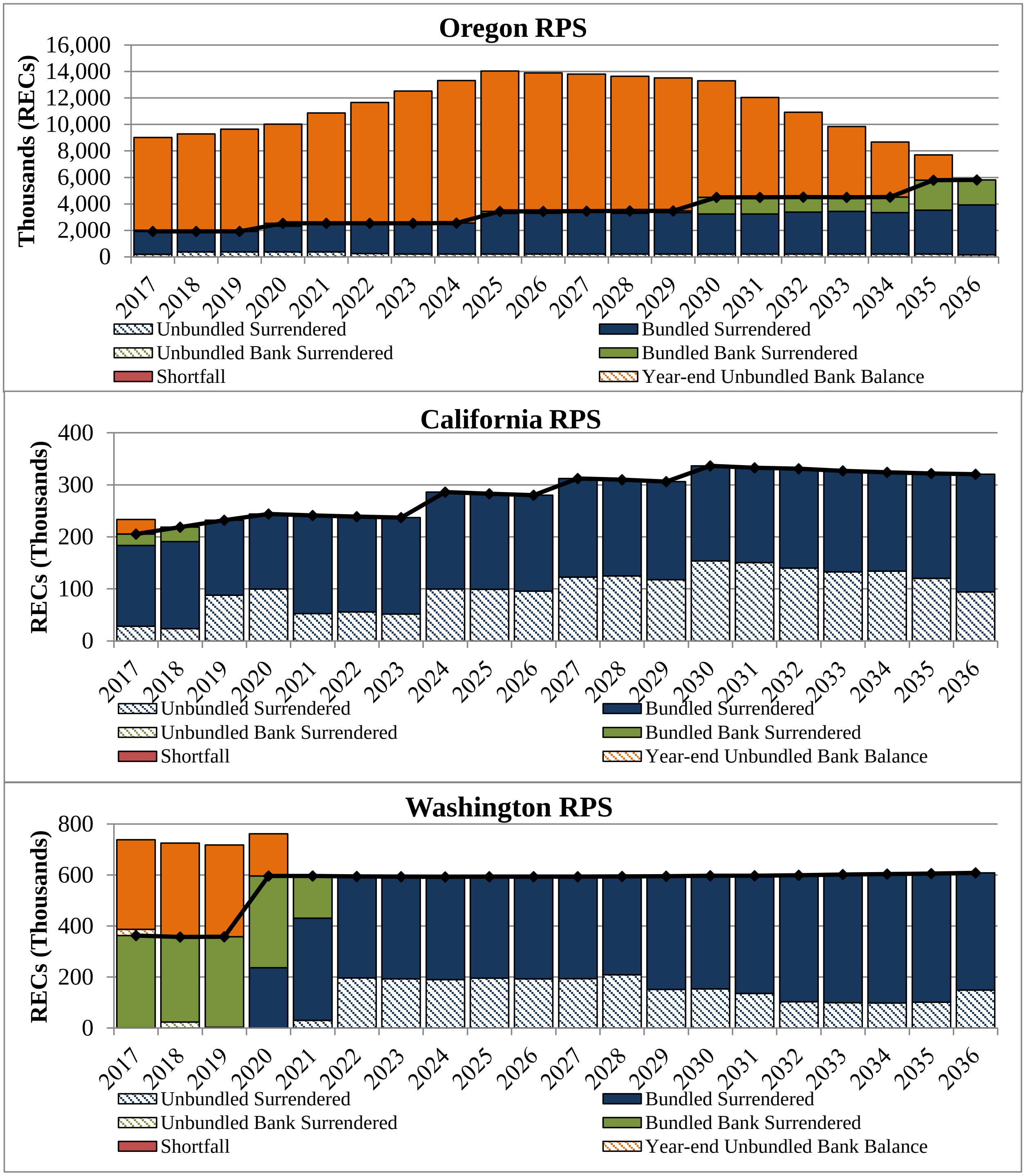
Oregon RPS compliance is achieved through 2034 with the addition of repowered wind and new renewable resources and transmission in the 2017 IRP preferred portfolio. A small increment of annual unbundled REC purchases, labeled "Unbundled Surrendered" in Figure 8.72 below, beginning at under 160,000 RECs in 2018 is required to achieve Oregon RPS compliance through 2036.

The California RPS compliance position is also improved by the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio and similarly requires a small amount of unbundled REC purchases under 150,000 RECs per year to achieve compliance through the planning horizon.

Washington RPS compliance is achieved with the benefit of the repowered wind assets located in the west side, Marengo and Leaning Juniper, new renewable resources added to the west side beginning 2028, and unbundled REC purchases under 200,000 RECs per year. Under current allocation mechanisms, Washington customers do not benefit from the repowered wind and new renewable resources added to the east side of PacifiCorp's system. Under an alternative allocation mechanism, in which Washing receives its system-allocated share of repowered wind and new wind located in Wyoming, Washington RPS targets would be met without the need for any incremental unbundled REC purchases throughout the 20-year planning period.

While not shown in Figure 8.72, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources before considering the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio.

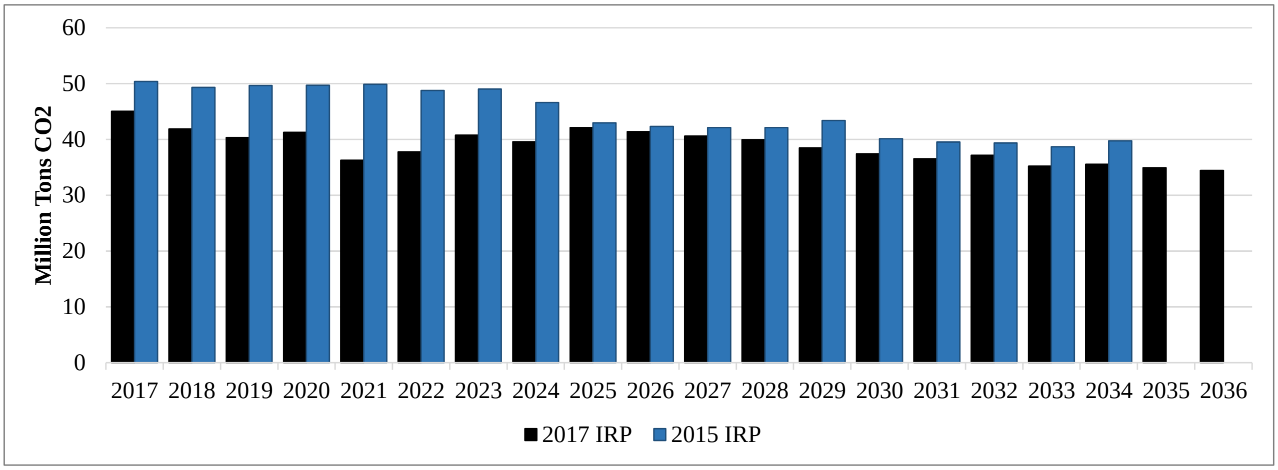
Figure 8.72 – Annual State RPS Compliance Forecast



Carbon Dioxide Emissions

The 2017 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean energy solutions for our customers and accordingly reflects a continued trajectory of declining CO_2 emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors including, PacifiCorp's participation in the EIM that reduces customer costs and maximizes use of clean energy, PacifiCorp's on-going expansion of renewable resources and transmission, and Regional Haze compliance that leverages flexibility. Figure 8.73 compares projected annual CO_2 emissions between the 2017 IRP and 2015 IRP preferred portfolios (as reported by PaR). Over the first 10 years of the planning horizon, average annual CO_2 emissions are down by over 10.5 million tons (21 percent) relative to the 2015 IRP. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.8 million tons in 2017 to 33.1 million tons in 2036—a reduction of 24.5 percent.

Figure 8.73 – Comparison of CO_2 Emission Forecasts between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



Detailed Preferred Portfolio

Table 8.17 provides line-item detail of PacifiCorp's 2017 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 8.18 and Table 8.19 show line-item detail of PacifiCorp's peak load and resource capacity balance for summer and winter (respectively) including preferred portfolio resources, through the first ten years of the planning horizon.

Table 8.17 – PacifiCorp's 2017 IRP Preferred Portfolio[6]

		Capacity (MW)																				Resource Totals 1/	
	Resource	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	774	-	774
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	85	-	-	-	-	774	1,100	1,959
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	167	210	41	291	13	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	300	291	300	300	300	300	300	300	3	137
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	11	97	-	38	70	16	8	-	-	-	240
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	41	-	10	167	76	137	400	400	400	400	400	400	400	400	364	30	200
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	299	375	344	375	375	375	375	375	375	375	375	375	375	375	375	375	285	330
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	308	-	287	295	-	-	-	400	41	390	351	-	377	4	291	208	197
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	312	51	375	-	-	337	-	375	375	92	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,223	114	118	118	112	111	109	306	563	536	303	323	980	117	356	861		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	1,336	1,987	2,126	2,081	2,065	2,026	2,012	2,052	2,054	2,305		
	Total Annual Additions	935	981	1,282	1,236	2,341	1,337	1,268	1,289	1,501	1,440	1,445	2,293	2,688	2,618	2,368	2,349	2,992	2,169	2,411	3,166		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

[6] The 2017 Preferred Portfolio includes repowering 905 MW of existing wind resources, not shown in the table

Table 8.18 – Preferred Portfolio Summer Capacity Load and Resource Balance

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East										
Thermal	6,406	6,406	6,126	6,126	5,739	5,739	5,739	5,739	5,739	5,656
Hydroelectric	103	106	113	113	113	113	113	92	92	92
Renewable	199	193	200	201	199	191	191	191	191	181
Purchase	249	249	249	249	221	221	221	221	121	121
Qualifying Facilities	656	646	689	681	672	661	657	603	598	594
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(652)	(652)	(652)	(652)	(172)	(172)	(172)	(146)	(146)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
Transfers	286	315	505	544	360	412	420	485	630	543
East Existing Resources	**7,532**	**7,547**	**7,516**	**7,548**	**7,417**	**7,450**	**7,454**	**7,472**	**7,512**	**7,410**
Front Office Transactions	0	0	0	0	0	0	0	0	0	29
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	174	174	174	174	174	174
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**0**	**0**	**0**	**0**	**174**	**174**	**174**	**174**	**174**	**203**
East Total Resources	**7,532**	**7,547**	**7,516**	**7,548**	**7,591**	**7,624**	**7,628**	**7,646**	**7,685**	**7,612**
Load	7,008	7,093	7,141	7,231	7,331	7,420	7,485	7,564	7,661	7,663
Distributed Generation	(33)	(51)	(72)	(80)	(86)	(91)	(94)	(98)	(104)	(112)
Existing Resources:										
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Class 2 DSM	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)
New Resources:										
Class 2 DSM	(72)	(124)	(179)	(232)	(289)	(343)	(402)	(461)	(518)	(575)
East obligation	**6,643**	**6,657**	**6,629**	**6,657**	**6,695**	**6,725**	**6,728**	**6,744**	**6,779**	**6,714**
Planning Reserves (13%)	889	891	887	891	896	900	900	902	907	898
East Reserves	**889**	**891**	**887**	**891**	**896**	**900**	**900**	**902**	**907**	**898**
East Obligation + Reserves	**7,532**	**7,547**	**7,516**	**7,548**	**7,591**	**7,624**	**7,628**	**7,646**	**7,685**	**7,612**
East Position	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
East Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
West										
Thermal	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247
Hydroelectric	855	859	717	806	635	549	644	648	634	651
Renewable	92	91	91	95	95	65	65	60	60	59
Purchase	18	18	1	1	1	1	1	1	1	1
Qualifying Facilities	195	200	202	207	198	195	186	185	184	182
Class 1 DSM	3	3	3	3	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)	(80)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Transfers	(287)	(316)	(506)	(545)	(361)	(413)	(421)	(486)	(631)	(544)
West Existing Resources	**2,957**	**2,935**	**2,589**	**2,648**	**2,653**	**2,531**	**2,610**	**2,573**	**2,413**	**2,515**
Front Office Transactions	532	552	931	856	847	971	895	938	1,105	1,008
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
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**532**	**552**	**931**	**856**	**847**	**971**	**895**	**938**	**1,105**	**1,008**
West Total Resources	**3,489**	**3,487**	**3,520**	**3,504**	**3,501**	**3,502**	**3,504**	**3,510**	**3,518**	**3,523**
Load	3,159	3,190	3,250	3,264	3,286	3,310	3,332	3,358	3,384	3,405
Distributed Generation	(5)	(7)	(10)	(11)	(13)	(15)	(17)	(19)	(22)	(24)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(34)	(34)	(34)	(34)	(34)	(34)	(34)	(34)	(34)	(34)
New Resources:										
Class 2 DSM	(33)	(63)	(92)	(118)	(142)	(162)	(180)	(199)	(215)	(230)
West obligation	**3,087**	**3,086**	**3,115**	**3,101**	**3,098**	**3,099**	**3,101**	**3,106**	**3,114**	**3,117**
Planning Reserves (13%)	401	401	405	403	403	403	403	404	405	405
West Reserves	**401**	**401**	**405**	**403**	**403**	**403**	**403**	**404**	**405**	**405**
West Obligation + Reserves	**3,488**	**3,487**	**3,519**	**3,504**	**3,501**	**3,502**	**3,505**	**3,510**	**3,518**	**3,523**
West Position	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	11,020	11,035	11,035	11,052	11,091	11,126	11,132	11,156	11,203	11,135
Obligation	9,730	9,743	9,743	9,758	9,793	9,824	9,829	9,850	9,892	9,831
Reserves	1,290	1,292	1,292	1,294	1,298	1,302	1,303	1,306	1,311	1,303
Obligation + Reserves	11,020	11,035	11,035	11,052	11,092	11,126	11,132	11,156	11,203	11,135
System Position	0	0	0	0	0	0	0	0	0	0
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.19 – Preferred Portfolio Winter Capacity Load and Resource Balance

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East										
Thermal	6,514	6,514	6,234	6,234	5,847	5,847	5,847	5,847	5,847	5,764
Hydroelectric	71	72	72	72	72	72	72	72	72	72
Renewable	199	193	201	199	191	191	191	191	191	181
Purchase	734	734	734	734	235	235	235	121	121	121
Qualifying Facilities	647	688	680	676	668	658	604	600	595	591
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(146)	(146)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
Transfers	100	27	(52)	48	(4)	(29)	(16)	(22)	(144)	(135)
East Existing Resources	**8,057**	**8,021**	**7,661**	**7,756**	**6,801**	**6,766**	**6,725**	**6,627**	**6,499**	**6,495**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	174	174	174	174	174	174
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**0**	**0**	**0**	**0**	**174**	**174**	**174**	**174**	**174**	**174**
East Total Resources	**8,057**	**8,021**	**7,661**	**7,756**	**6,975**	**6,940**	**6,899**	**6,800**	**6,673**	**6,669**
Load	5,550	5,617	5,686	5,597	5,770	5,847	5,923	5,956	5,919	5,924
Distributed Generation	(11)	(17)	(24)	(28)	(31)	(32)	(33)	(35)	(37)	(40)
Existing Resources:										
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Class 2 DSM	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)
New Resources:										
Class 2 DSM	(48)	(88)	(129)	(169)	(212)	(253)	(296)	(339)	(382)	(425)
East obligation	**5,252**	**5,274**	**5,294**	**5,161**	**5,288**	**5,323**	**5,355**	**5,343**	**5,262**	**5,220**
Planning Reserves (13%)	708	711	714	696	713	717	721	720	709	704
East Reserves	**708**	**711**	**714**	**696**	**713**	**717**	**721**	**720**	**709**	**704**
East Obligation + Reserves	**5,961**	**5,985**	**6,007**	**5,857**	**6,001**	**6,040**	**6,076**	**6,063**	**5,971**	**5,924**
East Position	**2,096**	**2,036**	**1,654**	**1,898**	**974**	**900**	**822**	**737**	**702**	**745**
East Reserve Margin	53%	52%	45%	50%	32%	30%	29%	27%	27%	28%
West										
Thermal	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308
Hydroelectric	993	915	943	937	784	782	783	779	786	786
Renewable	92	91	95	95	95	65	65	60	59	58
Purchase	6	1	1	1	1	1	1	1	1	1
Qualifying Facilities	200	192	195	197	190	183	177	176	175	171
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(162)	(162)	(162)	(154)	(154)	(113)	(113)	(81)	(81)	(81)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Transfers	(101)	(28)	51	(49)	3	28	15	21	143	134
West Existing Resources	**3,335**	**3,316**	**3,431**	**3,335**	**3,227**	**3,251**	**3,233**	**3,262**	**3,389**	**3,375**
Front Office Transactions	298	352	289	326	338	326	324	304	368	372
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
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**298**	**352**	**289**	**326**	**338**	**326**	**324**	**304**	**368**	**372**
West Total Resources	**3,633**	**3,668**	**3,720**	**3,661**	**3,565**	**3,577**	**3,558**	**3,566**	**3,758**	**3,747**
Load	3,264	3,290	3,305	3,416	3,359	3,378	3,399	3,416	3,540	3,557
Distributed Generation	(1)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(5)	(6)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
New Resources:										
Class 2 DSM	(37)	(72)	(107)	(137)	(164)	(188)	(210)	(231)	(249)	(267)
West obligation	**3,188**	**3,180**	**3,160**	**3,239**	**3,155**	**3,149**	**3,149**	**3,144**	**3,249**	**3,247**
Planning Reserves (13%)	414	413	411	421	410	409	409	409	422	422
West Reserves	**414**	**413**	**411**	**421**	**410**	**409**	**409**	**409**	**422**	**422**
West Obligation + Reserves	**3,603**	**3,593**	**3,571**	**3,661**	**3,565**	**3,559**	**3,558**	**3,553**	**3,671**	**3,670**
West Position	**30**	**75**	**149**	**0**	**0**	**19**	**0**	**13**	**87**	**77**
West Reserve Margin	14%	15%	18%	13%	13%	14%	13%	13%	16%	15%
System										
Total Resources	11,690	11,688	11,381	11,416	10,540	10,517	10,456	10,366	10,431	10,415
Obligation	8,441	8,453	8,453	8,400	8,443	8,472	8,503	8,487	8,511	8,467
Reserves	1,123	1,124	1,124	1,117	1,123	1,127	1,131	1,129	1,132	1,126
Obligation + Reserves	9,564	9,578	9,578	9,518	9,566	9,599	9,634	9,616	9,643	9,593
System Position	2,126	2,111	1,803	1,898	974	919	822	750	788	822
Reserve Margin	38%	38%	35%	36%	25%	24%	23%	22%	23%	23%

Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the three-step screening process used to select the preferred portfolio, a number of additional sensitivity cases were completed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. These sensitivity cases are useful in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risk.

Table 8.20 lists additional sensitivity studies performed for the 2017 IRP. To isolate the impact of a given planning assumption, each sensitivity case is compared to a benchmark, which was established during different stages of the portfolio development and selection processes outlined earlier in this chapter. Each benchmark case coincides with a resource portfolio developed during the three-stage portfolio selection process adopted for the 2017 IRP. Sensitivities benchmarked to the case labeled as "OP-1" in the table below, were performed before selecting the top performing portfolio from the first screening stage used to establish the 2017 IRP Regional Haze compliance assumptions. The OP-1 case is Regional Haze case 5 (RH-5), the top performing portfolio from the initial screening process before adopting alternative Regional Haze compliance assumptions for Naughton Unit 3 as used in Regional Haze case 5a (which became case OP-NT3 in the second stage of the portfolio selection process).

Table 8.20 – Summary of Additional Sensitivity Cases

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway
LD-1	1 in 20 Loads	OP-1	1 in 20	Base	Mass Cap B	Base	None
LD-2	Low Load	OP-1	Low	Base	Mass Cap B	Base	None
LD-3	High Load	OP-1	High	Base	Mass Cap B	Base	None
PG-1	Low Private Gen	OP-1	Base	Low	Mass Cap B	Base	None
PG-2	High Private Gen	OP-1	Base	High	Mass Cap B	Base	None
CPP-C	CPP Mass Cap C	OP-1	Base	Base	Mass Cap C	Base	None
CPP-D	CPP Mass Cap D	OP-1	Base	Base	Mass Cap D	Base	None
FOT-1	Limited FOT	OP-1	Base	Base	Mass Cap B	Restricted	None
CO2-1	CO_2 Price	OP-1	Base	Base	Tax, No CPP	Base	None
NO-CO2	No CO_2	OP-NT3	Base	Base	No Tax, No CPP	Base	None
BP	Business Plan	OP-NT3	Base	Base	Mass Cap D	Base	None
Battery	Battery Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2
CAES	CAES Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2
WCA	WCA	FS-REP	Base	Base	Mass Cap B	Base	None
WCA-RPS	WCA RPS	FS-REP	Base	Base	Mass Cap B	Base	None

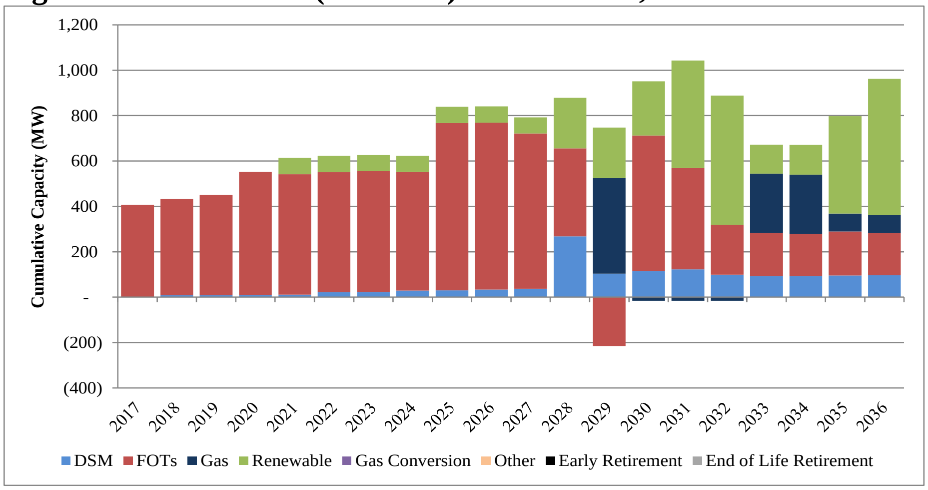
1-in-20 Load Growth Sensitivity (Case LD-1)

Table 8.21 shows the PVRR impacts of the LD-1 sensitivity relative to case OP-1. This sensitivity assumes 1-in-20 extreme weather conditions during the summer (July) for each state. System costs are higher due to requirements to meet additional peak load. Figure 8.74 summarizes resource portfolio impacts. Higher peak loads require more FOTs, renewables (+600 MW), DSM (+96 MW), and natural gas resources (+79 MW) by end of study period.

Table 8.21 – PVRR Cost/(Benefit) of LD-1 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	$187	$266

Figure 8.74 – Increase/(Decrease) in Resources, LD-1 vs. OP-1



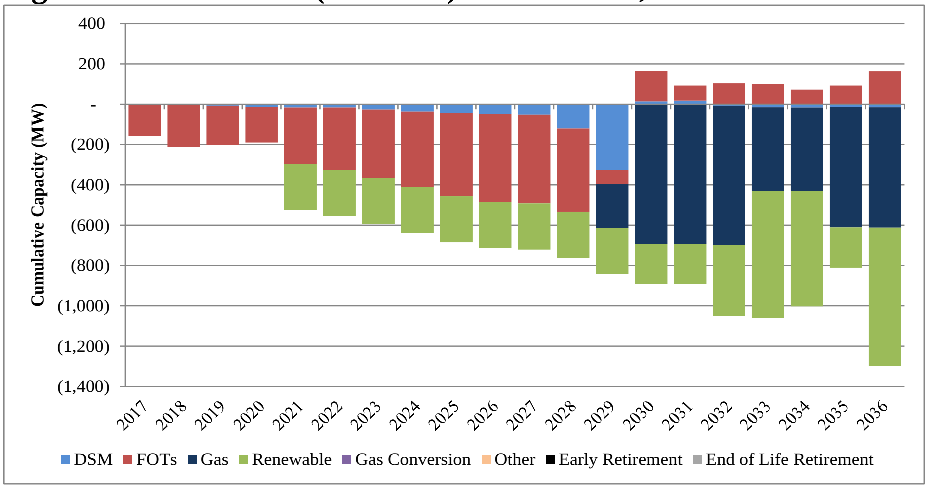
Low Load Growth Sensitivity (Case LD-2)

Table 8.22 shows the PVRR impacts of the LD-2 sensitivity relative to case OP-1. The reduced loads lower system costs significantly over the 20-year study period. Figure 8.75 summarizes portfolio impacts. FOTs are reduced by an average of 294 MW through 2029, and increase by an average of 109 MW thereafter with reduced gas and renewable resources. Renewable resources are reduced by 687 MW by the end of the study period. Natural gas resource capacity is down by 597 MW by the end of the study period.

Table 8.22 – PVRR Cost/(Benefit) of LD-2 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	($1,610)	($1,771)

Figure 8.75 – Increase/(Decrease) in Resources, LD-2 vs. OP-1



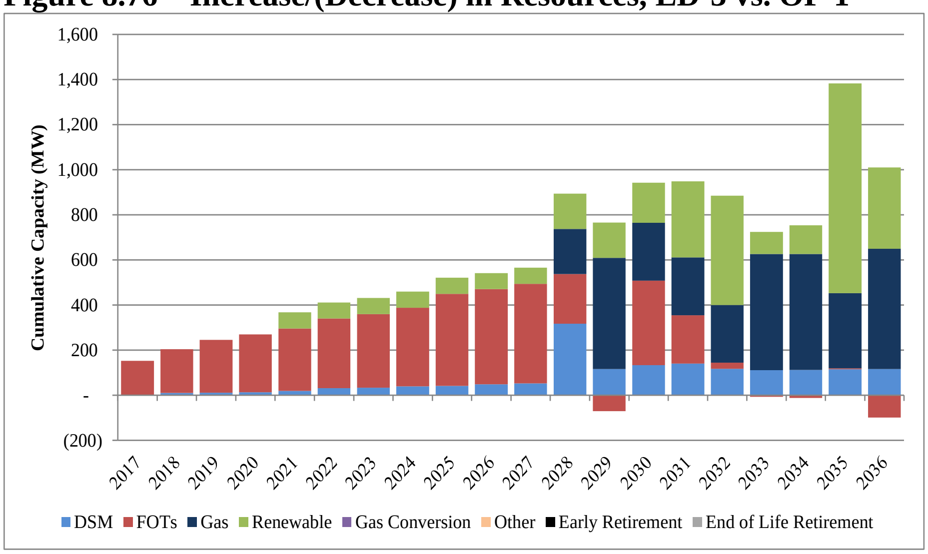
High Load Growth Sensitivity (Case LD-3)

Table 8.23 shows the PVRR impacts of the LD-3 sensitivity relative to case OP-1. Higher loads result in significantly increased system costs. Figure 8.76 summarizes resource portfolio impacts. FOTs increase by an average of 299 MW through 2028 while renewable resources increase by 71 MW in 2021 and rise to an additional 360 MW by the end of the study period. An additional 200 MW of natural gas capacity shows up in 2028, with 533 MW of additional gas-fired capacity by 2036. DSM increases by 116 MW by the end of the study period.

Table 8.23 – PVRR Cost/(Benefit) of LD-3 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	$1,641	$1,799

Figure 8.76 – Increase/(Decrease) in Resources, LD-3 vs. OP-1



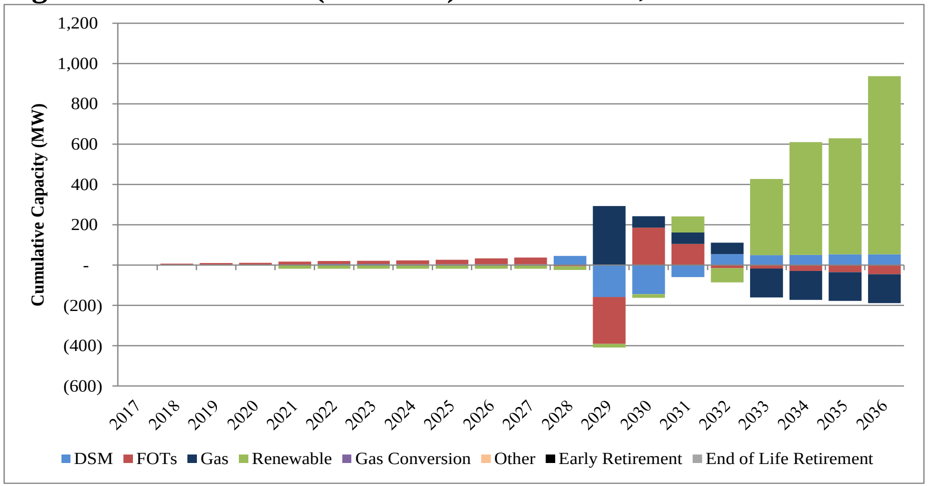
Low Private Generation Sensitivity (Case PG-1)

Table 8.24 shows the PVRR impacts of the PG-1 sensitivity relative to case OP-1. The lower private generation assumption results in higher net loads increasing system costs. Figure 8.77 summarizes portfolio impacts, which are minor through 2028. Over the long-term, this sensitivity produces more renewable capacity (883 MW) and less natural gas capacity (143 MW).

Table 8.24 – PVRR Cost/(Benefit) of PG-1 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	$127	$168

Figure 8.77 – Increase/(Decrease) in Resources, PG-1 vs. OP-1



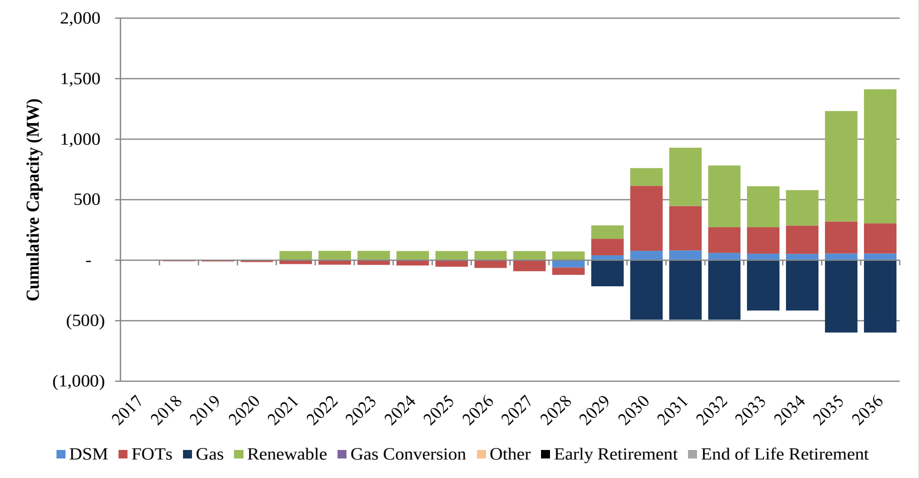
High Private Generation Sensitivity (Case PG-2)

Table 8.25 shows the PVRR impacts of the PG-2 sensitivity relative to case OP-1. The higher private generation assumptions decrease net load, which in turn decreases system costs. Figure 8.78 summarizes portfolio impacts, which are minor through 2028. Over the long-term, there is more renewable capacity (1,108 MW) and less natural gas-fired capacity (597 MW).

Table 8.25 – PVRR Cost/(Benefit) of PG-2 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	($278)	($273)

Figure 8.78 – Increase/(Decrease) in Resources, PG-2 vs. OP-1



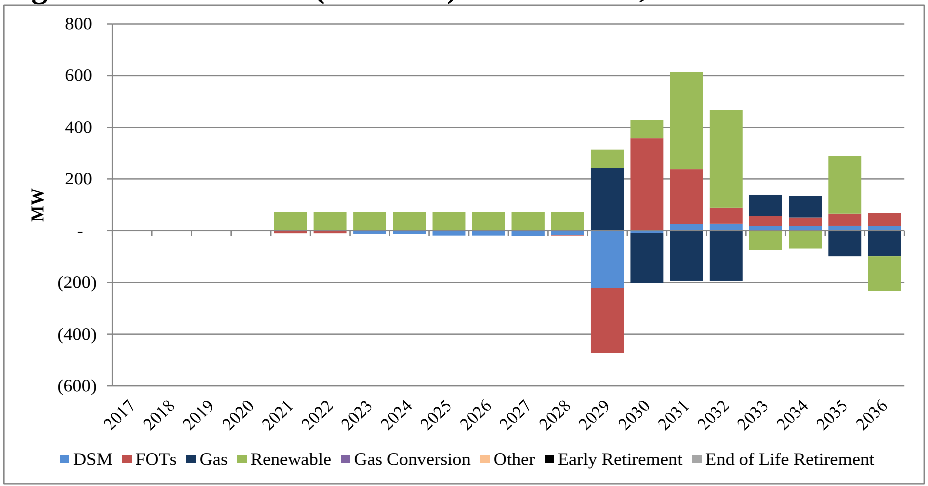
CPP Mass Cap C Sensitivity (Case CPP-C)

Table 8.26 shows the PVRR impacts of the CPP-C sensitivity relative to case OP-1. For the Mass Cap C sensitivity, PacifiCorp does not receive any allocation of set-asides and the emissions cap is assumed to only apply to existing resources. High natural gas prices put upward pressure on the mass cap (higher coal dispatch), which increases the cost of this sensitivity relative to case OP-1 under high natural gas price scenarios. As shown in Figure 8.79, renewables increase by 71 MW in 2021, but 135 MW fewer renewables are added by 2036. Timing of natural gas resources is accelerated by one year, but reduced by 99 MW by 2036—combined cycles replace gas-fired peaking resources.

Table 8.26 – PVRR Cost/(Benefit) of CPP-C vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from Case 1 (OP-1)	$91	$50	$69	$286	$47	$74	$471

Figure 8.79 – Increase/(Decrease) in Resources, CPP-C vs. OP-1



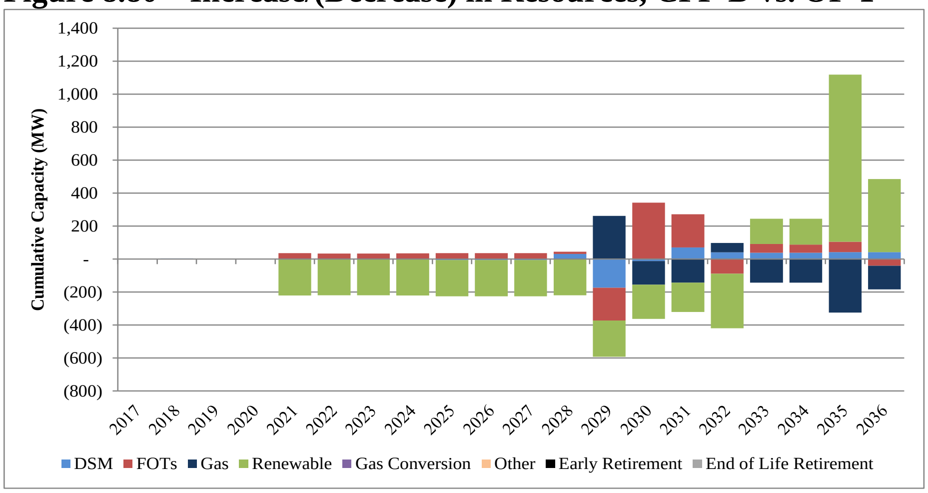
CPP Mass Cap D Sensitivity (Case CPP-D)

Table 8.27 shows the PVRR impacts of the CPP-D sensitivity relative to case OP-1. With a higher cap to accommodate new resources, dispatch costs are reduced, lowering system costs—most notably with higher gas prices. New CCCTs are assumed to be covered by the emissions cap, and there are no set-asides. As shown in Figure 8.80, there are 220 MW fewer renewables added in 2021, but 443 MW additional renewables are added by 2036. Timing of natural gas resource additions is altered, with a reduction of 143 MW by 2036.

Table 8.27 – PVRR Cost/(Benefit) of CPP-D vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from Case 1 (OP-1)	($76)	($64)	($80)	($320)	($69)	($100)	($357)

Figure 8.80 – Increase/(Decrease) in Resources, CPP-D vs. OP-1



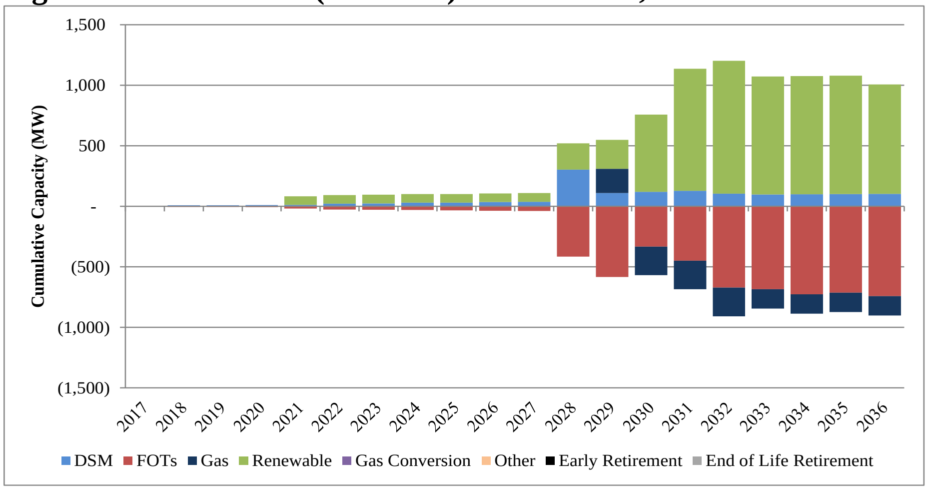
Limited FOT Sensitivity (Case FOT-1)

Table 8.28 shows the PVRR impacts of the FOT-1 sensitivity to case OP-1. In the FOT-1 sensitivity, FOTs are eliminated at Mona (300 MW) and NOB (100 MW) for both the summer and winter seasons beginning in 2021. Eliminating access to market by 400 MW increases system costs, particularly over the long-term—economics improve as gas prices rise, which improves the value of incremental renewable resource additions. As shown in Figure 8.81, new renewable resources increase by 71 MW in 2021 and increase by 905 MW by 2036. Over the study period, DSM resources increased by 102 MW. More natural gas capacity is needed in 2029, but overall gas resource additions are lower by 160 MW at the end of the study period.

Table 8.28 – PVRR Cost/(Benefit) of FOT-1 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from Case 1 (OP-1)	$169	$286	$237	$74	$282	$232	$47

Figure 8.81 – Increase/(Decrease) in Resources, FOT-1 vs. OP-1



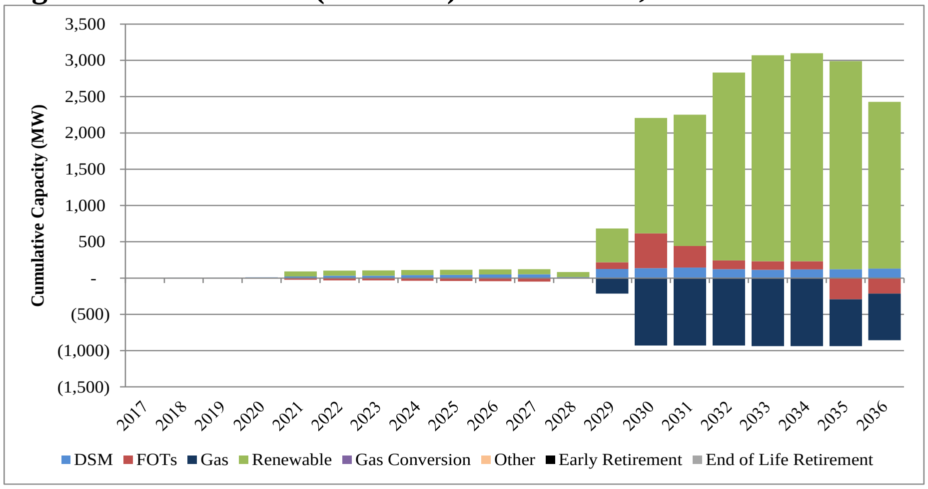
CO_2 Price Sensitivity (Case CO2-1)

Table 8.29 shows the PVRR impacts of the CO2-1 sensitivity relative to case OP-1. When compared to case OP-1, system costs are higher in all but the high gas price scenarios since the value of additional renewable resources increases with higher gas prices. As summarized in Figure 8.82, additional renewable resources are added to the system, particularly in the out years when the CO_2 price rises above $25/ton. The additional renewable resources displace natural gas resources over the long-term. When compared to case OP-1, system costs are higher in all but the high gas price scenarios since the value of additional renewable resources increases with higher gas prices.

Table 8.29 – PVRR Cost/(Benefit) of CO2-1 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from Case 1 (OP-1)	$928	$1,028	$862	($368)	$1,018	$830	($353)

Figure 8.82 – Increase/(Decrease) in Resources, CO2-1 vs. OP-1



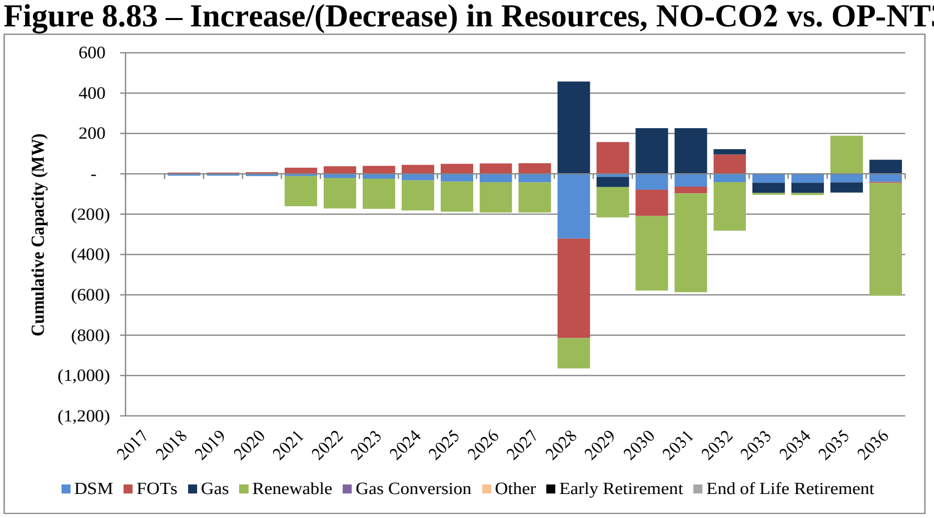
No CO_2 Policy Sensitivity (Case NO-CO2)

Table 8.30 shows the PVRR impacts of the NO-CO2 sensitivity relative to case OP-NT3. As requested by stakeholders, the NO-CO2 case examines the impact of having no incremental state or federal CO_2 emissions policy in place throughout the 2017-2036 study period. Overall, system costs decrease by between $161m (SO) and $194m (PaR). Figure 8.83 summarizes portfolio impacts. In this study, 150 MW of 2021 wind in Idaho is eliminated; however, the 300 MW of wind in Wyoming included in the OP-NT3 case remains cost effective absent a CO_2 policy assumption.

Table 8.30 – PVRR Cost/(Benefit) of NO-CO2 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from OP-NT3	($161)	($194)

Figure 8.83 – Increase/(Decrease) in Resources, NO-CO2 vs. OP-NT3



Business Plan Sensitivity (Case BP)

Table 8.31 shows the PVRR impacts of the Business Plan sensitivity relative to case OP-NT3. System costs increase by $146m when studied in SO and $108m when analyzed using PaR. This sensitivity complies with Utah requirements to perform a business plan sensitivity consistent with the Public Service Commission of Utah's order in Docket No. 15-035-04, summarized as follows:

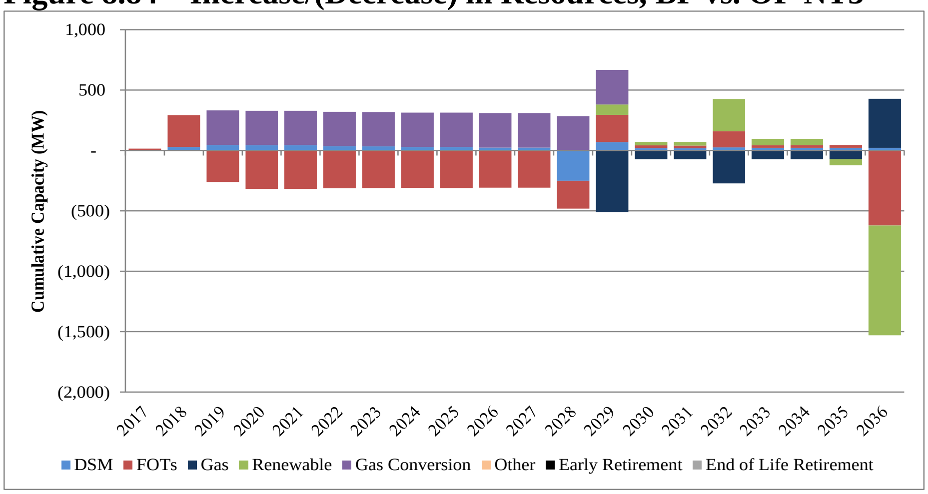
- Over the first three years, resources align with those assumed in PacifiCorp's fall 2016 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Figure 8.84 summarizes resource portfolio impacts, showing differences associated with Naughton Unit 3 (assumed to convert to natural gas in the business plan) offset by reduced FOTs through 2027. Longer term, there is a difference in the timing of new natural gas resources, renewable resources, and FOTs.

Table 8.31 – PVRR Cost/(Benefit) of BP vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from OP-NT3	$146	$108

Figure 8.84 – Increase/(Decrease) in Resources, BP vs. OP-NT3



Energy Storage Sensitivities

In the 2017 IRP, storage resources available to the models include pumped storage, compressed air energy storage (CAES), and lithium and flow batteries. Interest in storage resources continues to grow as these technologies advance. PacifiCorp recognizes that there are stacked benefits from storage systems, that certain benefit categories are difficult to value with existing IRP modeling tools, and that improving storage analytics is a priority. With this in mind, PacifiCorp continues to explore options for modeling storage resources that are capable of capturing additional benefit streams, including voltage support, renewable resource integration, and deferral of transmission and distribution upgrades. While the sensitivity cases conducted in the 2017 IRP cycle are limited in scope, PacifiCorp plans to leverage work being performed in its review of distribution level studies when evaluating storage applications in future IRPs.

PacifiCorp currently evaluates the economics for selection of specific energy storage projects, with a focus on distribution-level applications, outside of the IRP process. In this context, PacifiCorp considered procuring an energy storage project in Washington under the Clean Energy Fund 2, but ultimately withdrew its application. A combined energy storage plus solar project is being procured in Utah with a targeted in-service date mid-2018. In Oregon, PacifiCorp is working to meet the requirements of HB 2193, which will result in proposing one or more energy storage projects in Oregon.

For the 2017 IRP, two utility-scale energy storage sensitivities (battery storage and CAES) were conducted, using updated cost assumptions. The two energy storage sensitivities were based on the energy storage studies described in Volume II, Appendix P. The energy storage studies include analysis of benefits associated with ancillary services and updated prices. The battery energy storage study also includes forecasted price trends.

Storage – Battery Sensitivity (Case Battery)

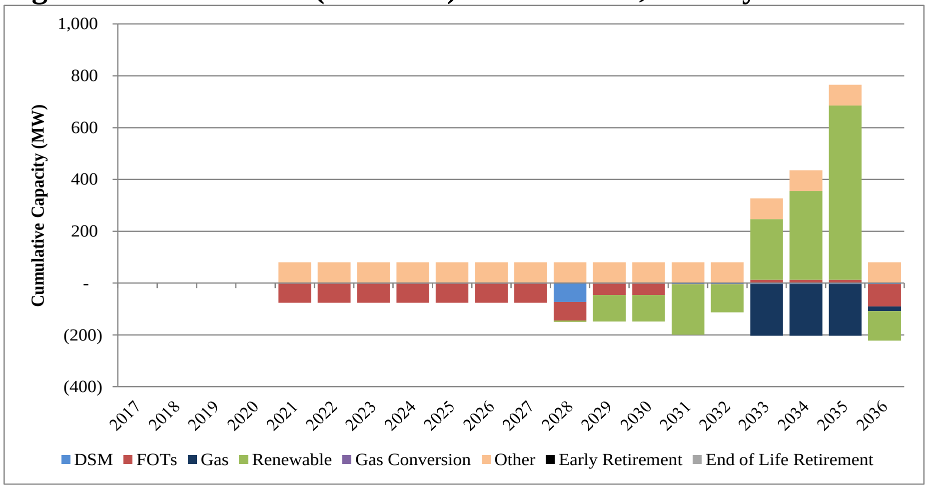
In this sensitivity, PacifiCorp added an 80 MW battery storage resource in 2021, coinciding with the incremental addition of new wind resources included in the preferred portfolio. Table 8.32 shows the PVRR impacts of the Battery sensitivity relative to the FS-GW4 case. System costs increase by $172m (SO) and $151m (PaR).

Table 8.32 – PVRR Cost/(Benefit) of Battery vs. FS-GW4

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from FS-GW4	$172	$151

Figure 8.85 shows the resource portfolio impacts of this sensitivity relative to the FS-GW4 benchmark. The added battery storage resource primarily defers FOTs through 2027. In the out years of the planning horizon, introduction of the storage system influences timing of new resources. Given changes to the resource mix over time, by the end of the study period, the battery storage system results in reduced FOTs and a slight reduction in overall renewable resource capacity.

Figure 8.85 – Increase/(Decrease) in Resources, Battery vs. FS-GW4



Storage – Compressed Air Energy Sensitivity (Case CAES)

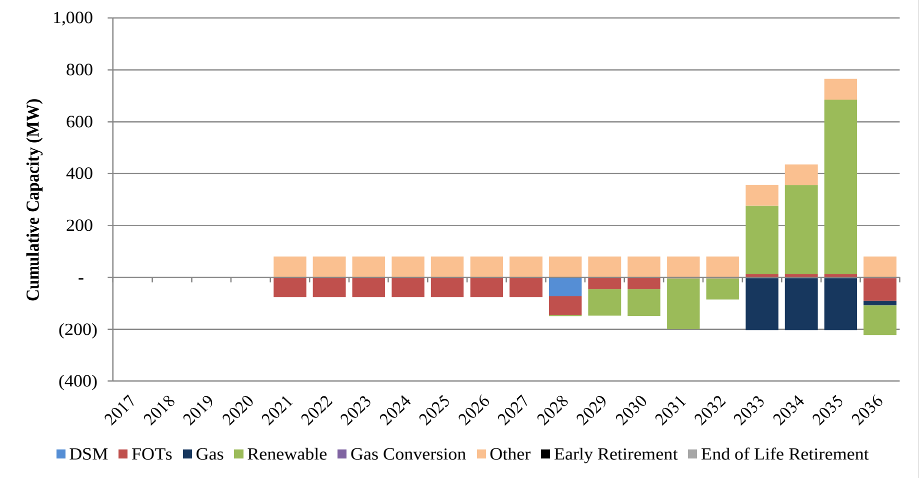
In this sensitivity, PacifiCorp added an 80 MW CAES resource in 2021, coinciding with the incremental addition of new wind resources included in the preferred portfolio. Table 8.33 shows the PVRR impacts of the CAES sensitivity relative to the FS-GW4 benchmark case. As in the Battery sensitivity, adding the CAES resources increases system costs. Overall system costs increase by between $131m (SO) and $110m (PaR), less of an increase than seen in the Battery sensitivity case.

Table 8.33 – PVRR Cost/(Benefit) of CAES vs. FS-GW4

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from FS-GW4	$131	$110

Figure 8.86 shows the resource portfolio impacts of this sensitivity relative to the FS-GW4 benchmark. The portfolio impacts are nearly identical to those seen in the Battery sensitivity case. The added CAES resource primarily defers FOTs through 2027. In the out years of the planning horizon, introduction of the storage system influences timing of new resources. Given changes to the resource mix over time, by the end of the study period, the CAES resource results in reduced FOTs and a slight reduction in overall renewable resource capacity.

Figure 8.86 – Increase/(Decrease) in Resources, CAES vs. FS-GW4



East/West Split Sensitivity (Case WCA)

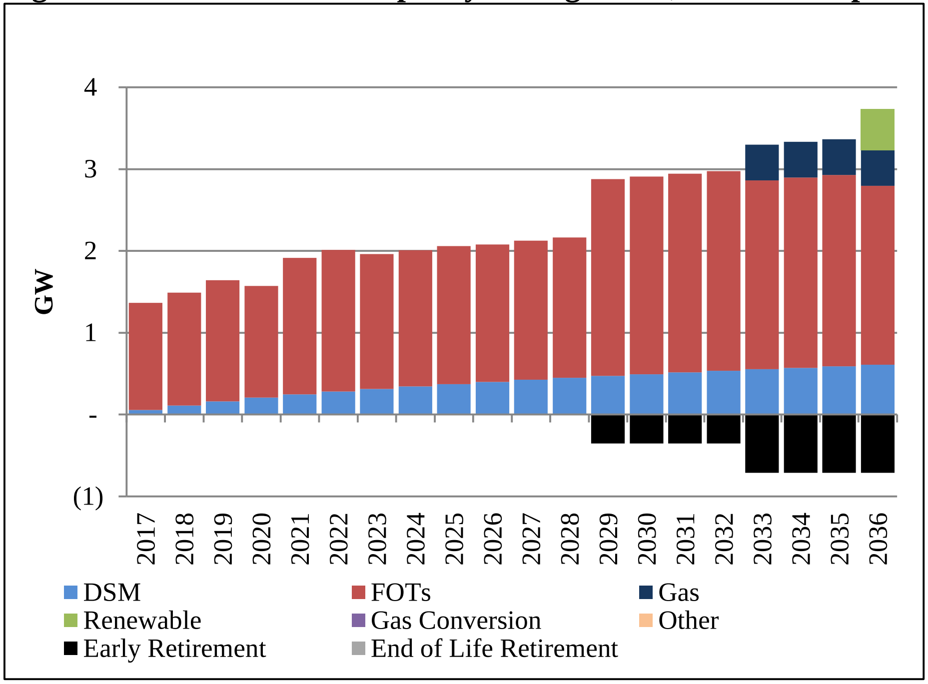
In response to the Washington Utilities and Transportation Commission (WUTC), PacifiCorp updated its West Control Area (WCA) sensitivity for the 2017 IRP to compare the impact of planning for the WCA as a stand-alone system on a WCA-to-WCA basis, rather than on a system-to-system basis as was done in the 2015 IRP. Table 8.34 shows the PVRR impacts of the East/West Split (WCA) sensitivity relative to the benchmark case, FS-REP, reported on a WCA-basis. Overall system costs increase by between $1,019m (SO) and $203m (PaR) when compared to the FS-REP benchmark case, reported on a WCA-basis, indicating that the WCA benefits from east-side resources.

Table 8.34 – PVRR Cost/(Benefit) of WCA vs. FS-REP

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
West (FS-REP)	$6,509	$6,863
West (WCA)	$7,528	$7,066
Change from FS-REP	$1,019	$203

Figure 8.87 shows the resource portfolio from the WCA case. When the east side of the system is eliminated from the planning study, the WCA-system relies on FOTs and incremental DSM resources through 2032. A 1x1 G-class 436 MW natural gas CCCT is added in 2033, coinciding with the assumed retirement of Jim Bridger Unit 2 and the end of 2032, and 500 MW of west-side wind is added in 2036. Without east-side resources in the energy mix, the WCA system is heavily reliant on wholesale power market purchases.

Figure 8.87 – Cumulative Capacity through 2036, East/West Split Case – WCA



PacifiCorp calculated the FOT values as a percentage of peak load over both the 10-year period (2017-2026) and 20-year period (2017-2036) for both the WCA case and the benchmark case. This analysis shows that WCA reliance on FOTs as a percentage of peak load is nearly double that of the integrated system, as shown Table 8.35. This results in increased market risk exposure under a WCA structure when compared to the integrated system. Alleviating this market risk would require accelerating the timing for new generating resources and significantly increase the cost of this sensitivity relative to the benchmark.

Table 8.35 – FOTs as a Percentage of Net Peak Load

	Summer		Winter	
	10 year	20 year	10 year	20 year
WCA	26%	31%	23%	28%
WCA-RPS	26%	31%	23%	28%
System	9%	12%	10%	14%

East/West Split RPS Sensitivity (Case WCA-RPS)

In this variant of the WCA sensitivity, additional renewable resources are added to the WCA system to achieve physical compliance with Washington RPS targets. Table 8.36 shows the PVRR impacts of the WCA-RPS relative to the FS-REP case, reported on a WCA-basis. Overall system costs increase by between $1,030m (SO) and $216m (PaR) when compared to the FS-REP case, reported on a WCA-basis.

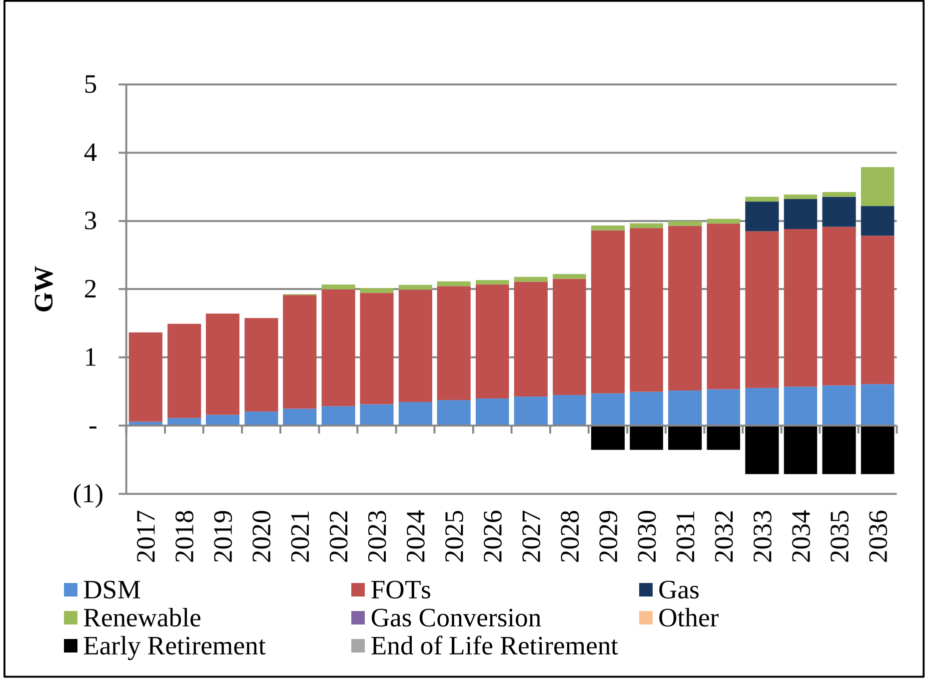
Table 8.36 – PVRR Cost/(Benefit) of WCA-RPS vs. FS-REP

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
West (FS-REP)	$6,509	$6,863
West (WCA-RPS)	$7,539	$7,079
Change from FS-REP	$1,030	$216

Figure 8.88 shows the resource portfolio from the WCA-RPS case. When the east side of the system is eliminated from the planning study and additional renewable resources are added to achieve Washington RPS targets, the WCA system relies on FOTs and incremental DSM resources through 2020. Additional west-side wind resources are added in 2021 and 2022 (70 MW), with an incremental 500 MW of wind added in 2036. As in the WCA sensitivity case, a 1x1 G-class 436 MW natural gas CCCT is added in 2033, coinciding with the assumed retirement of Jim Bridger Unit 2 and the end of 2032.

The additional renewable resources do not alleviate the reliance on FOTs described in the WCA case, and the market risk associated with such a portfolio described for the WCA case also applies to the WCA-RPS case.

Figure 8.88 – Cumulative Capacity through 2036, East/West Split RPS Case – WCA-RPS



2015 IRP WCA Sensitivity Discussion

PacifiCorp conducted a WCA sensitivity in the 2015 IRP that modeled separate east and west balancing authority areas (Sensitivity S-10 Separate East/West BAAs) in accordance with a request from the WUTC in its 2013 IRP Acknowledgement Letter.[7] Results of this analysis showed a need for additional resources in the west BAA during the study period. Following, in the WUTC's 2015 IRP Acknowledgement Letter, the Commission indicated that sensitivity case S-10 did not meet its request and that cost impacts should be presented at the BAA level rather than the system level as a means of quantifying the benefits of system integration to the individual BAAs.[8] As described earlier, PacifiCorp's 2017 IRP WCA sensitivity cases compare system cost impacts on a WCA-to-WCA basis. Additionally, the Acknowledgement Letter discusses subsequent analysis conducted by WUTC staff as part of the Multi-State Process for interstate cost allocations that included staff analysis of power flows across the Company's system. Based on this analysis, WUTC staff concluded that the west BAA is capable of meeting its peak load needs independent of any transfers from the east BAA, and thereby concluded that the west BAA would not need to add capacity resources as shown in the Company's S-10 analysis. The WUTC requested that the 2017 IRP repeat the analysis and that inputs consistent with the flow data used by WUTC staff be applied, or that the Company explain why different inputs are more appropriate.

As presented in the preceding sections, in both of PacifiCorp's 2017 IRP WCA sensitivities, additional resources are needed in the west BAA, and system costs are higher when compared to WCA costs derived from an integrated system. The WUTC staff analysis conducted in the Multi-State Process for interstate cost allocation was based on the scheduled delivery or receipt of energy based on e-Tag information across PacifiCorp's system. While this analysis showed that the west BAA is capable of meeting its peak load needs independent of any transfers from the east BAA, WUTC staff's analysis was limited, as it did not take into account the reserve and capacity requirements of the west BAA. Specifically, PacifiCorp must meet its load requirements both on an energy and capacity basis, holding contingency reserves equal to three percent of generation plus three percent of load, and regulating reserve requirements for ramping and deviations in load and variable energy resources. There are a limited number of resources in the west BAA that can hold contingency and regulating reserves, and in operating practice, it is common for the west BAA to rely on the east BAA for reserves as the most economical practice.

From an operational standpoint, hydro resources are advantageous resources for carrying reserves due to the high ramp capability of these generating units. However, due to operational limitations such as minimum flow requirements during high run-off periods or Endangered Species Act (ESA) mandated flow requirements, it is not always possible to hold reserves on these hydro resources during many hours of the year, primarily the winter and spring periods. The remaining resources in the west BAA that can hold contingency reserves limited to the Jim Bridger coal plant, the Hermiston gas plant, and the Chehalis gas plant. Reserves are economically held on the marginal unit on the system while energy is provided with the least expensive resources on the system. PacifiCorp is able to balance its reserve requirements across the east and west BAAs by holding reserves in a manner that is most economic. For example, if the Jim Bridger coal plant is less expense than a gas unit, but the east BAA gas units are less expensive than the west BAA gas units, PacifiCorp will make the economic decision to displace the west BAA gas unit and hold reserves on an east BAA gas unit while transferring energy from Jim Bridger to the east BAA and free up capacity. It is also reasonable to transfer energy to the east BAA form the Jim Bridger coal

[7] Docket UE-120416, Pacific Power & Light Company 2013 IRP Acknowledgement Letter Attachment (Nov. 25, 2013) at pages 5-6.
[8] Docket UE-140546, Pacific Power & Light Company 2015 IRP Acknowledgement Letter Attachment (Nov. 13, 2015) at pages 3-4.

plant, due to the fact that it can only hold a limited amount of contingency reserves due to ramp limitations, while the ability of a gas unit to hold reserves is only limited by its capacity. PacifiCorp conducted an analysis of January 2013, the time period in WUTC staff's analysis referenced in the 2015 IRP Acknowledgement Letter, which showed the west BAA relied on the east BAA for reserves in 58 percent of the hours, assuming a regulating requirement of 120 MW. This further supports the importance of considering energy and capacity needs for contingency reserves and regulating purposes when evaluating a split of the west and east BAAs.

PacifiCorp has consistently held reserves in its east BAA for the west BAA due to economics and limited generation capacity resulting from hydro operational constraints or planned or forced outages of west BAA gas plants. While WUTC staff's analysis accurately accounted for the scheduled delivery and receipt of energy through e-Tags across PacifiCorp's system, it was limited and did not take into consideration capacity needs of the west and east BAAs for contingency reserves and regulating purposes, which explains why staff's analysis appeared to be inconsistent with PacifiCorp's WCA sensitivity case presented in the 2015 IRP.

CHAPTER 9 – ACTION PLAN AND RESOURCE PROCUREMENT

CHAPTER HIGHLIGHTS

- The 2017 IRP action plan identifies steps to be taken during the next two to four years to deliver resources in the preferred portfolio.
- PacifiCorp's 2017 IRP action plan includes action items for renewable resources, transmission, short-term firm market purchases (front office transactions or FOTs), demand side management resources, and coal resources.
- The 2017 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, distributed generation, CO_2 emission polices, Regional Haze outcomes, and availability of purchases from the market.
- Differences between the 2017 IRP preferred portfolio and the 2015 IRP Update and fall ten-year business plan portfolios are primarily driven by changes in load forecasts, the cost for renewable resource alternatives, and other model assumption updates reflecting changes in the planning environment.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2017 IRP action plan identifies the steps the Company will take during the next two to four years to deliver its preferred portfolio of resources with a focus on the front ten years of the planning horizon. 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 frame that could materially impact resource acquisition strategies.

Resources included in the 2017 IRP preferred portfolio 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 2017 IRP action plan is based upon the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2017 IRP, such as capital and operating costs, are based upon recent cost and performance data. However, it is important to recognize that the resources identified in the plan are proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from th proxy resource identified in the plan with respect to resource type, timing, size, cost and location. PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and commission orders.

In addition to presenting the 2017 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2017 IRP acquisition path analysis, Chapter 9 covers the following resource procurement 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; and
- Treatment of customer and investor risks.

The 2017 IRP Action Plan

The 2017 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 2017 IRP process. Table 9.1 details specific 2017 IRP action items by category.

Table 9.1 – 2017 IRP Action Plan

Action Item	1. Renewable Resource Actions
1a	**Wind Repowering** • PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016. – Continue to refine and update the economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed. – By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills). – Pursue regulatory review and approval as necessary. – By May 2018, issue the engineering, procurement, and construction (EPC) notice to proceed to begin implementing the wind repowering for specific projects consistent with updated financial analysis. – By December 31, 2020, complete installation of wind repowering equipment on all identified projects.
1b	**Wind Request for Proposals** • PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020. – April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP. – May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission. – May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP. – June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and Necessity (CPCN) application with the Public Service Commission of Wyoming. – By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Washington Utilities and Transportation Commission. – By August 2017, issue the Wyoming wind RFP to the market. – By October 2017, Wyoming wind RFP bids are due.

	– November-December, 2017, complete initial shortlist bid evaluation. – By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission. – By March 2018, receive CPCN approval from the Wyoming Public Service Commission. – Complete construction of new wind projects by December 31, 2020.
1c	**<u>Renewable Portfolio Standard Compliance</u>** • PacifiCorp will issue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements. – As needed, issue RFPs seeking then-current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2020. – As needed, issue RFPs seeking low-cost then-current-year, forward-year, or older vintage unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets, deferring the currently projected 2035 initial shortfall after accounting for preferred portfolio renewable resources.
1d	**<u>Renewable Energy Credit Optimization</u>** • Before filing the 2017 IRP Update, evaluate potential opportunities to re-allocate RECs from Utah, Wyoming, and Idaho to Oregon, Washington, or California. • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.
Action Item	**2. Transmission Actions**
2a	**<u>Aeolus to Bridger/Anticline</u>** • By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary. – June-July 2017, file a CPCN application with the Public Service Commission of Wyoming. – By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way. – By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed. – By April 2019, issue EPC final notice to proceed. – Complete construction of the transmission line by December 31, 2020.
2b	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with the following near-term targets: – For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental

	consultant actions required as part of the federal permits. – For Segments D, E, and F, continue to support the projects by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.
3c	**<u>Wallula to McNary 230 kV Transmission Line</u>** • Complete Wallula to McNary project construction per plan with a 2018 expected in-service date. Continue to support the permitting and construction process for Walla Walla to McNary.
4d	**<u>Planning Studies</u>** • Complete planning studies that include proposed coal unit retirement assumptions from the 2017 IRP preferred portfolio and two other scenarios. • Summarize studies in the 2017 IRP Update.
Action Item	**3. Firm Market Purchase Actions**
3a	**<u>Front Office Transactions</u>** • Acquire economic short-term firm market purchases for on-peak summer deliveries from 2017 through 2019 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month-forward, balance-of-month, day-ahead, and hour-ahead non-brokered transactions.

<table>
<tr><th>Action Item</th><th>4. Demand Side Management (DSM) Actions</th></tr>
<tr><td>4a</td><td><u>Class 2 DSM</u>
• Acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp’s state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2017 IRP.
<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr>
<tr><td>2017</td><td>646</td><td>154</td></tr>
<tr><td>2018</td><td>559</td><td>128</td></tr>
<tr><td>2019</td><td>571</td><td>131</td></tr>
<tr><td>2020</td><td>527</td><td>122</td></tr>
</table>
*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.</td></tr>
<tr><th>Action Item</th><th>5. Coal Resource Actions</th></tr>
<tr><td>5a</td><td><u>Hunter Units 1 and 2</u>
• The EPA’s final Regional Haze Federal Implementation Plan (FIP) for Utah requires the installation of selective catalytic reduction (SCR) on Hunter Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
• As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.</td></tr>
<tr><td>5b</td><td><u>Huntington Units 1 and 2</u>
• The EPA’s final Regional Haze FIP for Utah requires the installation of SCR on Huntington Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
• As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.</td></tr>
<tr><td>5c</td><td><u>Dave Johnston Unit 3</u>
• The EPA’s final Regional Haze FIP requires the installation of SCR at Dave Johnston Unit 3 in 2019 or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. PacifiCorp’s commitment to the latter must be included in a permit before the 2019 compliance deadline.
• PacifiCorp will update its analysis of the commitment to shut down Dave Johnston Unit 3 by the end of 2027 as part</td></tr>
</table>

	of its 2017 IRP Update.
5d	**<u>Jim Bridger Units 1 and 2</u>** • The Wyoming Regional Haze State Implementation Plan (SIP) and EPA's final Regional Haze FIP for Wyoming require the installation of SCR on Jim Bridger Units 1 and 2 in 2021 and 2022. • PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units and will provide the associated analysis in its 2017 IRP Update.
5e	**<u>Naughton Unit 3</u>** • PacifiCorp will update its economic analysis of natural gas conversion in its 2017 IRP Update.
5f	**<u>Wyodak</u>** • Continue to pursue PacifiCorp's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.
5g	**<u>Cholla Unit 4</u>** • EPA has approved the Arizona SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025, with the option of natural gas conversion thereafter. • PacifiCorp will update its evaluation of Cholla Unit 4 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.
5h	**<u>Craig Unit 1</u>** • EPA is yet to approve the Colorado SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Craig Unit 1 as a coal-fueled resource by the end of 2025, with an option for natural gas conversion. • PacifiCorp will update its evaluation of Craig Unit 1 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update, as required.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous active action plan items documented in the 2015 Integrated Resource Plan and 2015 Integrated Resource Plan Update reports filed with the state commissions on March 31, 2015 and March 31, 2016, respectively. Many of these action items have been superseded in some form by items identified in the current IRP action plan. The status for all action items is summarized in Table 9.2.

Table 9.2 – 2015 IRP Action Plan Status Update

Action Item	Activity	Status
1a	**<u>Renewable Portfolio Standard Compliance</u>** • The Company will pursue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard targets through 2017. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2017. – With a projected bank balance extending out through 2027, defer issuance of RFPs seeking unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets until states begin to develop implementation plans under EPA's draft 111(d) rule, providing clarity on whether an unbundled REC strategy is the least cost compliance alternative for Oregon customers.	Consistent with the action plan in its 2015 IRP Update, which revised Action 1a, PacifiCorp issued a renewable resource and REC RFP in 2016. As a result of this RFP process, PacifiCorp executed REC purchase agreements in 2016 to acquire RECs eligible for the Washington, Oregon, and California RPS programs. For the California renewable portfolio standard requirements, the Company issued a REC RFP on March 13, 2017 with bids due April 3, 2017. Any offers that meet the Company's needs and specific pricing criteria will be selected and then submitted to the California Public Utilities Commission for review.
1b	**<u>Renewable Energy Credit Optimization</u>** • On a quarterly basis, and through calendar year 2016, issue reverse RFPs to sell 2016 vintage or older RECs that are not required to meet state RPS compliance obligations.	The Company issued a reverse RFP in December 2016 to sell RECs. The Company will continue to issue reverse RFPs in 2017 to seek REC sale opportunities for RECs allocated to states that do not have a state RPS

Action Item	Activity	Status
		compliance need.
1c	**<u>Oregon Solar Capacity Standard</u>** • Conclude negotiations with shortlisted bids from the 2013 Request for Proposals (RFP), seeking up to 7 MW of competitively priced capacity from qualifying solar systems that will be used to satisfy PacifiCorp's obligation under Oregon's 2020 solar capacity standard.	The Oregon Solar Capacity Standard was eliminated with the passage of Oregon Senate Bill 1547-B. This action item was deleted from the updated action plan presented in the Executive Summary of the 2015 IRP Update.
2a	**<u>Front Office Transactions</u>** • Acquire economic short-term firm market purchases for on-peak summer deliveries from 2015 through 2017 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month forward, balance of month, day-ahead, and hour-ahead non-brokered transactions.	For 2016, PacifiCorp acquired approximately 1,025 MW to 3,360 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2017, as of mid-March 2017, the Company has acquired approximately 450 MW to 700 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2018, as of mid-March 2017, the Company has not procured any short-term firm market purchases explicitly for delivery during the on-peak summer period.
3a	**<u>Class 1 DSM</u>** • Pursue a west-side irrigation load control pilot beginning 2016 to test the feasibility of program design. Additional information on the proposed pilot is provided in the implementation plan section of Appendix D in Volume II of the 2015 IRP.	On March 4, 2016, PacifiCorp filed with the Oregon Public Utilities Commission to implement an Irrigation Load Control pilot program. The pilot program was approved on May 4, 2016, and called its first event on August 19, 2016.

<table>
<tr><th>Action Item</th><th>Activity</th><th>Status</th></tr>
<tr><td>3b</td><td><u>Class 2 DSM</u>
• Acquire cost effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp’s implementation plan to acquire cost effective energy efficiency resources is provided in Appendix D in Volume II of the 2015 IRP.
<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr>
<tr><td>2015</td><td>551</td><td>133</td></tr>
<tr><td>2016</td><td>584</td><td>139</td></tr>
<tr><td>2017</td><td>616</td><td>146</td></tr>
<tr><td>2018</td><td>634</td><td>146</td></tr>
</table>
*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply side resource.</td><td>Initial review indicates that in 2015, PacifiCorp acquired 589 GWh of Class 2 DSM, 7 percent above the Action Plan target. Preliminary results for 2016 indicate PacifiCorp acquired 615 GWh of Class 2 DSM, 5 percent above the 2015 IRP target.</td></tr>
<tr><td>4a</td><td><u>Naughton Unit 3</u>
• Issue an RFP to procure gas transportation and resume engineering, procurement, and construction (EPC) contract procurement activities for the Naughton Unit 3 natural gas conversion in the first quarter of 2016.
• PacifiCorp may update its economic analysis of natural gas conversion in conjunction with the RFP processes to align gas transportation and EPC cost assumptions with market bids.</td><td>PacifiCorp updated its economic analysis for the 2017 IRP that reflects higher economic benefits to customers for PacifiCorp to continue to operate Naughton Unit 3 through year-end 2018 as a coal-fueled resource with a subsequent unit retirement. The Company will continue to analyze the economics surrounding Naughton Unit 3 retirement and/or natural gas conversion to achieve the most economic outcome for customers while complying with permits and compliance plans, as described in the 2017 IRP Action Items above.</td></tr>
<tr><td>4b</td><td><u>Dave Johnston Unit 3</u>
• The portion of EPA’s final Regional Haze Federal Implementation Plan (FIP) requiring the installation of selective catalytic reduction (SCR) at Dave Johnston Unit 3, or a</td><td>The Company’s commitment to shutting down Dave Johnson by the end of 2027 must be promulgated via permit prior to the 2019 compliance deadline. PacifiCorp will update its economic analysis of the commitment as</td></tr>
</table>

Action Item	Activity	Status
	commitment to shut down Dave Johnston Unit 3 by the end of 2027, is currently under appeal by the State of Wyoming in the U.S. Tenth Circuit Court of Appeals. • If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is upheld, PacifiCorp will commit to shutting down Dave Johnston Unit 3 by the end of 2027. • If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is or will be modified, PacifiCorp will evaluate alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.	part of its 2017 IRP Update.
4c	**<u>Wyodak</u>** • Continue to pursue the Company's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	PacifiCorp is still awaiting results of appeal of EPA's final regional haze FIP.
4d	**<u>Cholla Unit 4</u>** • Continue permitting efforts in support of an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025.	On March 16, 2017, Arizona Regional Haze State Implementation Plan was approved incorporating the alternative compliance approach described in this action item. The EPA's approval will be published in the Federal Register in the coming weeks and become effective thirty days after publication.
5a	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows:	PacifiCorp continues to fund the required federal agency permitting environmental consultant as actions to achieve final federal permits. – A final Environmental Impact Statement (EIS) for the

Action Item	Activity	Status
	– For Segments D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – For Segments D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.	Gateway South project, Segment F, was published May 2016 and the final Record of Decision was issued in December 2016. – A draft supplemental EIS for the deferred portions of Segment E for the Gateway West project was released in March 2016 and the final supplemental EIS was published in October 2016. A final Record of Decision was signed in January 2017. – The Record of Decisions and right-of-way grants contain many conditions and stipulations that must be met and accepted before the project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management to review progress. – PacifiCorp continues to support the Boardman to Hemingway project consistent with the project Joint Permit Funding Agreement. As a participant in the project PacifiCorp continues to collaborate with Idaho Power, the lead organization in the permitting process, by providing guidance of activities and plans associated with the permitting phase of the project.
5b	**<u>Wallula to McNary 230 kilovolt Transmission Line</u>** • Complete Wallula to McNary project construction per plan with 2017 expected in-service date. Continue to support the permitting process for Walla Walla to McNary.	Updates on the construction are as follows: – Received the Umatilla County Conditional Use Permit December 2015. – Received right-of-way agreement and grant from Bureau of Indian Affairs and Confederated Tribes of the Umatilla Indian Reservation in February 2017. – Continue permitting efforts with the Bureau of Land Management and the U.S. Fish and Wildlife agencies. – Bonneville Power Administration continues work on the studies and the development of the plan of service

Action Item	Activity	Status
		required to interconnect at the McNary substation. – Right-of-way appraisal work is scheduled for first quarter 2016. – Note that all permitting documentation as required by each agency has been submitted and that various agencies are working through their required processes.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define portfolio cost and risk analysis in the 2017 IRP. This analysis reflects a combination of specific planning assumptions related to CO_2 emission policies, compliance under the Clean Power Plan (CPP), potential Regional Haze compliance outcomes, state RPS compliance strategies, and DSM acquisition levels. PacifiCorp further analyzed sensitivity cases on planning assumptions related to load forecasts, private generation penetration levels, Energy Gateway transmission projects, and CO_2 emission policy variants. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2017 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 cost-effective renewable resources that qualify for federal income tax credits, FOTs, and energy efficiency resources are consistently selected. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2017 IRP shows that new renewable resource needs are driven economics, and potential CPP outcomes, and over the long-term, state RPS compliance requirements. Beyond load, the most significant driver affecting resource selection in the 2017 IRP are potential compliance outcomes related to future Regional Haze requirements that might trigger early coal unit retirements. CO_2 policy uncertainty, whether related to the CPP or some other future policy targeting electric sector emission reductions, also influences resource selections in the 2017 IRP. For these reasons, the acquisition path analysis focuses on load trigger events and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2017-2026) and long-term (2027-2036) 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."[1] 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. PacifiCorp uses the IRP and business plan to serve as decision support tools that can be used to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost. Table 9.3 summarizes PacifiCorp's 2017 IRP acquisition path analysis, which provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning

[1] 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.

environment will ultimately be reflected in future IRPs and will be incorporated in PacifiCorp's annual business planning process.

Table 9.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2017-2026)	Long Term Resource Acquisition Strategy (2027-2036)
Higher sustained load growth	High economic drivers and increased demand from industrial customers	• Increase acquisition of west side FOTs • Escalate acquisition of Class 2 DSM	• Increase acquisition of gas-fired thermal resources; accelerate acquisition of selected thermal resource by up to 5 years • Balance timing of thermal and renewable resource acquisition with FOTs and cost-effective Class 2 DSM energy efficiency resources • Increase acquisition of Class 2 DSM
Lower sustained load growth	Low economic drivers suppress load requirements with reduced demand from industrial customers	• Reduce acquisition of FOTs • Reduce acquisition of renewable resources	• Reduce and defer acquisition of gas-fired thermal resources • Balance timing of thermal resource and renewable acquisition with FOTs • Reduce Class 2 DSM energy efficiency resources (particularly in 2029)
Higher sustained private generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• Small reduction in acquisition of FOTs • Continue to pursue Class 2 DSM energy efficiency resources	• Reduce and defer acquisition of gas-fired thermal resources • Balance timing of thermal resource and renewable acquisition with FOTs and Class 2 DSM energy efficiency resources
Lower sustained private generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• Continue to pursue Class 2 DSM energy efficiency resources • Small increase in FOTs	• Accelerate acquisition of gas-fired thermal resources by four years (addition in 2029) • Balance timing of thermal resources with FOTs and cost-effective Class 2 DSM • Evaluate cost effective RPS compliance strategies in 2033-2036, including tradeoffs between increased renewable resource acquisition and use of compliance flexibility mechanisms like banking and use of unbundled RECs

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2017-2026)	Long Term Resource Acquisition Strategy (2027-2036)
State implementation of Clean Power Plan Mass Cap	Mass Cap C or D applied to PacifiCorp's system covering CO_2 emissions from existing and new fossil-fired generation beginning 2022	• Increase acquisition of Class 2 DSM resources • Balance timing of thermal resource acquisition and renewable resource acquisition with FOTs • Continue to pursue Class 2 DSM energy efficiency resources	• Increase acquisition of Class 2 DSM resources • Balance timing of thermal resource acquisition, Class 2 DSM resource acquisition and renewable resource acquisition with FOTs
New CO_2 policy replacing Clean Power Plan	Fossil-fired generation is faced with a CO2 emissions cost beginning in 2025 at $4.75/ton and reaching $38.02/ton by 2036	• Continue to pursue Class 2 DSM energy efficiency resources	• Procure increased renewable resource in 2029, increasing each year through 2036 • Balance timing of Class 2 DSM resource acquisition and renewable resource acquisition with FOTs
No CO_2 policy	Clean Power Plan and Washington CAR are never enacted; assumes no replacement policies are adopted	• Evaluate cost effective renewables strategies, including tradeoffs between renewable resource acquisition, REC purchases, and banking strategies	• Increased acquisition of fossil-fired assets offsetting decreased Class 2 DSM and FOT resources (particularly in 2028, concurrent with assumed Dave Johnston unit retirements) • Balance timing of thermal resource acquisition with reduced renewable, Class 2 DSM and FOT resources
Regional Haze outcome with varying coal retirements and emission controls	Potential Regional Haze inter-temporal and fleet trade-off compliance scenario with coal unit assumptions as defined in Regional Haze cases 1 through 4, and case 6 (see Volume I, Chapters 7 and 8)	• Balance timing of thermal and renewable resource acquisition with FOTs, cost-effective Class 2 DSM energy efficiency resources • Evaluate cost effective renewables strategies, including tradeoffs between renewable resource acquisition, REC purchases, and banking strategies	• Balance timing of thermal and renewable resource acquisition with FOTs, cost-effective Class 2 DSM energy efficiency resources • Evaluate cost effective renewables strategies, including tradeoffs between renewable resource acquisition, REC purchases, and banking strategies
Limited availability of FOTs	Eliminates availability of FOTs at NOB (100 MW) and Mona (300 MW) beginning 2019	• Continue to pursue Class 2 DSM energy efficiency resources	• Strategic REC and renewable resource acquisition to maintain RPS compliance, balanced with reduced FOTs and accelerated timing of thermal resource acquisition • Increase acquisition of Class 2 DSM resource

Procurement Delays

The main procurement risk is an inability to procure resources in the required timeframe to meet the least-cost, least-risk mix of resources identified in the preferred portfolio. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2017 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 there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where the Company is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below the target 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

Primary drivers in the resource differences between PacifiCorp's 2017 IRP and the 2015 IRP Update include decreased load forecasts and lower power prices. The 2017 IRP preferred portfolio assumes Naughton Unit 3 retires at the end of 2018, reflecting updated operating permits, instead of the end of 2017 as assumed in the 2015 IRP Update. The 2017 IRP preferred portfolio also assumes Cholla Unit 4 retires at the end of 2020 and Craig Unit 1 at the end of 2025. In the 2015 IRP Update, the preferred portfolio assumed Cholla Unit 4 would continue operating through the end of 2024 and that Craig Unit 1 would continue operating through the end of 2034. Finally, the 2017 IRP includes an updated DSM conservation potential assessment, which, when combined with an updated load forecast, informs changes to DSM acquisition targets relative to the 2015 IRP and 2015 IRP Update. Other changes in the portfolio reflect changes to renewable resource acquisition levels driven by investment in new transmission infrastructure and availability of federal income tax incentives.

Table 9.4 compares the 2017 IRP preferred portfolio with the 2015 IRP Update portfolio for the front ten years of the 2017 IRP planning period (2017-2026). The table shows year-by-year capacity differences by major resource categories (yellow highlighted table).

Table 9.4 – Comparison of the 2017 IRP Preferred Portfolio with the 2015 IRP Update Portfolio

2017 IRP vs 2015 IRP Update

2017 IRP Preferred Portfolio

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		154	128	131	122	123	114	118	118	112	111	**1,229**
DSM - Load Control		-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind		-	-	-	-	1,100	-	-	-	-	-	**1,100**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	**1,128**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	-	(280)	-	(387)	-	-	-	-	(82)	**(749)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-	-	-	

Study includes Naughton 3 retirement at the end of 2018

FOT in resource total are 10-year averages, and include Winter FOTs in the 2017 IRP.

2017 IRP Preferred Portfolio less 2015 IRP Update

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		16	(19)	(27)	(21)	(27)	(41)	(43)	(45)	(23)	(24)	**(254)**
DSM - Load Control		-	-	-	-	-	-	-	-	(39)	(24)	**(63)**
Renewable - Wind		-	-	-	-	1,100	-	-	-	-	-	**1,100**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		33	(241)	(95)	(88)	148	163	185	179	(51)	(111)	**12**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	280	(280)	-	(387)	-	-	-	387	(82)	**(82)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**(886)**	**(960)**	**(1,403)**	**(1,345)**	**(1,120)**	**(1,215)**	**(1,126)**	**(1,155)**	**(1,227)**	**(1,600)**	

FOT in resource total are 10-year averages

2015 IRP Update

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	128	138	146	158	142	149	155	161	162	135	136	**1,483**
DSM - Load Control	-	-	-	-	-	-	-	-	-	39	24	**63**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	1,440	**1,116**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	(280)	-	-	-	-	-	-	(387)	-	**(667)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,031	**886**	**960**	**1,403**	**1,345**	**1,120**	**1,215**	**1,126**	**1,155**	**1,227**	**1,600**	

Study includes Naughton 3 gas conversion in 2015

FOT in resource total are 10-year averages

Table 9.5 compares the fall 2016 ten-year business plan portfolio with the 2017 IRP preferred portfolio. Differences between the two portfolios are driven by changes to coal unit retirement and natural gas conversion assumptions, changes to load projections, updated DSM supply curve assumptions, and changes to renewable resource costs driven by the availability of federal income tax incentives. The 2017 IRP preferred portfolio assumes Naughton Unit 3 retires at the end of 2018, reflecting updated operating permits, instead of a natural gas conversion implemented by the summer of 2018 as assumed in the fall 2016 business plan. The 2017 IRP preferred portfolio also assumes the retirement of both Cholla Unit 4 at the end of 2020 and Craig Unit 1 at the end of 2025. In the fall 2016 business plan, the resource portfolio assumed Cholla Unit 4 would continue operating through the end of 2024 and that Craig Unit 1 would continue operating through the end of 2034. Finally, the 2017 IRP includes an updated DSM conservation potential assessment, which, when combined with an updated load forecast, informs changes to DSM acquisition targets relative to the fall 2016 business plan. Other changes in the portfolio reflect changes to renewable resource acquisition levels driven by investment in new transmission infrastructure and availability of federal income tax incentives.

Table 9.5 – Comparison of the 2017 IRP Preferred Portfolio with the Fall 2016 Business Plan Portfolio

2017 IRP vs Fall 2016 Ten-Year Business Plan sensitivity

2017 IRP Preferred Portfolio

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		154	128	131	122	123	114	118	118	112	111	**1,229**
DSM - Load Control		-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind		-	-	-	-	1,100	-	-	-	-	-	**1,100**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	**1,128**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	-	(280)	-	(387)	-	-	-	-	(82)	**(749)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Study includes Naughton 3 retirement at the end of 2018
FOT in resource total are 10-year averages

2017 IRP Preferred Portfolio less Fall 2016 Ten-Year Business Plan sensitivity

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		(4)	(29)	(17)	-	1	-	(0)	(1)	(6)	-	**(56)**
DSM - Load Control		-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind		-	-	-	-	650	-	-	-	-	-	**650**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		(10)	(250)	263	317	219	219	219	220	225	225	**165**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	(285)	-	-	-	-	-	-	-	**(285)**
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**(949)**	**(1,260)**	**(1,041)**	**(919)**	**(1,084)**	**(1,118)**	**(1,049)**	**(1,071)**	**(1,282)**	**(1,133)**	

FOT in resource total are 10-year averages

Fall 2016 Ten-Year Business Plan sensitivity

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		158	157	148	122	122	114	118	119	118	111	**1,286**
DSM - Load Control		-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind		-	-	-	-	450	-	-	-	-	-	**450**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		791	1,103	887	798	899	1,004	931	952	1,165	1,104	**963**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	-	(280)	-	(387)	-	-	-	-	(82)	**(749)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	285	-	-	-	-	-	-	-	**285**
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**949**	**1,260**	**1,041**	**919**	**1,084**	**1,118**	**1,049**	**1,071**	**1,282**	**1,133**	

Study includes Naughton 3 gas conversion at the end of 2018
FOT in resource total are 10-year averages

PacifiCorp's 2017 IRP preferred portfolio will serve as the starting point for resource assumptions in the fall 2017 ten-year business plan. Changes to the portfolio may be influenced by assumptions such as updated load forecast inputs, updated price curve inputs, an updated load and resource balance, and updated environmental policy developments.

Resource Procurement Strategy

To acquire resources outlined in the 2017 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, 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, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with business planning goals in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2017 IRP action plan.

Renewable Resources

PacifiCorp uses competitive request for proposals (RFPs) to procure renewable resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. The renewable resource RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

The Company uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-side Management

In 2016, through competitive procurement processes, the Company selected vendors to continue and adaptively manage the successful, cost-effective delivery of its two largest Class 2 DSM programs: Home Energy Savings and wattsmart Business. In 2017, The Company will evaluate and re-procure, as appropriate, the delivery contract(s) for residential behavior program(s).

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp 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, PacifiCorp is in a better position to control costs, make life extension improvements, as being implemented with the wind repower project analyzed in the 2017 IRP, 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 embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself from the uncertainty of the ability to perform consistent with the terms and conditions outlined in a power purchase agreement over time.

Depending on contract terms, purchasing power from a third party in a long term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power purchase agreement 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 PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures that might be cost-effective and practical from operational and regulatory perspectives. As evident in the 2017 IRP, known and prospective environmental regulations can impact utilization of resources and investment decisions.

Under the CPP, compliance strategies will be affected by how states choose to implement the rule and on-going legal challenges to the rule. Alternative policies could impute a carbon tax or implement a cap-and-trade framework. 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. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include early retirement, changes in plant dispatch, changing the fuel type, repowering with more efficient generation equipment, lowering the plant heat rate so it is more efficient, and adoption of new technologies such as CO_2 capture with sequestration, when commercially proven. Indirectly, plant CO_2 emission risk can be addressed by acquiring offsets or other environmental attributes that might become available in the market. Under an aggressive CO_2 regulatory environment, and depending on fuel costs, coal plant idling and replacement strategies may become tenable options.

High CO_2 costs would shift technology preferences both for new resources and existing resources to those with more efficient heat rates and also away from coal, unless carbon is sequestered. There may be opportunities to repower some of the existing coal fleet with a different less carbon-intensive fuel such as natural gas, as has been evaluated for the Naughton Unit 3 and Cholla Unit 4 generating units. An ongoing consideration 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 PacifiCorp 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) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; (2) reduce volatility of net power costs for PacifiCorp's customers. The purpose is solely to reduce customer exposure to net power cost volatility and adverse price movement. PacifiCorp does not engage in a material amount of proprietary trading activities. 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. PacifiCorp 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 Company representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the president of Pacific Power, who ultimately must approve any change to the risk management policy. PacifiCorp'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 PacifiCorp 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, PacifiCorp 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, PacifiCorp'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. PacifiCorp 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 PacifiCorp's hedging activities is documented in the Company's Risk Management Policy. In May 2010, PacifiCorp 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, PacifiCorp 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 PacifiCorp's longer-dated hedge activity, *i.e.*, four years forward on a rolling basis.

As a result of the hedging collaboratives, PacifiCorp made the following material changes to its policy in May 2012: (l) 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 l2-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. PacifiCorp 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. PacifiCorp 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, PacifiCorp 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. PacifiCorp 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, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default. In addition, PacifiCorp 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

PacifiCorp 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. PacifiCorp 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. Analysis has shown 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. PacifiCorp'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.

PacifiCorp's hedge program does not rely on a long power position. However, the Company's hedge program takes into account its 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.

PacifiCorp'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 producing 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. PacifiCorp 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.

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 emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp’s 2017 IRP portfolio development and evaluation process. The Company’s use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp’s resource investments determined to be prudent by state commissions is a risk borne by customers.